Northern Gas Networks

Long term development statement

2024

we are the network

Foreword

Welcome to our Long Term Development Statement 2024. This document provides essential information on the process for planning the development of the gas distribution system, which includes demand and supply forecasts, system reinforcement projects and associated investment. We publish the report at the end of our 2024 planning process for our two Local Distribution Zones, the North East and Northern. The main body of the document provides an overview of the key topics, with further details contained in the appendices.

At the time of publishing this report we are halfway through our fourth year of our RIIO-GD2 price control period and working hard to meet our license requirements and outperform our targets. The past twelve months has been another challenging time for many of our customers and communities. The energy supply and security crisis and increased cost of living continued to have an impact even as inflation has eased. This will have impacted the typical upturn of demand through the winter of 2023/24.

Innovation remains more important than ever in supporting delivery of our overarching objectives to provide a safe, reliable gas service; support the transition to net zero; continue to modernise our operations and provide help to our vulnerable customers. Over the past year, we have looked towards the future and explored the ways we can drive down the costs of alternative energy solutions and most effectively repurpose our network. Innovative solutions and technologies will enable us to keep pushing boundaries, explore and develop new energy sources, and improve how we better support our vulnerable customers both now and in generations to come.

As we look ahead, we are incredibly excited about building on the challenging work delivered by our colleagues throughout the network this year. We remain resolute that the only way to meet net zero targets is through a whole systems approach.

We are proud of all these achievements as we continually seek to further improve the service we provide to today’s customers and plan to deliver a net zero future.

P Bolton

Paul Bolton

Director of Programme Management

Version & Circulation

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This document, and any updates to this document will be circulated electronically and uploaded to our website.

Disclaimer

The Long-Term Development Statement provides a ten-year forecast of transportation system usage and likely system developments that can be used by companies contemplating connecting to our system or entering into transport arrangements, to identify and evaluate opportunities.

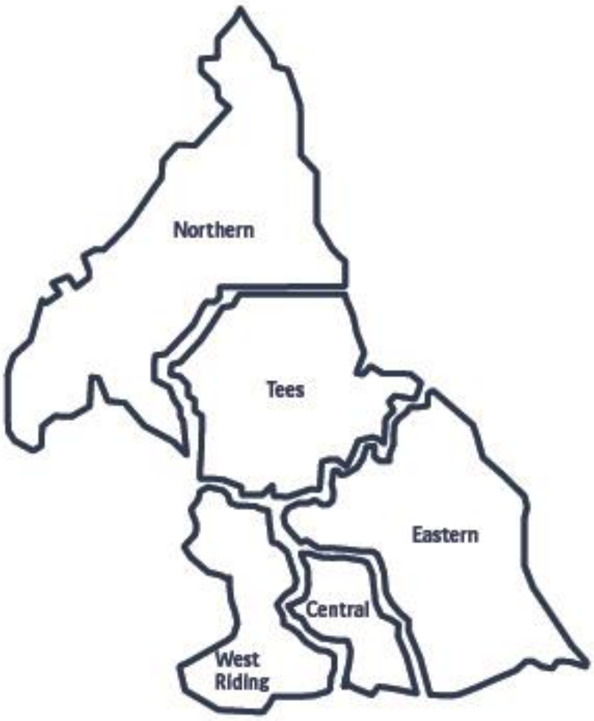
This document is not intended to have any legal force or to imply any legal obligations regarding capacity planning, future investment and resulting capacity.

Background & Context

The Long-Term Development Statement is the product of an annual cycle of planning and analysis. The statement sets out our assessment of future supply and demand for natural gas on our network. It also outlines proposals for investment in our local transmission and distribution systems. Interested parties may use this information to gain an understanding of how we expect gas demand to evolve on our networks over the next 10 years. This will help them plan accordingly when considering connection opportunities.

We are required to publish this annual statement in accordance with Standard Special Condition D3 of our Gas Transporters Licence and Section 4.1 of the Uniform Network Code Transportation Principal Document.

Northern Gas Networks (NGN) manages the development, operation and maintenance of the High Pressure and below 7bar Distribution Networks. These extend from the inlet valves of the pressure regulating installations at the National Transmission System interface, to the outlet of the consumer's emergency control valve in the North East of England, Northern Cumbria and West, North and East Yorkshire. The below map summarises the extent of NGN's two Local Distribution Zones (LDZs):



LDZ	No.	Location
Northern (NO)	1	Northern
	2	Tees
North East (NE)	3	Eastern
	4	Central
	5	West Riding

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Chapter 1

Demand

Chapter 1 - Demand

1.1 Demand Forecasts Overview

This chapter outlines the ten-year gas demand forecast for each Local Distribution Zone (LDZ) within NGN, including both the annual and 1 in 20 Peak day gas demands. It also includes discussion on how current forecasts relate to previously published forecasts. Further information is provided in Appendix 2.

Demand forecasts are prepared as part of an exchange of information that is intended to inform respective capacity planning processes between the Gas Distribution Networks and National Gas. These forecasts are compliant with the demand forecasting requirements of Section H of the Uniform Network Code (UNC) Offtake Arrangements Document.

1.2 Demand Forecasts

1.2.1 Annual Demand

This section provides an outline of our latest annual gas demand forecasts up to and including gas year 2033/34 along with the key underlying assumptions. A more detailed view can be found in Appendix 2.

Annual demand forecasts are produced without the knowledge of future weather conditions. Consequently, we use past data (historical averages) to estimate what future temperature would be under seasonal normal conditions. To compare demand data between years, we adjust our estimates to account for the variance of actual weather and seasonal normal temperature. This adjustment is called ‘weather corrected demand’.

The annual demand forecasts are based on analysis of how historic weather corrected demand is influenced by non-weather factors such as the economy, environmental and efficiency initiatives and how the most influential factors are likely to change in the future. Evidence suggests that the most influential factor that determines gas demand annually, after weather, is its price. The largest single components of customer bills are gas and electricity wholesale prices. The wholesale gas prices rose steeply through 2021 and this continued through 2022. From early 2023 prices reduced considerably, levelling to an average price around 20% lower than the average price for 2021. Prices in early 2024 reduced again by another 25%. This was due the UK’s strong position on gas supplies; mainly from increased LNG; and was alongside high European storage supply levels. However, this is still around 50% higher than the prices of early 2021, before prices began to rise from their historical levels, and is due mainly to the increase in cost of sourcing gas from outside of Russia as a result of the conflict in Ukraine and market concerns around events in the middle east, alongside an underlying increase in economic activity post covid. In spring 2024, when the forecast was produced, prices have shown a consistent but slow increase, but still remain below levels of the previous year, due to some of the aforementioned factors. The average gas price was 122p/th in 2021, increasing to 203p/th in 2022, before reducing to 102p/th in 2023 and 75p/th from January to August 2024.

In our demand forecast we assumed that gas prices would stabilise, then continue to steadily decrease, therefore annual gas demand was forecast to increase by 16% over the next 10 years in the NGN networks. It is important to contextualise this, as almost all of this growth is recovery from the 12% reduction in gas demand experienced in the NGN networks since the cost of living crisis began in 2021. This mainly affected the domestic sector, which accounts for 57% of our total demand. This was almost all due to behaviour change, as households reduced their expenditure by using their heating less as they had less disposable income and gas prices have also increased.

Our forecast of decreasing gas prices and increasing household disposable income results in domestic behaviour returning to pre cost of living levels by 2031 in the North East LDZ and 2032 in the Northern LDZ. It then increases slightly above this at the end of the forecast period. This results in domestic demand being only 2% higher than the pre cost of living crisis demand of 2021. A large proportion of this 2% is also for new houses forecast to connect to our network.

When domestic demand is added to the forecast for the non domestic sectors, total gas demand in our networks is forecast to be only 1.2% higher at the end of our forecast period than it was in 2021.

Economic indices that underlie large parts of our forecasts continue to remain uncertain, with gas prices arguably the most difficult to forecast. Since our forecast has been produced, gas price reductions experienced in early 2024 have reversed to small increases. These would limit the increase in our forecast further, if they continue.

As economic uncertainties exist, our approach to forecasting splits out non economic factors where possible and forecasts them separately. Contributary factors to the decline in gas demand are thermal efficiency improvements in residential housing, combined with the switch to renewable heat. Factors that potentially increase demand are the changing number of network supply points from new connections. These are all forecast separately and are then combined with the economic forecasts to produce a joined up granular forecast.

Analysis of recent domestic thermal efficiency improvements and switch to renewable heat, shows little impact on the forecast. Both factors have mainly been driven by government schemes. These have all been assessed and incorporated in the forecast. Whilst new schemes and increased budgets for both have occurred in the last couple of years, and their most recent performance is included in the forecast, their overall impact on gas demand is limited.

Overall, thermal efficiency reduces domestic gas demand in the forecast by 1.1%, and the switch to renewable heating reduces gas domestic demand by 0.4 % over the forecast period.

All factors combined result in an average annual increase over the whole forecast period of 1.7% for our North East LDZ and 1.4% for our Northern LDZ. As previously stated, most of this is recovery from reductions in demand in 2022 and 2023. Compared to 2021 demand levels, our North East LDZ is 2.8% higher at the end of the forecast period and Northern LDZ is 0.7% below. In the Northern LDZ the small reduction is due to demand from some of our largest customers not forecast to recover to 2021 levels.

Load Band	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
0-73 MWh	35.9	38.2	38.1	38.0	38.4	38.9	39.1	39.4	39.7	40.0
73-732 MWh	5.0	5.0	5.1	5.1	5.1	5.1	5.1	5.0	5.0	5.0
732-5860 MWh	3.7	3.7	3.8	3.8	3.8	3.8	3.9	3.9	3.9	4.0
Small User	44.6	47.0	46.9	46.9	47.3	47.8	48.1	48.3	48.6	49.0
Firm> 5860 MWh	19.2	19.3	19.5	19.6	19.7	19.8	20.0	20.1	20.3	20.5
NGN Consumption	63.9	66.3	66.4	66.5	67.0	67.7	68.1	68.5	68.9	69.4
NGN Shrinkage	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
NGN Demand	64.1	66.5	66.6	66.7	67.2	67.9	68.3	68.7	69.2	69.7

Table 1.2.1 NGN's forecast annual demand by load category & calendar year (in TWh)
Note: Figures may not sum exactly due to rounding.

The chart below illustrates the actual annual throughput and our most recent forecasts through to the end of our RIIO GD2 price control[1] period.

