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UK Gas: Demand Volatility Requires Supply Flexibility

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Executive Summary

Natural gas is a crucial element of energy supply in Great Britain (GB). The vast majority of GB gas consumption occurs in three main sectors: industry, Local Distribution Zone (residential, commercial, and services), and power generation. While there are strong seasonal patterns of demand across all three sectors, the volatility of daily fluctuations in demand has become increasingly visible. This daily demand volatility is driven primarily by a shift in the structure of GB power generation. With coal-fired power generation no longer part of the mix, gas-fired power stations act as the main balancing element between fluctuations in electricity demand and fluctuations in power generation from non-dispatchable sources (wind and solar). When a short-run surge in gas demand for power generation coincides with a spell of particularly cold weather that drives a surge in gas demand for space heating, the need for flexible gas supply to serve that demand is particularly acute.

GB gas supply is drawn from multiple sources: domestic production on the UK Continental Shelf (UKCS), pipeline imports from Norway, and imports of LNG from the global market into regasification terminals at Milford Haven and the Isle of Grain. This supply is finessed by bi-directional pipeline flows between the UK and Belgium (via the Interconnector pipeline [iUK]), between the UK and the Netherlands (via Bacton-Balgzand Pipeline [BBL]) and further by daily net injections into, and withdrawals from, gas storage facilities. The seasonal flexibility of GB gas supply is exhibited in all these supply sources. During the peak winter demand period, domestic production and pipeline imports from Norway reach a high winter plateau, above which there is no short-run upside flexibility. As a consequence of the decline in European pipeline gas imports from Russia since 2022, the market in north-western Europe is structurally less flexible (due to the loss of flexibility associated with Russian pipeline supply), and the pre-crisis dynamic of the UK exporting to continental Europe during summer and importing during winter is now mostly limited to summer exports from the UK to the EU. Therefore, the short-run flexibility in GB gas supply is found in storage withdrawals and LNG sendout. The fast-cycle nature of GB medium-range storage (excluding Rough), with cycles of withdrawal and injection even during winter means that greater use of storage requires, in turn, a greater call on the upside supply flexibility from LNG imports. The combination of underground gas storage stocks and LNG stocks held at regasification terminals are complementary and perform key roles in providing flexible supply, especially during winter. The drawdown of stocks at Rough in summer 2025 and its potential closure if a new business model is not found, will put greater emphasis on the medium-range storage facilities and LNG storage stocks as sources of short-run flexibility in GB gas supply during winter.

To conclude, during the winter peak demand period (December to February), GB can experience short-run surges in daily gas demand that are primarily driven by power generation and space heating that must be met by flexibility in daily supply. In the absence of large-scale seasonal gas storage, this flexibility is provided by a combination of underground storage withdrawal and sendout from LNG stocks, both of which are constantly replenished during the winter by LNG imports, in the absence of upside flexibility to pipeline imports once the high winter plateau is reached.

Finally, please note that this paper focuses on gas demand and supply in GB, while also accounting for the call on pipeline gas supply from GB to the island of Ireland by both Northern Ireland and the Republic of Ireland, with both served by the GB gas supply system. This reflects the operational separation between the GB system and the gas system on the island of Ireland. The ability of the GB gas supply system to meet both GB gas demand and the call on supply to Northern Ireland underpins the security of gas supply of the UK as a whole. This is also of great importance for security of gas supply in the Republic of Ireland, which sources gas from its own production and from imports from the UK.

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1. Introduction

Natural gas is a critical component in the UK energy supply portfolio. On an annualised basis, natural gas provided 36 per cent of UK primary energy supply in 2024 – just behind petroleum (38 per cent) but well above the shares provided by primary electricity (13 per cent) and biomass/bioenergy (12 per cent).[1] Natural gas also provided 29 per cent of UK electricity generation by major producers – just behind wind (30 per cent) and almost twice the amount provided by the next-largest source of supply, nuclear (15 per cent).[2] In final energy consumption, natural gas provided 28 per cent of the total, behind petroleum (47 per cent) but ahead of electricity (18 per cent). While natural gas is almost entirely absent from the transport sector, its 37 per cent share in industrial sector energy consumption (excluding the manufacture of iron and steel) is equal to that of electricity and its share of iron and steel industry energy consumption (55 per cent) is significantly greater than the shares of manufactured fuels (21 per cent) and electricity (19 per cent). Gas (38 per cent) and electricity (34 per cent) also have similar shares in commercial and services energy consumption, while gas (64 per cent) and electricity (24 per cent) account for the vast majority of household energy consumption.[3] To summarise, UK energy consumption outside the transport sector is dominated by a combination of natural gas and electricity. Therefore, when the combined shares of gas and electricity generated from gas are considered, the importance of natural gas in the UK energy system cannot be overstated.

The purpose of this paper is to examine the security of UK gas supply from the perspective of the ability to meet demand that exhibits both seasonal swing and daily volatility. This requires a gas supply system that has the ability to ramp up and down for sustained periods to meet seasonal swing, and the flexibility to track short-run volatility. By examining the causes of seasonal swing and short-run volatility in demand and the extent of flexibility of supply from different sources at present, and the outlooks for both demand in different sectors and supply from different sources over the next five years, this paper aims to highlight the key factors that both challenge and underpin UK security of supply, now and for the mid-term future.

For the purpose of this analysis, it is important to note the distinction between the United Kingdom of Great Britain and Northern Ireland (UK), which includes Northern Ireland, and Great Britain (GB), which does not. This distinction is reflected in both the operational separation between the GB transmission network (owned and operated by National Gas Transmission [NGT]) and the Northern Irish transmission network (operated by Gas Market Operator for Northern Ireland [GMO NI][4] on behalf of four transmission system operators [TSOs][5]), and the operational integration between the Northern Ireland transmission system and the Republic of Ireland transmission system (the latter owned and operated by Gas Networks Ireland).

Therefore, this paper focuses on gas demand and supply in GB, while also accounting for the call on pipeline gas supply from GB to the island of Ireland by both Northern Ireland and the Republic of Ireland, with both served by the GB gas supply system. Thus, the ability of the GB gas supply system to meet both GB gas demand and the call on supply to Northern Ireland underpins the security of gas supply of the UK as a whole.

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[1] DESNZ, 2025. *Energy Trends - Inland energy consumption: primary fuel input basis (ET 1.2 - monthly).* https://www.gov.uk/government/statistics/total-energy-section-1-energy-trends

[2] DESNZ, 2025. *Energy Trends - Fuel used in electricity generation and electricity supplied (ET 5.1 - quarterly).* https://www.gov.uk/government/statistics/electricity-section-5-energy-trends

[3] DESNZ, 2025. *Energy Trends - Supply and use of fuels (ET 1.3 - quarterly).* https://www.gov.uk/government/statistics/total-energy-section-1-energy-trends

[4] GMO NI, 2025. *About Us*. https://www.gmo-ni.com/about

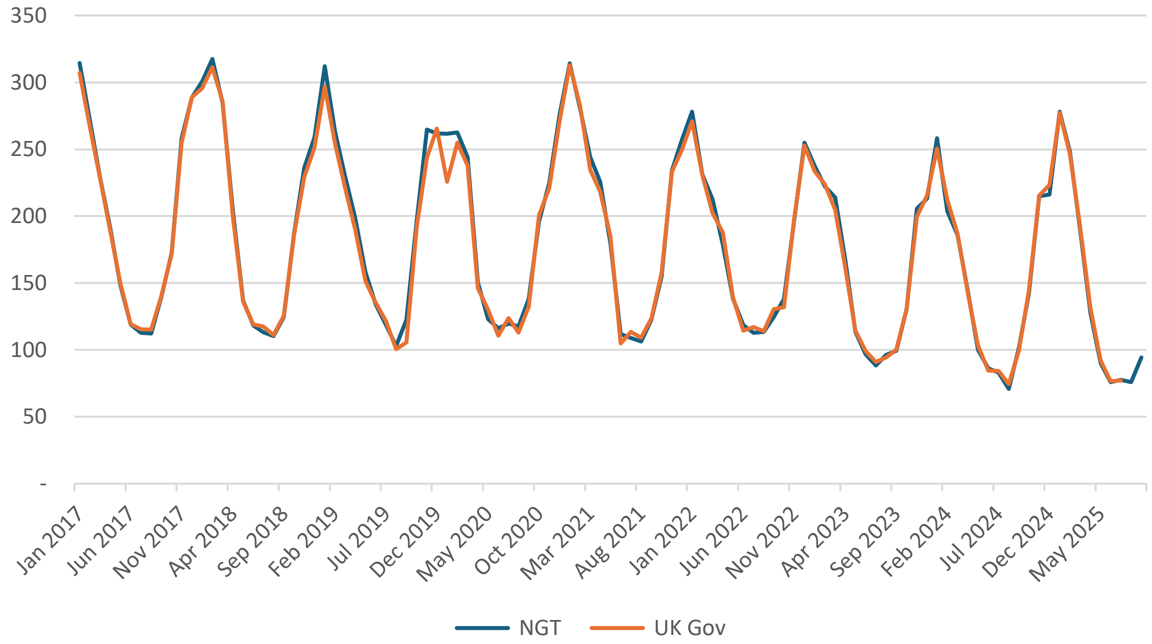
[5] Gas Networks Ireland UK (GNI UK), Premier Transmission Limited (PTL), Belfast Gas Transmission Limited (BGTL), and West Transmission Limited (WTL)

2. GB gas consumption by sector

GB gas demand is concentrated in three key sectors: industry, Local Distribution Zones (LDZ), and power generation. The LDZ demand includes residential, commercial, and public sector consumers, or indeed, any consumer that is connected to the low-pressure distribution grid. The seasonality of GB gas demand is driven by a combination of gas demand for space heating (in both the LDZ and industrial sectors) and the greater use of gas-fired power generation during the winter peaks in GB electricity demand.

Given the focus on volatility of demand and flexibility of supply, this paper is largely based on daily data sourced from the GB Transmission System Operator, National Gas Transmission (NGT). However, for the purpose of triangulation, it is worth comparing the monthly aggregates of this daily data with the monthly data published by the UK Department for Energy Security and Net Zero (DESNZ) as part of their 'Energy Trends' series of statistics. As **Figure 1** illustrates, the monthly total consumption volumes in the three main sectors reported by NGT and DESNZ are very similar (with the exception of January 2020). However, it should be noted that the monthly DESNZ consumption volumes up to and including December 2022 are calculations based on net supply – monthly consumption by sector is provided from January 2023 onward.

Figure 1: Monthly GB gas consumption for LDZ, power, and industry – NGT & DESNZ (MMcm/d)



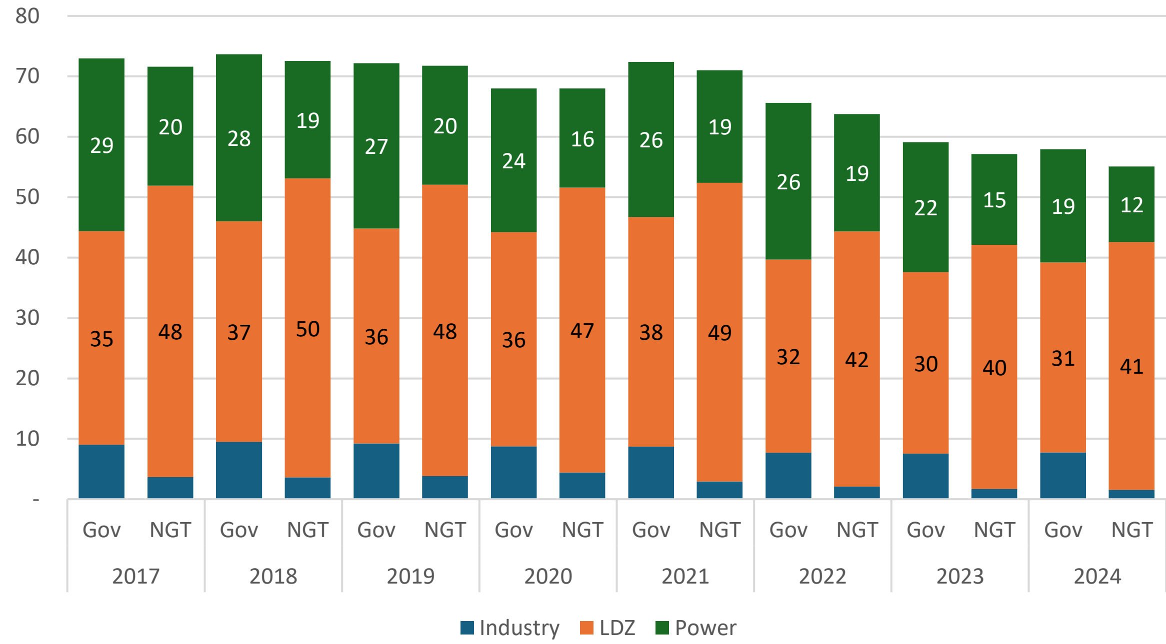
Source: Graph by the author (Sharples). Data from National Gas Transmission[6] and DESNZ Energy Trends.[7]

Although the total consumption for industry, LDZ, and power generation combined are very similar, there is a difference between the two data sources in terms of consumption by each of these sectors individually, as illustrated in **Figure 2**. Specifically, NGT attributes lower consumption volumes to industry and power generation, and more to LDZ, compared to DESNZ. The difference is one of definition and attribution, as explained below.

[6] National Gas Transmission, 2025. *NGT Data Portal*. https://data.nationalgas.com/

[7] DESNZ, 2025. *Energy Trends: UK Gas*. 30 September. https://www.gov.uk/government/statistics/gas-section-4-energy-trends

Figure 2: Annual GB gas consumption for LDZ, power, and industry – NGT & DESNZ (Bcma)



Source: Graph by the author (Sharples). Data from National Gas Transmission.[8]

Gas consumption for power generation: The difference in volumes of gas consumption for power generation is explained by the fact that NGT reports gas consumption for power generation in power stations for which electricity is the main activity. By contrast, DESNZ appears to report both the consumption of gas in power stations (with users referred to as 'Major Power Producers') *and* the consumption of gas for the generation of electricity during industrial processes (referred to as 'autoproducers').

This is confirmed by the detailed breakdown of annual gas consumption by sector and sub-sector provided by the EU statistical agency, Eurostat, for UK gas data up to 2019.[9] According to Eurostat, in 2017-2019, UK gas consumption for power generation at power stations was 21-22 Bcm per year (roughly in line with the volumes reported by NGT), but when gas consumption for power generation by autoproducers is included, this figure rises to 27-29 Bcm per year (in line with the volumes reported by DESNZ).

Gas consumption for industry: However, the fact that NGT reported volumes for industrial sector consumption are lower than those reported by DESNZ suggest that even if NGT is attributing this gas-fired electricity generation by autoproducers to the industrial, rather than power, sector, this is being offset by NGT attributing other gas consumption to the LDZ rather than industry.

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[8] National Gas Transmission, 2025. *NGT Data Portal*. https://data.nationalgas.com/

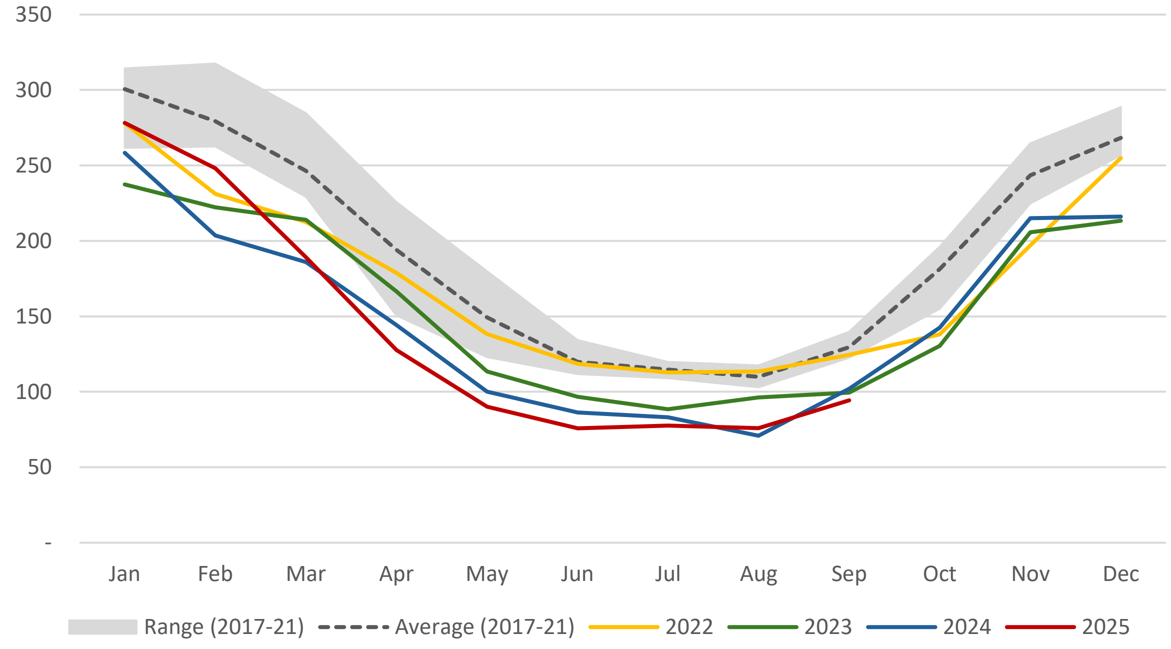
[9] Eurostat, 2025. *Supply, Transformation and Consumption of Gas*. https://ec.europa.eu/eurostat/databrowser/view/nrg_cb_gas__custom_18204361/default/table

This is explained by a comparison of the two data sources, which shows that DESNZ has a significantly wider definition of industrial gas consumption than NGT. The operational approach taken by NGT is to measure offtake from the National Transmission System (NTS) at 22 specific locations, at which individual industrial consumers offtake relatively large volumes.[10] By contrast, DESNZ adopts a statistical approach in accordance with Standard Industrial Classification (SIC), and attributes to the industrial sector all gas consumption by entities classified as 'industrial',[11] even if they are offtaking from the low-pressure local distribution network.[12]

Gas consumption in Local Distribution Zones: Referring again to Eurostat data as a benchmark, it is notable that the volumes reported by Eurostat for UK gas consumption in LDZ sectors in 2017-2019 (34-36 Bcma) are in line with the volumes reported by DESNZ (35-37 Bcma), while NGT reported volumes of gas consumption in LDZs as 48-50 Bcma in the same period.

Overall, the effect of these different definitions and attributions is for NGT to report gas consumption as being higher in LDZs and lower in the industry and power sectors, compared to DESNZ data, but for the overall volume of gas consumption reported by the two sources to be very similar. This generates confidence in the data as it is analysed in terms of seasonal shapes and daily volatility, as illustrated in **Figure 3** and **Figure 4**, below. This is particularly important for this paper, as it focuses on the daily volatility in demand – especially during winter – as the main security of supply challenge to be met in terms of GB supply being sufficiently flexible to meet GB demand on a daily basis.

Figure 3: Monthly GB gas consumption for LDZ, power, and industry – NGT (MMcm/d)



Source: Graph by the author (Sharples). Data from National Gas Transmission.[13]

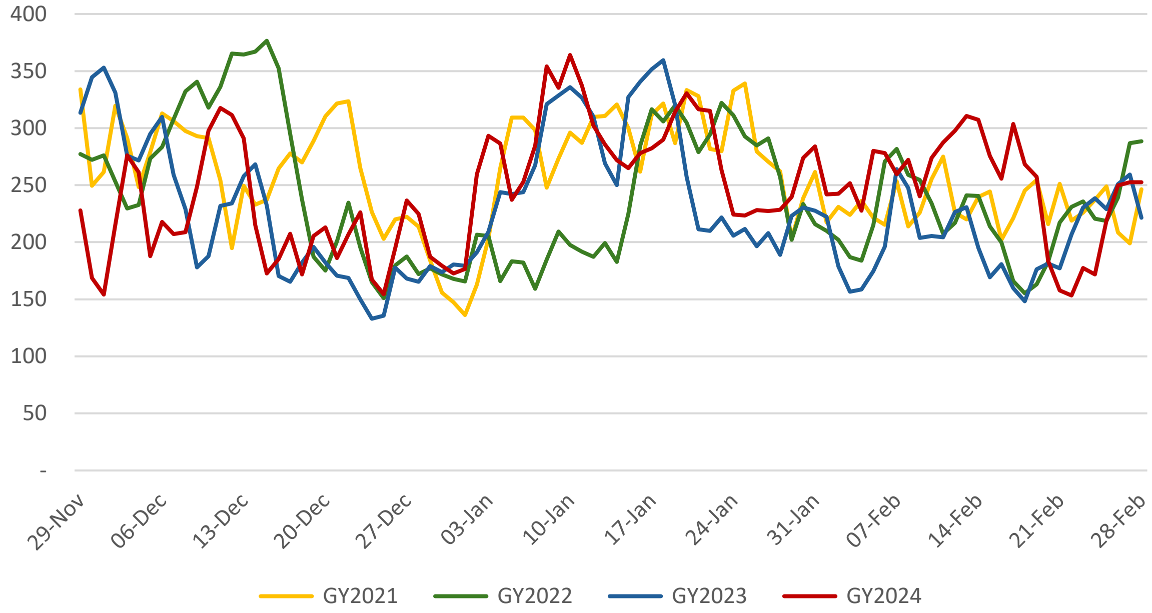
[10] NGT, 2025. *Find Gas Data*. https://data.nationalgas.com/find-gas-data (See 'Demand' – 'Exit Point Actuals' – 'Industrial Offtake' – 'Energy' to find a list of these NTS exit points for industrial activity).

[11] Iron and steel; Non-ferrous metals; Mineral products; Chemicals; Mechanical engineering and metal products; Electrical and instrument engineering; Vehicles; Food, beverages & tobacco; Textiles, clothing, leather, & footwear; Paper, printing & publishing; Other industries; Construction.

[12] DESNZ, 2010. *Energy Balance Methodology Note*. https://www.gov.uk/government/publications/energy-balance-methodology-note (see pg.11)

[13] National Gas Transmission, 2025. *NGT Data Portal*. https://data.nationalgas.com/

Figure 4: Daily GB gas consumption for LDZ, power, and industry – NGT (MMcm/d)



Source: Graph by the author (Sharples). Data from National Gas Transmission.[14]

The key point regarding GB daily gas demand is its volatility during winter, as seen over the four winters between Gas Year 2021 (2021/22) and Gas Year 2024 (2024/25). Specifically, total gas demand has fluctuated between lows of just below 150 MMcm/d and highs of 340-375 MMcm/d, and supply must be sufficiently flexible to meet that demand. The following sub-sections examine the three key demand sectors in more detail, to further illustrate the causes of that demand volatility.

2.1. Industrial sector

Gas consumption for industry in GB accounts for a limited share of total gas consumption, according to the data from both NGT and DESNZ. According to the former, where monthly average GB gas consumption peaked at roughly 315 MMcm/d in 2017-2021, and 237-278 MMcm/d since 2022, GB gas consumption for industry averaged 9-11 MMcm/d in 2017-2021 and much lower since 2022 (**Figure 5**). Therefore, even when industrial sector gas demand exhibits an increase or a decline that is significant in percentage terms (such as the spike in October 2020 or the decline during the course of 2021), the swing is not substantial in volume terms relative to total GB gas consumption. The same is also true of the daily swings in demand during winter (**Figure 6**).

However, the fact that industrial sector gas consumption includes not only the burning of gas to generate process heat but also the use of gas for space heating in large industrial sites means that (within its own narrow corridor), industrial sector gas demand can vary from day to day during the coldest parts of the winter, in response to temperature changes. This impact occurs in parallel with, and exacerbates the effect of, temperature-driven day-to-day fluctuations in LDZ gas demand.

As noted earlier, the broader definition of 'industrial sector' gas demand used by DESNZ results in a notably higher volume of demand and a strongly seasonal shape, compared to the data from NGT. In both cases, the decline since 2021 is evident: According to DESNZ, quarterly industrial sector gas demand in Q1 fell from around 40 MMcm/d in 2019-21 to 35-36 MMcm/d in 2024 and 2025, with an even stronger decline in Q4, from 38-40 MMcm/d in 2019-21 to 29-30 MMcm/d in 2022-2024.