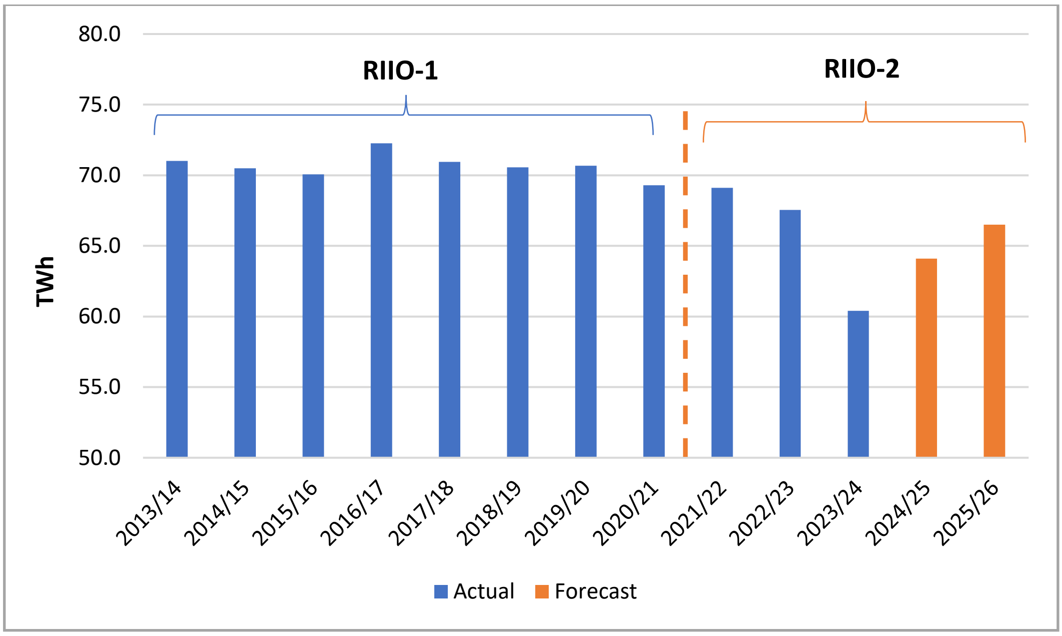

Figure 1.2.2 RIIO GD1/GD2 historic annual demand and forecast RIIO GD2 annual demand

1.2.2 Forecast Accuracy

Table 1.2.3 below provides a comparison of actual and weather corrected throughput during the 2023 calendar year with the forecast demands presented in our 2023 plan. Annual forecast demands are presented in the format of consumption load bands/categories, consistent with the basis of system design and operation.

Load Band	Actual 2023	Weather Corrected 2023	Forecast for 2023	Weather Corrected v Forecast (%)
0-73 MWh	31.45	33.80	38.53	-12.3
73 – 732 MWh	4.70	4.94	5.21	-5.1
>732 MWh	21.01	21.33	24.34	-12.4
Network Shrinkage	0.28	0.28	0.28	2.4
NGN Network Total	57.47	60.40	68.35	-11.6

Table 1.2.3 Comparison of actual and weather corrected throughput in 2023 calendar year (TWh)
Note: Figures may not sum exactly due to rounding.

[1] RIIO GD2 Price Control https://www.ofgem.gov.uk/publications/riio-2-final-determinations-transmission-and-gas-distribution-network-companies-and-electricity-system-operator

On a Network basis, the weather corrected annual throughput in 2023 was 60.40 TWh. This shows a decrease of -11.6% from the 2023 forecast.

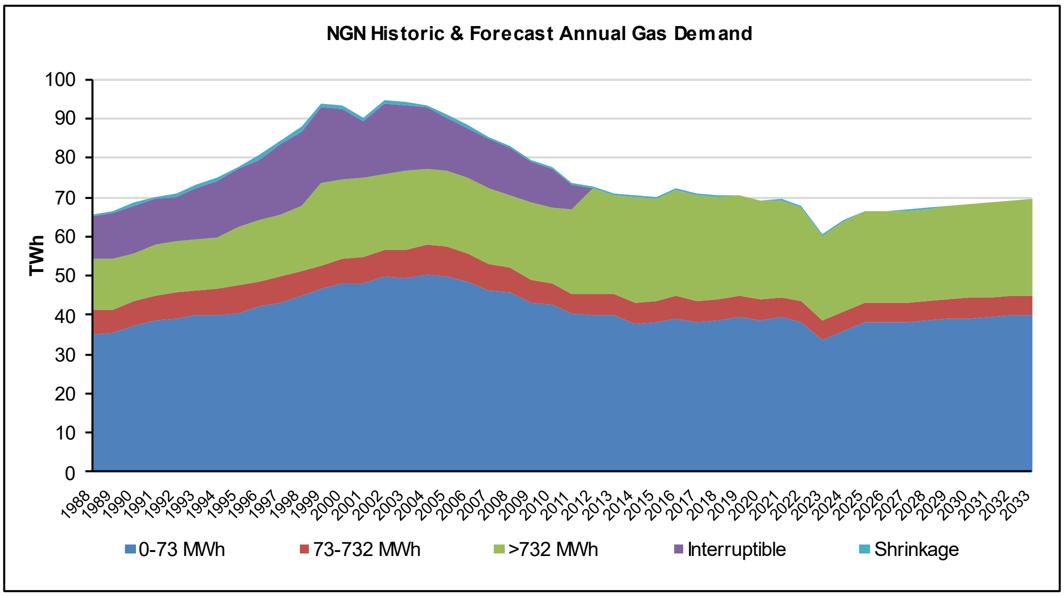

Figure 1.2.4 Historical Weather Corrected Throughput & Forecast Annual Gas Demand by Load Band

The chart above shows weather corrected and forecast gas demand by load band through to 2033. The most significant change in this chart is the change in the Interruptible load in 2011. Following a modification in UNC Interruption Arrangements (Mod 90), which came into effect 01 October 2011, interruptible contracts were only made available at specific supply points where NGN had identified an area in which interruption was necessary. This change to the Interruption process resulted in a significant reduction in Interruptible Load.

1.2.3 Peak Forecast Demand

NGN is required to forecast 1 in 20 Peak day demand on an annual basis. We maintain and operate our network to be able to satisfy this level of demand, as defined in Uniform Network Code section W2.6.4(c):

1 in 20 Peak day demand - 1 in 20 peak day demand is the level of daily 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.

Peak demand is calculated using an established industry methodology[2] and is based on determining the weather-demand relationship for each loadband in each LDZ. Smaller loadbands, which tend to represent households and smaller businesses, are much more weather sensitive than larger loadbands. This is because they tend to use most of their gas for space heating rather than industrial processes which aren't linked to weather.

The forecast 1 in 20 peak day demand in the 2024/25 gas year is 0.1% lower than the forecast made in 2023. Overall, peak demand is forecast to increase by 0.12% over the 10-year period within our Northern LDZ and 0.04% in our North East LDZ.

This compares with an increase of 0.09% and 0.23% respectively, for these LDZs in the 2023 forecast. As we move into the winter of 2024/25, we are gaining a better understanding of the impact of the large increase in

[2] Further information can be found here: https://www.nationalgas.com/connections/national-transmission-system-connections

the gas prices, which reached record levels in 2022, and have since reduced, but remain considerably higher than seen prior to 2021. We have seen they have had a higher impact on gas demand in the domestic compared to the non domestic sectors.

In the domestic sector, there have been two main factors influencing demand.

Since the cost of living crisis began in 2022, we have seen daily demands become more sensitive to weather especially at lower temperatures. This offsets some of the reduction in annual demands, and is the reason for our assumption to remove behaviour change due to the cost of living from our domestic peak demand assessment. The assumption underlying this in our current forecast is that at times of really low temperatures, the requirement to stay warm would override the requirement to save money. Whilst the temperature has not been low enough to fully test this, the increased weather sensitivity observed in cold conditions corroborates the assumption in our forecast that as weather gets colder there is a greater cold weather upturn. This is why we have removed behaviour change that exists due to increased cost of living in our annual forecast, from our peak forecast. This assumption becomes less prevalent after the first few years of the forecast, as the impacts of the cost of living crisis become less relevant in the forecast; with our LDZs forecast to return to the 2021 comfort levels towards the end of the forecast period.

The following table summarises our 1 in 20 peak day forecasts for the period 2024/25 to 2033/34. These are the forecasts for each gas year covering the period 1st October to 30th September.

1 in 20 Peak day Demand (GWh)										
LDZ	**2024/25**	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**2030/31**	**2031/32**	**2032/33**	**2033/34**
North	222	222	222	222	222	222	222	222	222	222
North East	261	261	261	261	261	261	261	261	261	261
Total	483	484	483	483	483	483	483	483	483	483

Table 1.2.5 Forecast 1 in 20 Peak day Firm Demands by LDZ from the 2024 Demand Statements (GWh)

Note: *Figures may not sum exactly due to rounding*

The chart below illustrates the historic peak day demands from RIIO GD1/GD2, and the RIIO GD2 forecasts. Prior to GD1 the highest demand in recent years was seen in the winter of 2010/11.

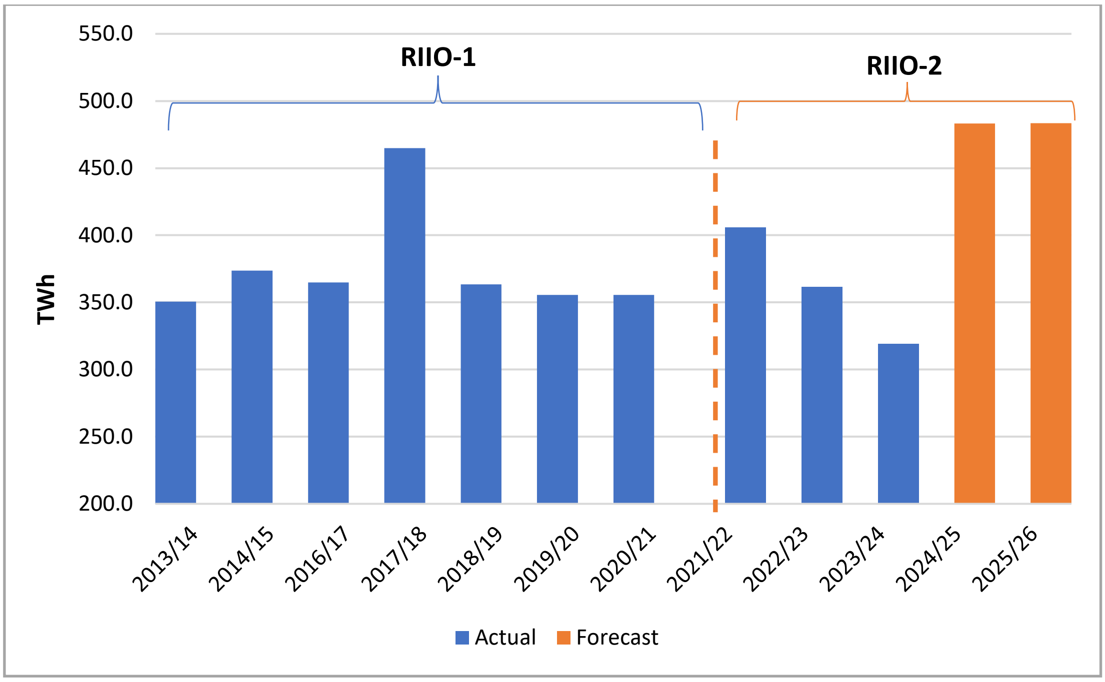

Figure 1.2.6 Historic Peak day Demand Actuals and RIIO GD2 forecasts (GWh)

National Energy System Operator (NESO) carry out Future Energy Scenarios (FES) for both transmission and distribution networks, which are supplied to distribution networks in May each year. The FES outline four different pathways for the future of energy over the next 30 years. A five-year central forecast is also supplied. Each pathway considers how much energy we might need and where it could come from.

Comparisons are undertaken with the data received in previous years to understand how NESO drivers are changing. There is a great deal of variance across the pathways and the drivers are dependent on factors such as policy surrounding the decarbonisation of heat, the state of the economy, societies willingness to change and advancements in technology. NESO may apply diversity so that the national generation figure reflects national requirements whereas the distribution network will book sufficient capacity for our large loads to operate at a 1:20 in line with their bookings without making assumptions about which loads NESO would call into operation. NESO also assume behaviour change does not return to 2021 levels in two of their four pathways and they may assume the annual to peak relationship remains unchanged; both of these are different to the outcomes of our forecast. More information can be found at

https://www.neso.energy/publications/future-energy-scenarios-fes/

Impact assessment will continue to be undertaken and form part of the future NGN forecasts and FES outcomes.

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Chapter 2

Supply and storage

we are the network

Chapter 2 - Supply & Storage

2.1 Supply

Gas is predominantly brought into our network through offtakes connected to the National Transmission System (NTS). Offtakes are above ground installations (AGIs) that connect the NTS to NGN's Local Transmission System (LTS). NGN's offtakes can operate to an inlet pressure of up to 85bar. From the offtake, gas then passes through the Local Transmission System, into the Distribution System and then onward to consumers.

We develop the network to meet our customers' requirements. National Gas will also develop the NTS in line with supply and demand forecasts, provided by us and used in conjunction with their own demand forecasts of network demand. The National Gas Ten Year Statement can be found on their website[3].

The amount of gas NGN requires to satisfy its 1 in 20 peak day demand commitment is secured from National Gas on an annual basis via an offtake capacity booking process. This process involves our network modelling team using the 1 in 20 forecasts at the Local Distribution Zone (LDZ) level to derive a booking quantity at each of our offtakes to satisfy demand at the local level. NGN then request a daily energy quantity and a volume of storage for each of the offtakes. We also indicate the peak hourly flow and associated minimum inlet pressure required. Following discussion between the two parties, National Gas will allocate the capacity and our Control Room will operate the system accordingly.

Over the course of RIIO GD2 we have optimised our capacity bookings to 1 in 20 peak day forecast levels. Historically, capacity was held at levels that were in excess of current demand levels, mainly due to demand levels being higher in the past. In order to reduce our customer bills and free-up capacity on the National Transmission System for other users, we have made significant changes to reduce and optimise our bookings at each of our offtakes. We comply with the Exit Capacity Planning Guidance which is available here: **Exit Capacity Planning Guidance**, and NGN's Exit Capacity Planning Guidance can be found on NGN's Document Library online, in the Safe & Reliable section: **Document Library** The Exit Capacity regime as we know it was under review and we are supporting and encouraging positive regime changes which will allow us to run an even more efficient network for our customers.

2.2 Distributed Network Entry

We are committed to enabling the connection of biomethane and other low carbon gases to our network to support the transition to a flexible, low carbon energy system and enable net zero by 2050. To date we have 19 biomethane connections to our network. It is of note that the development of new biomethane sites is significantly influenced by the availability of government subsidies / incentives. The Green Gas Support Scheme (GGSS), which launched in autumn 2021 will be open to applications until March 2028.

We continue to regularly engage with our connected biomethane production sites as part of business as usual and work closely with producers to enable them to maximise their gas injection volumes and minimise down time.

We are actively involved the Entry Customer Forum and the Entry Technical Workgroup. The purpose of these groups is to drive standardisation, streamlining and continuous improvement of the connections process across the GDNs and thereby improve outcomes for producers. We are confident in our mature connections process but see value in promoting knowledge and best practice sharing between GDNs to the benefit of potential connections customers.

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[3] https://www.nationalgas.com/insight-and-innovation/gas-ten-year-statement-gtys

We are also still receiving a healthy number of requests for detailed analysis relating to available injection capacity in areas of our network, with a handful of enquires reaching the connection reservation stage. We hope to see some of these projects move forward to build and commissioning in the coming years.

2.3 Storage in the Network

2.3.1 Linepack

The compressibility of natural gas allows the use of linepack to compensate for fluctuations of gas demand. Linepack refers to the volume of gas that can be 'stored' in the gas pipeline during periods of low demand when the pressure in the system is lower. When demand increases this stored gas can be released to ensure supply to consumers. Linepack is of strategic importance to NGN in the absence of physical storage vessels such as gas holders.

Chapter 3

Investment in the Distribution Networks

Chapter 3 - Investment in the Distribution Networks

The Local Transmission System is designed to transport gas across our network and store it for the purposes of satisfying the 1 in 20 peak day forecast demands. The system is developed, based on demand and supply forecasts, to ensure that this capability is maintained. This routinely involves significant investment projects to improve efficiency, system design and replace ageing equipment.

We will continue to develop and invest in our networks to operate a safe and efficient network and to meet current and future customers' requirements and operating behaviours.

3.1 Below 7barg Distribution System

The NGN below 7barg system is designed to operate between levels of pressure defined by statute, regulation and safe working practices.

We also continue to invest in the replacement of our transportation network assets, primarily for the renewal of mains and services within Distribution systems. This includes expenditure associated with decommissioning of mains and services to a programme agreed with the Health and Safety Executive. This covers the decommissioning of all smaller-diameter iron gas pipes (Tier 1: 8 inches and below) within 30 metres of occupied buildings before April 2032, and the progressive decommissioning of larger iron pipes based on their risk and condition.

Mains Workload (km)	21/22	22/23	23/24	24/25	25/26	TOTAL	ALLOWED
Tier 1	437.4	430.4	469.6	442.3	406.9	2,186.5	2,144.3
Tier 2a	3.2	1.6	0.8	0.5	2.0	8.2	10.1
Tier 2b	19.1	17.7	24.6	21.7	18.9	102.0	102.0
Tier 3	5.3	5.4	5.5	5.8	6.2	28.1	22.7
Iron Mains (ex. >30m)	464.9	455.0	500.5	470.3	434.0	2,324.8	2,279.2
Steel <2"	45.4	33.0	36.0	44.0	44.0	202.4	218.9
Other	35.8	31.0	40.2	42.7	42.7	192.4	189.8
Diversions	11.1	9.4	13.2	13.3	13.3	60.3	56.6
Total	557.3	528.4	590.0	570.3	534.0	2,779.9	2,744.4

This year we have delivered a total of 590.0 km of mains abandonment.

The **Tier 1 Mains** target is 2,144.3km over RIIO-2, or 428.9km per annum. Over RIIO-2 we plan on delivering 2,186.8km, or 437.4km per annum. This is an increase of 8.5km each year, 42.5km over the 5 years. This will allow us to recover the Covid-19 related shortfall of workload seen in the final year of RIIO-1 by the end of the Repex programme in 2032. This increased workload will be funded under the Tier 1 Mains volume driver. This year we abandoned 469.6km of **Tier 1 Mains**, 32.2km above our annual target.

Tier 2a Mains are also subject to a volume driver as the workload is very difficult to predict. We expect to deliver 8.2km over RIIO-2.

We are on track to deliver the allowed workload for **Tier 2b** and **Tier 3 Mains**, as well as **>2" Steel** by the end of RIIO-2.

We expect to deliver broadly in line with the allowed **<2" Steel mains** commissioned workload over the price control, however we will likely under deliver against the decommissioned targets. Volumes are likely to vary year on year as the majority of this mains type is replaced when we find it whilst replacing Tier 1 iron mains. The under delivery on decommissioned targets is due to a combination of the lay to abandon ratio used as part of RIIO-2 planning, and the volume of these main found as part of Tier 1 replacement schemes.

4

Chapter 4
Innovation

Chapter 4 - Innovation

4.1 Gas in Our Future Energy Systems

In March 2024, the gas networks, in collaboration with the Energy Networks Association (ENA) published their latest Energy Networks Innovation Strategy for network innovation projects and priorities. This latest strategy expanded on the previous success' associated with the prior inaugural strategy set out in 2022, to reflect the latest net zero policy and technology developments.

Network innovation projects are essential to provide critical evidence and understanding to support the energy systems transition and ensure that impact on customers in vulnerable situations is clearly understood to help deliver increased efficiency and value for money, and develop the new technologies and approaches needed for decarbonisation. The gas networks collaborate to share learnings and ensure that projects are delivering industry and government goals.

You can find out more information about individual projects at the **Smarter Networks Portal** and via NGNs latest **Annual Innovation Summary**.

In addition to the strategy documents, we have worked in partnership with the ENA and electricity DNO's to produce the Energy Networks Innovation Process (ENIP[4]). As part of the Ofgem requirement for RIIO-2 price control, this industry-led reporting and collaboration process was put in place. This process is followed by all Energy Networks, formally in place and operational for RIIO-2 on 1 April 2021. ENIP is scheduled to be reviewed at least every two years, with the latest version published in March 2023. This document contains the full details of the end-to-end industry led process for reporting, collaboration, and dissemination of Ofgem funded Network Innovation Allowance (NIA) projects in GB. This process has been presented to Ofgem and external stakeholders, and feedback from these groups have been incorporated.

The latest versions of the Energy Networks Innovation Strategy and Energy Networks Innovation Process can be found in the following link: https://smarter.energynetworks.org/enip/

The RIIO-T2 and RIIO-GD2 price controls, which apply from April 2021, include a new mechanism called the **Strategic Innovation Fund (SIF)** detailed in section 4.2.

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4 https://smarter.energynetworks.org/enip/

East Coast Hydrogen

East Coast Hydrogen is a collaborative project between Northern Gas Networks, Cadent and National Gas, which over the next 15 years, plans to utilize the existing gas distribution and transmission networks to connect planned hydrogen production and storage with industrial and large commercial gas users. This strategic move not only aims to secure jobs and investment in the region but also support industrial decarbonisation. The programme will leverage the natural assets of the North of England, including existing and potential hydrogen storage facilities, and build on the hydrogen production in two of the UK's largest industrial clusters in Teesside and the Humber. This will not only ensure significant private sector investment in the UK's industrial heartlands but also stimulate further investment. Details of the project can be found in its Delivery Plan.