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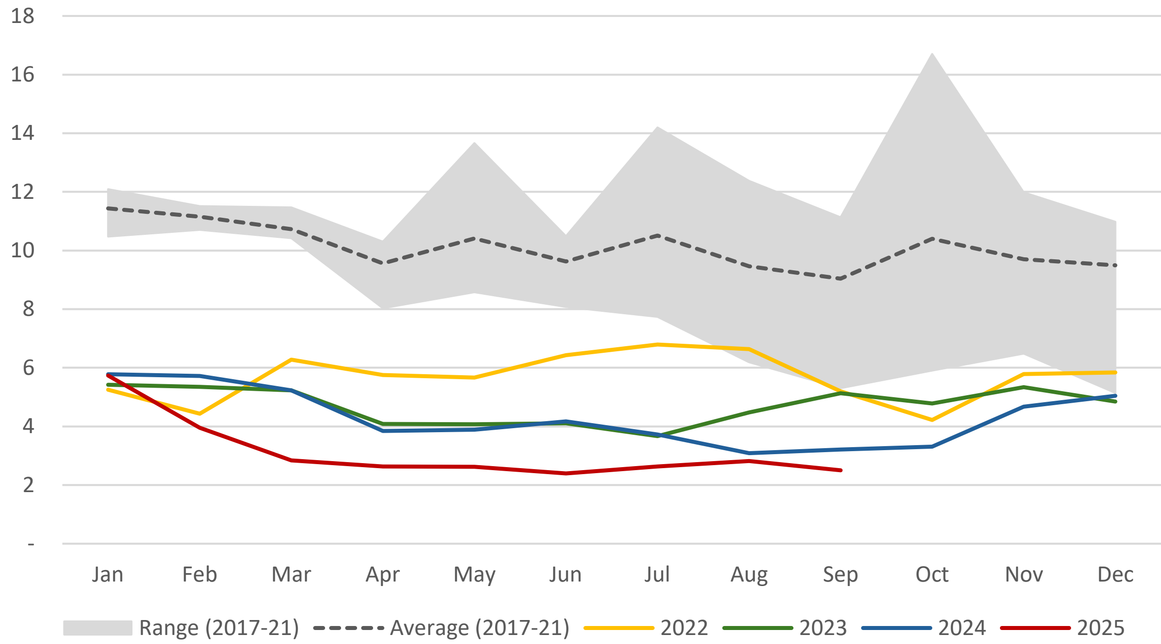
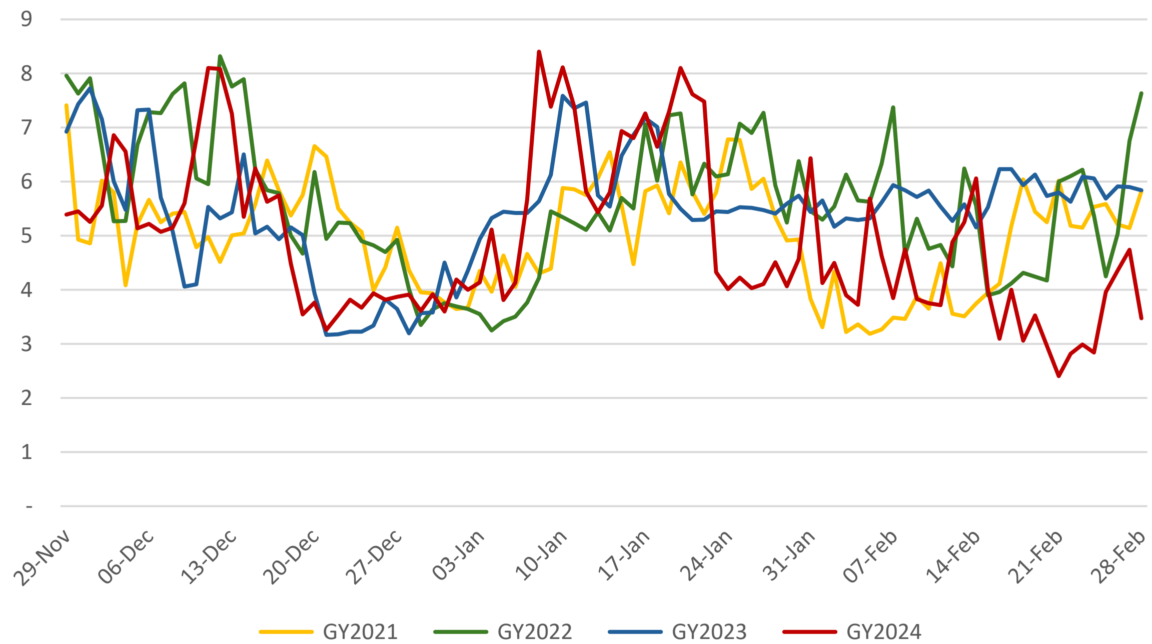
[14] National Gas Transmission, 2025. *NGT Data Portal*. https://data.nationalgas.com/

Figure 5: Monthly GB gas consumption for industry – NGT (MMcm/d)



Source: Graph by the author (Sharples). Data from National Gas Transmission.[15]

Figure 6: Daily GB gas consumption for industry – NGT (MMcm/d)



Source: Graph by the author (Sharples). Data from National Gas Transmission.[16]

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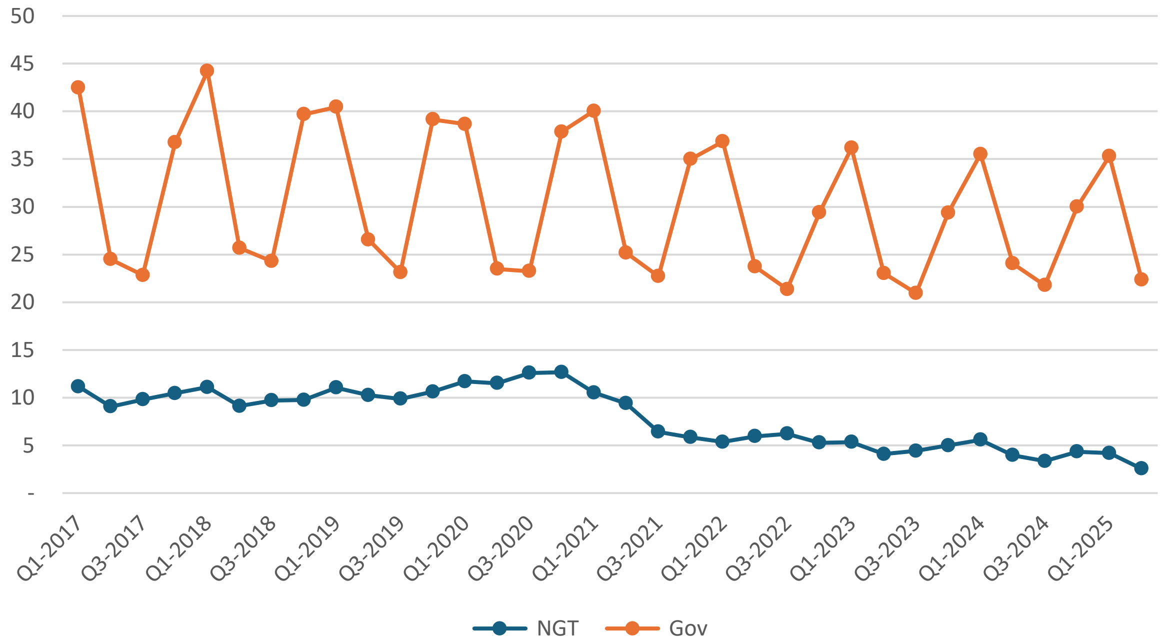
[15] National Gas Transmission, 2025. *NGT Data Portal*. https://data.nationalgas.com/

[16] National Gas Transmission, 2025. *NGT Data Portal*. https://data.nationalgas.com/

Figure 7: Quarterly GB gas consumption for industry – NGT & DESNZ (MMcm/d)



Source: Graph by the author (Sharples). Data from National Gas Transmission[17] and DESNZ Energy Trends.[18]

[17] National Gas Transmission, 2025. *NGT Data Portal*. https://data.nationalgas.com/

[18] DESNZ, 2025. *Energy Trends: UK Gas*. https://www.gov.uk/government/statistics/gas-section-4-energy-trends

2.2. Local Distribution Zones (LDZ)

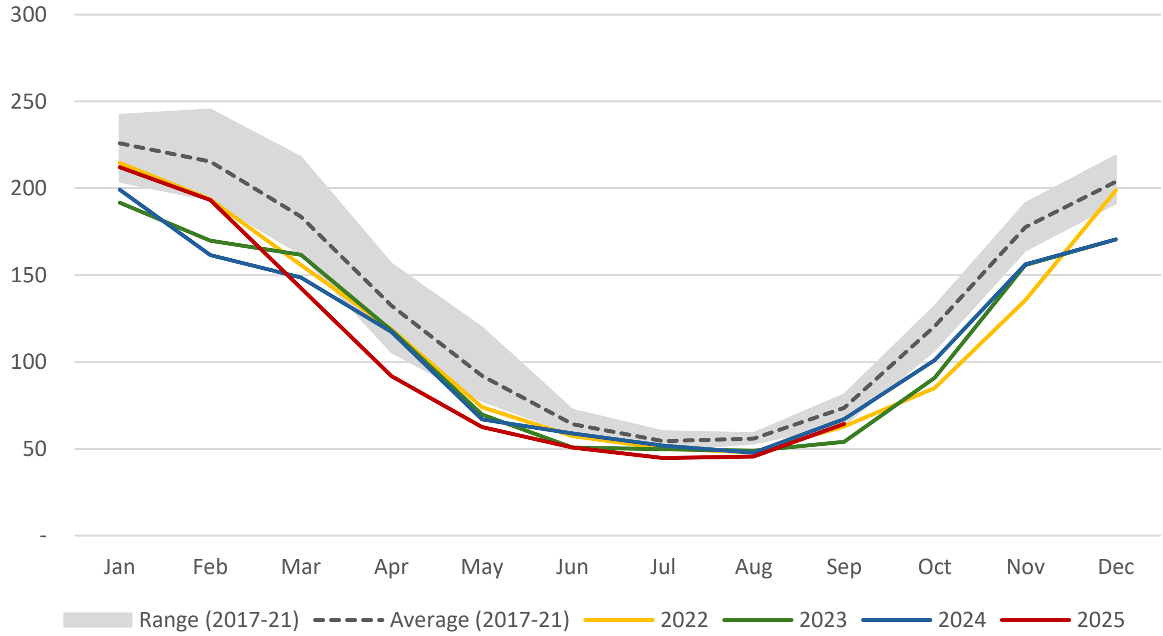
Gas demand in the LDZ (residential, commercial, and services) sector exhibits more seasonality than gas demand in the industrial sector, as illustrated in **Figure 8**. It is also more greatly affected by short-run spells of particularly cold weather during winter, as shown in **Figure 9**.

The standout feature of LDZ gas demand in winter is the sheer size of the swing. On a quarterly basis, since Q4-2021, the swing is from a low of 30 MMcm/d in Q3 to a high of 150 MMcm/d in Q1 (DESNZ) or a swing from 50 MMcm/d in Q3 to 188 MMcm/d in Q1 (NGT) (**Figure 8**). The importance of gas demand for space heating in winter as a driver of total gas demand is a key factor in the OIES 'Winter Outlook' papers.[19]

Looking only at the NGT data, the swing in monthly demand is from 50 MMcm/d in August to over 200 MMcm/d in January (**Figure 8**). The swing in daily demand is much greater: during the coldest winter period (the three months from the end of November to the end of February), the swing can be from 120 MMcm/d to 280 MMcm/d in the space of ten days (**Figure 9**).

The outlook for LDZ gas demand in the next five years is likely to see temperatures and consumer behaviour as the main drivers of demand, given the relatively slow pace of heat-pump deployment: the UK currently has roughly 25 million homes with gas boilers (85 per cent of the total)[20] compared to 250,000 heat pumps,[21] with the latter being deployed at a rate of 10,000-12,000 per month since 2024.[22]

Figure 8: Monthly GB gas consumption for LDZ – NGT (MMcm/d)



Source: Graph by the author (Sharples). Data from National Gas Transmission.[23]

[19] Farren-Price, B., Honoré, A., and Sharples, J., 2024. European Gas Market Supply & Demand: Winter Outlook 2024/25. *OIES Energy Insight № 159 (November).* https://www.oxfordenergy.org/publications/european-gas-market-supply-demand-winter-outlook-2024-25/

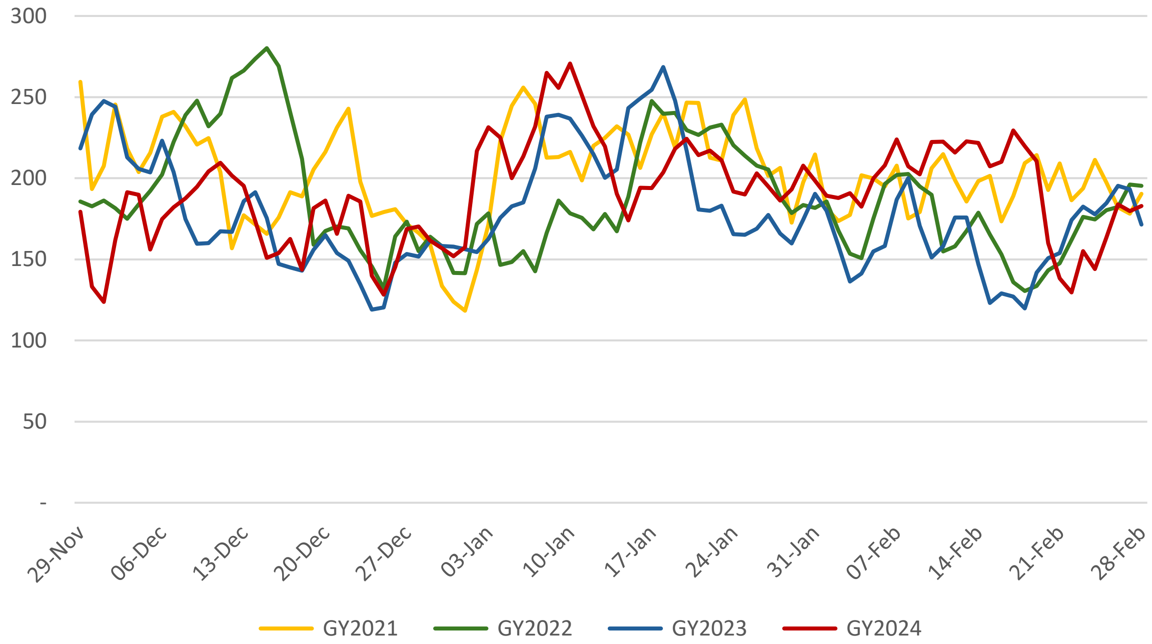
[20] DESNZ, 2024. *Hydrogen Heating: Overview*. 17 December. https://www.gov.uk/government/publications/hydrogen-heating-overview/hydrogen-heating-overview--2

[21] MCS, 2024. UK reaches 250,000 certified heat pump installations. *Press Release*, 19 August. https://mcscertified.com/uk-reaches-250000-certified-heat-pump-installations/

[22] DESNZ, 2025. *Heat Pump Deployment Statistics: June 2025*. 4 September. https://www.gov.uk/government/statistics/heat-pump-deployment-statistics-june-2025

[23] National Gas Transmission, 2025. *NGT Data Portal*. https://data.nationalgas.com/

Figure 9: Daily GB gas consumption for LDZ – NGT (MMcm/d)



Source: Graph by the author (Sharples). Data from National Gas Transmission.[24]

Figure 10: Quarterly GB gas consumption for LDZ – NGT & DESNZ (MMcm/d)

Source: Graph by the author (Sharples). Data from National Gas Transmission[25] and DESNZ Energy Trends.[26]

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[24] National Gas Transmission, 2025. *NGT Data Portal*. https://data.nationalgas.com/

[25] National Gas Transmission, 2025. *NGT Data Portal*. https://data.nationalgas.com/

[26] DESNZ, 2025. *Energy Trends: UK Gas*. https://www.gov.uk/government/statistics/gas-section-4-energy-trends

2.3. Power generation sector

Gas demand in the power generation sector exhibits less seasonality (in terms of absolute gas demand measured in MMcm/d by month) than gas demand in the LDZ sector. Since 2022, the swing has been from lows of 20-25 MMcm/d in June-August to highs of 60 MMcm/d in January (**Figure 11**). This swing of 35-40 MMcm/d between the lowest and highest months of demand is less than one-third of the swing between the lowest and highest months of LDZ demand.

However, gas demand for power generation is particularly volatile on a day-to-day (**Figure 12**) and within-day (**Figure 13**) basis, due to the role of gas-fired power stations as the 'balancing element' between the dynamics of electricity demand and the dynamics of electricity supply from non-dispatchable sources (mainly wind and solar). This short-run volatility in gas demand for power generation is particularly visible in winter, during spells of 'dunkelflaute': periods of limited solar and winter power generation occurring at periods of peak electricity demand. The issue of dunkelflaute driving gas demand volatility across Europe as a whole has been addressed in a recent OIES paper.[27]

The relative consistency of gas consumption for electricity generation by autoproducers in the industrial sector means that the difference between gas consumption for power generation reported by NGT (which does not include autoproducers) and DESNZ (which does include autoproducers) is also relatively consistent (**Figure 14**).

The mid-term outlook for gas demand in the power generation sector will be strongly influenced by the availability of other electricity supply sources: the build-out of renewable power generation capacity towards the end of the decade offset by the dip in nuclear power generation capacity due to the gap between the closure of existing capacity (2028-2030) and the launch of new capacity (2030-2035).

Notable large-scale renewable power generation capacity currently under construction and due for launch in the next several years include projects at Hornsea-3 (2.9 GW),[28] Dogger Bank (3.6 GW),[29] and Sofia (1.4 GW).[30] However, Ørsted's announcement in May 2025 of its cancellation of the Hornsea 4 project (2.4 GW) is a sign of the challenges faced by project developers in terms of cost inflation.[31]

Nuclear power generation capacity in GB is set to decline by the end of the decade, with the planned closure of plants at Hartlepool and Heysham-1 (2.2 GW combined) in 2028 and at Heysham-2 and Torness (2.4 GW combined) in 2030. [32] [33] [34] [35] New capacity is currently under construction at Hinkley Point C (3.2 GW). In January 2024, EDF announced that the first of the two 1.6 GW units is planned for launch between 2029 and 2031.[36] In July 2025, a Final Investment Decision was reached for the Sizewell C project, which is planned to follow the same design as Hinkley Point C (two 1.6 GW units).[37]

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[27] Honoré, A., and Sharples, J., 2024. Dunkelflaute: Driving Europe Gas Demand Volatility. *OIES Energy Insight № 161 (December)*. https://www.oxfordenergy.org/publications/dunkelflaute-driving-europe-gas-demand-volatility/ (p.12-13)

[28] Orsted, 2025. *Hornsea 3*. https://hornseaproject3.co.uk/

[29] Dogger Bank Wind Farm, 2025. *Dogger Bank Wind Farm*. https://doggerbank.com/

[30] RWE, 2025. *Sofia Offshore Wind Farm*. https://uk.rwe.com/project-proposals/sofia/

[31] Ørsted, 2025. Ørsted to discontinue the Hornsea 4 offshore wind project in its current form. *Press Release*, 7 May. https://orsted.com/en/company-announcement-list/2025/05/orsted-to-discontinue-the-hornsea-4-offshore-wind--143901911

[32] EDF, 2024. Investment boost to maintain UK nuclear output at current levels until at least 2026. *Press Release*, 9 January. https://www.edfenergy.com/media-centre/investment-boost-maintain-uk-nuclear-output-current-levels-until-least-2026

[33] EDF, 2024. EDF confirms boost to UK's clean power targets with nuclear life extensions. *Press Release*, 4 December. https://www.edfenergy.com/media-centre/edf-confirms-boost-uks-clean-power-targets-nuclear-life-extensions

[34] EDF, 2025. Two UK nuclear plants to generate for longer supporting energy security . *Press Release*, 2 September. https://www.edfenergy.com/media-centre/two-uk-nuclear-plants-generate-longer-supporting-energy-security

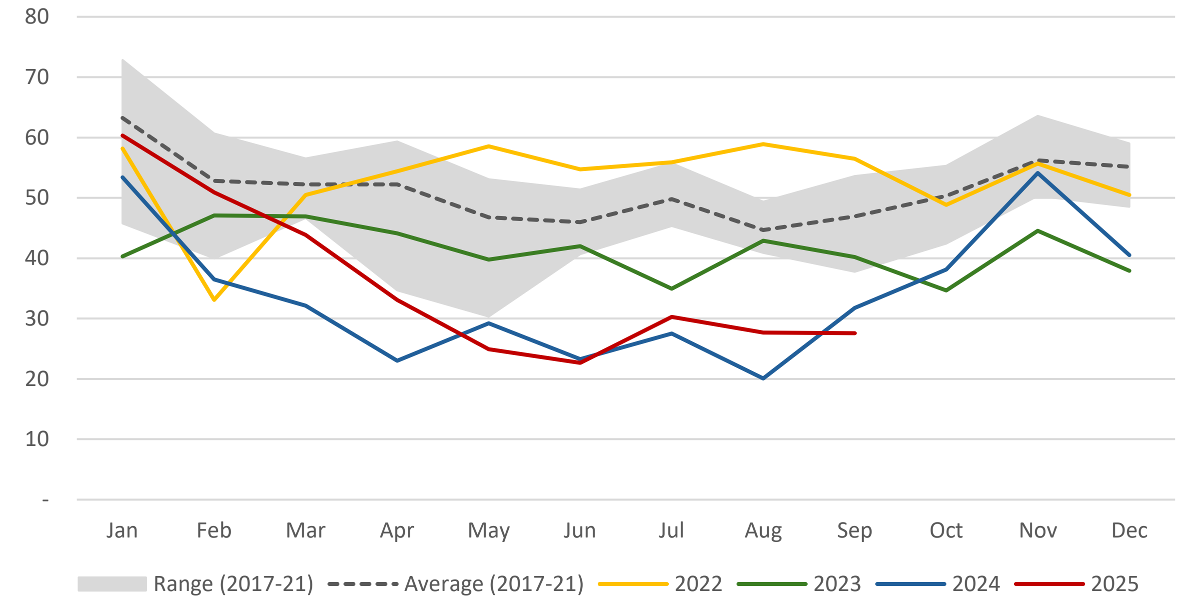
[35] Office for Nuclear Regulation, 2025. *Operational sites/facilities*. https://www.onr.org.uk/our-work/what-we-regulate/operational-power-stations/operational-sitesfacilites

[36] EDF, 2024. Hinkley Point C Update. *Press Release,* 23 January. https://www.edf.fr/en/the-edf-group/dedicated-sections/journalists/all-press-releases/hinkley-point-c-update-1

[37] Sizewell C, 2025. Final Investment Decision reached for Sizewell C – the biggest British clean energy project in a generation. *Press Release*, 22 July. https://www.sizewellc.com/news-views/final-investment-decision-reached-for-sizewell-c-the-biggest-british-clean-energy-project-in-a-generation/

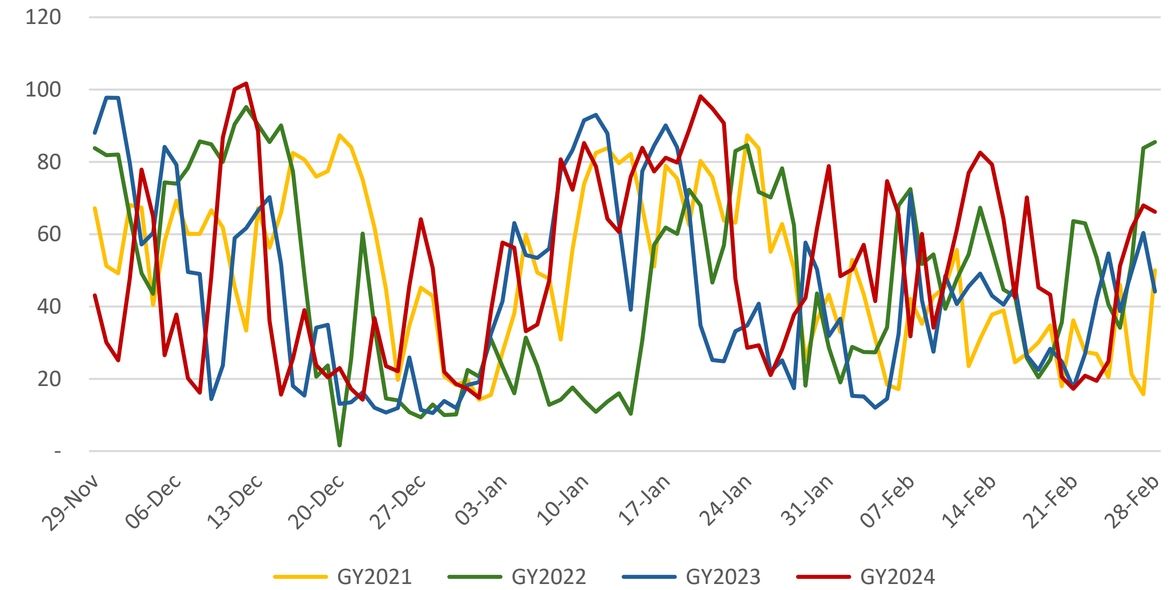
It is not until the planned launch of Sizewell C, in the 'mid-to-late 2030s', according to the project company, that GB nuclear power generation capacity will return to its present level, following the closures in 2028-2030.[38]

Figure 11: Monthly GB gas consumption for power generation – NGT (MMcm/d)



Source: Graph by the author (Sharples). Data from National Gas Transmission.[39]

Figure 12: Daily GB gas consumption for power generation – NGT (MMcm/d)



Source: Graph by the author (Sharples). Data from National Gas Transmission.[40]

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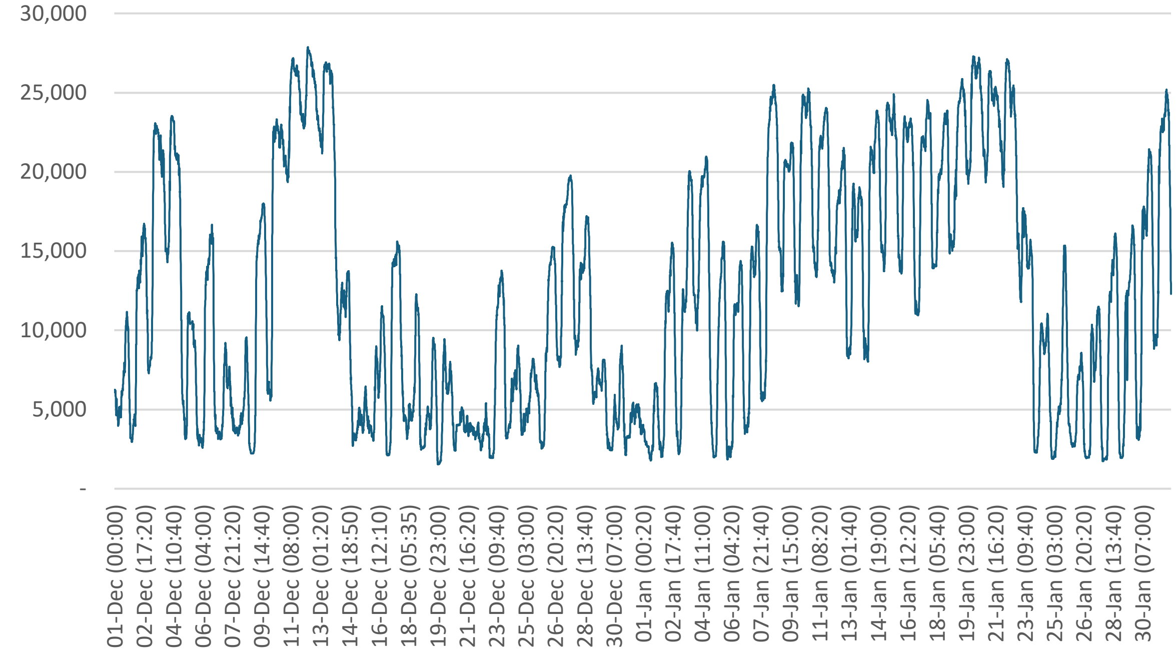
[38] Clun, R., and Issimdar, M., 2025. Sizewell C nuclear power plant costs rise to £38bn. *BBC News*, 22 July. https://www.bbc.co.uk/news/articles/cev03wer0p2o

[39] National Gas Transmission, 2025. *NGT Data Portal*. https://data.nationalgas.com/

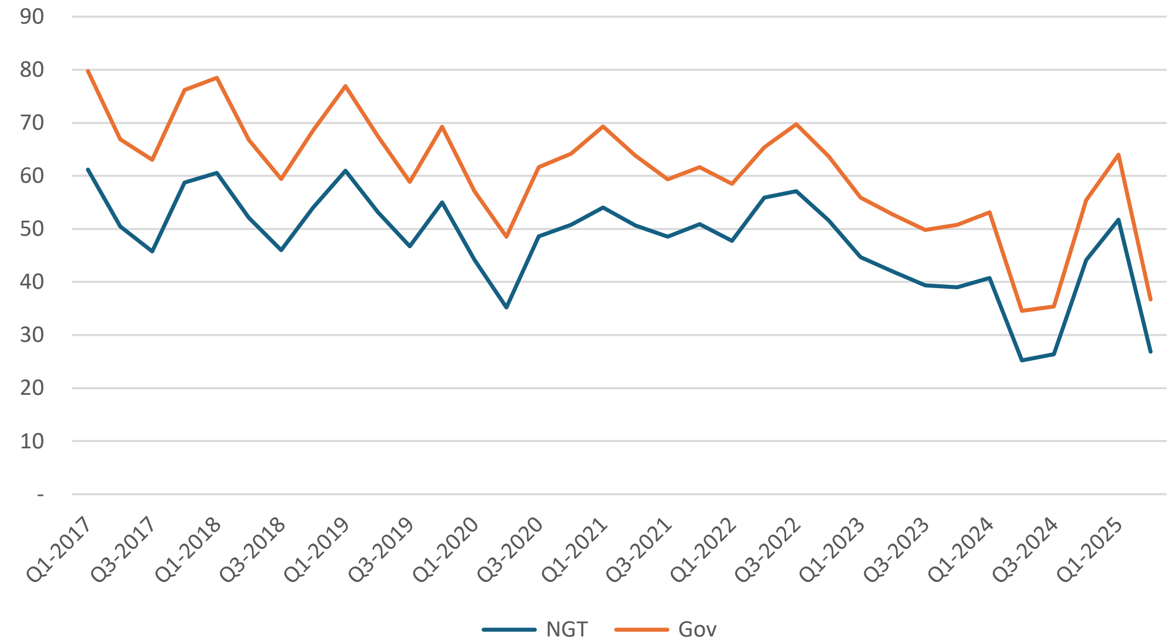
[40] National Gas Transmission, 2025. *NGT Data Portal*. https://data.nationalgas.com/

Figure 13: GB electricity generation from combined-cycle gas turbines (CCGTs) and open-cycle gas turbines (OCGTs) at 5-minute intervals in December 2024 and January 2025 (MW)



Source: Graph by the author (Sharples). Data (5-minute intervals) from GridWatch[41]

Figure 14: Quarterly GB gas consumption for power generation (MMcm/d)



Source: Graph by the author (Sharples). Data from National Gas Transmission[42] and DESNZ Energy Trends.[43]

[41] GridWatch, 2025. *Download Data Sets from the GridWatch Database*. https://www.gridwatch.templar.co.uk/download.php

[42] National Gas Transmission, 2025. *NGT Data Portal*. https://data.nationalgas.com/

[43] DESNZ, 2025. *Energy Trends: UK Gas*. https://www.gov.uk/government/statistics/gas-section-4-energy-trends

2.4. Total gas demand

To summarise, total gas demand in Great Britain for industry, LDZ, and power generation combined is strongly seasonal **(Figure 3**) and is subject to substantial volatility in daily demand, especially during the coldest parts of winter (late November to late February – see **Figure 4**), with particular seasonality in gas demand for space heating and daily and intra-day volatility in gas demand for power generation.