It will be the first major step in converting gas networks to hydrogen and will act as a blueprint for subsequent conversions across the UK. The project also demonstrates the innovation, engineering capabilities, and economic opportunity in the North and creates tens of thousands of highly skilled green jobs in the future hydrogen economy.
https://www.eastcoasthydrogen.co.uk/

HyBreak

This project seeks to develop a device which uses smart technology to increase the safety levels of hydrogen installations in domestic UK buildings, ensuring that hydrogen can be delivered more safely than today's current natural gas system. The ideal solution will be required to detect a hydrogen leakage/pressure issue, automatically isolate the supply at the ECV, automatically notify the customer/network and have programmable flowrate set points to account for various appliances' usage. The project is being led by NGN in collaboration with Cadent Gas, Gas Network Ireland and National Gas Metering as project partners and Bohr Energy as Innovator.

The project will conduct tests and demonstrations at NGN's Futures Close and Caretaker's Lodge at Redcar & Cleveland College, Gas Network Ireland's innovation centre in Dublin and National Gas Metering's hydrogen demonstrator and test facilities at Tyseley park, Birmingham. The prototype and design work are underway; some key parts (short lead items) of the system have already been identified and the 1st prototype is due for delivery in October 2024.

Hydrogen Blending Implementation Plan – Phase 2a

There is a requirement for the gas networks to develop blending implementation plans for blending in parallel with the HyDeploy safety evidence review by HSE. Implementation plans will allow for blending to be expedited assuming a change to GSMR is implemented following HSE evidence review.

Industry therefore needs to progress with the design and implementation of a hydrogen blending programme which follows Phase 1 of the programme. The focus of this phase of work will be to develop the final blending delivery model and a full operational implementation plan. The underpinning options assessment and analysis will be informed by operational implementation considerations, and engagement with hydrogen producers to ensure the solution is investable and deliverable. Project deliverables include; an Operational Implementation Plan for application across the transmission and distribution networks, and a Blending Delivery Model identifying market framework and network code changes required to facilitate blending.

Real Time Settlement Methodology (RTSM)

The current natural gas billing methodology is not fit for purpose for alternative gas fuel types. RTSM – Phase 1 aims to develop an integrated system for the processes of characterising, settling, and billing gas in a multi-gas energy system. It has been assumed that hydrogen and unpropanated biomethane will form part of the multi-gas system of the network.

The project will review existing billing methodologies used in global gas networks with varying calorific values. This baseline information will be used to produce a model to meet UK industry requirements. A feasibility study will identify an optimal model to form a flexible settlement and billing approach.

More information on NGN's RIIO2 NIA innovation portfolio can be found in the latest version of our Annual Innovation Summary Report: https://docs.northerngasnetworks.co.uk/innovation-report-2024/

4.2 Strategic Innovation Fund (SIF)

The Strategic Innovation Fund (SIF) is a funding mechanism which aims to find and fund ambitious, innovative projects with the potential to accelerate the transition to net zero. These projects should help shape the future of energy networks and succeed commercially where possible. OFGEM have allocated £450 million to this fund over the period 2021 to 2026, with the option to extend and increase as necessary. The SIF is delivered in partnership with Innovate UK, part of UK Research and Innovation (UKRI). The Strategic Innovation Fund (SIF) is a major opportunity for innovative businesses and academics to work with energy networks on innovative projects that will deliver benefits to consumers.

The Innovation Challenges for Round 1 of the SIF, which opened August 2021, were: whole system integration, data and digitalisation, heat, and zero emission transport. These broad areas remain the focus of the SIF. For Round 2, a refined set of Innovation Challenges was developed. These were: supporting a just energy transition, preparing for a net zero power system, improving energy system resilience and robustness, and accelerating decarbonisation of major energy demands. For Round 3, in 2023, SIF will further focus on specified areas that are key to achieving key sectoral targets over the next decade, such as delivering a net zero power system by 2035.

Round 3 SIF Innovation Challenges are as follows:

1. Whole system network planning and utilisation to facilitate faster and cheaper network transformation and asset rollout
2. Novel technical, process and market approaches to deliver an equitable and secure net zero power system
3. Unlocking energy system flexibility to accelerate electrification of heat.
4. Enabling power-to-gas (P2G) to provide system flexibility and energy network optimisation.

SIF is structured to deliver positive outcomes over three Project Phases (Discovery Phase, Alpha Phase and Beta Phase), with successful application and assessment against Eligibility Criteria as a condition of receiving SIF Funding for the relevant Project Phase.

The following are recent projects from NGN's RIIO-2 SIF innovation portfolio:

HyCoRe (Hydrogen Cost Reduction) (Round 2 Discovery & Alpha)

Renewable hydrogen and energy storage options are widely regarded as critical to achieving the UK's 2050 net-zero target. For project developers planning offshore-wind/hydrogen production facilities, an abundance of design choices and configurations exist, each of which has advantages and disadvantages, and questions remain about how to integrate electrolysers/energy storage devices into the existing energy systems.

These include:

1. Where best to locate these systems;
2. What enabling technologies are required to deploy them efficiently;
3. How to validate/demonstrate novel enabling technologies;
4. How to efficiently incorporate the resultant hydrogen into the existing gas network while minimising the costs of a secure, resilient, multi-vector energy system.

The Discovery Project Phase aimed to answer these questions through delivery of the following three primary work streams:

1. Defining the optimal methods of exporting energy from an offshore-wind farm in the context of value for money for customers
2. Defining the energy carrying characteristics of electricity vs hydrogen to establish the cost drivers and identify opportunities for cost reduction.
3. Understanding the impact on the gas/electricity networks of the imminent increase in renewable generation into the network and how strategic deployment of electrolysers, energy storage devices, and novel enabling technologies can reduce energy network investment requirements.

The Alpha Project Phase aimed to follow on from the Discovery phase further developing the project by focussing on the three key research areas below:

- National Modelling: identifying high-potential areas based on offshore/onshore constraints and opportunities.

- Modelling of a selected regional specific solution: understanding infrastructure solutions that will provide connectivity between offshore wind production areas and energy consumers/gas network.

- Technical challenge assessment: identifying technical challenges that may impede deployment and design/optimisation of test/validation solutions to de-risk technology pathways.

The Alpha phase identified UK regions with a strong potential for green hydrogen, produced from offshore-wind and injected into the onshore gas networks, to offer a more economic and deliverable solution than offshore wind farms producing electricity directly. Currently the project team are in discussions about a Beta phase submission.

Further information on the HyCoRe project can be found at the following link: https://smarter.energynetworks.org/projects/ref-10079341/

Regional Energy Strategic Modelling (RESM) Project (Round 3 Discovery)

Wholesale changes to the national strategic planning of electricity and gas/hydrogen networks are underway, with the creation of the National Energy System Operator (NESO) and 11-13 Regional Energy Strategic Planners (RESPs); the RESPs will develop whole system strategic plans for each region, and these plans will need to be coherent with both national and local net zero ambitions and energy security priorities.

The Regional Energy Strategic Modelling (RESM) project set out to develop and test a system dynamics tool that could be used to deliver socio-economic development of regional decarbonisation pathways across Britain which, depending on requirements, could be over different time horizons, keeping vulnerable customers at the core of the decision-making process to ensure a just and equitable transition.

The tool is planned to be a decision-support tool which embeds coordination and coherence across the whole energy system (gas, hydrogen, electricity, and water), providing strategic steering or ‘a north star’ for network development plans and infrastructure investment. The discovery phase of the project was completed in July 2024 and was led by NGN in partnership with Northern Powergrid, Northumbrian Water Group, Durham University and DNV.

You can read more about the fund on the UKRI website and Ofgem’s Strategic Innovation Fund (SIF) website.

Appendix 1
Process methodology

A1

Appendix 1 - Process Methodology

A1.1.2 Daily Demand / Weather Modelling

Temperature explains most of the variation in daily LDZ demand, but a better fit can be obtained by including other variables. Within each model the Composite Weather Variable (CWV) which is the gas industry's data item that provides a measure of daily weather in each Local Distribution Zone (LDZ). It is calculated in UK Link using various data items, including weather variables such as temperature, wind speed and a set of parameters designed to provide a strong linear relationship to LDZ gas demand.

In order to compare gas demand between different years, we need to take out the variability of weather and see the underlying pattern. We do this by correcting records of actual weather to seasonal normal weather basis which is the same for all years. This allows comparison of demand under the same weather conditions to see underlying trends. The Seasonal Normal value of the Composite Weather Variable (SNCWV) is therefore a key parameter used in various calculations. CWV and SNCWV are key building blocks in the production of demand models, profiles, peak load factors and the Non-Daily Metered allocation formulae.

For stability across the many industry processes impacted, the Demand Estimation Sub Committee[5] (DESC) review the CWV and SNCWV, as a minimum, every 5 years. New CWV and SNCWV figures came into effect on the 1st October 2020. The calculation now includes a 'solar effect' variable which provides substantial improvement in demand estimation, particularly for the colder months.

A1.1.3 Peak day Demand Modelling

Once the annual demand forecasts and daily demand/weather models have been developed, a simulation methodology is employed using historical weather data for each LDZ dating back to 1st October 1960. This determines the peak day and severe winter demand estimates. The model estimates what demand would be if historical weather from 1960 were to repeat today and generates a statistical distribution of the results which can be used to determine 1 in 20-year peak day demand. That is the level of demand you would statistically expect to occur once in every 20 years.

A1.1.4 High Pressure Tier Planning

Although the development of the GDN's Local Transmission System (LTS) is largely demand led, LTS capacity planning processes are not dissimilar to those utilised for the development of the National Transmission System (NTS). GDNs use forecast demand to model system flow patterns and produce capacity plans that take account of anticipated changes in system load and within-day demand profiles.

The options available to relieve LTS capacity constraints include:

- Uprating pipeline operating pressures
- Uprating offtakes from the NTS, regulators and control systems
- Constructing new pipelines or storage
- Constructing new supplies (offtakes from the NTS), regulators and control systems

[8] http://www.gasgovernance.co.uk/desc

As well as planning to ensure that LTS pipelines are designed to the correct size to meet peak flows, there is a requirement to plan to meet the variation in demand over a 24-hour period. Diurnal storage is used to satisfy these variations and for NGN this is in the form of linepack.

A1.1.5 Below 7 barg planning

The lower pressure tier system (distribution system) is designed to meet expected gas flows in any peak six-minute period assuming reasonable diversity of demand. Lower tier reinforcement planning is based on LDZ peak demand forecasts adjusted to take account of the characteristics of specific networks.

Network analysis is carried out using a suite of planning tools with the results being validated against a comprehensive set of actual pressure recordings. The planned networks are then used to assess future system performance to predict reinforcement requirements and the effects of additional loads. Reinforcement options are then identified, costed and programmed for completion before the constraint causes difficulties within the network. Reinforcement is usually carried out by installing a new main or by taking a new offtake point from a higher-pressure tier. In general, the reinforcement project is of such a size that the work can be completed and operational before the following winter.

A1.1.6 Investment Procedures and Project Management

All investment projects must comply with The Investment Planning Policy, which set out the broad principles that should be followed when evaluating high value investment or divestment projects.

The Investment Planning Policy defines the methodology to be followed for undertaking individual investments in a consistent and easy to understand manner. This policy is used to ensure maximum value is obtained. For non-mandatory projects, the key investment focus in most cases is to undertake only those projects that carry an economic benefit.

For projects that are associated with Network Assets a key factor is the successful delivery of the Network Asset Risk Measure (NARM) risk reduction. This is a metric agreed with Ofgem at the beginning of the regulatory period and will help show that investment has delivered the required outputs.

For mandatory projects such as safety-related work, the focus is on minimising the net cost whilst not undermining the project objectives or the safety and reliability of the network. The successful management of major investment projects is central to our business objectives.

Our project management strategy involves:

- Allocating the appropriate project management expertise to manage the project
- Determining the level of financial commitment and appropriate method of funding for the project
- Monitoring and controlling the progress of the project to ensure that financial and technical performance targets are achieved post project and post investment review to ensure compliance and capture lessons learned

NGN have four frameworks in place to help deliver our Capital Investment Programme which were all competitively tendered through the OJEU process. These framework agreements ensure we build lasting relationships with our partners to deliver quality at the most efficient cost for our customers. Our new design framework was re-tendered this year and consists of five designers currently with a further three potentially being added subject to ongoing contract challenges mainly around liability. Our three delivery frameworks were re-tendered during 2021 and went live in May 2022, the Major Framework consists of six framework partners and work is awarded via mini competition, the two Minor Frameworks consist of four framework partners each, two assigned in the North and two in the South, and work is shared between them and prices negotiated. The frameworks have been designed to suit the work type, complexity, and volume to deliver the most economical value. All four frameworks are based on the NEC forms of contract which are renowned and approved worldwide as a project management contract, focussing particularly on cost and programme.

All projects are completed in line with the Capital Projects Integrated Management System (IMS) which covers the project lifecycle. The IMS is critical to ensuring NGN delivers projects consistently and in line with all relevant legislative requirements fulfilling NGN's obligations as the employer.

Our project management of capital investment projects is designed to ensure that they are delivered on time, to the appropriate quality standards at minimum cost. The project management process makes use of professional consultants and specialist contractors, all of whom are appointed subject to competitive tender.

Performance of the Contractors is monitored using Key Performance Indicators (KPI's) to ensure that the standards of Health & Safety, Environmental Performance, Quality, Commercial Performance and Programme management are all of the required level. Within the new framework, these figures will be used to incentivise high levels of performance, whilst still providing a tool to ensure consistent levels of performance.

Where Third Party funded schemes are raised, these are sanctioned, awarded, and managed in exactly the same way with a focus on value, programme and quality, however the Project Manager role may be sourced from the Professional Services Framework (as opposed to an NGN employee) on an ad-hoc basis to ensure that the Capex workload is delivered without compromise.

Appendix 2

Gas Demand Forecasts

A2

Appendix 2 - Gas Demand Forecasts

A2.1 Annual Demand

Annual demand forecasts are developed without knowledge of future weather conditions. Consequently, we calculate a Seasonal Normal Temperature (SNT) based on past averages. To compare throughput between years, actual demand data is adjusted to account for the variance of actual weather and SNT. This is known as weather corrected demand.

The network code states that the calculated methodology used to derive seasonal normal values must be reviewed periodically. The 'seasonal normal composite weather variables' (SNCWV) have been reviewed and the new figures went live on the 1st October 2020. These figures now include solar effect. Seasonal normal values reflect the general upturn, in warm weather, that has been experienced over the past decade.

Derivation of the seasonal normal values is designed to reflect the most accurate statistical relationship between demand and weather. It does not attempt to estimate any potential impact of global warming and as such the peak 1 in 20 weather assumptions have not altered. Prior to the 2005 revision, seasonal normal values were carried out using 35 years of weather data, this was revised and implemented in 2005 using 17 years of data.

Over the next ten years annual gas demand is forecast to increase by 6.83% in the Northern LDZ and an increase of 10.26% in the North East LDZ. As discussed in section 1.2, most of this is due to recovery of gas demand to levels seen in 2021 prior to the cost of living crisis. When compared to 2021 gas demand levels the gas demand at the end of the forecast period is 0.65% lower than 2021 in the Northern LDZ and an 2.78% higher in the North East LDZ. There is always an uncertainty over the economic outlook and UK gas prices; amongst other factors which are outlined overleaf. The following tables show the LDZ specific forecasts:

Northern LDZ

Load Band	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
0-73 MWh	16.5	17.5	17.4	17.4	17.5	17.7	17.8	17.9	18.0	18.2
73-732 MWh	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
732-5860 MWh	1.7	1.7	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
> 5860 MWh	9.3	9.3	9.3	9.4	9.4	9.4	9.4	9.5	9.5	9.5
LDZ Shrinkage	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
LDZ Demand	29.9	30.9	30.9	30.9	31.1	31.4	31.5	31.6	31.8	32.0

Table A2.1A Forecast Annual Demand by Load Category & Calendar Year for North LDZ from 2024 Demand Statements
Note: Figures may not sum exactly due to rounding.

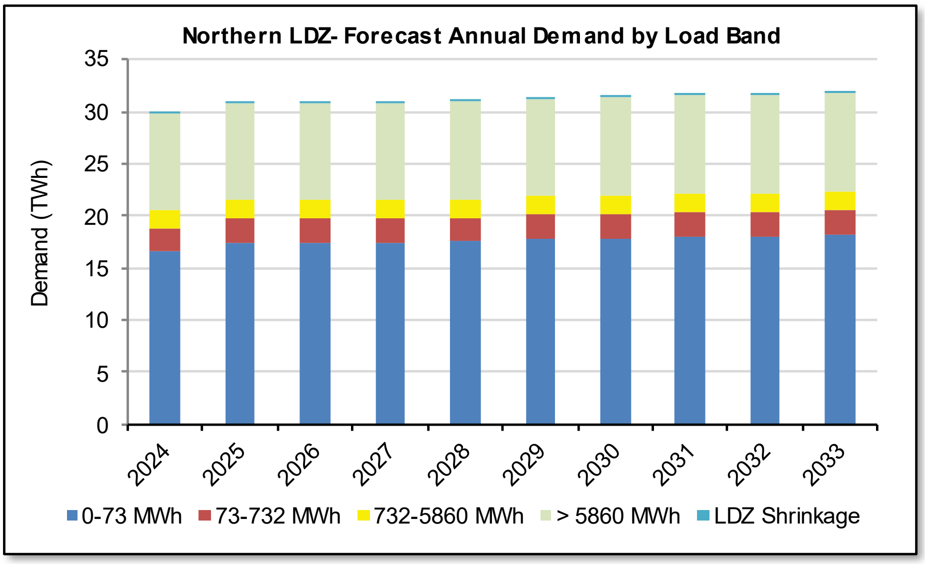


Figure A2.1A Northern LDZ - Forecast Annual Demand by Load Band

North East LDZ

Load Band	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
0-73 MWh	19.4	20.7	20.6	20.6	20.9	21.2	21.3	21.5	21.7	21.8
73-732 MWh	2.7	2.8	2.8	2.8	2.8	2.7	2.7	2.7	2.7	2.7
732-5860 MWh	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.1	2.2
> 5860 MWh	9.9	10.0	10.1	10.2	10.3	10.4	10.6	10.7	10.8	10.9
LDZ Shrinkage	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
LDZ Demand	34.2	35.6	35.7	35.8	36.1	36.5	36.8	37.1	37.4	37.7

Table A2.1B Forecast Annual Demand by Load Category & Calendar Year for North East LDZ from 2024 Demand Statements (TWh)

Note: Figures may not sum exactly due to rounding.

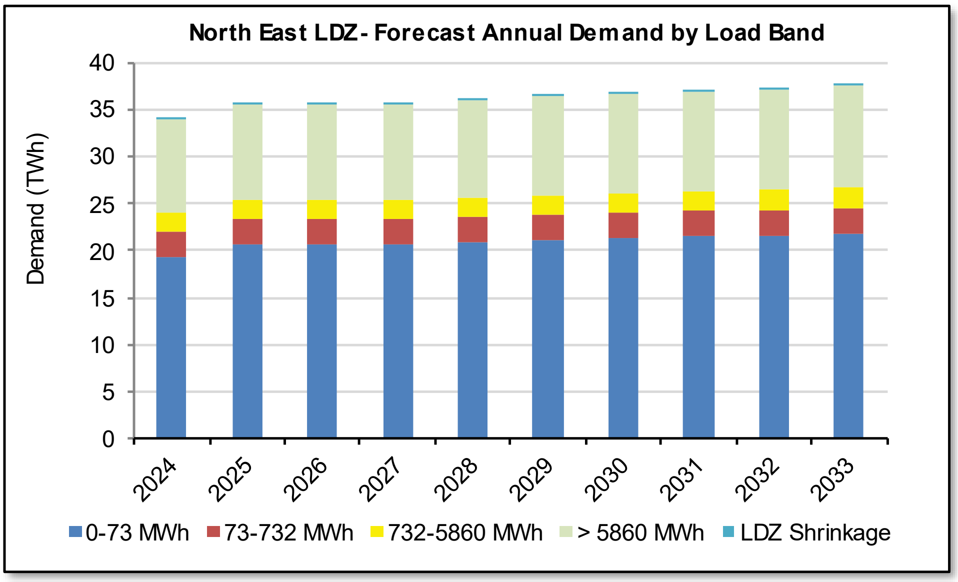


Figure A2.1B North East LDZ - Forecast Annual Demand by Load Band

A2.2 Forecasting approach and Key Assumptions in developing the 2024 NGN Demand Forecasts

Our annual forecast is based on bottom up granular forecasting where possible. Where this is not possible, econometric analysis is used. Annual demand is forecast first, then relationships between annual and peaks demands are established and used to derive peak. This is done per demand load band.