The overall trend for total gas demand in Great Britain (industry, LDZ, and power generation combined) has been one of decline in the period from 2021 to 2024. According to data from NGT, the 12-month rolling average for quarterly demand declined from 202 MMcm/d in Q2-2021 to 149 MMcm/d in Q3-2024, before rebounding slightly to 153 MMcm/d in the 12 months to Q2 2025. That decline was shared across the three main sectors, with industrial demand and consumer behaviour impacted by high prices (although the impact is now fading as prices fall back to the pre-crisis levels), and power sector demand impacted by the continued deployment of renewable sources of power generation.

In the very near term (12-24 months), the key factors will be temperature-driven demand for space heating and the performance of non-dispatchable renewables. Looking further ahead, the reduction in gas demand associated with the deployment of heat pumps and further build-out of renewables could be offset by the retirement of baseload power generation at nuclear power plants in 2028-2030, prior to the launch of new nuclear power generation capacity in the early to mid-2030s.

In the next several years, the key challenge will be managing the volatility of demand associated with temperature-driven gas demand for space heating and the use of gas-fired power generation to balance the electricity grid, especially at times of peak electricity demand and lower generation from non-dispatchable sources of power generation (primarily wind and solar). The following section of this paper will address the ability of the GB gas supply system to meet that call upon gas demand.

3. GB gas supply by source

A brief overview

GB has a long history of gas **production**, with significant development of North Sea production from the late 1960s onwards. Notably, GB was largely self-sufficient in gas until 2004. Import dependence subsequently grew, and since 2012, imports have provided roughly 45-50 per cent of gross consumption.

GB began receiving **pipeline imports** into St Fergus from the Norwegian North Sea in 1977.[44] [45] St Fergus is also one of several landing points for gas produced in the UK part of the North Sea. Three decades later, the launch of the Langeled pipeline in 2006 allowed more substantial imports from Norway, as GB became more import-dependent.

Pipelines connecting GB to Belgium (iUK) and Netherlands (BBL) were launched in 1998 and 2006, respectively. These allowed GB to export gas to continental Europe during the summer (when GB was supply long) and import volumes during the winter (when GB was supply short). For further **pipeline exports**, between 1993 and 2003, two interconnectors were built to export gas to the Republic of Ireland, and the Scotland-Northern Ireland Pipeline (SNIP) was built to supply Northern Ireland.[46]

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[44] Government of Norway, 2002. *Fact Sheet 2002 Norwegian Petroleum Activity*. *Chapter 2: A Brief History*. https://www.regjeringen.no/en/dokumenter/Fact-Sheet-2002-Norwegian-Petroleum-Activity-/id419395/ See also: https://www.regjeringen.no/globalassets/upload/kilde/oed/bro/2002/0006/ddd/pdfv/152165-facts_02.pdf (p.14)

[45] National Gas Transmission, 2025. *History of the Gas Industry*. https://www.nationalgas.com/about-us/history-gas-industry.

[46] Office for Budget Responsibility, 2023. *A History of Natural Gas in the UK*. https://obr.uk/box/a-history-of-natural-gas-in-the-uk/ See also: OBR, 2023. *Financial Risks and Sustainability – July 2023. Chapter 3: Energy*. https://obr.uk/frs/fiscal-risks-and-sustainability-july-2023/ https://obr.uk/frs/fiscal-risks-and-sustainability-july-2023/

LNG imports began with the launch of the Isle of Grain LNG terminal in 2005 and expanded following the launch of the South Hook and Dragon terminals at the port of Milford Haven in 2009. This LNG regasification capacity provides seasonal flexibility through variation in monthly import volumes, and daily flexibility through variation in sendout from the terminals into the grid system.

Taken together, this combination of domestic production, pipeline imports from Norway, gas trade with Belgium and the Netherlands, and LNG imports make up the portfolio of GB gas supply. In addition, the GB gas system has several **gas storage** facilities. Unlike many of the seasonal gas storage facilities in continental Europe, the GB storage facilities have small storage capacity relative to GB gas demand and operate on 'fast cycle' basis, being constantly drawn from and replenished throughout the year.

Total GB daily gas supply

It is at this point that two brief notes on methodology must be made.

Firstly, it is worth reiterating the distinction between the United Kingdom (UK) as a whole, which includes Northern Ireland, and Great Britain (GB), which does not. Therefore, supply to GB is effectively supply to the UK minus the supply from GB to Northern Ireland via the SNIP noted above. This distinction reflects both the operational separation between the GB transmission network (owned and operated by National Gas Transmission [NGT]) and the Northern Irish transmission network (operated by Gas Market Operator for Northern Ireland [GMO NI][47] on behalf of four transmission system operators [TSOs][48]), and the operational integration between the Northern Ireland transmission system and the Republic of Ireland transmission system (the latter owned and operated by Gas Networks Ireland).

Secondly, total supply (production, plus imports and gross storage withdrawals) is equal to total consumption plus pipeline exports and gross storage injections. The graph below (**Figure 15**) illustrates total daily supply. It therefore includes not only volumes that were consumed in GB, but also volumes that were delivered to Northern Ireland via SNIP and volumes that were exported to the Republic of Ireland. Given that gas supply to the island of Ireland is sourced from a combination of gas production in the Republic of Ireland and pipeline supply from GB, with pipeline supply from GB providing both seasonal flexibility generally and daily flexibility during winter in particular, it is vital that the system operated by NGT has sufficient flexibility to meet both demand in GB and Northern Ireland, and the call on imports from GB by the Republic of Ireland.

In the four winters from 2021/22 to 2024/25, total daily GB gas supply saw the ten highest daily volumes occur in the nine weeks between 29 November and 31 January with only one exception: 1 April 2022. That exception occurred at the overlap between the end of the GB winter seasonal gas demand and the start of summer re-exports to continental Europe via the iUK and BBL.

For the purposes of this paper, the focus is therefore on this nine-week period when GB experiences the greatest need for flexibility in gas supply. Notably, in the past two winters (2023/24 and 2024/25), the lowest daily supply of 208-216 MMcm/d occurred in the period 25-31 December, and the highest daily supply of 340-400 MMcm/d occurred in the period 8-22 January, in addition to the smaller peaks in daily supply experienced in the period 30 November-12 December. Intra-day volatility in gas demand means that peak supply (for example, for a period of several hours) is higher still, thus requiring hourly supply capacity to be even higher than that calculated on the basis of daily demand.

In short, over the past five winters, the GB gas transmission system demonstrated the flexibility to vary daily supply volumes from roughly 350 MMcm/d in November-December down to just over 200 MMcm/d in late December and then back up to almost 400 MMcm/d in January, without the type of large-scale seasonal gas storage capacity that exists in parts of continental Europe.

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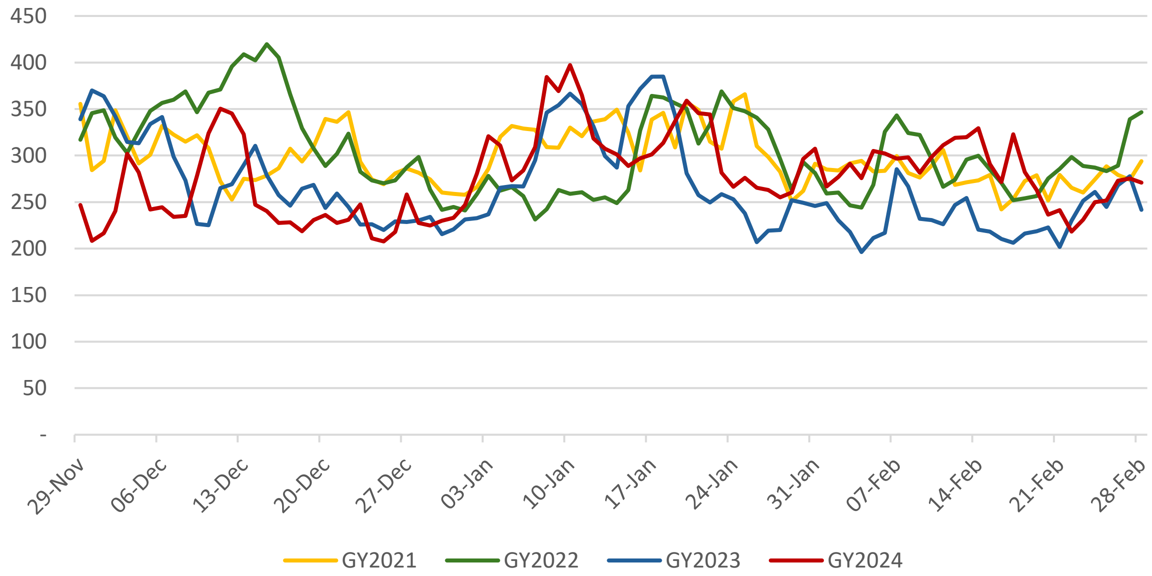
[47] GMO NI, 2025. *About Us*. https://www.gmo-ni.com/about

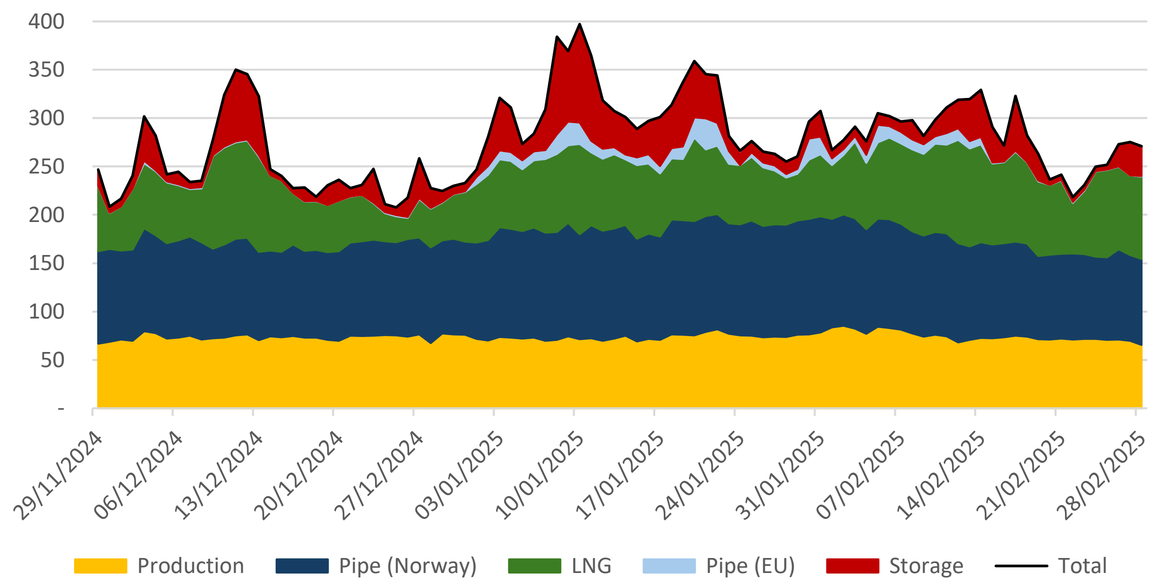
[48] Gas Networks Ireland UK (GNI UK), Premier Transmission Limited (PTL), Belfast Gas Transmission Limited (BGTL), and West Transmission Limited (WTL)

Figure 15: Gross gas supply to GB (MMcm/d)



Source: Graph by the author (Sharples). Data from National Gas Transmission.[49] Note that 'gross gas supply' refers to a combination of production brought ashore at terminals, pipeline imports, sendout from LNG regasification terminals, and gross withdrawals from storage. GY = Gas Year (which lasts from 1 October to 30 September).

Figure 16: GB daily gross gas supply by source in winter 2024/25 (MMcm/d)



Source: Graph by the author (Sharples). Data from National Gas Transmission.[50] Note that 'gross gas supply' refers to a combination of production brought ashore at terminals, pipeline imports, sendout from LNG regasification terminals, and gross withdrawals from storage.

[49] National Gas Transmission, 2025. *NGT Data Portal*. https://data.nationalgas.com/

[50] National Gas Transmission, 2025. *NGT Data Portal*. https://data.nationalgas.com/

3.1. GB domestic gas production

As illustrated in **Figure 17**, while GB was briefly a net gas exporter in a meaningful sense from 1999 to 2003, the trend from 2004 to 2013 was for the share of imports in total supply to grow, with net imports exceeding production for the first time in 2013. Since then, the trend has stabilised, with production providing 45-55 per cent of consumption on an annual basis.

According to data from DESNZ, net GB gas production (gross production minus gas industry use) peaked at 108 Bcm in 2000 before declining continuously to 32 Bcm in 2013. After a limited recovery to 38 Bcm in 2017, the decline resumed, falling to 27.5 Bcm in 2024. As illustrated in **Figure 18**, the annual data from DESNZ is consistent with the collated daily data from NGT.[51] In both cases, the original data is collected in GWh and converted to MMcm at a ratio of 10.97222 GWh per MMcm (39.5 megajoules (MJ) per cubic metre).

As GB gas production has fallen, the seasonal shape of that production has flattened. Since 2013, GB has not exhibited an ability to substantially increase gas production in the winter (Q1 and Q4) relative to summer (Q2 and Q3), as illustrated in **Figure 19**. The sharp dip in Q2-2021 is explained by the hold-over of maintenance from the COVID-afflicted 2020. The monthly GB gas production data highlighted in **Figure 20** shows the lack of a distinct peak in production during the months of highest GB demand (December-January). Rather, GB gas production appears to be on a continuous decline, with the monthly data showing a winter 'plateau' followed by downside in the summer during maintenance.

The level of the 'winter plateau' is also declining. In winter 2021/22 and 2022/23, GB net production peaked at around 90-95 MMcm/d, with the winter peak in 2023/24 falling to 80-85 MMcm/d, and the winter peak in 2024/25 falling even further to 70-75 MMcm/d.

Here it should be noted that at St Fergus, volumes produced on the UK continental shelf (UKCS) are mixed with volumes produced on the Norwegian continental shelf (NCS). In daily volume data (**Figure 21**), NGT does not distinguish between GB and Norwegian volumes. Therefore, this report considers the volumes landing at St Fergus separately from the rest of GB gas production, which comprises offshore production landed at terminals in Easington (York & Dimlington), Bacton, Barrow, and Teesside, and small volumes of onshore production at Burton Point, Saltfleetby, and Theddlethorpe.

As **Figure 22** shows, the non-St Fergus volumes of GB gas production in gas year 2023 (winter 2023/24) and gas year 2024 (winter 2024/25), were relatively flat in the range of 50-60 MMcm/d. In terms of volumes landed at St Fergus, there was a limited increase in daily supply in January 2025. However, according to UK government data, the gas imports from Norway showed a notable month-on-month increase in January 2025. When the monthly import volume reported by DESNZ is subtracted from the total volume landed at St Fergus, the remainder (attributed as UKCS production) was virtually unchanged month-on-month in January 2025.

Looking ahead, investment in new gas production in the UK North Sea could slow the decline in GB gas production but will not be sufficient to prevent the decline continuing, let alone reverse it. When Shell took FID on the development of the Victory gas field in January 2024, which has a planned production volume of 4.25 million standard cubic metres per day, or 1.55 Bcm per year, they noted that "Continued investment is required to sustain domestic production, which is declining faster than the UK's demand for oil and gas".[52] Another Shell project for new gas production in the UK North Sea,

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[51] Daily data for UK gas production comprises volumes produced offshore and landed at the following terminals: Easington (York & Dimlington), Bacton, Barrow, Burton Point, Rough Sub-Terminal, Teesside (CATS and PX), Theddlethorpe (closed in 2018), and St Fergus. In addition, National Gas Transmission reports daily production at Saltfleetby (onshore). The figure for St Fergus is calculated, dividing the total volume landed at St Fergus between a percentage allocated as UK production and a percentage allocated as import from Norway. The percentages are based on the figure for total imports from Norway into St Fergus reported by DESNZ.

[52] Shell, 2024. Shell invests in the Victory gas field in the UK North Sea. *Press Release*, 24 January. https://www.shell.co.uk/about-us/news-and-publications/media-releases/2024-media-releases/shell-invests-in-the-victory-gas-field-in-the-uk-north-sea.html Shell referred to this gas production volume as "enough gas to heat almost 900,000 homes per year".

Jackdaw, has an estimated planned production volume of 2.4 Bcm per year.[53] As **Figure 18** shows, the decline in total GB gas production between 2023 and 2024 was 4.3 Bcm according to NGT and 3.6 Bcm according to DESNZ, meaning that the new production from Victory and Jackdaw would only be sufficient to reverse one year of decline in total GB gas production.

The view of the North Sea Transition Authority (NSTA)[54] and the UK government[55] is that the decline in GB gas production is ongoing and its continuation is inevitable, and the only question is how rapid the decline is going to be over the coming decades. As shown in **Figure 23**, the NSTA projects that GB net gas production could fall from 27.3 Bcm in 2024 to 12.2 Bcm in 2030, while **Figure 24** highlights the view of the UK government (in March 2025) that:

> *"Given the maturity of the basin, and the high proportion of future production projected to come from existing developments versus new developments and discoveries, further licensing in the North Sea would not reverse the basin's natural decline. Future exploration and production licences would not meaningfully increase UK production levels, nor would they change the UK's status as a net importer of oil and gas. The government has been clear that it would not issue new licences to explore new fields."* [56]

Conversely, Offshore Energy UK (OEUK) has called on the government to commit to new licencing rounds to help extend the life of existing assets:

> *"Most of the UK's future oil and gas production will come from existing, licenced blocks where fields have already been identified. However, new licences will play a part in ensuring that the life of existing assets are extended through tie-backs, helping the UK meets as much of its own demand through homegrown production."* [57]

The combination of the current decline in production and reluctance of the UK government to issue new licences for exploration and production suggest that the decline will not be reversed. The decline will only be slowed if there is a change in government policy to allow the issue of new exploration and production licences. Not only does this mean that GB will remain a significant net importer of its gas supply, but also that GB will not gain new upside flexibility in supply from domestic production, compared to its current levels.

The ongoing decline in annual GB gas production underpins a key point: during winter when GB production is at its high plateau, it has no flexible upside potential to meet a short-run surge in gas demand, such as those generated by 'dunkelflaute' in the power-generation sector or by a blast of cold weather spurring gas demand for space heating, primarily in the residential-commercial sector and to a lesser extent, in the industrial sector. Given the outlook for GB gas production in the coming five years and beyond, this lack of upside flexibility is likely to continue.

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[53] Shell, 2025. *Jackdaw field*. https://www.shell.co.uk/about-us/what-we-do/oil-and-gas/shell-jackdaw-project.html Shell has not stated the planned production volume but has stated that it will be "enough fuel to heat 1.4 million UK homes". If 1.55 Bcma at Victory is sufficient for 900,000 homes, then 1.4 million homes could be supplied by 2.4 Bcma. The Jackdaw field was approved by the UK government in June 2022 but is now subject to legal challenge.

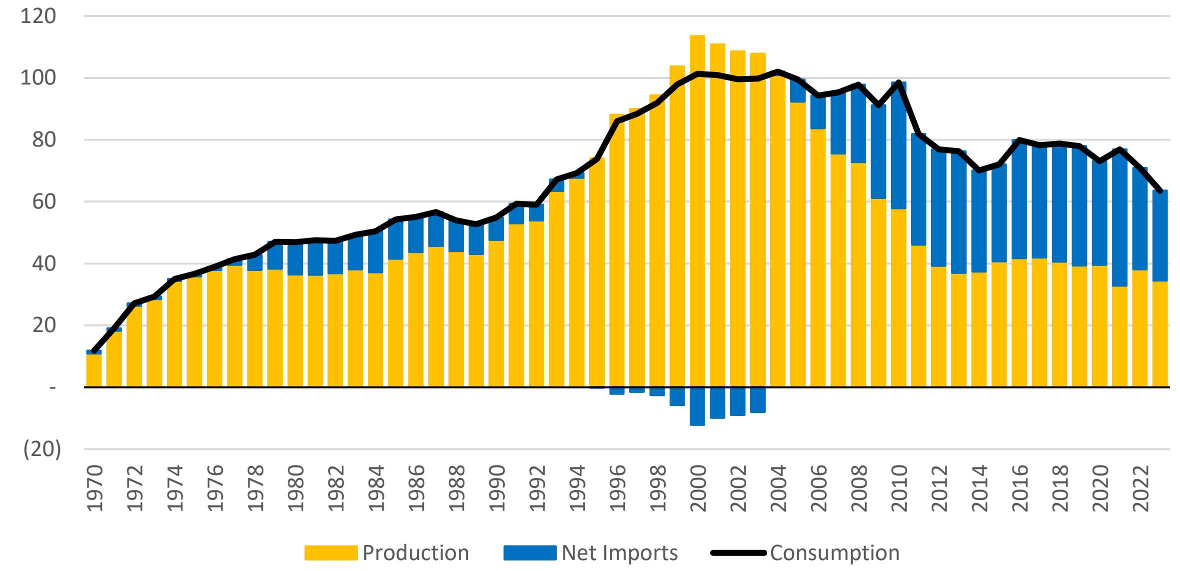
[54] NSTA, 2025. *NSTA August 2025 Production Projections Plus CCC and DESNZ Demand Projections*. https://www.nstauthority.co.uk/data-and-insights/insights-and-analysis/production-and-expenditure-projections/

[55] UK government, 2025. Building the North Sea's Energy Future. *Consultation Document*, 25 March. https://www.gov.uk/government/consultations/building-the-north-seas-energy-future/building-the-north-seas-energy-future-consultation-document-accessible-webpage (See Chapter 2: The need for action to secure the future of the UKCS)

[56] UK government, 2025. Building the North Sea's Energy Future. *Consultation Document*, 25 March. https://www.gov.uk/government/consultations/building-the-north-seas-energy-future/building-the-north-seas-energy-future-consultation-document-accessible-webpage (See Chapter 4.1.2: Offshore licensing)

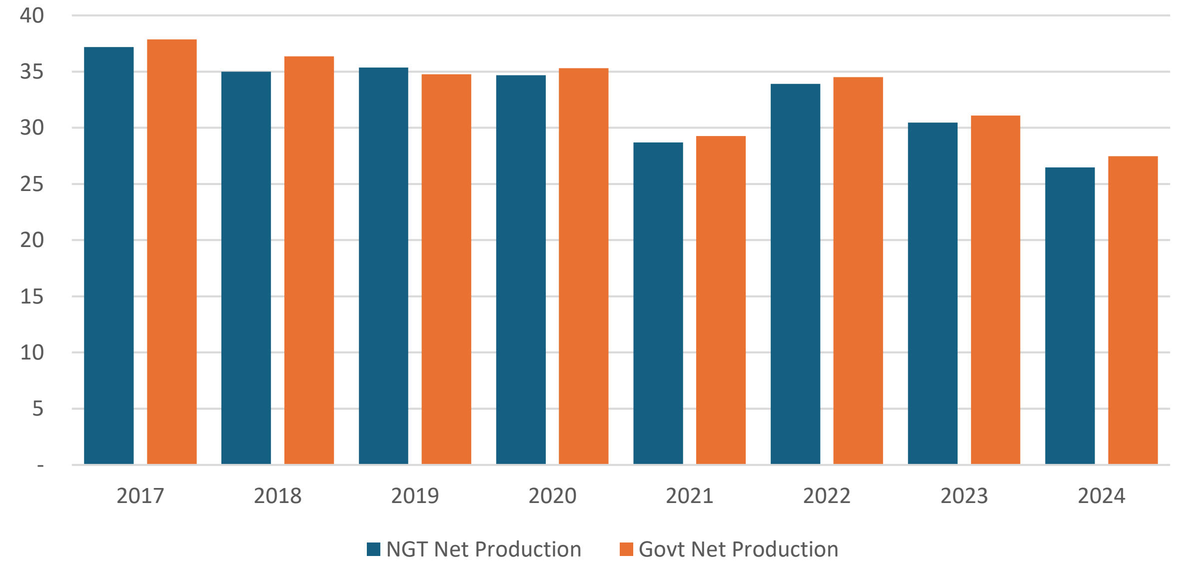
[57] OEUK, 2025. *Future of the North Sea – Briefing Document 2025*. August. https://oeuk.org.uk/product/future-of-the-north-sea-briefing-document-2025/. OEUK is a trade association for the UK offshore energy industry.

Figure 17: GB gas production, consumption, and net imports (Bcm per year)



Source: Graph by the author (Sharples). Data from Energy Institute Statistical Review of World Energy 2024.[58] Note that this graph refers to gross production and that consumption by the gas industry is included in 'consumption'.

Figure 18: GB net gas production (Bcm per year)



Source: Graph by the author (Sharples). Data on net gas production from National Gas Transmission[59] and DESNZ.[60] Note that this graph refers to net production, with gas use by the gas industry subtracted from the gross production.