The method for our annual forecast is:

- For our domestic customers all elements except one are forecast on a bottom-up basis. Modern houses and older houses are forecast separately, as they have different thermal efficiencies. The bottom-up elements forecast separately include:
  - numbers of customers connected to our networks,
  - impacts of energy efficiency, both thermal and heating from boilers and heating controls.
  - The numbers of houses switching to renewable heating, via heat pumps

  Comfort levels – the degree to which people heat their homes - is then forecast via econometric forecasting, and applied to all houses.
- Our largest customers are forecast individually.
- Econometric forecasting is used to forecast demand for the rest of our customers. This is done by LDZ and by loadband.

Our peaks forecast are derived from annual demands per loadband. This uses the analysis of historical demand and the composite weather variables per LDZ derived by Xoserve. Whilst the annual demand forecast is a bottom up process where possible, the derivation of peak demands is a top down approach, per load band.

This section provides an overview of the key assumptions used to inform our 2024 demand forecasts – both economic and non economic assumptions. The commentary underpins the forecasts made back in the first quarter of this year, in which the continued impact of the cost of living crisis and high energy prices on the economy are still being felt. The base date for our 2024 forecast models captures the currently high levels in gas prices, but also recognises they have started to reduce from their highest points. Our modelling has assessed the impacts these have had on different sectors of demand. We forecast prices will continue to reduce although there remains uncertainty how the market and prices over the coming years.

Our analysis of how demand in different load bands are affected by economic factors concludes that domestic prices have been greatly affected by high prices and the current economic situation, whereas non domestic sectors have been considerably less affected by these factors, especially price.

For the domestic sector we have managed to assess how comfort levels (the temperature to which people heat their homes) have been impacted by prices and other factors. This forms the largest element of gas demand changes in our forecast. As previously described, most of the forecast variation is recovery towards 2021 demand levels, as economic burdens ease.

This section provides an overview of the key assumptions that have most impact on our 2024 demand forecasts – both economic and non economic assumptions

Gross Domestic Product (GDP) and Gross Value Added (GVA)

GVA measures the contribution to the economy of each individual producer, industry or sector in the United Kingdom. GVA is used in the estimation of GDP, which is a key indicator of the state of the whole economy. Therefore, it is an important driver for gas demand. A significant decline in GDP occurred during 2008/9 set against a long period of growth from 1992, and a more recent decline occurred as a result of the covid pandemic in 2020. Other than these periods, there has generally been steady and sustained growth in GDP. The economic figures produced by the Office of National Statistics (ONS) show the impact to the economy during 2023 (see graph below). The preliminary figures from the ONS show that annual GDP growth for 2023 is around 0.6%. This is a decrease from the outturn figure for 2022 of 4.3%.

The level of growth is expected to recede slightly with a rate of -0.8% in 2024, and the level of growth to recover by 0.9% in 2025 and 1.4% in 2026. The forecasts for 2027 and 2028 are 1.1% and 1.7% respectively. The Office for Budget Responsibility (OBR) published the range of forecasts of potential GDP paths in November 2023 which is shown in figure A2.2.1A.

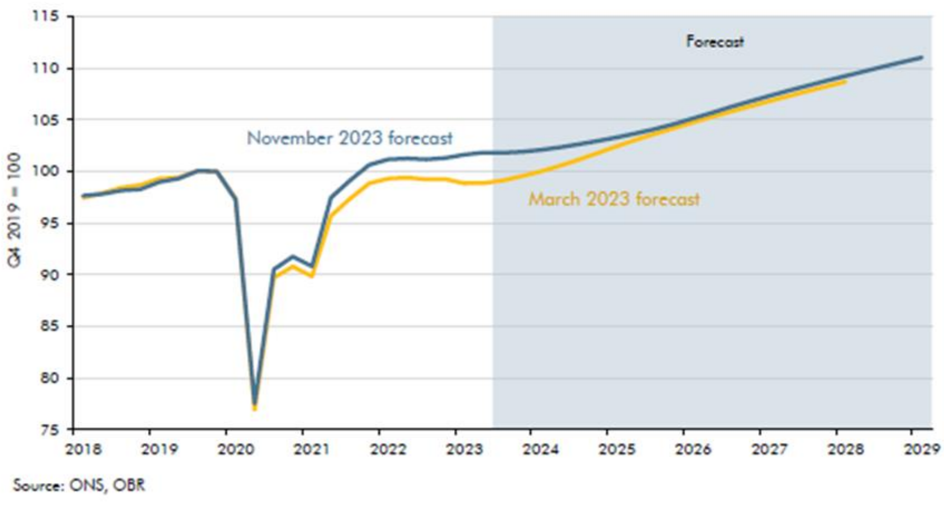


Figure A2.2.1A – UK Real GDP Growth Chart

Gas & Energy Prices

We have witnessed a delinkage between gas markets and energy markets in recent years, most notably a delinkage between oil and gas. This has been particularly noticeable since the Ukraine conflict. As a result we forecast gas markets separately, and do not focus on other energy markets to inform the gas price forecast we use.

Analysis shows that gas prices and demand are inversely related; an increase in price leads to a demand reduction. The section focusses on changes in wholesale gas price. There is a delay before this feeds into other retail markets, for domestic commercial and industrial gas prices. These vary between markets, and each year we assess the linkage and incorporate this into the forecasts we have for wholesale gas prices. The retail gas prices we use for gas demand forecast are ultimately derived from the wholesale forecast that we have.

Figure A2. 2.1B– Retail & Industrial gas price index (1987 = 100; base figure)

Wholesale Price

All prices in all gas markets reduced from the previous year. The wholesale price has reduced, significantly in 2023. The average wholesale gas price in 2023 was around half that of the previous year, although this was still considerably higher than historic prices prior to 2021. The wholesale price continued to reduce in early 2024 when our gas price forecast was created. It should be noted that since our forecast was created in early 2024, market concerns around current geopolitical situations and their impact on energy supply, have led to gas prices steadily rising. However they still averaged a 25% reduction compared to the previous year at the time of writing. If these were to be included in the forecast it would have the impact of suppressing demand in our forecast to some extent.

Our forecasting process captures data related to the recent price spikes and seeks to understand any associated effects on gas supply and demand. At the time of producing our 2024 forecasts there has been some significant fluctuation in the wholesale gas price (as represented by the UK NBP price at 2019 prices) over time but the general trend has until recently been upwards. Following the steep decline in oil prices between 2014 and 2015 the wholesale price fell in 2016, but then increased again in 2017 and 2018. The price then fell sharply and only partially recovered during 2019 followed by another dip and rise during 2020, then a steep rise through 2021, and 2022. The price is currently higher than previous years, but has stabilised through the second and third quarters of 2023. The forecast provided is the price forecast provided by our forecast provider. It is based on an assessment of market fundamentals, and sentiment, and is informed by and benchmarked with available gas price forecasts at the time of its creation. These include forecasts of wholesale price used by National Gas and DESNZ for their energy demand forecasts, but adjusted to account for the current high levels. It results in an enduring forecast that remains relatively stable on an annual basis at levels that are significantly lower than those experienced in the last couple of years, but is also higher than the average price experienced in 5 year period from the start of 2016 to the end of 2020.

Efficiency

Thermal efficiency of properties improved greatly between 2008 and 2012, due the Carbon Emissions Reduction Target (CERT). This was a government policy that ran between 2008 and 2012, which required larger gas and electricity suppliers to achieve targets for reducing carbon emissions from domestic premises in Great Britain. At its peak, it was installing over 1 million measures of retrofit thermal insulation into properties per year. These were mainly cavity wall, loft and solid wall insulation measures.

Since 2012 the main government policy to incentivise thermal efficiency improvements in properties has been the Energy Companies Obligation (ECO), which is now on its 4th iteration – ECO4. ECO has resulted in lower levels of retrofit insulation, and each iteration of ECO has delivered less the previous. This largely due to having a smaller target market, with only householders in receipt of benefits being eligible.

In the last 2 years two new policies have been launched to aid retrofit insulation measures in gas fired houses. These are Great British Insulation Scheme (GBI) and Social Housing Decarbonising Fund (SHDF). SHDF has very little impact on our forecasts, as its focus is more on whole house retrofit for social housing, and its budget does not cover many houses; however the GBI is designed for wider rollout of insulation measures, and as a result has a larger impact on the gas demand forecast. We have included forecasts of all of these schemes in our demand forecast, based on current performance levels. Whilst they have some impact on overall efficiency improvements, there is only a limited reduction in gas demand over the forecast period. Overall, they result in a reduction of 1.1% of domestic gas demand over the 10-year period.

Other than recent behaviour changes, the one single measure that had the most impact on domestic gas demand in our LDZs is the increasing efficiencies of boilers. Since 2005 the government requirement for all boilers to be high efficiency condensing boilers has had a significant impact in reducing domestic gas demand. Domestic gas demand has reduced by 5.7% in the last 10 years, as a result of more efficient boilers. As boilers have become more efficient, the future improvement potential has lessened, but it is still significant. Our forecast for improving boiler efficiency result in a 3.2% reduction in gas demand over the ten year period.

Domestic Behaviour changes

Comfort levels – the degree to which people heat their homes, has had the greatest single impact on gas demand in our LDZs in the last couple of years. Between 2021 and 2023 domestic demand in our networks reduced by 14%. This was almost all due to comfort levels lowering, as people have reduced their heating temperatures, and periods of heating to save as much money as possible, as a result of the cost of living crisis.
Our forecast for how this is to change is the result of our economic analysis, not an assumption, but its impact is so significant, it is highlighted here.
Our forecast of fuel prices, household disposable income and wider impacts are used to establish the behaviour change in our forecast. Overall reducing gas prices and a slowly improving economy and household disposable income, result in increases in our forecast over the next few years. Our forecast for this results in comfort levels returning to pre cost of living crisis levels in our LDZs towards the end of the period, and are the main reason for

increases in our gas demand forecast over the next 10 years. Although it should be noted the forecast increases are not really underlying increases, but recovery to demand levels seen in 2021. Comfort levels are forecast to return to 2021 levels in our Northern LDZ in 2032 and in our North East LDZ in 2031.

New houses

For gas demand from new houses we forecast the number of new houses and also the gas demand per new house. The numbers of new houses are forecast at growth rates linked to GDP using the historical relationship of new houses to GDP; and applied to our GDP forecast. New houses have a much lower gas demand than an average house due to higher energy efficiency of new houses. Gas demand per new house is assessed separately using EPC values for new and existing houses as a basis for this analysis. We have not included the potential impact of Future Homes Standard in the forecast, because at the time of the forecast and writing, this is yet to be legislated and there remain uncertainties as to what any final legislation, may be. The forecast remains based only on legislation that is in place, and does not speculate on that which may occur. Any impact of this policy should it come into place would be relatively low, around 1-2% in total at the end of the forecast period, due to the relatively low numbers of houses built in this period, and their low gas demand.

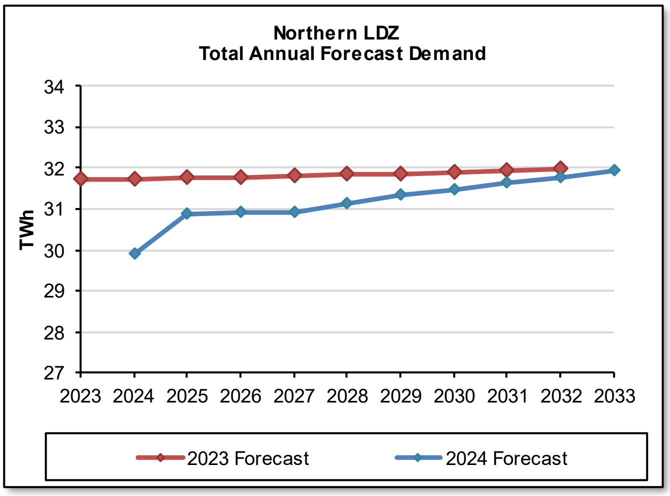
Renewable Heating

To aid the move to renewable heating, the Boiler Upgrade Scheme (BUS) began in April 2022. The scheme provides grants to encourage property owners to replace existing fossil fuel heating with, low carbon heating systems. Our forecast for BUS reflects the performance since the September 2023 incentive and budget were increased. This performance continues until 2028, the end of the new budgeted period. It then continues for the rest of the forecast period at this rate.

Its impact is negligible as the numbers of boiler replacements for low carbon heating numbers are so low. The impact of boilers being replaced by heat pumps is 0.25% reduction in total domestic demand in 2033.

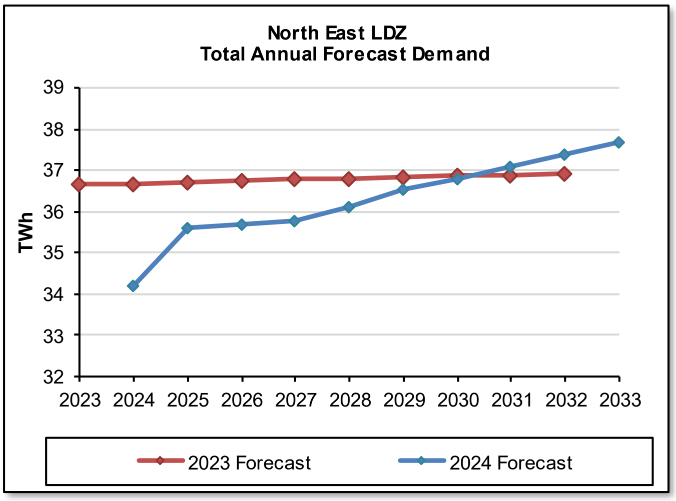
A2.3 Forecast Comparisons

The following charts provide a comparison of the current forecasts with those published in the 2023 Demand Statements (DS).



Forecast (TWh)			
Year	2023 DS	2024 DS	% Difference
2024	31.73	29.91	-5.73
2025	31.76	30.89	-2.73
2026	31.78	30.92	-2.71
2027	31.81	30.92	-2.82
2028	31.84	31.11	-2.29
2029	31.87	31.36	-1.61
2030	31.90	31.49	-1.29
2031	31.93	31.62	-0.94
2032	31.96	31.78	-0.55
2033		31.95	

Figure 2.3A – Northern LDZ Total Annual Forecast Demand



Forecast (TWh)			
Year	2023 DS	2024 DS	% Difference
2024	36.68	34.20	-6.77
2025	36.71	35.62	-2.97
2026	36.74	35.71	-2.81
2027	36.77	35.78	-2.69
2028	36.80	36.13	-1.82
2029	36.84	36.55	-0.78
2030	36.87	36.81	-0.16
2031	36.90	37.08	0.49
2032	36.93	37.38	1.22
2033		37.70	

Figure 2.3B – North East LDZ Total Annual Forecast Demand

Appendix 3

Actual Flows 2023

A3

Appendix 3 – Actual Flows 2023

A3.1 Annual Flows

Annual forecasts are based on average weather conditions. Therefore, when comparing actual throughput with forecasts, throughput 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 throughput.

The basis for any calculation of forecast demand is the accuracy of the previous forecast.

Table A3.1.A and chart A3.1.B provide a comparison of actual and weather corrected throughputs during the 2023 calendar year, with the forecast demands presented in the 2023 Demand Statements. Annual demands are presented in the format of LDZ and NTS load bands/categories, consistent with the basis of system design and operation.

The 2023/24 winter severity, compares the latest winter against the previous 64 winters starting from Winter 1960/61, and it was deemed to be a warmer than average winter. The 6 month period from October 2023 to March 2024, was the second warmest winter in the last 64 years, the type of warmth expected to occur once every 13 years..

Northern LDZ 2023	Actual Demand	Weather Corrected Demand	Forecast Demand	Corrected v Forecast (%)
0 to 73.2 MWh	14.30	15.65	17.77	-12.0
73.2 to 732 MWh	2.12	2.26	2.35	-4.0
>732 MWh	9.90	10.10	11.45	-11.8
Shrinkage	0.13	0.13	0.13	2.0
Total LDZ	26.49	28.17	31.71	-11.1

Table A3.1A Northern LDZ Throughput 2023 **Note:** Figures may not sum exactly due to rounding.

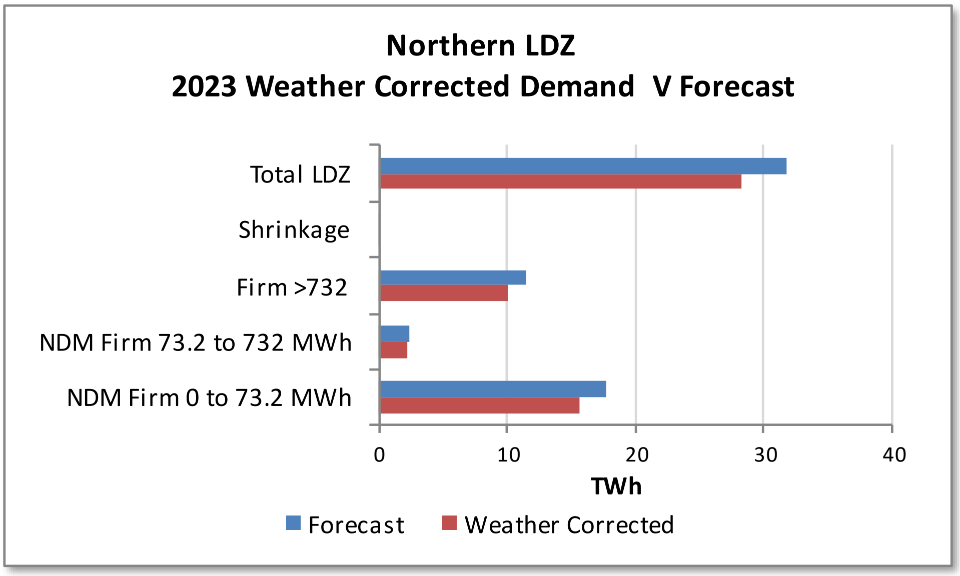


Chart A3.1B 2023 Northern LDZ Weather Corrected Demand V Forecast

In the Northern LDZ, the forecasts for each of the loadbands, were higher than the actual throughput. Overall the total LDZ weather corrected throughput was 11.1% lower than forecast.

North East LDZ 2023	Actual Demand	Weather Corrected Demand	Forecast Demand	Corrected v Forecast (%)
0 to 73.2 MWh	17.15	18.15	20.76	-12.6
73.2 to 732 MWh	2.58	2.68	2.85	-5.9
>732 MWh	11.10	11.23	12.89	-12.9
Shrinkage	0.15	0.15	0.15	2.7
Total LDZ	30.98	32.23	36.65	-12.0

Table A3.1C North East LDZ Throughput 2023 **Note:** Figures may not sum exactly due to rounding.

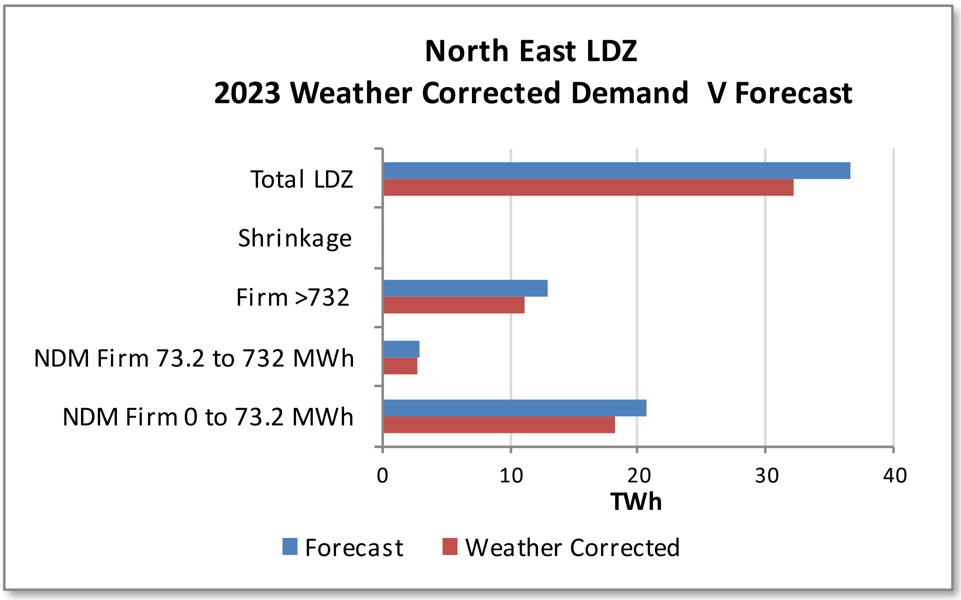


Chart A3.1D 2023 North East LDZ Weather Corrected Demand V Forecast

Similarly, the North East LDZ forecasts were overstated for all load bands. At LDZ level, the weather corrected throughput was 12.0% lower than forecast.

A3.2 Peak Flows

The maximum demand day for Northern LDZ during winter 2023/24 was 18th January 2024, when the network demand was 14. 14 mcm, equating to **71.8%** of the expected 1 in 20 peak day for winter 2023/24. This was 2.4% lower than the highest demand day in 2022/23 of 14.49 mcm.