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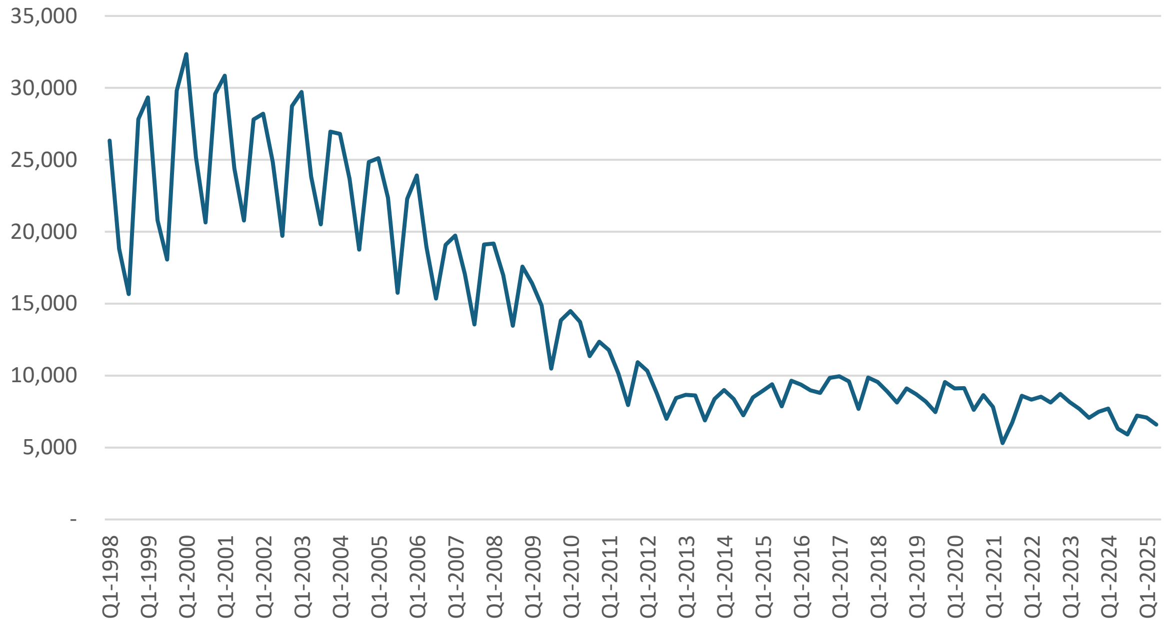
[58] Energy Institute, 2024. *Statistical Review of World Energy*. https://www.energyinst.org/statistical-review/resources-and-data-downloads

[59] National Gas Transmission, 2025. *Gas Transmission Data*. https://data.nationalgas.com/find-gas-data

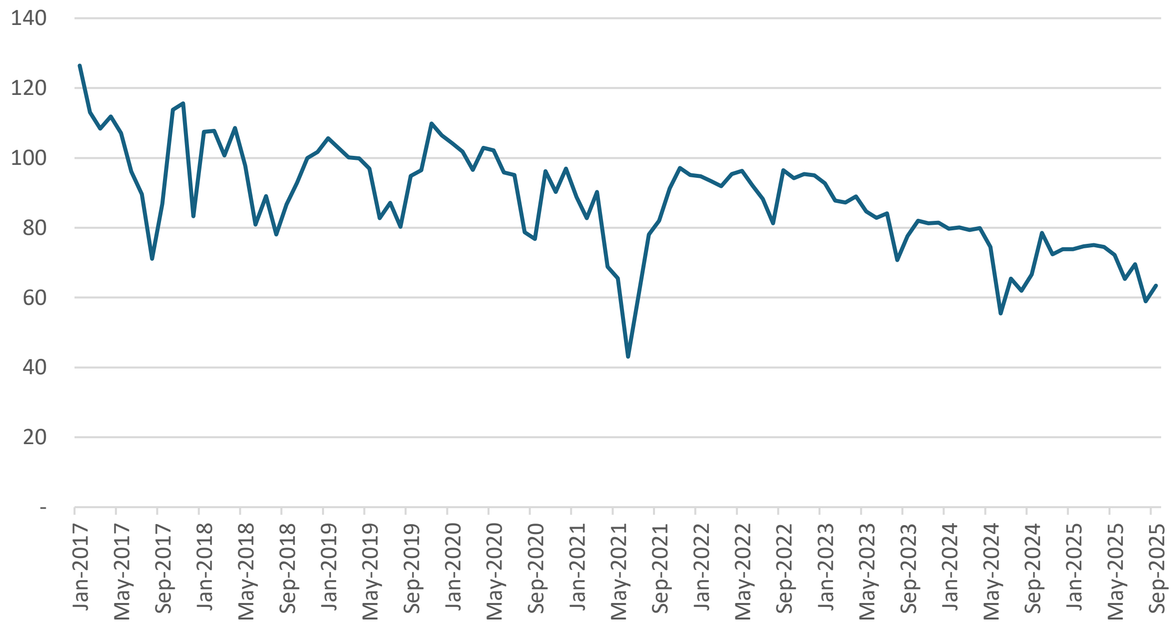
[60] DESNZ, 2025. *Energy Trends gas tables (ODS)*. https://www.gov.uk/government/statistics/gas-section-4-energy-trends

Figure 19: GB quarterly net gas production since 2000 (MMcm/d by quarter)



Source: Graph by the author (Sharples). Data from DESNZ.[61]

Figure 20: GB monthly net gas production since January 2017 (MMcm/d by month)



Source: Graph by the author (Sharples). Data from National Gas Transmission.[62] [63]

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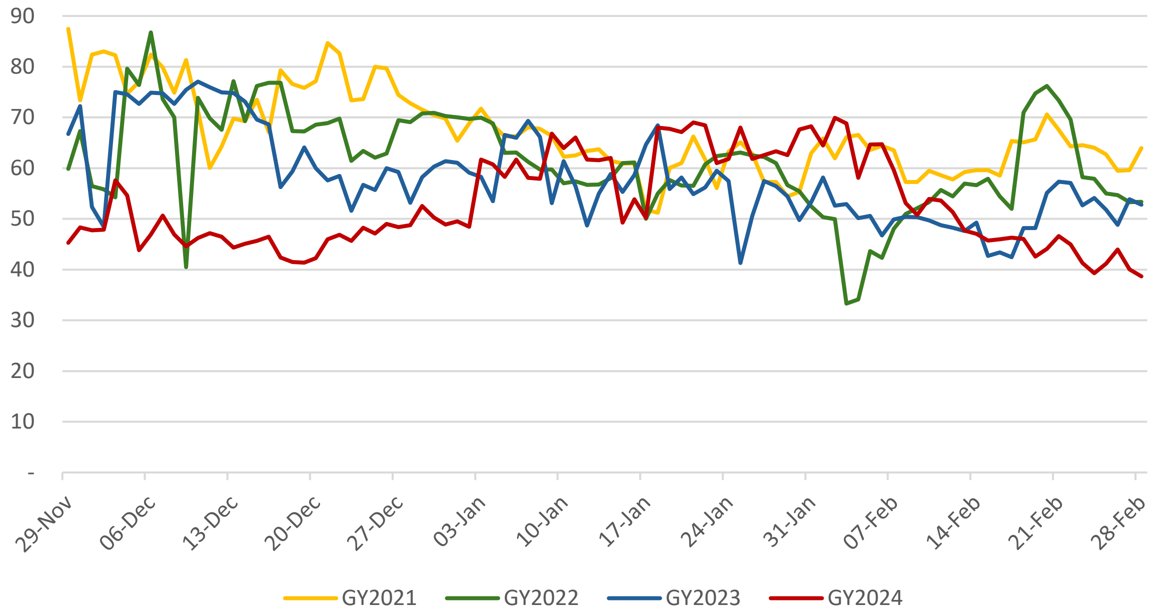
[61] DESNZ, 2025. *Energy Trends gas tables (ODS)*. https://www.gov.uk/government/statistics/gas-section-4-energy-trends

[62] National Gas Transmission, 2025. *Gas Transmission Data*. https://data.nationalgas.com/find-gas-data

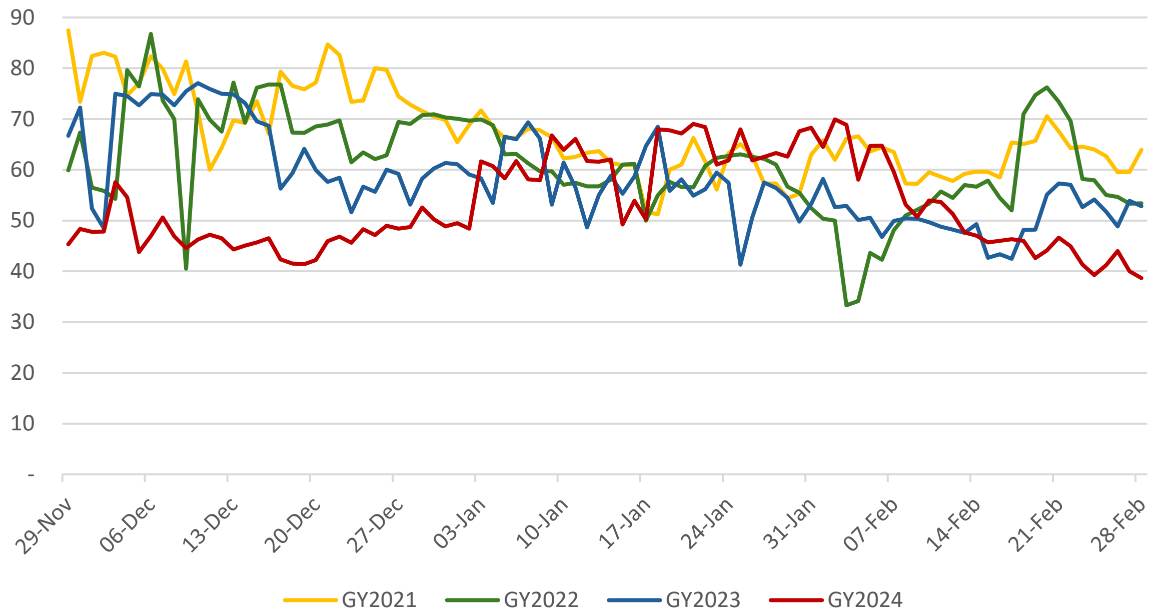
[63] Data for UK gas production comprises Easington (York & Dimlington), Bacton, Barrow, Burton Point, Saltfleetby, Rough Sub-Terminal, Teesside (CATS and PX), Theddlethorpe, and St Fergus. The figure for St Fergus is calculated, dividing the total

Figure 21: Daily volume landed at St Fergus: volumes produced on UKCS and NCS (MMcm/d)



Source: Graph by the author (Sharples). Data from National Gas Transmission.[64] UKCS = UK Continental Shelf and NCS = Norwegian Continental Shelf. GY = Gas Year (which lasts from 1 October to 30 September).

Figure 22: GB daily net gas production excluding St Fergus (MMcm/d)



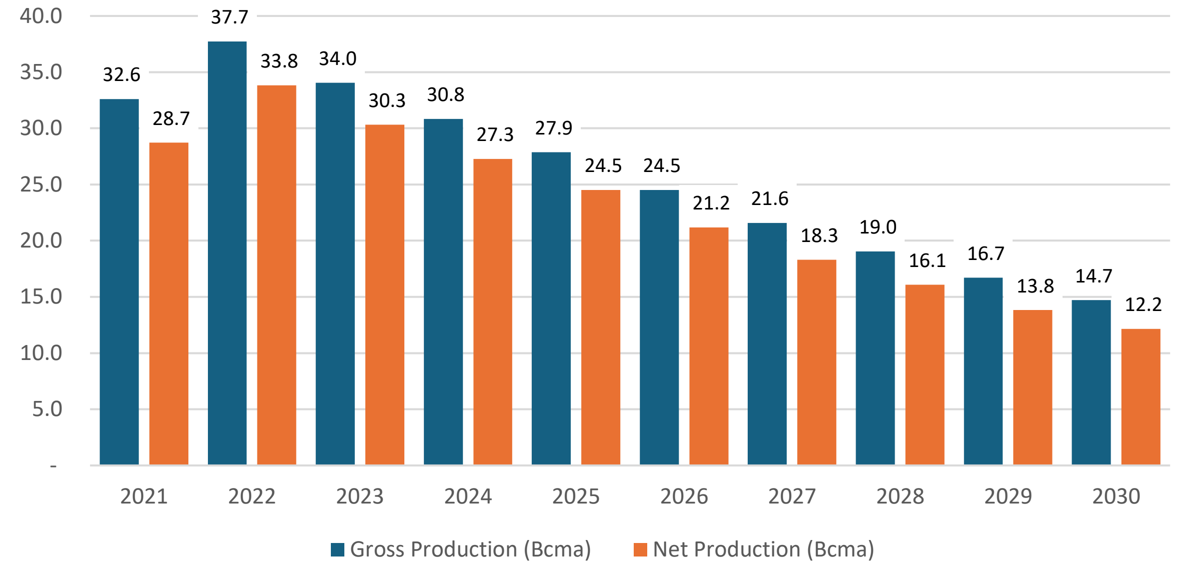
Source: Graph by the author (Sharples). Data from National Gas Transmission.[65]

volume landed at St Fergus between a percentage allocated as UK production and a percentage allocated as import from Norway. The percentages are based on the figure for total imports from Norway into St Fergus reported by DESNZ.

[64] National Gas Transmission, 2025. *Gas Transmission Data*. https://data.nationalgas.com/find-gas-data

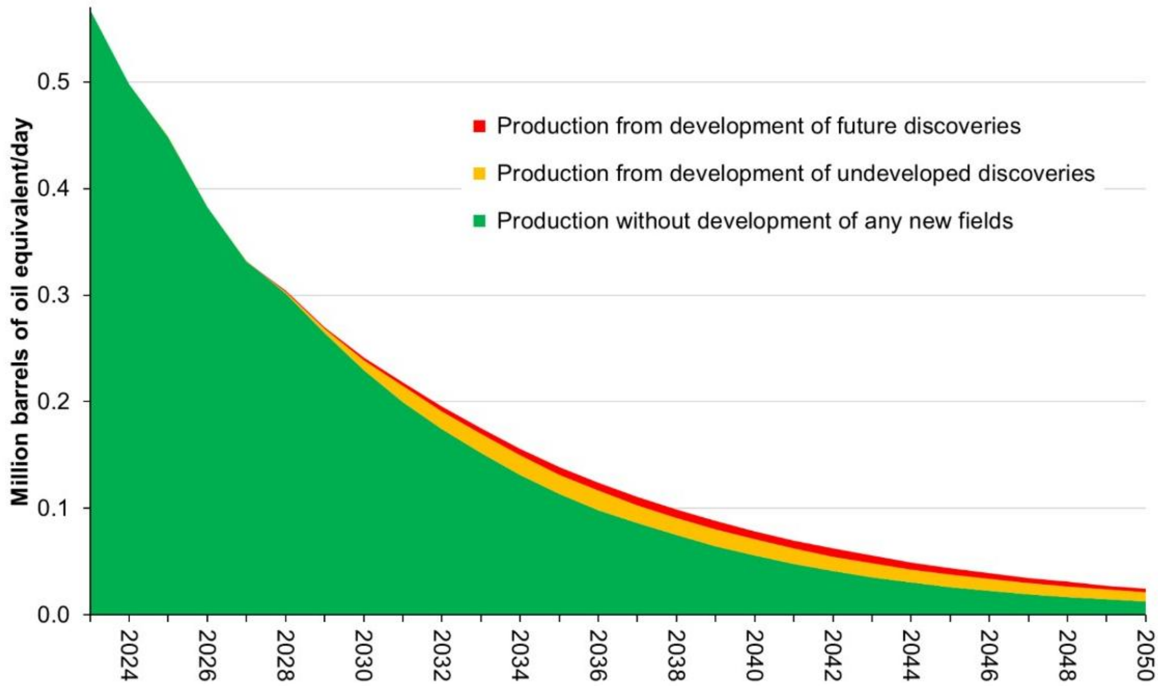
[65] National Gas Transmission, 2025. *Gas Transmission Data*. https://data.nationalgas.com/find-gas-data

Figure 23: UK North Sea Transition Authority UK gas production forecast (March 2025 - Bcma)



Source: Graph by the author (Sharples). Data from UK NSTA.[66]

Figure 24: UK gross gas: illustrative splits of NSTA October 2024 production projections



Source: Graph from UK government.[67]

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[66] NSTA, 2025. *NSTA March 2025 Projections of UK Oil and Gas Production and Expenditure*. https://www.nstauthority.co.uk/data-and-insights/insights-and-analysis/production-and-expenditure-projections/

[67] UK government, 2025. Building the North Sea's Energy Future. *Consultation Document*, 25 March. https://www.gov.uk/government/consultations/building-the-north-seas-energy-future/building-the-north-seas-energy-future-consultation-document-accessible-webpage (See Chapter 2: The need for action to secure the future of the UKCS)

3.2. Pipeline gas imports from Norway

As GB became more import-dependent from 2004 onwards, the shortfall was initially largely met through the growth in pipeline imports from Norway, firstly into St Fergus and then later into Easington, following the launch of the Langeled pipeline in 2006. This growth in annual imports from Norway via these two routes is illustrated in **Figure 25**. GB imports of pipeline gas from Norway make landfall at two receiving terminals, St Fergus and Easington, both of which also receive gas produced in UK waters of the North Sea.

3.2.1. St Fergus

At St Fergus, the capacity to supply a mixture of GB and Norwegian gas into the national transmission system is determined by the multifaceted nature of the supply from multiple fields via several pipelines to the receiving terminal.

SEGAL (FLAGS and FGL)

The Shell-Esso Gas and Liquids (SEGAL) system incorporates the Far North Liquids and Associated Gas System (FLAGS), the Fulmar Gas Line (FGL), the receiving terminal at St Fergus, the Mossmorran Natural Gas Liquids (NGL) fractionation plant and the Braefoot Bay loading facilities in Fife. The system processes wet gas[68] from GB and Norwegian fields. The FLAGS connects to the Brent field, the Tampen Link pipeline (to the Statfjord field), and dedicated pipelines to the Knarr and Gjøa fields, while the FGL sources from a number of fields in the Central North Sea.

The ownership of SEGAL is split 50-50 between Shell and ExxonMobil. According to Shell, the SEGAL terminal at St Fergus has a 45 MMcm/d capacity, but only 32 MMcm/d of "wet gas modular capacity". The terminal is fed by FLAGS (32 MMcm/d capacity) and FGL (12 MMcm/d capacity).[69] [70]

FUKA (Frigg) & Vesterled

St Fergus also receives gas from via the FUKA (Frigg UK Association) pipeline system (which has a capacity of 36 MMcm/d) and via the Gassco-owned Vesterled pipeline, which supplies dry gas from the Gassled JV to North Sea Midstream Partners (NSMP), from the Heimdal platform.[71] [72]

SAGE

St Fergus is also the landing point of the Scottish Area Gas Evacuation (SAGE) system, which consists of a gas processing plant in St Fergus that is fed by the SAGE pipeline from Alvaheim, Edvard Greig, and Ivar Aasen fields.[73] According to Ancala Midstream, the capacity of the SAGE system is 1,990 million standard cubic feet per day (MMscf/d), which equates to approximately 28 MMcm/d.

Data on gas supply into St Fergus

As the GB Transmission System Operator, NGT reports daily flows into St Fergus in three categories as 'St Fergus – Shell', 'St Fergus – Mobil', and 'St Fergus – NSMP'. [74] This daily data is provided by the three named operators and does not distinguish between volumes produced in UK and in Norwegian waters (i.e., between domestic production and imports from Norway). Similarly, the ENTSOG

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[68] Natural gas is primarily methane. Wet gas contains other hydrocarbons (typically ethane, propane, butane, and/or pentane) and/or non-hydrocarbons (water vapor, carbon dioxide, hydrogen sulfide, nitrogen and trace amounts of helium). Once a sufficient proportion of these other elements are removed, the natural gas may be injected into the grid system. See: Energy Information Administration (EIA), 2025. *Glossary - Wet natural gas*. https://www.eia.gov/tools/glossary/index.php?id=W

[69] ExxonMobil, 2025. *The SEGAL system*. https://www.exxonmobil.co.uk/company/overview/uk-operations/access-to-oil-and-gas-infrastructure#SEGALsystem

[70] Shell, 2025. *The SEGAL system*. https://www.shell.co.uk/business/oil-and-gas/segal-system.html

[71] NSMP, 2025. *St Fergus Gas Terminal*. https://nsmp-limited.com/our-assets/st-fergus-gas-terminal/

[72] NSMP, 2025. *FUKA Pipeline*. https://nsmp-limited.com/our-assets/fuka-pipeline/

[73] Ancala Midstream, 2025. *Our Assets*. https://www.ancalamidstream.com/our-assets/

[74] National Gas Transmission, 2025. *Find Gas Data. Supplies – Daily Actuals (Physical) – Volume – System Entry Volume, St Fergus.* https://data.nationalgas.com/find-gas-data

Transparency Platform reports only a single daily figure for total flows into St Fergus. Therefore, the total volume flowing into St Fergus can be calculated from NGT data by adding together the volumes reported by Shell, Mobil, and NSMP, and can be compared to the single figure reported by ENTSOG.

DESNZ reports monthly *imports* into St Fergus via FLAGS, Frigg/Vesterled, and SAGE as separate items. However, DESNZ does not publish data on the volume of specifically GB gas production landed at St Fergus, nor does it publish a single figure for the total volume of gas landing at St Fergus, from which the imports may be subtracted to calculate the volume attributed to UKCS production.

The Norwegian pipeline operator, Gassco, reports daily nominations (not physical flows) for these volumes in two categories: 'Fields Delivering into SEGAL' and 'St Fergus'. Here it is worth noting that Gassco only reports nominations for pipeline infrastructure that it owns and operates. Therefore, the Gassco nominations for SEGAL apply to the Tampen Link (25 MMcm/d capacity) and Gjøa Gas Pipeline (18.2 MMcm/d capacity), and the Gassco nominations for 'St Fergus' only apply to the Vesterled pipeline (35 MMcm/d capacity).[75]

Taking the different elements of the supply system into consideration, it is notable that the volume of monthly physical supply into St Fergus during the peak month each winter has fallen from 105 MMcm/d in January 2017 to 75-85 MMcm/d in January in 2019, 2021, and 2022, before falling further to 65 MMcm/d in December 2023 and 62 MMcm/d in January 2025 (see **Figure 29**). This suggests that the peak flows into St Fergus are constrained by gas production capacity, rather than the capacity for pipeline transportation and gas processing.

3.2.2. Easington

The Easington terminal receives small volumes of GB gas production from the North Sea (4-5 MMcm/d outside summer maintenance periods, since 2019). However, the vast majority of supply into Easington is delivered via the Langeled pipeline, which has a capacity of 76 MMcm/d[76] (793.3 GWh/d[77]). As illustrated in **Figure 27** and **Figure 28**, GB imports via Langeled show substantial seasonal flexibility, but once they reach the high winter plateau (as they did from November to April in winter 2023/24 and from November to February in winter 2024/25), there is no further upside flexibility.

Looking ahead, and given the importance of Norwegian supply into Easington via Langeled, it is worth noting the Norwegian forecasts for a decline in total gas exports in the period 2025-2035 (**Figure 30**), which reflect expectations by the Norwegian Ministry of Energy and the Norwegian Offshore Directorate that Norwegian gas production will remain broadly stable at around 120 Bcma until 2027, before entering a gradual decline to 2030. Thereafter, the pace of the decline will depend upon the extent to which new resources in existing fields, new resources in new discoveries, and as-yet-undiscovered resources are developed, to offset the decline in production from existing reserves.[78]

According to the Norsk Petroleum forecast (**Figure 30**), total Norwegian gas exports to GB and EU-27 could fall from around 120 Bcm in 2025 to around 100 Bcm in 2030 and then fall further to 60-80 Bcm in 2035. Such a decline would result in spare capacity on Norway's pipeline export system, even during the peak winter demand period. This, in turn, would provide optionality for Norwegian gas sellers and stimulate competition between buyers of Norwegian pipeline gas in GB (via Langeled to Easington) and buyers of Norwegian pipeline gas in continental Europe (via the Franpipe, Zeepipe, Norpipe, Europipe 1, Europipe 2, and Baltic Pipe), as illustrated in **Figure 48** in the annex to this report. Under such

[75] Gassco, 2025. *Gassco Map*. https://gassco.eu/en/transport-map/

[76] UK Government Department for Business, Energy, and Industrial Strategy (BEIS), 2018. *UK national risk assessment on security of gas supply*. https://assets.publishing.service.gov.uk/media/5c50367e40f0b625504f4574/national-risk-assessment-security-gas-supply.pdf (Published November 2018 – see page 26)

[77] GIE, 2025. *System Capacity Map*. https://www.gie.eu/publications/maps/system-capacity-map/ [updated10 January 2025]

[78] Norsk Petroleum, 2025. *Production forecasts*. https://www.norskpetroleum.no/en/production-and-exports/production-forecasts/#production-forecasts

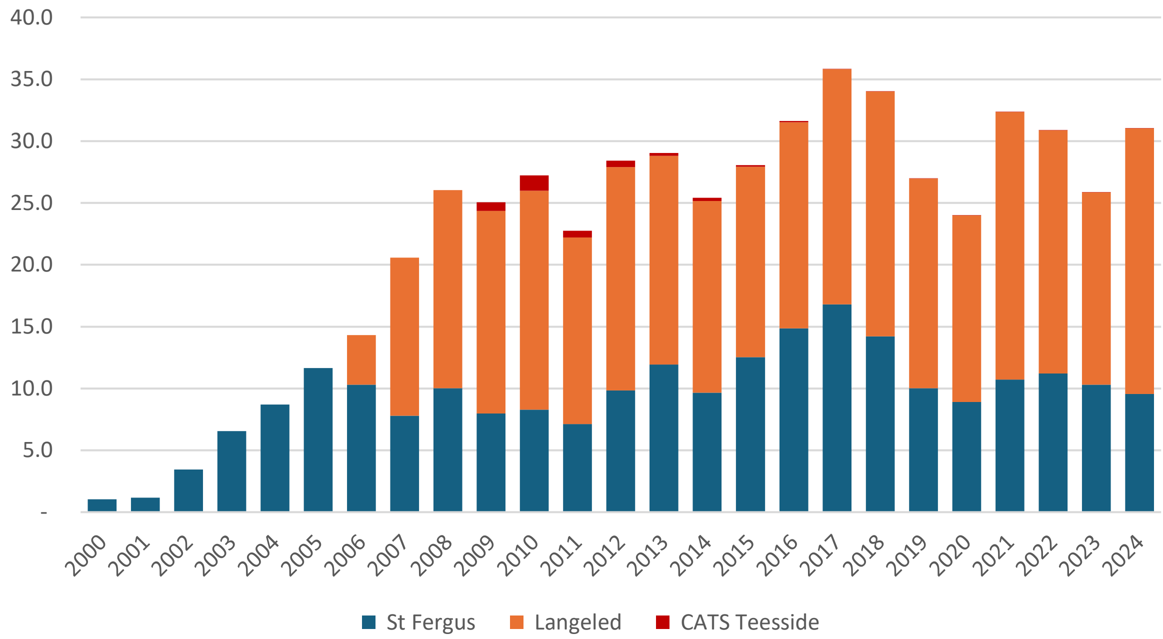
circumstances, the differential between NBP and TTF would play a significant role in determining the volume of Norwegian pipeline gas imported into GB during winter.