The maximum demand day for North East LDZ during winter 2023/24 was 18th January 2024, when the network demand was 16.83 mcm, equating to **71.3%** of the expected 1 in 20 peak day for winter 2023/24. This was 0.7% higher than the highest demand day in 2022/23 of 16.72 mcm.

Our 2024 forecasts suggest that over the next ten years, the 1 in 20 Peak day forecast demand will decrease by 0.04% in the Northern LDZ and increase by 0.03% in the North East LDZ in line with annual forecasts, as shown by the charts below.

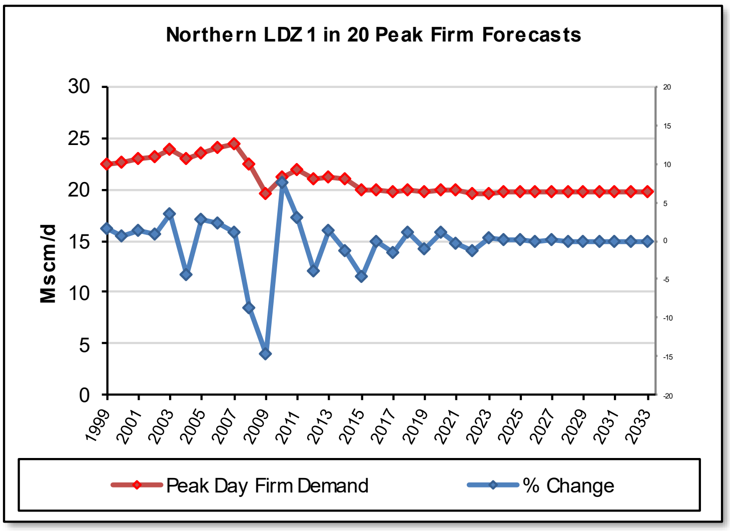


Figure 3.2a Historical Throughput & Forecast Peak day Firm Demand for Northern LDZ

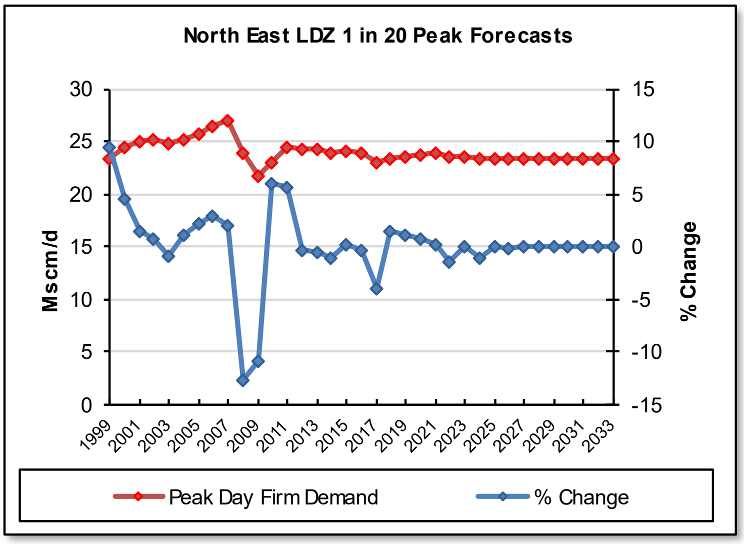


Figure 3.2b Historical Throughput & Forecast Peak day firm Demand for North East LDZ

Appendix 4

Connections to our system

A4

Appendix 4 – Connections to our System

A4.1 Connection Services

Within the space of a few years, the gas industry in the UK has evolved from a situation where one company provided all new connections, to one where many alternative connection services are now available on a competitive basis.

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

The following are the generic classes of connection;

Entry Connections: connections to delivery facilities processing gas from gas producing fields or, potentially in the future, LNG vaporisation (i.e. importation) facilities, for the purpose of delivering gas into the NGN system. Biomethane is a fully renewable source of energy and NGN is fully committed to maximising the entry of biomethane into our gas network.

Exit Connections: connections that allow gas to be off taken from our system to premises (a 'Supply Point') or to Connected System Exit Points (CSEPs). There are several types of connected system including:

- A pipeline system operated by another gas transporter
- Any other non-NGN pipeline transporting gas to premises consuming more than 2,196MWh per annum
- Storage Connections: connections to storage facilities for the purpose of temporarily off taking gas from our system and delivering it back at a later date

Please note that storage may both deliver gas to the system and offtake gas from the system, therefore specific arrangements pertaining to both Entry and Exit Connections will apply. In addition to new pipes being termed connections, any requirement to increase the quantity of gas delivered or off taken is also treated as a new connection.

A4.2 Connections to the Local Transmission System

There have been 7 HP Connection enquiries and 0 HP connections for the gas year Oct 23 – Sep 24. There have been no new physical HP connections.

A4.3 Non-Standard Connections

NGN have seen a continued reduction in the number of quotation enquiries for large load flexible generation connections- 5 year to date (Oct 23 – Sept 24). We expect that flexible generation enquiries will continue to reduce in numbers throughout the remainder of GD2 due to the areas of the UK that require flexible generation already being covered and the increasing focus on decarbonisation. We currently have 11 live issued quotes with customers and expect a number of these to be accepted and progress to a connection.

There are 17 flexible power generation sites currently connected to NGN's system, with another 9 accepted sites anticipated to progress across RIIO-GD2. There are also 2 compressed natural gas (CNG) sites connected to the network.

NGN have ongoing innovative hydrogen projects and are continuously working with producers to facilitate a mixture of both blending and 100% hydrogen injection enquires.

A4.4 Additional Information Specific to System Entry and Storage Connections

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

A4.4.1 Network Entry Quality Specification

For any new entry connection to our system, the connecting party should notify us as soon as possible as to their likely gas composition. We will then determine whether the gas can be accepted, taking into account our existing statutory and contractual obligations.

The ability of NGN to accept gas supplies into the system is affected by, among other things, the composition of the new gas, the location of the system entry point, volumes entered, pressure ranges and the quality and volumes of gas already being transported within the system.

In assessing the acceptability of any proposed new gas supply, we will take account of the following.

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) Our ability to continue to meet our contractual obligations.

For indicative purposes, the schedule set out below is usually acceptable for most locations and encompasses, but is not limited to, the statutory requirements set out in the GS(M)R. https://www.legislation.gov.uk/uksi/1996/551/schedule/3/made

A4.5 Additional Information Specific to System Exit Connections

Any person can contact NGN to request a connection, whether a shipper, operator, developer or consumer. However, gas can only be taken off the system where the Supply Point created has been confirmed by a shipper, in accordance with the Uniform Network Code.

More information regarding NGN connections can be found here https://www.northerngasnetworks.co.uk/gas-connections/

A4.6 National Transmission System (NTS) Connections

For information regarding NTS Connections visit https://www.nationalgas.com/connections/national-transmission-system-connections

A4.7 Distribution Network Connections

Gas will normally be made available for offtake to consumers at a pressure that is compatible with a regulated metering pressure of 21mbarg.

A4.8 Self Lay Pipes or Systems

In accordance with Section 10(6) of the Gas Act, and subject to the principles set out in the published Licence Condition 4B Statement and the terms and conditions of the contract between us and the customer in respect of the proposed connection, where a party wishes to lay their own service pipe to premises expected to consume 2,196MWh per annum or less, ownership of the pipe will vest in us once the connection to our system has been made.

Where the connection is for a pipe laid to premises expected to consume more than 2,196MWh per annum or the connection is to a pipe in our system which is not a relevant main, self-laid pipe do not automatically vest in us. However, subject to the principles set out in the published Licence Condition 4B Statement and the relevant contractual terms and conditions, we may take ownership of pipes to such premises.

Parties considering laying a pipe that will either vest in us or is intended to come into our ownership should refer to our Connections Methodology Statement and contact our connections team on 0800 040 7766 and (option 2) or email gasconnections@northerngas.co.uk

A4.9 Reasonable Demands for Capacity

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

In many instances, specific system reinforcement may be required to maintain system pressures for the winter period after connecting a new supply or demand. Details of how we charge for reinforcement and the basis on which contributions may be required can be found in the published Licence Condition 4B Statement. Please note that dependent on scale, reinforcement projects may have significant planning, resource and construction lead-times and that as much notice as possible should be given. We will typically require three to four years' notice of any project requiring the construction of high-pressure pipelines or plant, although in certain circumstances, project lead-times may exceed this period.

Glossary
Of terms

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Glossary of Terms

Calorific Value (CV)
The ratio of energy to volume measured in mega Joules per cubic meter (MJ/m3), which for a gas is measured and expressed under standard conditions of temperature and pressure.

Composite Weather Variable (CWV)
A single measure of weather for each LDZ, incorporating the effects of both temperature and wind speed. A separate composite weather variable is defined for each LDZ.

Distribution Network (DN)
An administrative unit responsible for the operation and maintenance of the local transmission system (LTS) and <7barg distribution networks within a defined geographical boundary.

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

Formula Year
A twelve-month period commencing 1st April, predominantly used for regulatory and financial purposes.

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

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

Kilowatt hour (kWh)
A unit of energy used by the gas industry. Approximately equal to 0.0341 therms. One megawatt hour (mWh) equals 103 kWh, one gigawatt hour (GWh) equals 106 kWh, and one terawatt hour (TWh) equals 109 kWh.

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

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

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

Local Distribution Zone (LDZ)
A geographic area supplied by one or more offtakes. Consists of LTS and distribution system pipelines.

Local Transmission System (LTS)
A pipeline system operating at >7barg that transports gas from one or more offtakes to distribution systems. Some large users may take their gas direct from the LTS.

National Transmission System (NTS)

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

Non-Daily Metered (NDM)

Gas distribution networks review their total consumption in an LDZ vs the total consumption of the daily metered (DM) sites within a particular LDZ. The remaining consumption is then allocated as non-daily metered (NDM) consumption, which is then divided between the shippers, who supply gas to that LDZ, by applying an agreed formula.

It should also be noted, that following the implementation of project nexus in 2017, all meter points regardless of the supply class or registered demand volumes are reconciled when a valid meter read is submitted by the consumer.

Odorisation

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

Offtake Capacity Statement (OCS)

The Offtake Capacity Statements are received by NGN in September of each year from National Grid specifying assured pressures and the amount of capacity available at each offtake.

Own Use Gas (OUG)

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

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.

Seasonal Normal Composite Weather Variable (SNCWV)

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

Shrinkage

Shrinkage refers to the gas which is lost from the transportation network. Shrinkage is a combination of Leakage, Own Use Gas and Theft of Gas.

Therm

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

Unaccounted for Gas (UAG)

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

Uniform Network Code (UNC)

The document that defines the contractual relationship between System Users. The Uniform Network Code has replaced the Network Code and, as well as existing arrangements, covers the arrangements between all gas transporters.

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we are the network