3.2.3. Total pipeline imports from Norway

According to the volumes reported by DESNZ, the annual volumes of imports into St Fergus between 2019 and 2024 were relatively stable in the range of 8.9-11.2 Bcm per year. By contrast, the import volumes delivered to Easington via the Langeled pipeline have seen much more variation, in the range of 15.1-21.6 Bcm per year. Imports via Langeled to Easington also exhibit much greater seasonal variation, ramping up during the peak winter demand periods and ramping down during the summer months, to accommodate both lower GB gas demand and maintenance-led curtailments in Norwegian gas production.

GB pipeline gas imports from Norway exhibit substantial seasonal flexibility, mainly in relation to imports via the Langeled pipeline. However, once the Langeled pipeline is operating at full capacity during the winter months, there is virtually no upside flexibility to GB pipeline imports from Norway. Looking ahead, the projected decline in Norwegian pipeline gas exports from the late 2020s onwards could introduce greater competition between buyers of Norwegian pipeline gas, especially during winter. This could require NBP to remain at a premium to TTF, if the GB imports via Langeled are to remain at full capacity during winter, in order to incentivise Norwegian supply to flow to GB rather than to continental Europe.

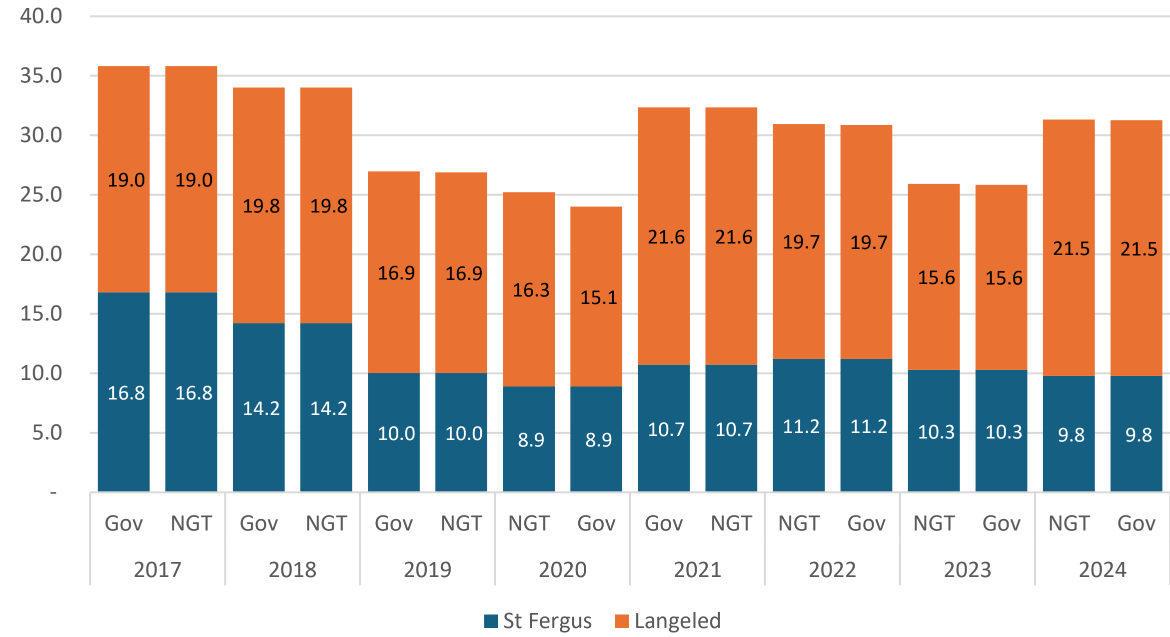
Figure 25: GB pipeline imports from Norway by route (Bcm per year)



Source: Graph by the author (Sharples). Data from National Gas Transmission.[79]

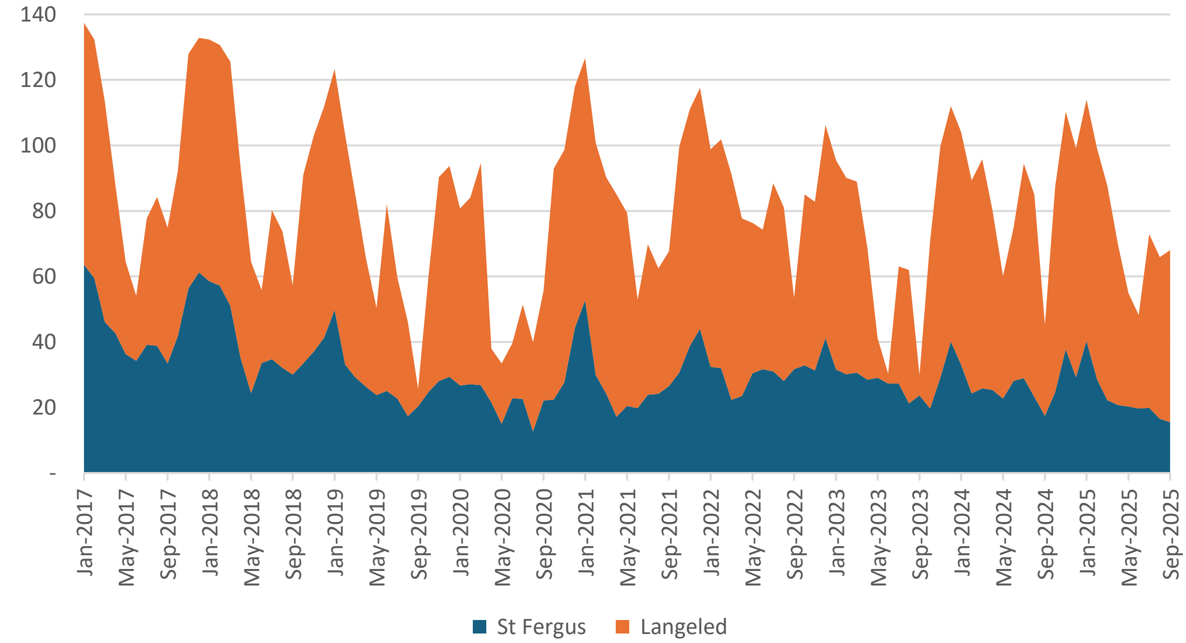
[79] National Gas Transmission, 2025. *Gas Transmission Data*. https://data.nationalgas.com/find-gas-data

Figure 26: GB pipeline imports from Norway by route and data source (Bcm per year)



Source: Graph by the author (Sharples). Data from National Gas Transmission[80] and DESNZ.[81]

Figure 27: GB pipeline imports from Norway by route (MMcm/d by month)



Source: Graph by the author (Sharples). Data from DESNZ.[82]

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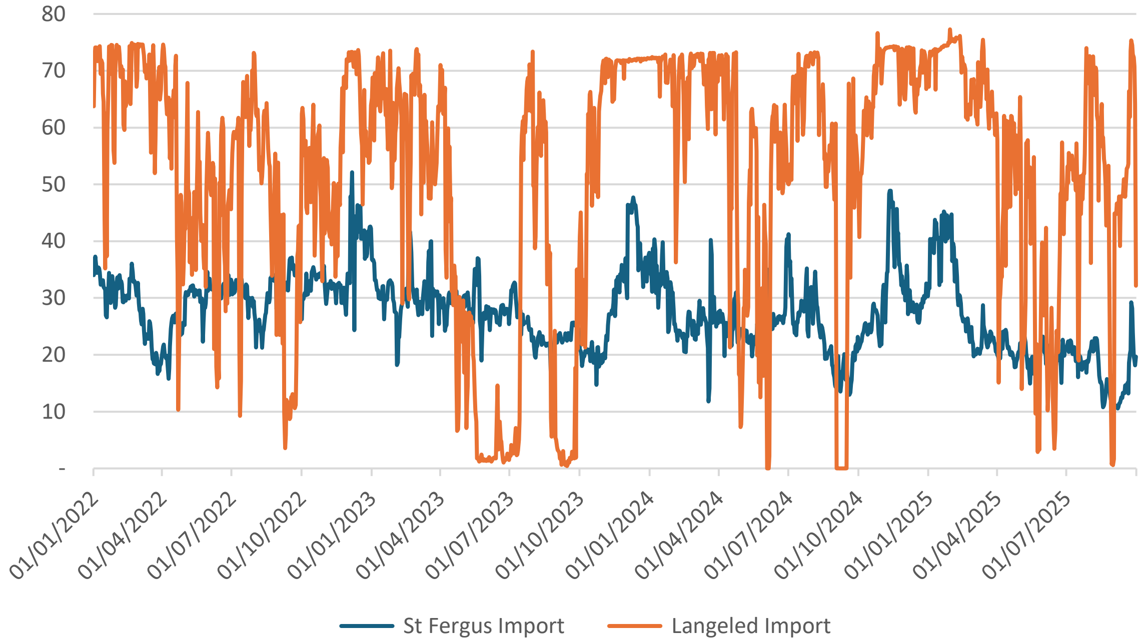
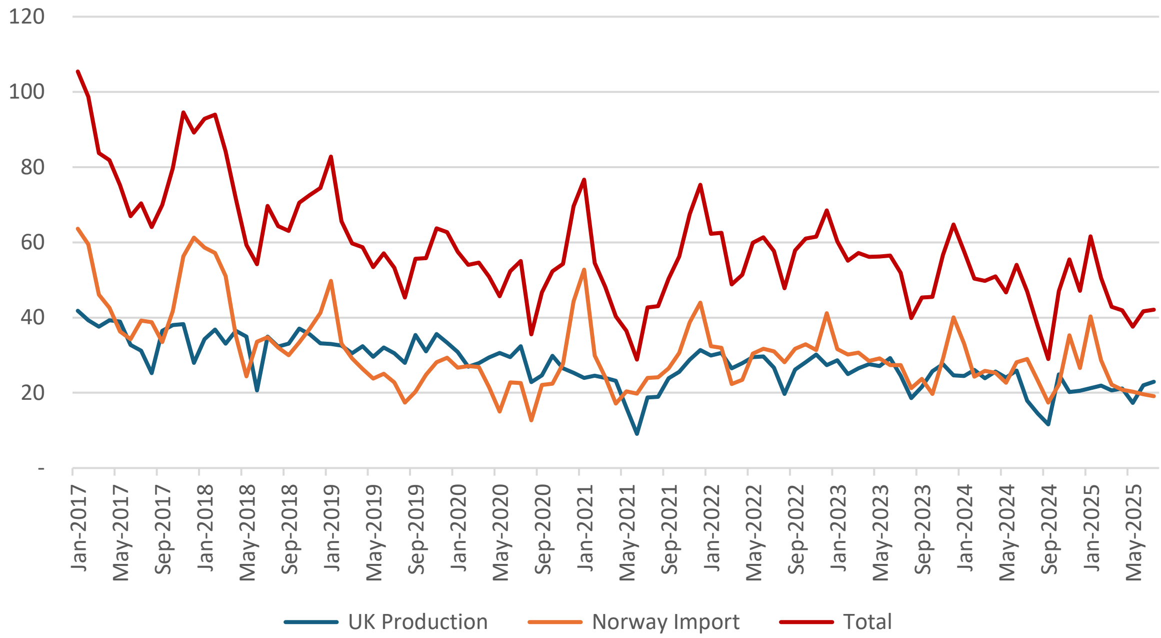
[80] National Gas Transmission, 2025. *Gas Transmission Data*. https://data.nationalgas.com/find-gas-data
[81] DESNZ, 2025. *Energy Trends gas tables (ODS)*. https://www.gov.uk/government/statistics/gas-section-4-energy-trends
[82] DESNZ, 2025. *Energy Trends gas tables (ODS)*. https://www.gov.uk/government/statistics/gas-section-4-energy-trends

Figure 28: GB pipeline imports from Norway by route (MMcm/d)



Source: Graph by the author (Sharples). Data from National Gas Transmission.[83]

Figure 29: Gas flows in St Fergus by source (MMcm/d by month)



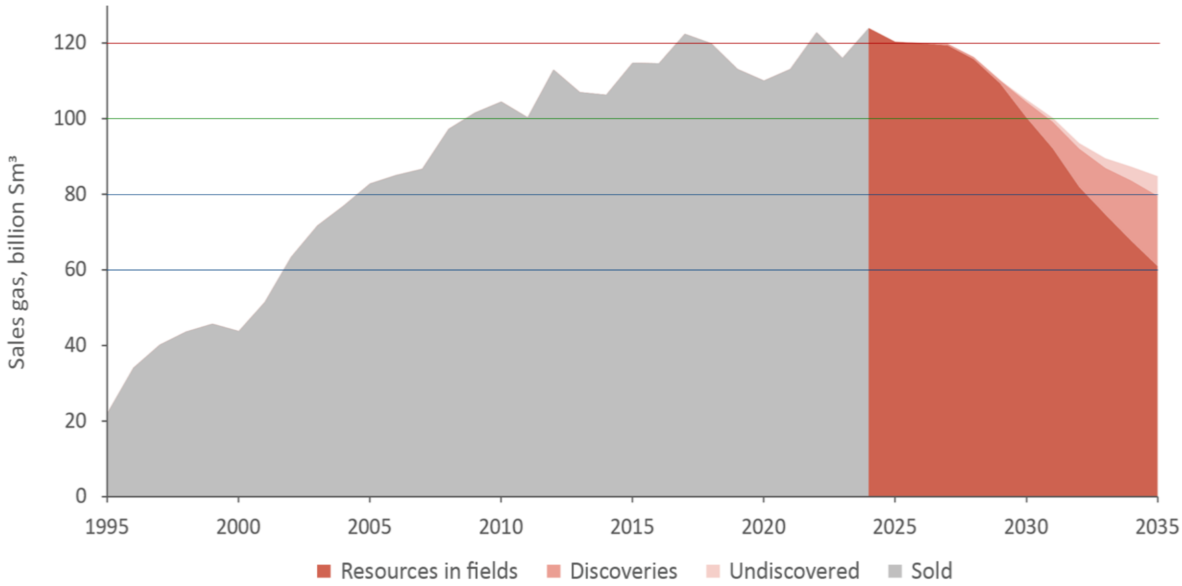
Source: Graph by the author (Sharples). Data from National Gas Transmission[84] and DESNZ.[85]

[83] National Gas Transmission, 2025. *Gas Transmission Data*. https://data.nationalgas.com/find-gas-data

[84] National Gas Transmission, 2025. *Gas Transmission Data*. https://data.nationalgas.com/find-gas-data

[85] DESNZ, 2025. *Energy Trends gas tables (ODS)*. https://www.gov.uk/government/statistics/gas-section-4-energy-trends

Figure 30: Expected volumes of sales gas from Norwegian fields, 1995-2035 (Bcma)



Source: Graph from Norsk Petroleum.[86] Annotations by the author (Sharples): lines at 60 Bcma and 80 Bcma (blue), 100 Bcma (green), and 120 Bcma (red).

3.3. Pipeline gas imports from the Netherlands and Belgium

As noted earlier, pipelines connecting GB to Belgium (Interconnector UK, known as iUK) and Netherlands (Bacton-Balgzand Line, known as BBL) were launched in 1998 and 2006, respectively. However, the BBL was only able to physically deliver gas from the Netherlands to GB until 18 July 2019, when physical flows from GB to the Netherlands became possible.[87] For further pipeline exports, two interconnectors (Interconnector 1 and Interconnector 2) were built between 1993 and 2003 to export gas to the Republic of Ireland, and the Scotland-Northern Ireland Pipeline (SNIP) was built to supply Northern Ireland.[88] The locations of these pipelines are illustrated in **Figure 45**, **Figure 46**, and **Figure 47** in the annex to this report.

3.3.1. Interconnectors between the GB and Belgium / Netherlands

The two interconnectors connecting GB with continental Europe have the following capacities:

- iUK GB to BE: 651.7 GWh/d (59.8 MMcm/d) [89] [90]
- iUK BE to GB: 803.4 GWh/d (73.4 MMcm/d)

[86] Norsk Petroleum, 2025. Expected volumes of sales gas from Norwegian fields (1995-2035) – Updated 09.01.25. *Exports of oil and gas – natural gas*. https://www.norskpetroleum.no/en/production-and-exports/exports-of-oil-and-gas/#natural-gas

[87] BBL, 2025. *BBL – Our history*. https://bblcompany.com/about-bbl

[88] Office for Budget Responsibility, 2023. *A History of Natural Gas in the UK*. https://obr.uk/box/a-history-of-natural-gas-in-the-uk/ See also: OBR, 2023. *Financial Risks and Sustainability – July 2023. Chapter 3: Energy*. https://obr.uk/frs/fiscal-risks-and-sustainability-july-2023/ https://obr.uk/frs/fiscal-risks-and-sustainability-july-2023/

[89] Fluxys, 2025. *Interconnector infrastructure – technical capacities*. https://www.fluxys.com/en/about-us/interconnector-uk/infrastructure

[90] This is based on an assumed gross calorific value (GCV) of 11.5 kilowatt hours (kWh) per normal cubic metre, which equates to 10.90 per standard cubic metre, or 39.24 megajoules (MJ) per standard cubic metre, in accordance with values reported by Fluxys.

- BBL GB to NL: 240 GWh/d (21.9 MMcm/d) since 1 April 2025. Previously, the capacity was 185 GWh/d (16.9 MMcm/d).[91]
- BBL NL to GB: 240 GWh/d (21.9 MMcm/d) since 13 December 2024. Previously, the capacity was 432 GWh/d (39.4 MMcm/d).[92] [93]

Therefore, the total current capacity (at the time of writing) for imports from Belgium and the Netherlands into GB is 1,043 GWh/d (95 MMcm/d) and the total capacity for exports from GB to Belgium and the Netherlands is 891.7 GWh/d (82 MMcm/d).

According to daily data from NGT for the period from 1 January 2017 to 30 July 2025, the following maximum daily volumes were achieved:

- iUK GB to BE: 747 GWh/d - 115 per cent of nameplate daily capacity (24 July 2022).
- iUK BE to GB: 723 GWh/d - 90 per cent of nameplate daily capacity (29 December 2017).
- BBL GB to NL: 233 GWh/d - 97 per cent of nameplate capacity (14 May 2025). This was made possible due to the introduction of the Enhanced Pressure Service from 1 April 2025, which raised the capacity from 185 GWh/d to 240 GWh/d. Prior to this, flows never exceeded 189 GWh/d, which was 102 per cent of the nameplate capacity of 185 GWh/d.
- BBL NL to GB: 497 GWh/d - 115 per cent of nameplate daily capacity (9 January 2021).

Historically, the export capacity from GB to Belgium and the Netherlands was used during summer, when GB was supply long, and the import capacity from continental Europe into GB was used during winter, when GB was supply short. However, as **Figure 31** shows, GB imported virtually nothing from continental Europe between April 2021 and December 2024. Between 1 January and 17 February 2025, GB received some imports from continental Europe, up to a daily peak of 32 MMcm/d on 21 January, one-third of the 95 MMcm/d combined capacity of iUK and BBL (**Figure 33**).

The limited utilisation of iUK and BBL for imports into GB during periods of peak GB winter daily gas demand in the last several years reflects a shift in the market configuration in north-western Europe since 2022. Previously, both north-western continental Europe and GB had access to Norwegian pipeline gas and LNG, while north-western continental Europe also had access to pipeline supply from Russia and seasonal storage stocks and GB did not. This kept NBP at a premium to TTF, which attracted supply to GB via iUK and BBL. The loss of Russian pipeline supply has resulted in a structurally tighter market in north-western continental Europe, with both GB and north-western continental Europe seeking LNG supply in the winter. This has narrowed the winter spread between TTF and NBP and limited the commercial viability of imports into GB via iUK and BBL, which requires a spread greater than the cost of transport. However, the currently limited utilisation of iUK and BBL in winter (resulting in spare transportation capacity) does suggest scope for additional supply to GB via this route if there is an urgent need due to a surge in GB gas demand. In physical terms, this would effectively draw on seasonal storage stocks in north-western Europe, and in pricing terms would require prompt NBP prices to rise to a sufficient premium over TTF to attract supply despite the entry-exit costs of shipping gas from Belgium/Netherlands to GB.

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[91] BBL, 2025. BBL physical flow switch and Enhanced Pressure Service. *Press Release*, 28 March. https://bblcompany.com/news/change-in-forward-flow-technical-capacity

[92] BBL, 2025. *BBL Company*. https://bblcompany.com/ . According to BBL Company, the capacity of BBL is 10,000,000 kWh/hour of forward flow (NL to GB) and 7,699,193 kWh/h (Reverse Flow, GB to NL). This equates to 240 GWh/d forward flow and 184.78 GWh/d reverse flow. The increase in reverse flow from 184.78 GWh/d to 240 GWh/d is due to the introduction of an ‘Enhanced Pressure Service’, “should the market indicate a demand for such increased capacity”.

[93] BBL, 2024. Change in Forward Flow Technical Capacity. *Press Release*, 12 December. https://bblcompany.com/news/change-in-forward-flow-technical-capacity

3.3.2. Flows from GB to Northern Ireland and Republic of Ireland

Taken together, the capacity for gas flows from GB to the island of Ireland via the Moffat interconnection point is 387 GWh/d (35.3 MMcm/d), of which 89.3 GWh/d (8.1 MMcm/d) is reserved by GMO NI (Gas Market Operator Northern Ireland) for supply to Norther Ireland via the SNIP.[94]

As **Figure 32** shows, monthly flows from GB to the island of Ireland between 2017 and 2024 saw seasonal peaks in January that utilised a maximum of 20 MMcm/d of the 35 MMcm/d capacity. However, a new peak was reached in January 2025, with a monthly flow of 22 MMcm/d.

Peak utilisation on a daily basis is higher. As **Figure 34** illustrates, Gas Year[95] 2022, 2023, and 2024 each saw several days of flows in the range of 25-30 MMcm/d, while 8 January 2025 saw a new peak of 31 MMcm/d (89 per cent of capacity).

In terms of likely future call on gas supply from GB to the Republic of Ireland, it is worth noting that gas production in the Republic of Ireland declined from 3.5 Bcm in 2017 to 1.6 Bcm in 2021 and then declined more slowly to 1.1 Bcm in 2024. Conversely, imports rose from 1.66 Bcm in 2017 to 4.0 Bcm in 2024. During this time period, consumption rose from 5.25 Bcm in 2017 to a peak of 5.47 Bcm in 2020, before falling back to 5.1 Bcm in 2024.[96]

It is also worth noting that in March 2025, the Irish government approved a state-led 'Strategic Gas Emergency Reserve' in the form of an FSRU "to be owned on behalf of the State by the system operator, Gas Networks Ireland (GNI)". The purpose is to maintain a stock equivalent to one LNG cargo, which would have "the ability to supply the entire gas demand for Ireland for seven days and would be refilled to continue to supply the national gas network. GNI will ensure appropriate contractual arrangements are in place to refill the FSRU throughout an emergency situation to provide consistent gas supplies via the FSRU for the duration required". Given the need to regasify and sendout boil-off gas, a minimum sendout will take place, which "is likely to result in the strategic gas emergency reserve being refilled up to 6 times per year".[97] According to Gas Networks Ireland, multiple locations in Cork harbour and the Shannon estuary are currently being assessed, with allocation to be announced 'in late 2025'.[98] The purpose of the FSRU is not to replace supply from domestic production and imports from GB, but to act as back-up to those supplies.

The ongoing annual trend is a gradual decline in demand that is being outpaced by a slightly quicker decline in production, with the market balanced by a gradual increase in imports. On a seasonal basis, it is worth noting that gas production in the Republic of Ireland follows a flat profile, with seasonal variation in demand being met by seasonal variation in imports from GB.

In 2023, electricity supply to the Republic of Ireland totalled 34,646 GWh, of which 3,280 GWh (9.5 per cent) was supplied in the form of imports from GB. Of the remaining 31,366 GWh, 15,352 GWh (49 per cent of domestic power generation) was provide by gas-fired power stations and 14,096 GWh (45 per cent of domestic power generation) was sourced from renewable power generation (mostly wind). This left 1,918 GWh (6 per cent) of domestic power generation being sourced from coal, peat, oil, and non-

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[94] Gas Infrastructure Europe, 2025. *System Capacity Map (10 January 2025)*. https://www.gie.eu/publications/maps/system-capacity-map/

[95] Note that the Gas Year begins on 1 October. Therefore, Gas Year 2024 spans the period from 1 October 2024 to 30 September 2025.

[96] Eurostat, 2025. *Supply, transformation and consumption of gas - monthly data*. https://ec.europa.eu/eurostat/databrowser/view/nrg_cb_gasm__custom_17644586/default/table

[97] Government of Ireland, 2025. Government approves development of State-led strategic gas emergency reserve. *Press Release*, 4 March. https://www.gov.ie/en/department-of-climate-energy-and-the-environment/press-releases/government-approves-development-of-state-led-strategic-gas-emergency-reserve/

[98] Gas Networks Ireland, 2025. *Strategic Gas Emergency Reserve*. https://www.gasnetworks.ie/about/projects/strategic-gas-emergency-reserve

renewable waste.[99] Daily data from the Irish grid operator, EirGrid, for both the whole island of Ireland and disaggregation into the Republic of Ireland and Northern Ireland, shows that Northern Ireland also has a power generation mix based on a combination of gas-fired power stations, renewables, and electricity imports from GB.[100]

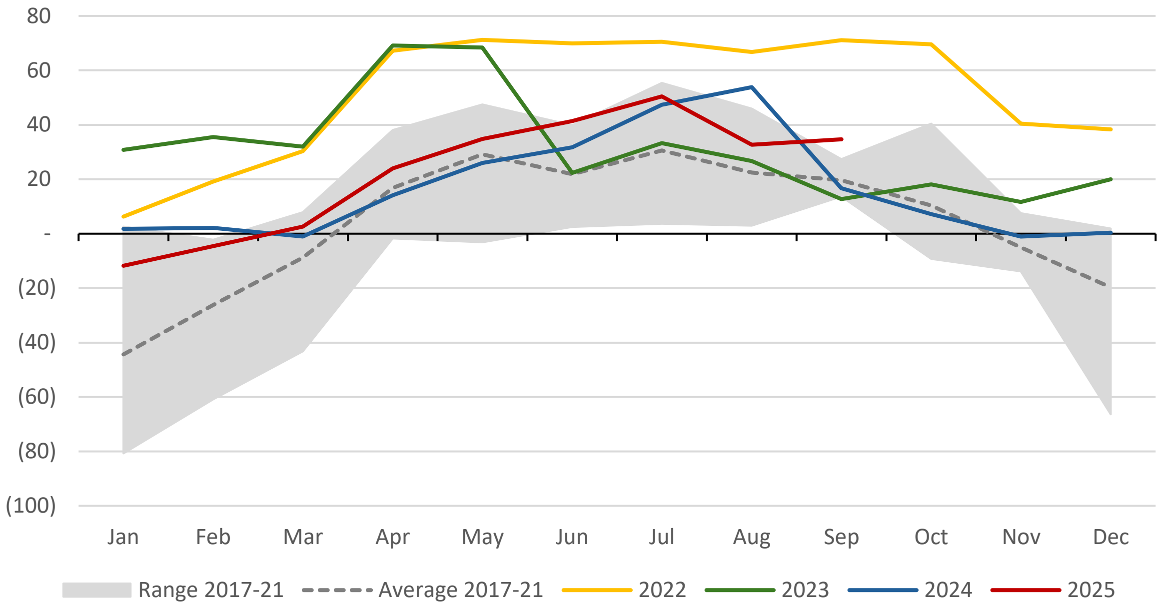
To summarise, the power generation mix for the whole island of Ireland is, to a significant extent, based upon wind power balanced by electricity imports from GB and domestic gas-fired power generation largely fuelled by gas imports from GB. This suggests that at times of peak power demand on the island of Ireland, especially at time of low wind power generation and maximum utilisation of electricity import capacity, upside flexibility in gas supply from GB is crucial for power grid balancing. The maximum daily gas flows from GB to the island of Ireland via Moffat in the winter period from 29 November to 31 January since Gas Year 2021 have seen daily peaks of 25-30 MMcm/d (compared to a maximum transportation capacity of 35 MMcm/d), in the context of total gross gas supply to GB of 350-400 MMcm/d. This means that daily flows from GB to the island of Ireland can be the equivalent of 6.5-8.0 per cent of gross gas supply to GB and 71-86 per cent of the combined capacity of the pipeline interconnections between GB and the island of Ireland.

While the total flows via SNIP to Northern Ireland and Interconnector 1/2 to the Republic of Ireland have rarely exceeded 85 per cent of the combined capacity of those pipelines, it remains imperative that GB gas supply is sufficiently flexible to offer flexibility of gas supply to the island of Ireland up to the combined capacity of those interconnectors, even once the Irish Strategic Gas Emergency Reserve FSRU is in place. While demand for outward flows from GB to the island of Ireland account for a relatively small share of the call on gross GB gas supply at peak times, the volumes concerned are non-negligible and should be considered as part of the variable call on gas supply in GB.

[99] Sustainable Energy Authority of Ireland, 2025. *Electricity - Electricity generated by fuel.* https://www.seai.ie/data-and-insights/seai-statistics/electricity [Original data reported in thousand tonnes of oil equivalent [ktoe]. Converted to GWh at a ratio of 1 ktoe equals 11.63 GWh.

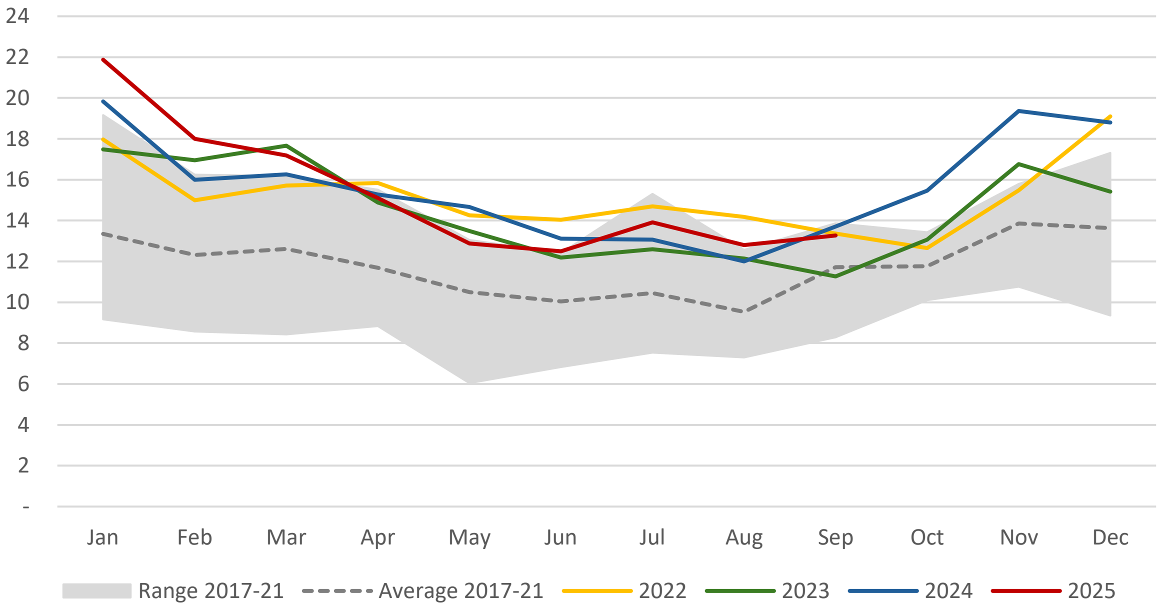
[100] EirGrid, 2025. *Real Time System Information – Fuel Mix*. https://www.eirgrid.ie/grid/real-time-system-information

Figure 31: Monthly average gas flows via iUK and BBL combined (MMcm/d by month)



Source: Graph by the author (Sharples). Data from National Gas Transmission.[101] Note that positive values indicate net exports from GB to Belgium and the Netherlands. Conversely, negative values indicate net imports into GB.

Figure 32: Monthly average gas flows from GB to Northern Ireland and Republic of Ireland (MMcm/d by month)



Source: Graph by the author (Sharples). Data from National Gas Transmission.[102]

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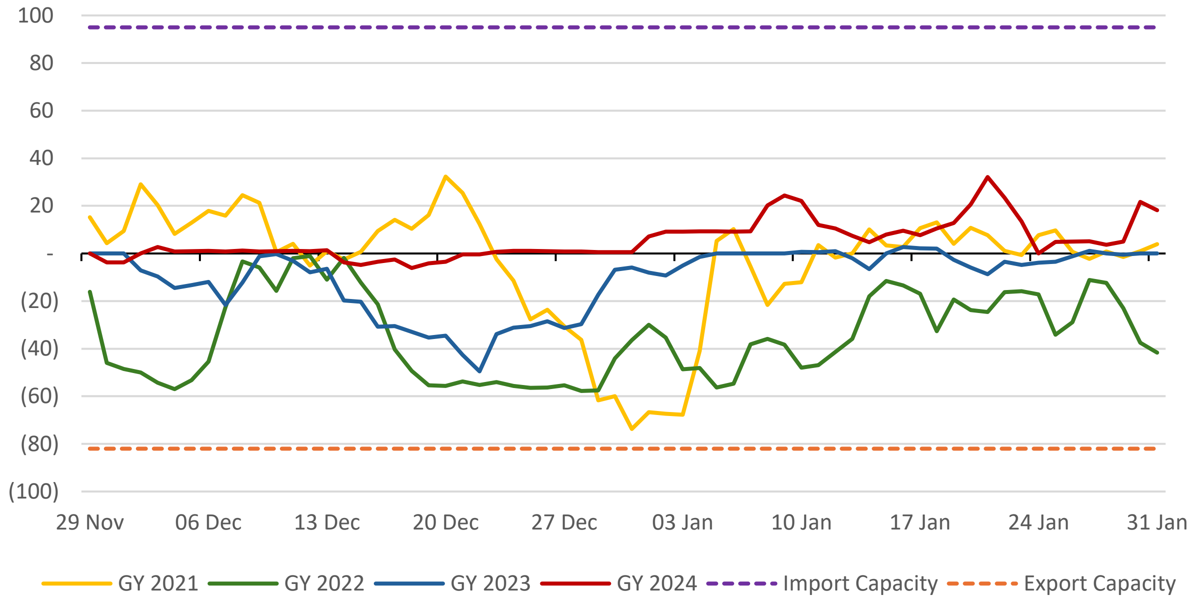
[101] National Gas Transmission, 2025. *Gas Transmission Data*. https://data.nationalgas.com/find-gas-data

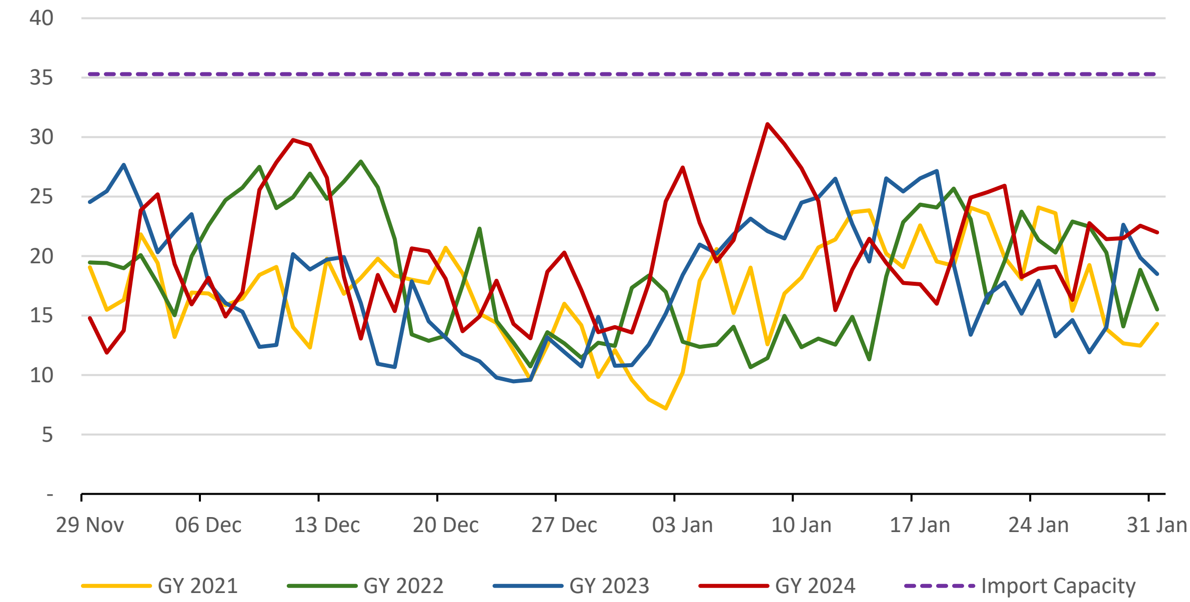
[102] National Gas Transmission, 2025. *Gas Transmission Data*. https://data.nationalgas.com/find-gas-data

Figure 33: Daily GB gas imports (positive values) and exports (negative values) via iUK (Belgium) and BBL (Netherlands) combined during GB peak winter demand period (MMcm/d)



Source: Graph by the author (Sharples). Data from National Gas Transmission.[103]

Figure 34: Daily gas flows from GB to Northern Ireland and Republic of Ireland combined via Moffat interconnection point and Interconnector 1/2 and Scotland-Northern Ireland Pipeline (SNIP) during peak winter demand period (MMcm/d)



Source: Graph by the author (Sharples). Data from National Gas Transmission.[104]

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[103] National Gas Transmission, 2025. *Gas Transmission Data*. https://data.nationalgas.com/find-gas-data

[104] National Gas Transmission, 2025. *Gas Transmission Data*. https://data.nationalgas.com/find-gas-data

3.4. LNG imports

The UK has three LNG import terminals, all located in GB. The Isle of Grain LNG terminal was opened in 2005, while the South Hook and Dragon terminals at the port of Milford Haven were opened in 2009.

3.4.1. Calculating effective LNG import capacities at Isle of Grain and Milford Haven

The ‘real world’ capacity of any LNG regasification terminal to provide gas supply to the national grid system is subject to a series of bottlenecks, in accordance with the steps it is necessary to take to transfer the liquid LNG cargo to the grid. Those steps (and bottlenecks) are as follows:

1. **The number of jetties at the terminal.** This determines how many LNG carriers can dock at the terminal at a given time.
2. **The minimum and maximum size of LNG carriers that can dock at those jetties.** The vast majority of the global fleet of 697 LNG carriers have capacities between 90,000 and 210,000 m3 of LNG. [105] [106] In addition, a further 45 LNG carriers have larger capacities of either 210,000-217,000 m3 (Q-Flex) or 263,000-266,000 m3 (Q-Max) for the larger-scale delivery of Qatari LNG. [107] Therefore, if a terminal can accommodate vessels up to 210,000 m3, they can accommodate most LNG carriers, and if they can accommodate vessels up to 267,000 m3, they can accommodate Q-Flex and Q-Max vessels from Qatar.
3. **The hourly rate at which LNG can be offloaded from the LNG carrier into the storage tanks.** This determines how long an LNG carrier must remain docked to unload its cargo. The quicker cargoes can be unloaded, the more LNG carriers can dock and unload cargoes in a given timeframe.
4. **The number of LNG storage tanks and size of the LNG storage tanks.** This determines how much LNG can be stored at a terminal awaiting sendout into the grid. At terminals with limited storage capacity, a new cargo cannot be unloaded until the LNG from the previous cargo has been regasified and sent out into the grid system. Terminals with larger storage capacity have the flexibility to unload several cargoes in relatively quick succession, even if the full volume is not being rapidly regasified and sent out into the grid.
5. **The rate at which LNG can be regasified, the capacity of the pipeline connecting the grid, and any further bottlenecks that may prevent that connecting pipeline from operating at full capacity.** This determines how quickly the LNG storage tanks can be emptied and how much of a contribution the LNG regasification terminal can make to national gas supply. The greater the capacity to regasify and send out regasified LNG into the grid, the quicker the storage tanks can be emptied (to receive more cargoes) and the greater the contribution the terminal can make to national gas supply, especially during peaks in demand.

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[105] According to GIIGNL, at the end of 2024, the global LNG carrier fleet consisted of 831 vessels, including 697 dedicated LNG carriers, 56 LNG Bunker Vessels (LNGBVs), 52 FSRUs, and 26 small-scale LNG carriers (with capacities of 30,000 cubic metres or less). The vast majority of LNG carriers currently operational fall into one of three size categories: 90,000-150,000 m3 (193 vessels), 150,000-170,000 m3 (132 vessels), and 170,000-210,000 m3 (363 vessels).

[106] GIIGNL, 2025. *Annual Report 2025*. https://www.giignl.org/annual-report (see pages 38-45)

[107] Nakilat, 2025. *Our Fleet*. https://www.nakilat.com/our-fleet/

The profile of the three GB LNG regasification terminals according to the criteria above are as follows:

	Isle of Grain	South Hook	Dragon LNG
Number of jetties	2	2	1
Slots per year	‘over 200’	Not officially stated	Not officially stated
Jetty 1 carrier size (m3)	70,000-217,000	125,000-267,000	Up to 217,500
Jetty 2 carrier size (m3)	125,000-266,000	125,000-267,000	-
Hourly capacity (as per GIE)	2.65 (N) MMcm/hour 2.80 (S) MMcm/hour	2.44 (N) MMcm/hour 2.57 (S) MMcm/hour	1.14 (N) MMcm/hour 1.20 (S) MMcm/hour
Number of storage tanks	8	5	2
Total storage capacity (m3 of LNG)	1,000,000 m3 (+200,000 m3 with new storage tank in 2025)	775,000 m3	320,000 m3
Total storage capacity (MMcm of natural gas)	600 MMcm (720 MMcm with new storage tank in 2025)	465 MMcm	192 MMcm
Daily regasification rate	Current: 645 GWh/d (58.8 MMcm/d) Expanded: 800 GWh/d (72.9 MMcm/d)	650 GWh/d (59.2 MMcm/d)	298 GWh/d (27.2 MMcm/d)
Nominal annual import capacity	19.5 Bcma (+5 Bcma with expansion from 2025)	21.0 Bcma	7.6 Bcma
Connecting pipe capacity	Current: 645 GWh/d (58.8 MMcm/d) Expanded: 800 GWh/d (72.9 MMcm/d)	Aggregate 950 GWh/d (86.6 MMcm/d) at the Milford Haven Aggregate System Entry Point (ASEP) (as per Joint Office of Gas Transporters)	

Source: Data from Grain LNG,[108] South Hook Gas,[109] Dragon LNG, [110] Gas Infrastructure Europe (GIE) LNG Database,[111] Joint Office of Gas Transporters. [112]

[108] Grain LNG, 2025. *Terminal Characteristics*. https://www.grainlng.com/operational-information#4257225834-45733678

[109] South Hook Gas, 2025. *What We Do: Our Capacity*. https://www.southhookgas.com/what-we-do/#capacity

[110] Dragon LNG, 2025. *2029 Capacity*. https://www.dragonlng.co.uk/2029capacity

[111] GIE, 2025. *LNG Database*. https://www.dragonlng.co.uk/2029capacity

[112] Joint Office of Gas Transporters, 2025. *UNC 0906: Cancellation of the March 2025 QSEC Auction at the Milford Haven ASEP (24 January 2025)*. https://www.gasgovernance.co.uk/dl-mod-attachment/39b44b8d-dc5f-4bb9-93a7-10a6ed03d932 (p.3_

3.4.2. LNG sendout at Isle of Grain and Milford Haven

As **Figure 35** illustrates, LNG provides a substantial degree of seasonal flexibility in monthly GB gas supply. Since 2023, this has spanned from lows of less than 10 MMcm/d in the summer months (June to September) to highs of 82-93 MMcm/d in the colder months (January-April). Here it should be noted that the periods April-October 2022 and April-May 2023 saw effectively full utilisation of the iUK and BBL for exports from GB to Belgium and the Netherlands, respectively (**Figure 31**), with those volumes being sourced from higher-than average LNG sendout (**Figure 35**). Since June 2023, GB LNG monthly sendout has been within the 2017-2021 range, except for February 2025, which exceeded LNG sendout in the month of February in every year between 2017 and 2022. The role of LNG in UK energy security has been analysed in depth in a previous OIES Insight.[113]

If capacity utilisation is considered on a monthly basis, **Figure 35** suggests that GB has plenty of spare capacity, given that monthly sendout between January 2017 and July 2025 did not exceed 107 MMcm/d, which is just under 74 per cent of monthly sendout capacity. However, given the limited upside flexibility in winter gas supplies from production and pipeline imports discussed above, the peak daily capacity utilisation during the winter peak demand period is a key consideration.

The daily sendout figures for Isle of Grain and Milford Haven combined – relative to the combined daily sendout capacity of 145.2 MMcm/d – during the winter period of peak GB gas demand since Gas Year 2021[114] are shown in **Figure 36**. It was only in Gas Year 2022 that daily sendout exceeded 120 MMcm/d (83 per cent of capacity) on any given day. This occurred for 16 days in December 2022 and 4 days in January 2023, peaking at 134 MMcm/d (92 per cent of capacity) on 15-16 December 2022. This suggests that at times of maximum call on LNG supply in recent years, GB has experienced a high rate of LNG sendout capacity utilisation, but only for a limited number of days.

When this total daily sendout is disaggregated between the Isle of Grain (**Figure 37**) and Milford Haven (**Figure 38**), it is clear that the combined South Hook and Dragon terminals utilise at least two-thirds of the daily network entry capacity at the Milford Haven Aggregate System Entry Point (ASEP) more often than the Isle of Grain utilises at least two-thirds of its daily network entry capacity.

With its expansion due for imminent completion, the Isle of Grain terminal will add another 190,000 m3 storage tank, a second cryogenic unloading line (making it "the only terminal in Europe able to perform simultaneous unloads"), and will see regasification capacity increase from 645 GWh/d (58.8 MMcm/d) to 800 GWh/d (72.9 MMcm/d).[115]

3.4.3. Cargo frequency as a factor in LNG supply

Assuming a ratio of one cubic metre of LNG being equivalent to 600 cubic metres of natural gas in its gaseous state, LNG cargoes in the range of 170,000-217,000 m3 are equivalent to 102-130 MMcm of natural gas. Assuming maximum daily sendout, the three GB LNG regasification terminals would regasify and send out an entire cargo of 102-126 MMcm in the following timeframe:

- Isle of Grain (current): 1.74-2.21 days (two jetties)
- Isle of Grain (expanded): 1.40-1.78 days (two jetties)
- South Hook: 1.72-2.20 days (two jetties)
- Dragon: 3.75-4.79 days (one jetty)

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[113] Hall, M., 2023. LNG and UK Energy Security. *OIES Paper (NG 181) (May)*. https://www.oxfordenergy.org/publications/lng-and-uk-energy-security/

[114] The period from 1 October 2021 to 30 September 2022

[115] Grain LNG, 2022. Grain LNG sets new record for utilisation and increases global reach. *Press Release*, 23 May. https://www.nationalgrid.com/grain-lng-sets-new-record-utilisation-and-increases-global-reach

Therefore, excluding consideration of stocks held in the LNG storage tanks, the sustained full utilisation of the sendout capacity of the GB LNG regasification terminals would require the unloading of a cargo roughly every 3.5-4.5 days per jetty. This is roughly the maximum capacity stated by Isle of Grain, which offers the unloading of 'over 200' cargoes per year at its two jetties (therefore over 100 per jetty every 365 days, or more than one every 3.65 days at each jetty).

3.4.4. The role of LNG stocks in increasing LNG supply flexibility

The ability to hold more than a single cargo's worth of LNG in storage at a regasification terminal increases the flexibility of supply, insofar as the terminal does not need to send out the entirety of a previously-delivered cargo before receiving the next one. Returning to the assumption of cargoes sized 170,000-210,000 m3 of LNG, the three GB terminals can hold the following number of cargoes in storage:

- Isle of Grain (existing): 4.76-5.88 cargoes (1.0mn m3 of storage & 645 GWh/d sendout)
- Isle of Grain (expanded): 5.71-7.06 cargoes (1.2mn m3 of storage & 800 GWh/d sendout)
- South Hook: 3.69-4.56 cargoes
- Dragon: 1.52-1.88 cargoes

Assuming full storage tanks and sendout operating at maximum daily capacity, each of the three terminals will take the following number of days for each terminal to fully discharge its stocks:

- Isle of Grain (existing): 10.2 days (1.0mn m3 of storage & 645 GWh/d sendout)
- Isle of Grain (expanded): 9.88 days (1.2mn m3 of storage & 800 GWh/d sendout)
- South Hook: 7.9 days
- Dragon: 7.1 days

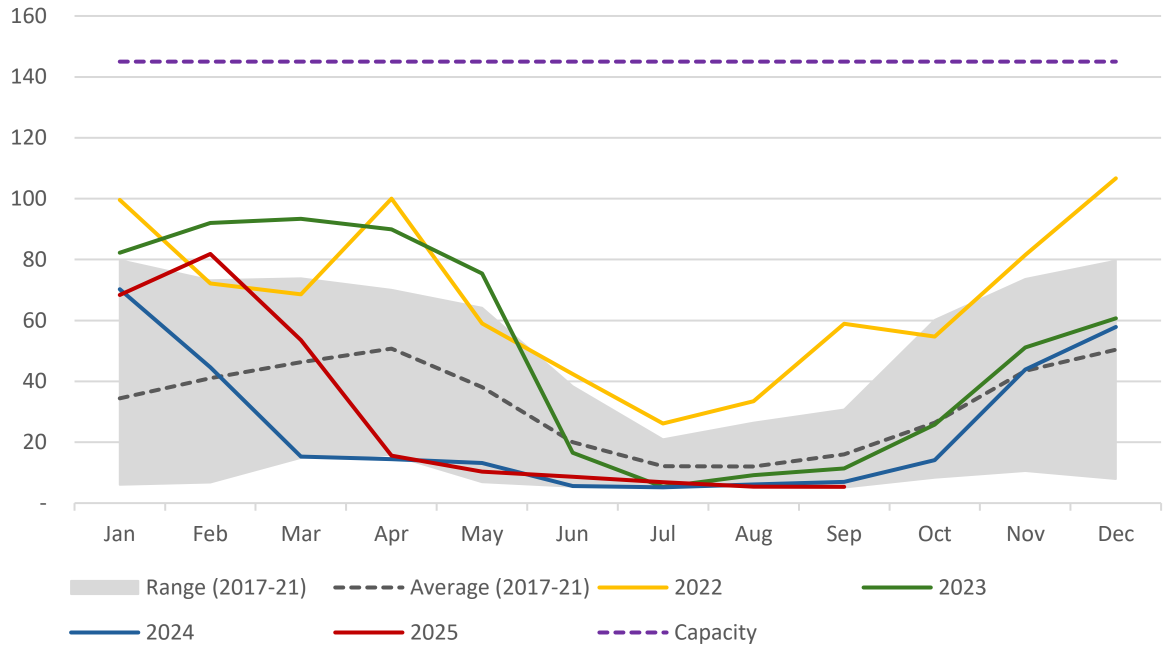
The cycle of unloading cargoes into the storage tanks and extracting LNG from those storage tanks for regasification and sendout into the national grid means that LNG storage stocks are constantly fluctuating. The stock level generally rises gradually throughout the summer and declines throughout the winter, as illustrated in **Figure 39**. However, the pattern is by no means as strongly seasonal as in seasonal underground gas storage of the type seen in continental Europe.

As **Figure 40** shows, the three GB LNG regasification terminals generally hold between 500 MMcm and 1,000 MMcm of natural gas equivalent in stocks during the peak winter demand period between the end of November and end of January.

With LNG as a provider of flexible supply that can respond to rapid surges in demand during winter, the larger the LNG stocks at any given point in time, the greater the extent to which stocks can be used to meet that short-run demand. However, as a caveat, storage capacity needs to remain available to accommodate the unloading of cargoes, which are generally 100-130 MMcm of natural gas equivalent in size, as noted earlier. Therefore, the maximum stocks of roughly 1,000 MMcm with a further 257 MMcm of available storage capacity (in the context of total LNG storage capacity of 1,257 MMcm) means that even during the winter peaks of recent years, the GB regasification terminals were generally able to unload two cargoes between them at relatively short notice.

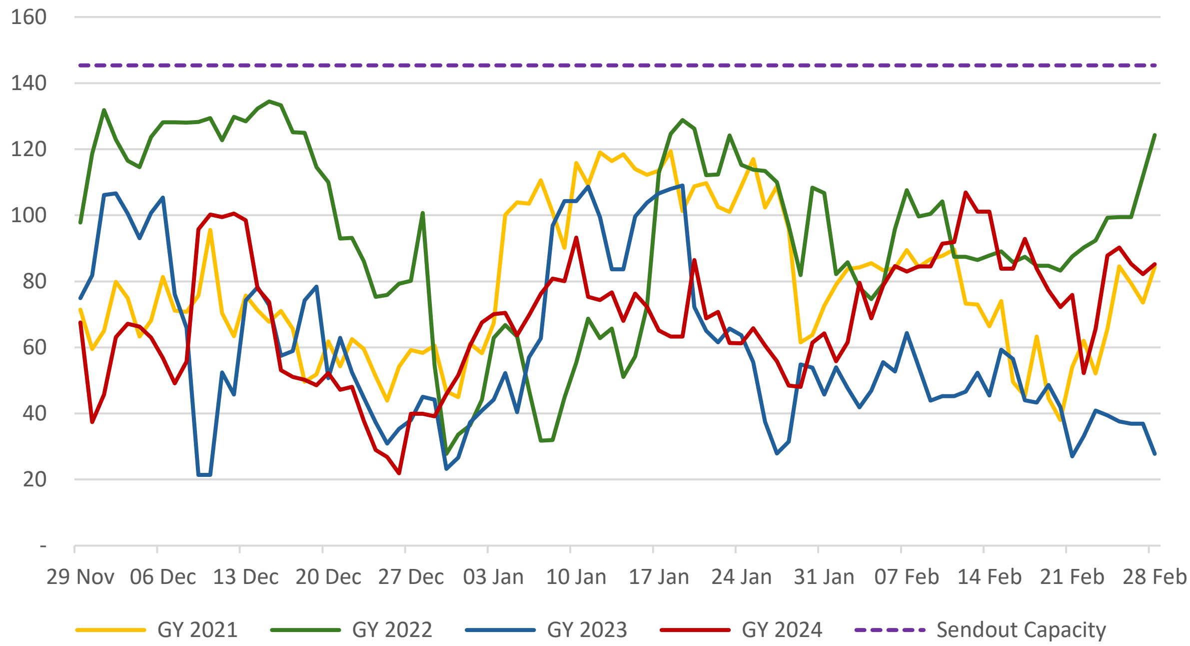
The addition of further capacity at the Isle of Grain for unloading cargoes, storing LNG, regasifying that LNG, and sending it out into the grid does not mean that capacity will be used at its fullest year-round, but rather increases the ability of the terminal to contribute to GB gas supply during periods of peak demand, both on a seasonal basis and in rapid response to short-run surges in demand. This is particularly important in the context of the absence of upside flexibility from production and pipeline imports beyond their winter plateaus, and in relation to the GB gas storage system that is not seasonal (with summer injections and winter-long withdrawals) and must be constantly replenished in order to help meet short-run fluctuations in demand, especially in light of the challenges faced at the Rough storage facility (see below).

Figure 35: GB monthly average LNG sendout (MMcm/d)



Source: Data from National Gas Transmission.[116] Graph by the author.

Figure 36: GB daily LNG sendout during peak winter demand period (MMcm/d)



Source: Data from National Gas Transmission.[117] Graph by the author.

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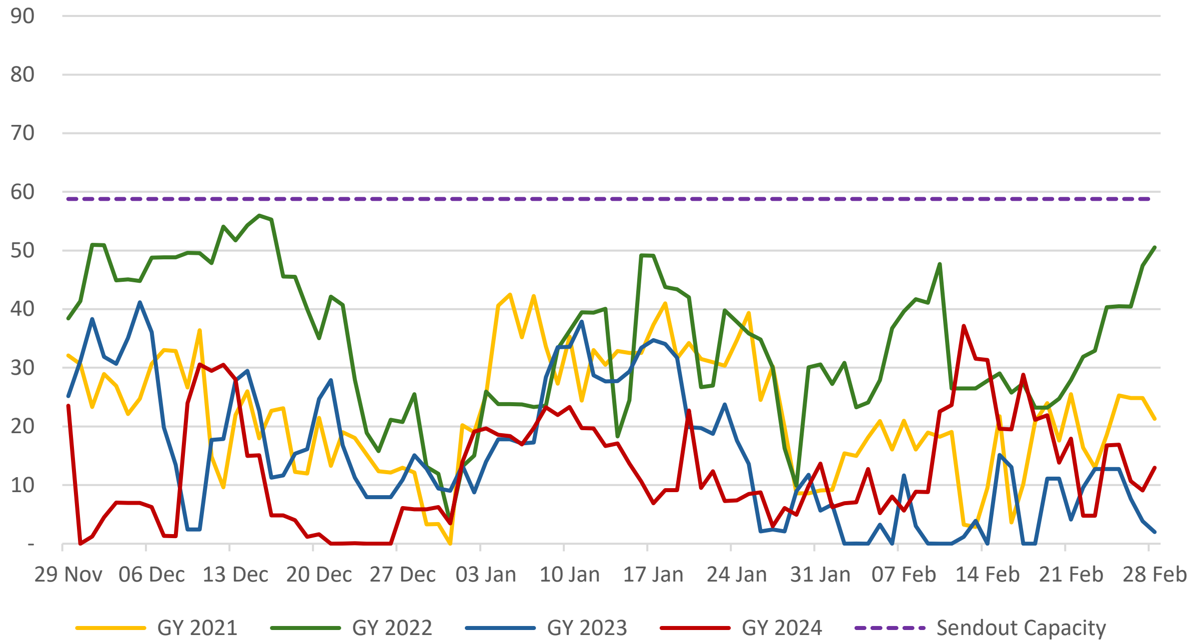
[116] National Gas Transmission, 2025. *Gas Transmission Data*. https://data.nationalgas.com/find-gas-data

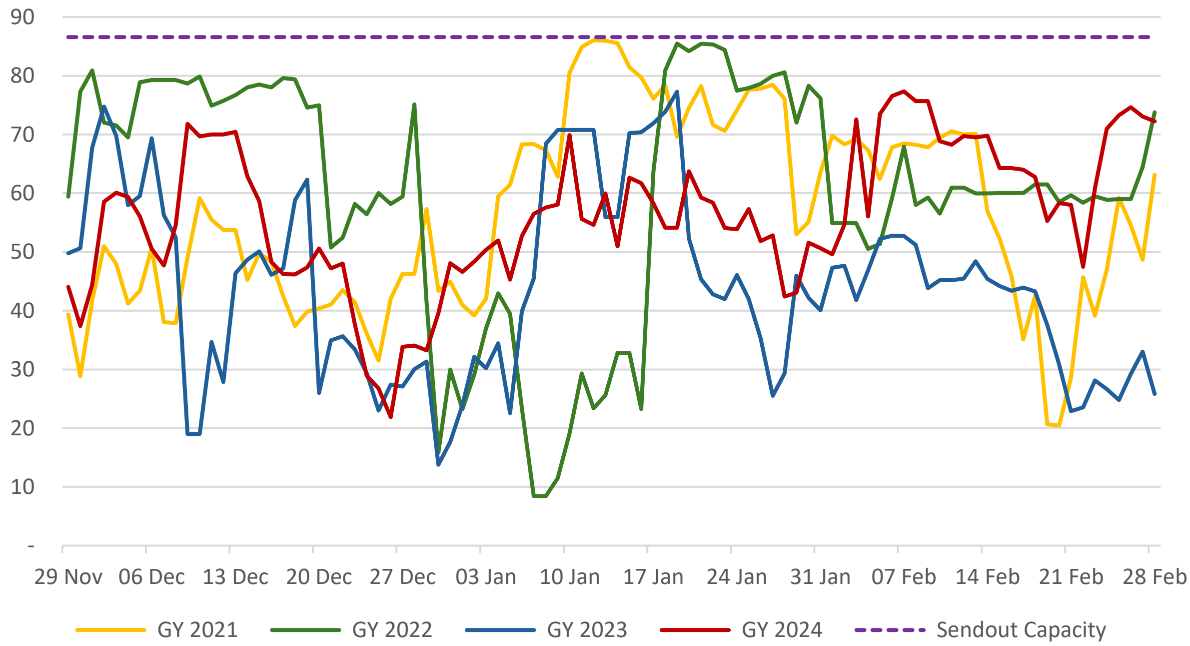
[117] National Gas Transmission, 2025. *Gas Transmission Data*. https://data.nationalgas.com/find-gas-data

Figure 37: Isle of Grain daily LNG sendout during peak winter demand period (MMcm/d)



Source: Data from National Gas Transmission.[118] Graph by the author.

Figure 38: Milford Haven daily LNG sendout during peak winter demand period (MMcm/d)

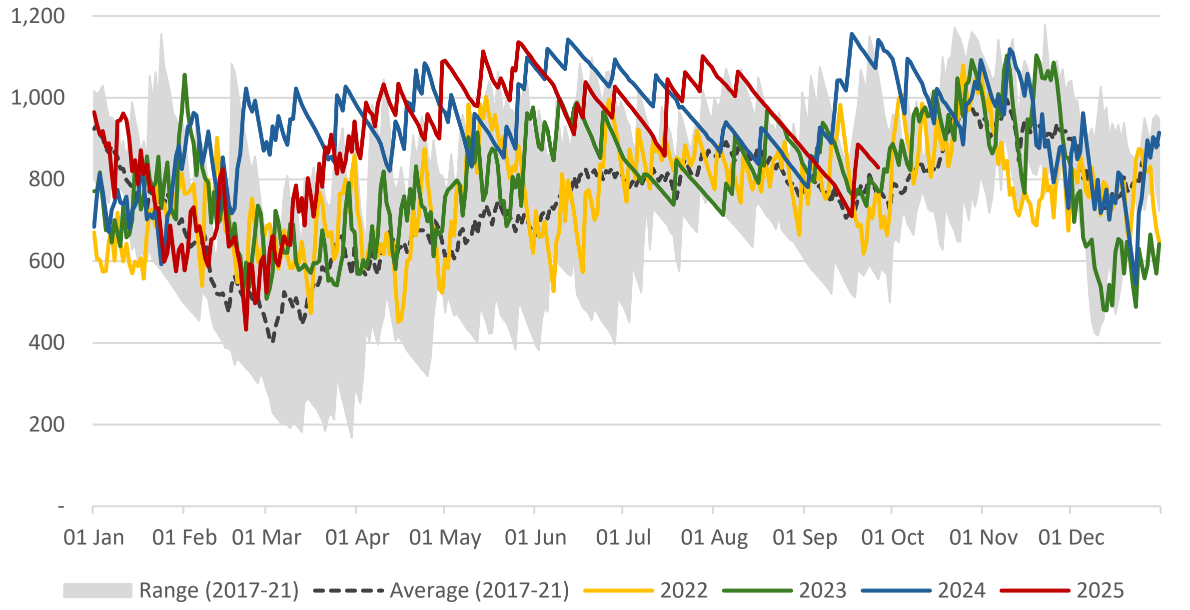


Source: Data from National Gas Transmission.[119] Graph by the author.

[118] National Gas Transmission, 2025. *Gas Transmission Data*. https://data.nationalgas.com/find-gas-data

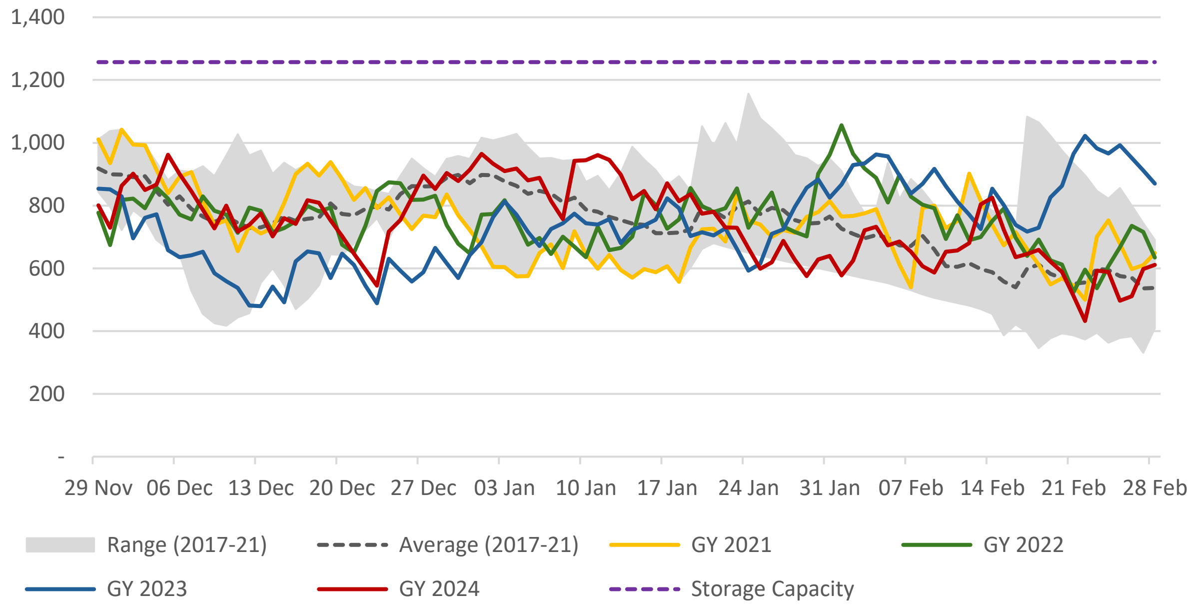
[119] National Gas Transmission, 2025. *Gas Transmission Data*. https://data.nationalgas.com/find-gas-data

Figure 39: GB daily LNG stocks (MMcm of natural gas)



Source: Data from National Gas Transmission[120] and Kpler LNG platform.[121] Graph by the author.

Figure 40: GB daily LNG stocks during peak winter demand period (MMcm of natural gas)



Source: Data from National Gas Transmission[122] and Kpler LNG platform.[123] Graph by the author. Note that capacity is before the Isle of Grain expansion in summer 2025.

[120] National Gas Transmission, 2025. *Gas Transmission Data*. https://data.nationalgas.com/find-gas-data
[121] Kpler, 2025. *Kpler LNG Platform*. https://terminal.kpler.com/map/search [Subscription required]
[122] National Gas Transmission, 2025. *Gas Transmission Data*. https://data.nationalgas.com/find-gas-data
[123] Kpler, 2025. *Kpler LNG Platform*. https://terminal.kpler.com/map/search [Subscription required]

3.5. Storage

The GB gas storage system (aside from LNG stocks discussed above) effectively consists of two elements: the offshore gas storage facility at Rough (referred to by NGT as 'Long Range' storage) and a collection of smaller, onshore underground gas storage facilities (referred to by NGT as 'Medium range' storage).[124]

3.5.1. The Rough 'long-range' gas storage facility

The Rough gas storage facility is based on a depleted offshore gas field, from which gas was brought ashore and processed at Easington. Today, Easington continues to receive small volumes of offshore gas production, in addition to much larger volumes of Norwegian gas delivered via the Langeled pipeline. When Centrica acquired the Rough facility in 2002, it had a storage capacity of 100 billion cubic feet (Bcf) (2,832 MMcm).[125]

The facility was closed in 2017, when Centrica announced that under the prevailing market conditions, it would not be economic to refurbish the facility and extend its working life. Instead, Centrica announced its intention to "to permanently end Rough's status as a storage facility, and to produce all recoverable cushion gas from the field", which was estimated at 183 Bcf (5,182 MMcm).[126]

The dramatic change in market conditions led Centrica to reverse that decision and re-open the facility in October 2022 with a partial capacity of 30 Bcf (850 MMcm).[127] Then, in June 2023, Centrica announced that the storage capacity had been raised further to 54 Bcf (1,529 MMcm).[128] Over winter 2024/25, stocks at Rough reached their highest since re-opening (1,130 MMcm) on 5 November 2024.[129] [130] Since re-opening, the highest daily withdrawal from Rough is 115 GWh/d (10.5 MMcm/d) on 21 November 2024, while the 'deliverability' (daily withdrawal capacity) reported by NGT is 120.4 GWh/d (10.97 MMcm/d). However, the re-opening of Rough now appears to have been reversed. On 24 July, the Centrica CEO, Chris O'Shea, stated:

> "We welcome Government's recently announced consultation on gas storage, which will consider possible regulatory frameworks to unlock investment. Rough is a vital strategic asset for this country, but we've been clear that a loss of up to 100 million pounds this year is not sustainable. We continue to produce the remaining gas, and we are ready to develop Rough as soon as we get the right framework in place. This will be another long-term project delivering energy security for the country and value for our shareholders. Now we remain hopeful, but we can't keep this option open indefinitely. Without a positive outcome from the consultation, and the consultation is due to start in the autumn, it's hard to see Rough operating beyond the end of this winter, so we will be urging the government to move at speed."[131]

The full withdrawal of stocks took place over summer 2025 (**Figure 42**). By 30 September, this left GB with only medium-range storage capacity (1.6 Bcm) and stocks of almost exactly 1 Bcm. Looking ahead,

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[124] National Gas Transmission provides daily data on stocks levels for past year for the following 'medium-range' facilities: Aldborough, Hatfield Moor, Hilltop, Hole House Farm, Holford, Hornsea, Humbly Grove, and Stublach. NGT also provides aggregated daily data for stocks at the 'medium-range' facilities for the past five years.

[125] Centrica, 2002. Centrica secures Rough storage facility. *Press Release*, 14 November. https://www.centrica.com/media-centre/news/2002/centrica-secures-rough-storage-facility/

[126] Centrica, 2017. Cessation of Storage Operations at Rough. *Press Release*, 20 June. https://www.centrica.com/media-centre/news/2017/cessation-of-storage-operations-at-rough/

[127] Centrica, 2022. Centrica re-opens Rough storage facility. *Press Release*, 28 October. https://www.centrica.com/media-centre/news/2022/centrica-re-opens-rough-storage-facility/

[128] Centrica, 2023. Centrica bolsters UK's energy security by doubling Rough storage capacity. *Press Release*, 30 June. https://www.centrica.com/media-centre/news/2023/centrica-bolsters-uk-s-energy-security-by-doubling-rough-storage-capacity/

[129] Centrica, 2024. Rough pumps gas into grid to manage demand from early winter. *Press Release*, 29 November. https://www.centrica.com/media-centre/news/2024/rough-responds-to-manage-demand-from-early-winter/

[130] National Gas Transmission, 2025. *Gas Transmission Data*. https://data.nationalgas.com/find-gas-data

[131] Centrica, 2025. 2025 Interim Results Transcript and Q&A. *Press Release*, 24 July. https://www.centrica.com/investors/results-reports-and-presentations/2025-interim-results/ (p.3-4)

the future of Rough will be determined by the outcome of negotiations between Centrica and the UK government, and the impact of government policy on the establishment of a business model that prevents the type of losses that caused the initial closure of Rough in 2017.

3.5.2. The 'medium-range' gas storage facilities

In addition to Rough, GB has a collection of smaller gas storage facilities. The capacity of those facilities combined is an estimated 1.6 Bcm, with full stocks being reached on several occasions since winter 2020/21, as shown in **Figure 42**. These facilities differ from Rough insofar as they (collectively) have significantly higher daily withdrawal rates (deliverability). These include: Aldborough (30 MMcm/d), Stublach (25.5 MMcm/d), Holford (22 MMcm/d), Hill Top (13.4 MMcm/d), Humbly Grove (7.2 MMcm/d), Hornsea (6.4 MMcm/d), and Hatfield Moor (1.8 MMcm/d). This is a combined 106.2 MMcm/d.

Taken together, if used at maximum daily withdrawal capacity, these facilities would draw down from full stocks (c.1.6 Bcm) to empty in 15 days. For comparison, if used at full daily withdrawal capacity, Rough would take 146 days to draw down its stocks entirely.

3.5.3. The use of GB gas storage facilities

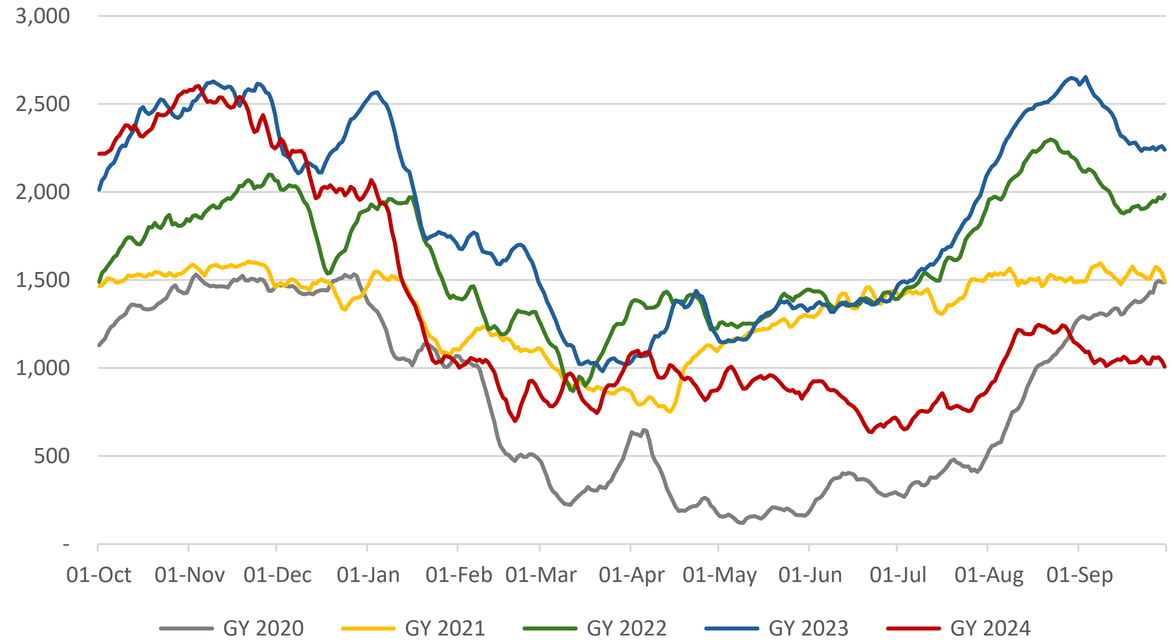
As **Figure 41** and **Figure 42** illustrate, GB gas storage stocks have a seasonal shape, reaching their peaks at the start of winter and their lowest point in summer. However, the range between minimum and maximum stocks is between 750 MMcm (minimum) and 2,650 MMcm (maximum) – a range of roughly 1.9 Bcm in a market that saw peak monthly supply of 287-307 MMcm/d in January 2023-2025.

The gas storage facilities in GB are not designed to meet a substantial proportion of GB gas demand over a sustained period throughout winter. Rather, the maximum daily net withdrawal of c.100 MMcm/d can meet up to a quarter of GB gas demand for a period of several days. A good example of this occurred on 8 and 10 January 2025, when GB gas supply peaked at 384 MMcm/d and 397 MMcm/d, with net storage withdrawal providing just over 100 MMcm/d of supply – 26 per cent of the total. This event was not an anomaly. In the 90 days between 21 November 2024 and 18 February 2025, net storage withdrawals provided at least 15 per cent of GB gas supply on 22 days. For comparison, on 8 and 10 January 2025, LNG sendout was 81 and 93 MMcm/d, imports via Langeled were 74 and 67 MMcm/d, total flow into St Fergus was 58 and 64 MMcm/d, other production was 51 and 49 MMcm/d, imports via BBL and iUK were 20 and 22 MMcm/d, and storage withdrawal was 101 and 102 MMcm/d.

Therefore, it is on the peak days that storage demonstrates its value to its greatest extent. Earlier in this paper it was noted that gross UK daily gas supply (consumption in GB plus onward flows to Northern Ireland and the Republic of Ireland) in the three winters between 2022/23 and 2024/25 peaked at 385-420 MMcm/d. For comparison, total net storage withdrawal peaked at 69-74 MMcm/d in winter 2022/23, 85-93 MMcm/d in winter 2023/24, and 101-102 MMcm/d in winter 2024/25. On every day in the winters of 2023/24 and 2024/25 that UK gas supply has exceeded 350 MMcm/d, net storage withdrawal provided 15-16 per cent of that supply.

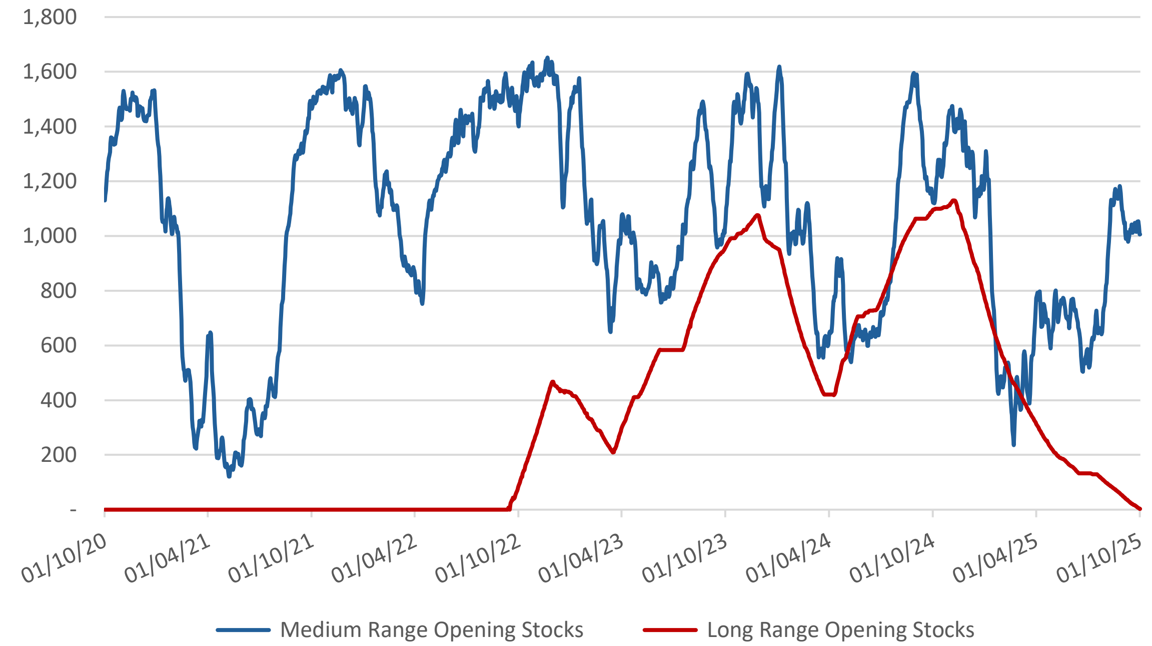
Although GB gas storage facilities do exhibit a seasonal profile in their stock levels, (Figure 41), those facilities demonstrate their value when providing a notable share of GB gas supply for short periods of several days, after which the facilities are replenished ready for the next short burst of withdrawal. If GB experiences a particular surge in demand that is met by storage, the replenishment of those stocks requires an uptick in LNG sendout, given the lack of upside from GB production and pipeline imports from Norway beyond the winter plateau. If the drawdown of stocks at Rough leads to a permanent shutdown of the facility, this will increase the responsibility of medium-range storage and LNG stocks to balance the GB gas market.

Figure 41: GB underground gas storage stocks (MMcm)



Source: Data from National Gas Transmission.[132]

Figure 42: GB medium and long-range gas storage stocks (MMcm)

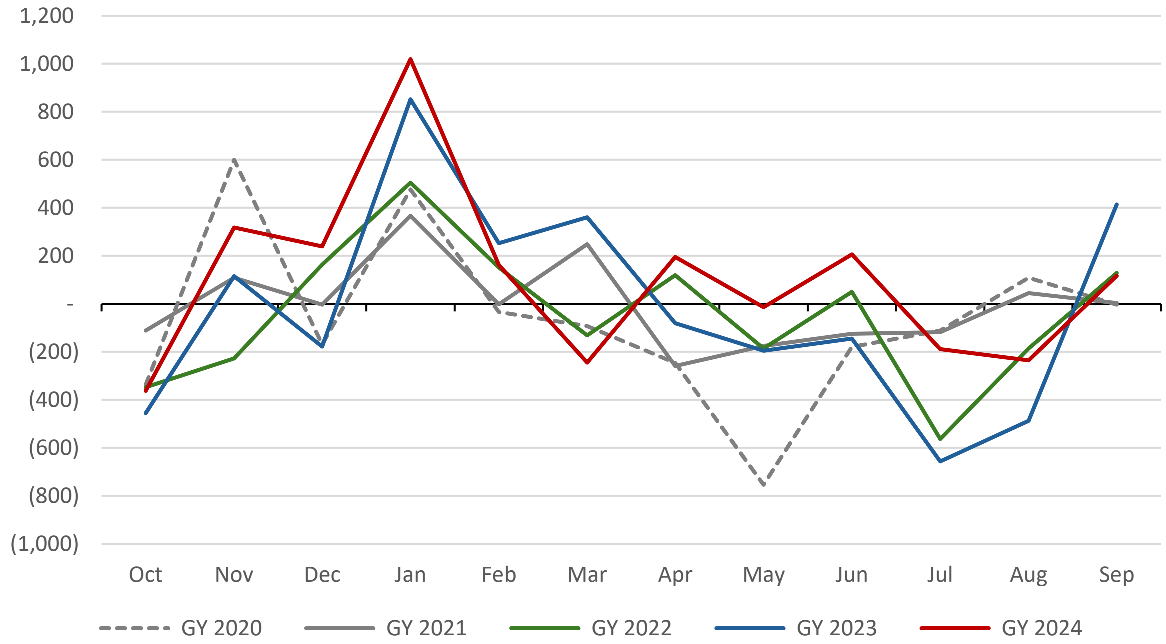


Source: Data from National Gas Transmission.[133]

[132] National Gas Transmission, 2025. *Gas Transmission Data*. https://data.nationalgas.com/find-gas-data

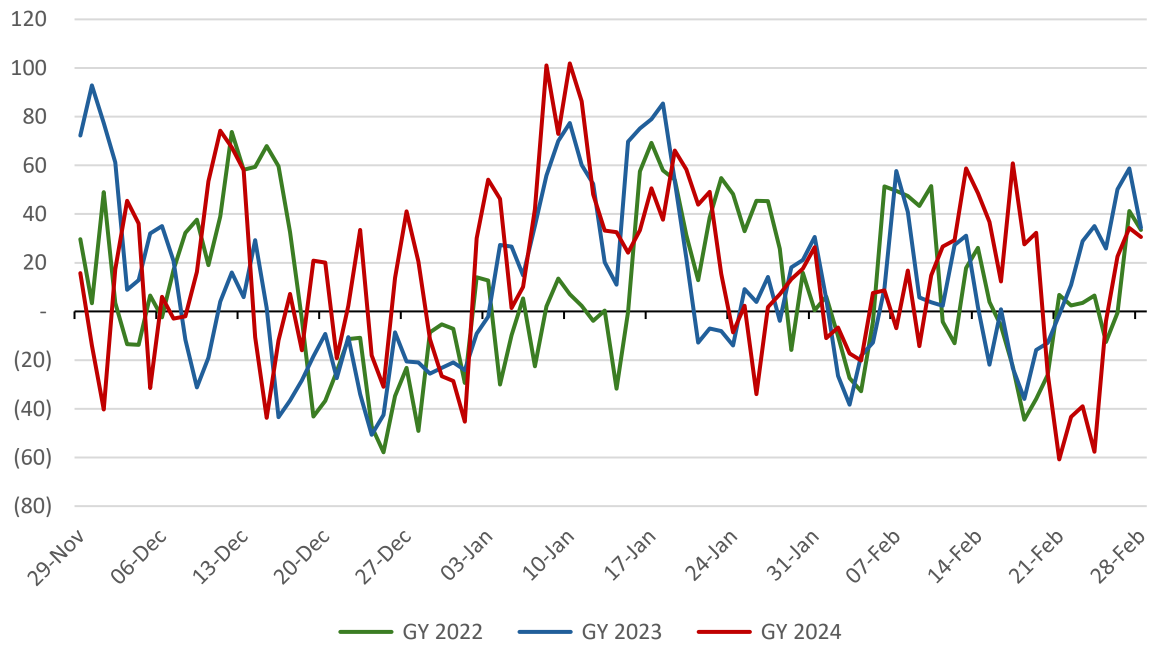
[133] National Gas Transmission, 2025. *Gas Transmission Data*. https://data.nationalgas.com/find-gas-data

Figure 43: GB monthly net gas storage withdrawal (MMcm)



Source: Data from National Gas Transmission.[134]

Figure 44: GB daily net gas storage withdrawal during peak winter demand period (MMcm/d)



Source: Data from National Gas Transmission.[135]

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[134] National Gas Transmission, 2025. *Gas Transmission Data*. https://data.nationalgas.com/find-gas-data

[135] National Gas Transmission, 2025. *Gas Transmission Data*. https://data.nationalgas.com/find-gas-data

4. Demand and supply-side analysis

4.1. Demand-side analysis

Taken as a whole, the combination of demand in GB and the call on pipeline supply to the island of Ireland has a strongly seasonal pattern. In GB, this reflects the dominant role of gas for space heating in the LDZ sector (and to a much lesser extent, the role of gas in space heating in industrial enterprises, which is statistically attributed to the industrial sector). This is exacerbated by the higher electricity demand in winter, which raises the call on gas for baseload electricity supply. Gas demand on the island of Ireland also follows a seasonal pattern, which is balanced by flexibility in pipeline imports from GB, given the lack of seasonal flexibility in Ireland's offshore gas production. Overall, this seasonal shape means that the GB gas supply system must be able to provide high volumes of supply for sustained periods during the winter, despite the absence of seasonal gas storage capacity.

During the coldest parts of the winter (from December to February), GB gas demand for the industrial, LDZ, and power sectors combined can rise from 150 MMcm/d to over 350 MMcm/d within the space of ten days, driven by the need for gas-fired power generation to balance the grid at times of peak demand (especially if wind power generation is low) and at times of low temperatures, which cause a surge in both gas demand for space heating. Given the co-occurrence of low temperatures, low wind speeds, and limited solar generation during midwinter cold spells, the 'cold dunkelflaute' signifies the peak of GB gas demand. Although this paper focuses on daily demand, it is also notable that gas demand in the power sector also experiences significant within-day fluctuation, as gas-fired power stations fill the gap between fluctuations in demand and fluctuations in non-dispatchable supply.

The outlook for GB gas demand over the next five years is influenced by a combination of dynamics. In industry, the high prices of 2022-2024 encouraged temporary fuel-switching away from gas and the deployment of heat pumps for low-temperature process heat. However, the displacement of fossil methane by hydrogen or biogas for high-temperature process heat appears a distant future aspiration. Rather, the main factor will be the economic performance of the industrial sector and related industrial demand for gas and electricity, as seen over the past several years. Until the slow pace of heat pump deployment increases, gas will retain its dominant role in space heating, at the core of LDZ demand. This means that LDZ demand will be driven primarily by temperatures and consumer behaviour, rather than the roll-out of competing sources of heat supply. Finally, gas demand for power generation will be influenced by the combination of the overall electricity demand (which appears to have stabilised after continuous decline between 2005 and 2023, and has the potential to grow due to electrification during the energy transition), the pace of renewable power generation infrastructure build-out (primarily in wind, but also in solar), and fluctuation in nuclear power generation capacity (driven by the timings of the closure of existing nuclear power plants by 2030 and the opening of new plants in the 2030s). This combination of factors suggests that gas-fired power generation to balance the grid is likely to become even more volatile than at present and will require a suitably flexible supply to meet that demand.

4.2. Supply-side analysis

Taken together, GB has a portfolio of gas supplies from different sources, each with their own characteristics. Domestic gas production is now gradually declining and cannot offer upside flexibility during winter. Pipeline imports from Norway – especially via Langeled to Easington – already provide substantial seasonality, ramping down in the summer to less than 20 MMcm/d and up in the winter to full capacity around 76 MMcm/d. However, once the high winter plateau is reached, additional pipeline supply from Norway cannot be obtained.

Therefore, the flexibility in GB gas supply on the side of production and imports is derived primarily from sendout from LNG regasification terminals. Here, the benefit of having substantial LNG storage capacity at both the Isle of Grain and Milford Haven (in excess of one million cubic metres of LNG – 600 MMcm of natural gas – at each) is particularly valuable, insofar as it enables the terminals to unload cargoes without waiting for previous cargoes to be fully discharged into the grid system. Moreover, the combination of substantial LNG storage capacity and plentiful daily sendout capacity (a combined of 145 MMcm/d, soon to be close to 160 MMcm/d) means that sendout can be varied to follow demand in a flexible manner, including both demand in terms of consumption and in terms of volumes needed to replenish short-range storage.

Finally, the fact that GB gas storage capacity (c.3 Bcm divided equally between Rough and several medium-range facilities) is equivalent to just 4 per cent of total annual supply in 2024 (74 Bcm), which is low compared to the 106 Bcm of gas storage capacity available in the EU-27 for a market of c.390 Bcm in 2024, should not disguise the important role storage plays in meeting short-run surges in GB gas demand, especially during winter. In GB, storage is constantly replenished and drawn down over the course of winter, around a baseline stock level that only moves roughly 1 Bcm from its highest to its lowest over the course of a year. The importance of short cycles of storage injection and withdrawal in providing flexible gas supply in winter means that the drawdown of stocks at Rough and its potential closure has significant consequences for GB security of gas supply. The loss of flexibility at Rough will need to be balanced by the greater use of medium-range storage facilities and LNG storage stocks.

Looking ahead to the next five-to-ten years, GB is likely to lose more of its existing supply insofar as domestic gas production is set to continue declining. Competition for Norwegian supply will likely increase, given that the forecast decline in Norwegian gas production from the late 2020s will open up spare capacity on Norway's export pipeline system, allowing for optionality between sales markets and increasing competition between importers. This will be offset by a greater availability of LNG, in the context of the anticipated substantial growth in global LNG supply based on new liquefaction capacity that will be brought online in the period 2025-2030. The role of LNG in meeting seasonal swings in GB gas demand, short-run surges in demand for consumption, and the constant cycle of replenishing fast-cycle storage is likely to become even more important, even if overall GB gas demand continues to decline. This dynamic will become even more visible if GB gas demand becomes more volatile due to the role of gas-fired power generation in balancing non-dispatchable power generation.

5. Conclusion

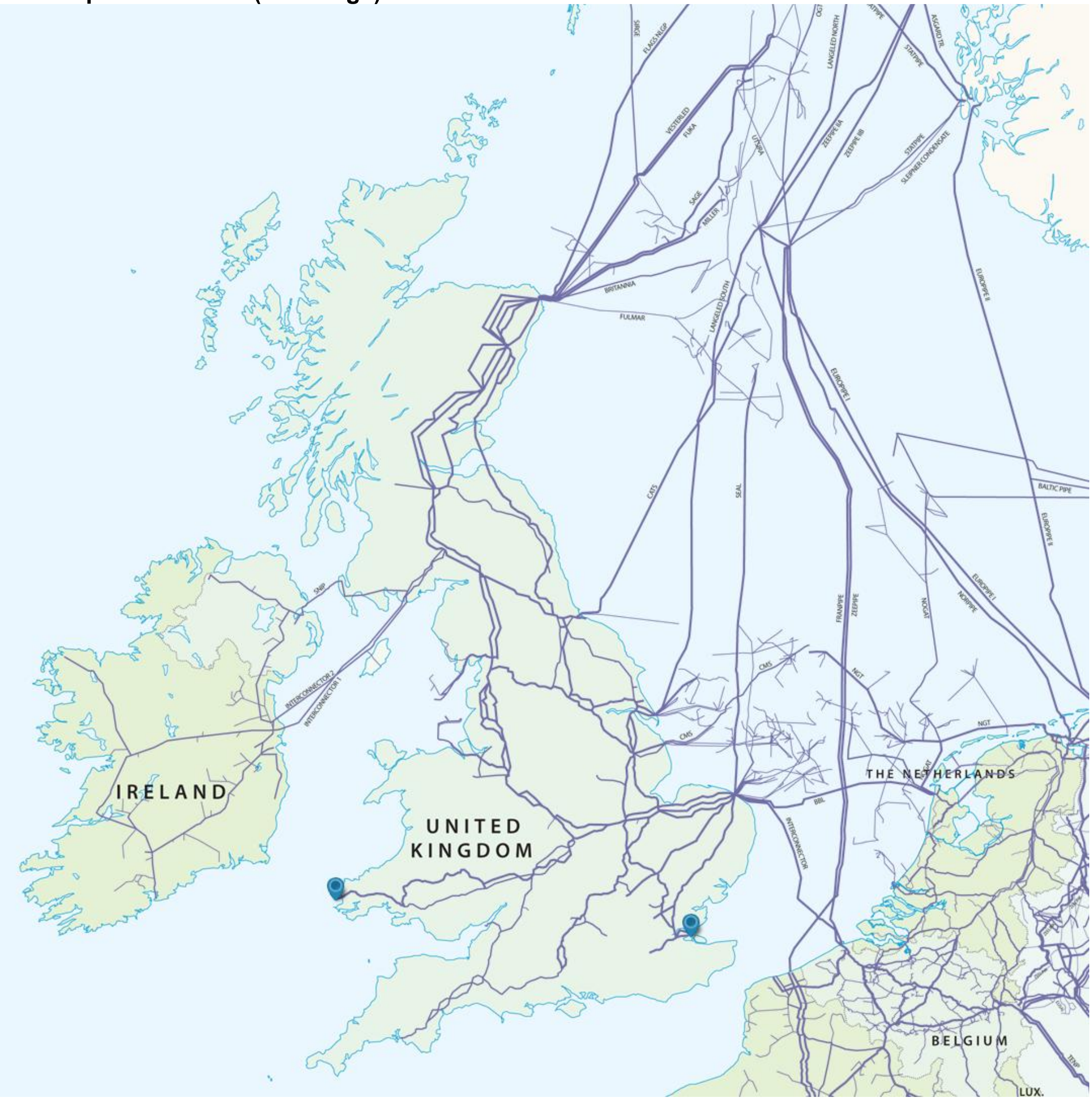
Although GB gas demand does not appear set to grow substantially over the coming five years, neither is it set to decline substantially. While the outlook for annual demand is potentially one of very gradual decline in industry and LDZ, the outlook for gas-fired power generation is more nuanced. While gas demand for power generation may decline gradually as renewables provide more baseload supply, gas-fired power generation is likely to become more volatile as it bridges the gap between volatile electricity demand and variable supply from non-dispatchable power generators, especially until grid-scale electricity storage becomes substantial enough to impact the picture. This means that total gas demand is likely to decline gradually, but become more volatile, especially on a daily and intra-day basis.

On the supply side, the seasonal swing in supply from domestic production and Norwegian pipeline supply is likely to diminish over the next 5-10 years, as GB and Norwegian production declines. Given the absence of seasonal storage capacity as seen in the EU-27, the seasonal swing in GB gas supply will come from LNG imports. Moreover, the flexibility in daily and intra-day supply will depend on a combination of fast-cycle underground storage and sendout from storage tanks at LNG terminals, while LNG sendout will also play a key role in replenishing that fast-cycle storage during winter.

To conclude, GB currently has sufficient infrastructure to meet the present challenge of supply meeting demand. However, as the volatility of demand is likely to grow, the flexibility of supply will become even more important. In the context of the outlook for demand in different sectors and supply from different sources, developments in the power generation sector and in relation to gas storage (both gas storage and storage tanks at LNG regasification terminals) in particular will combine to provide a gas-sector illustration of the broader challenge facing the UK government and energy market participants: how to maintain security of supply and encourage investment in infrastructure while simultaneously promoting competitive markets and supporting the process of decarbonisation.

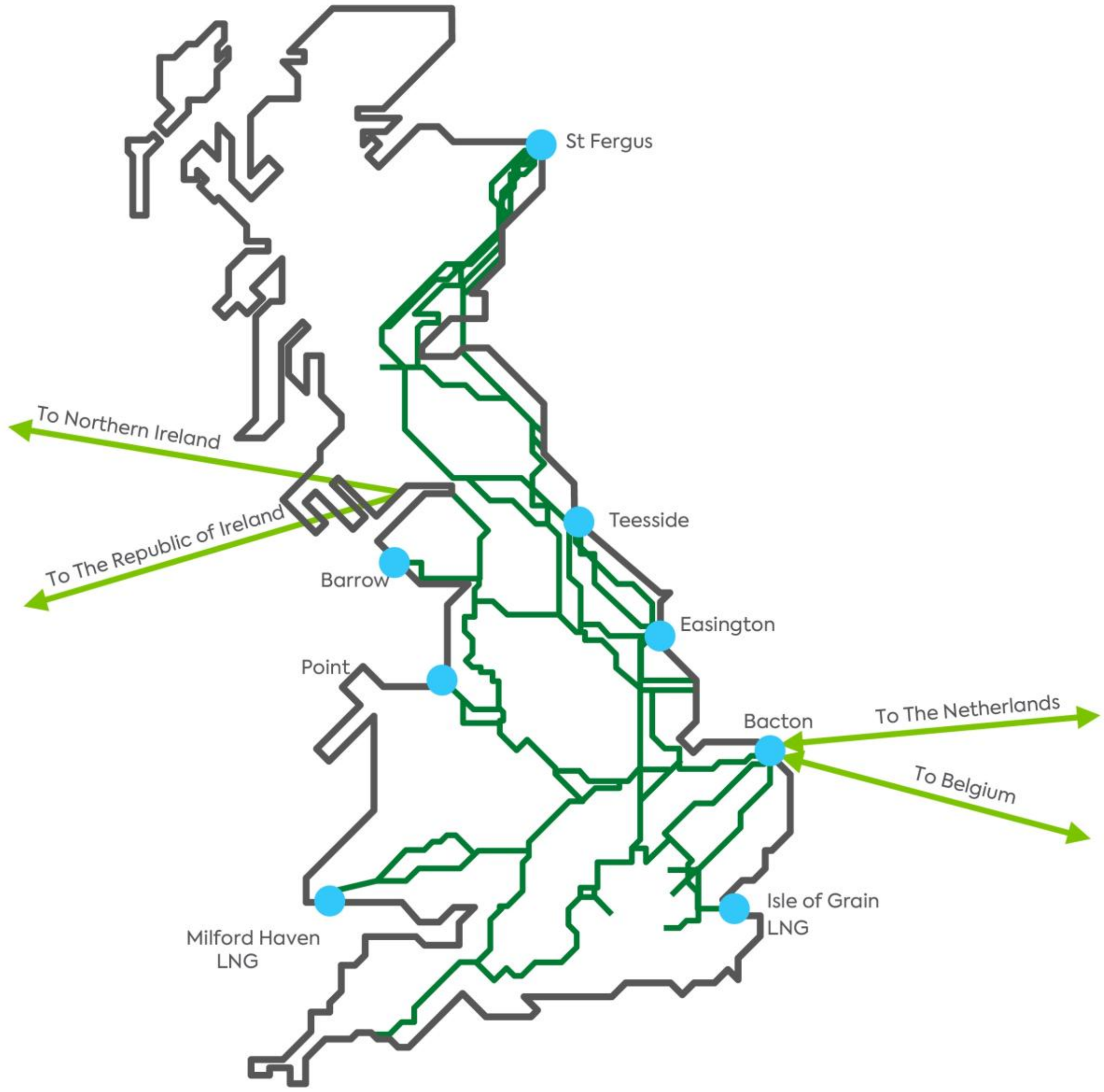
Appendix 1: Maps of GB Gas Supply Infrastructure

Figure 45: Pipelines for GB gas imports / exports and landing gas produced offshore, plus GB LNG import terminals (blue flags)



Source: Original map from ENTSOG Transparency Platform. Annotated by the author.

Figure 46: GB national transmission system (NTS) supply terminals

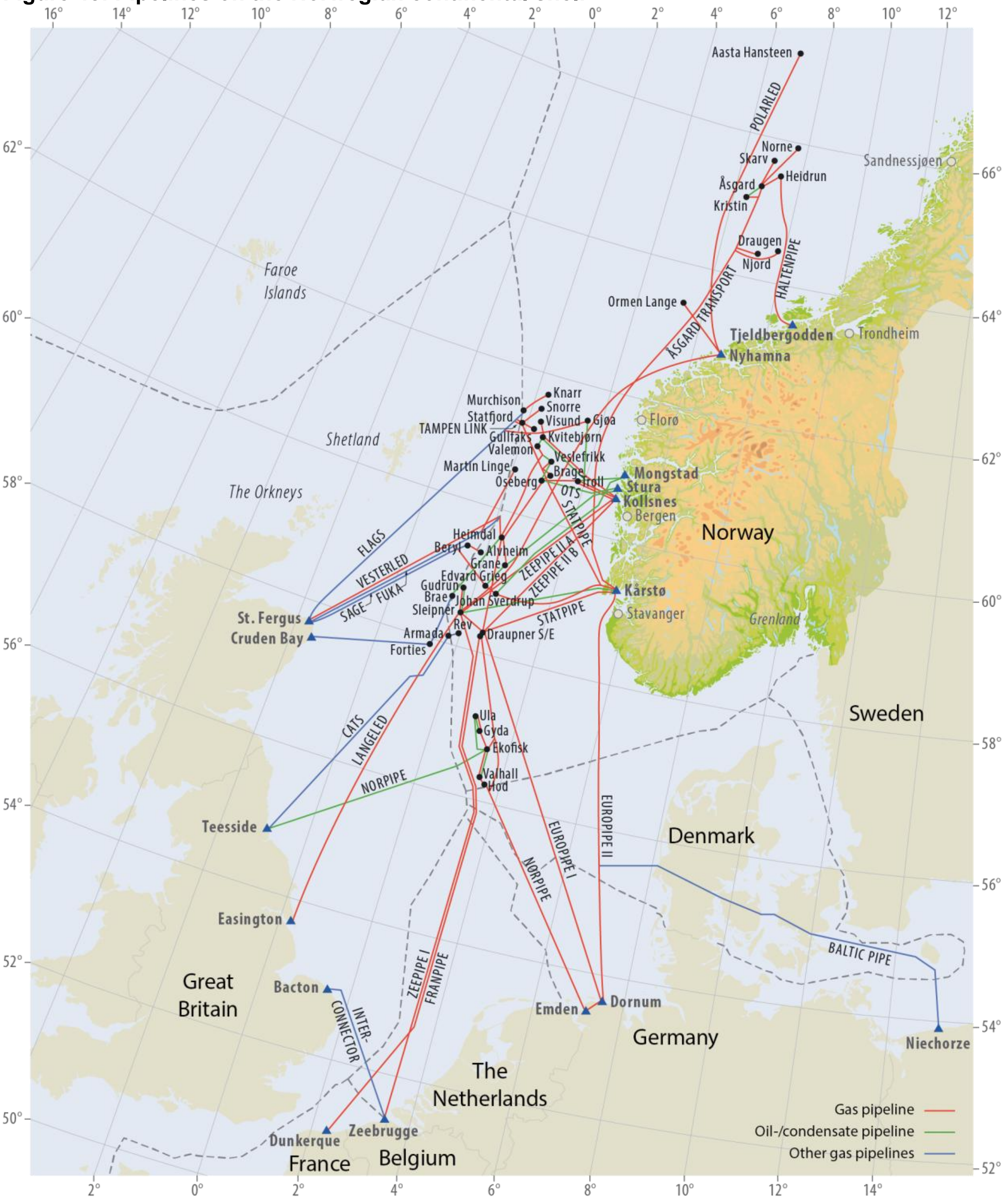


Source: DESNZ, 2025. *Midstream gas system: update to the market*. 30 June. https://www.gov.uk/government/publications/midstream-gas-system-update-to-the-market/midstream-gas-system-update-to-the-market

Figure 47: GB interconnectors: Scotland to Northern Ireland (SNIP) and Republic of Ireland (Interconnector 1 and 2)

Source: Gas Infrastructure Europe, 2025. *System Capacity Map.* https://www.gie.eu/publications/maps/system-capacity-map/ (published 10 January 2025).

Figure 48: Pipelines on the Norwegian continental shelf



Source: Norwegian Offshore Directorate, 2025. *The oil and gas pipeline system*. https://www.norskpetroleum.no/en/production-and-exports/the-oil-and-gas-pipeline-system/ (map updated 22 September 2022).

Appendix 2: Relevant publications for further reading

UK Government

In March 2023, the UK Department for Energy Security and Net Zero (DESNZ) published its energy security plan, 'Powering Up Britain'.[136] [137] While the main report focused on decarbonisation as a means of reducing exposure to fossil fuel imports, a second document, entitled 'Powering Up Britain: Energy Security Plan' was published at the same time, with a focus on security of supply of fossil fuels. In particular, that second report noted that "The UK's energy security remains hugely dependent on a reliable, resilient and affordable supply of gas."[138]

The Powering Up Britain: Energy Security Plan committed NESO to publish a Gas Supply Security Assessment (GSSA). In December 2023, the proposed methodology for that GSSA was published.[139]

Also in December 2023, DESNZ published 'Role of Gas Storage and Other Forms of Flexibility in Security of Supply: Energy Security Plan Update'.[140]

Every year, DESNZ publishes a Statutory Security of Supply Report, covering all energy sources. The most recent report was published on 19 December 2024.[141]

On 30 June 2025, DESNZ published the policy paper, 'Midstream gas system: update to the market'.[142]

Finally, the Gas Security of Supply Assessment by NESO is due for publication in Q4-2025.

National Gas Transmission

The GB Transmission System Operator, National Gas Transmission (NGT), publishes Winter and Summer Outlooks every year. The most recent Winter Outlook was published on 9 October 2025.[143]

NGT also publishes a Gas Ten-Year Statement (GTYS) every year, to provide an understanding of how NGT intend to operate and plan for the gas National Transmission System (NTS) over the next ten years. The most recent GTYS was published in December 2024.[144]

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[136] DESNZ, 2023. *Powering Up Britain*. 30 March. https://www.gov.uk/government/publications/powering-up-britain

[137] DESNZ, 2023. *Powering Up Britain*. 30 March. https://assets.publishing.service.gov.uk/media/642468ff2fa8480013ec0f39/powering-up-britain-joint-overview.pdf

[138] DESNZ, 2023. *Powering Up Britain: Energy Security Plan*. 30 March. https://assets.publishing.service.gov.uk/media/642708eafbe620000f17daa2/powering-up-britain-energy-security-plan.pdf

[139] DESNZ, 2023. *Medium range gas supply security assessment: methodology*. 23 December. https://www.gov.uk/government/publications/medium-range-gas-supply-security-assessment-methodology

[140] DESNZ, 2023. *Role of gas storage and other forms of flexibility in security of supply*. 23 December. https://www.gov.uk/government/publications/role-of-gas-storage-and-other-forms-of-flexibility-in-security-of-supply

[141] DESNZ, 2024. *Statutory Security of Supply Report 2024*. 19 December. https://www.gov.uk/government/publications/statutory-security-of-supply-report-2024/statutory-security-of-supply-report-2024

[142] DESNZ, 2025. *Midstream Gas System: Update to the Market*. 30 June. https://www.gov.uk/government/publications/midstream-gas-system-update-to-the-market/midstream-gas-system-update-to-the-market

[143] NGT, 2025. *Winter Outlook 2025*. 09 October. https://www.nationalgas.com/media/news/national-gas-publishes-2025-gas-winter-outlook

[144] NGT, 2024. *Gas Ten Year Statement (GTYS)*. December. https://www.nationalgas.com/media/publications/gas-ten-year-statement-gtys