Data Classification: Public

Gas Supply Security Assessment

Assessing gas supply security five and ten years ahead

November 2025

Resilience & Emergency Management

NESO
National Energy System Operator

Welcome

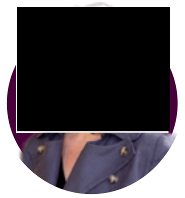
Reliable and resilient energy systems underpin society. We all depend on reliable energy supplies, and one of NESO's primary duties is ensuring security of supply for current and future energy customers in Great Britain. This includes identifying future risks to security of supply.

Our energy system is expected to transform over the next decade, accelerated by the government's Clean Power 2030 Action Plan, as we decarbonise to meet our net zero targets and mitigate the threat of climate change. Great Britain has one of the most reliable energy systems in the world, and maintaining security of supply will be critical in this energy transition.

Natural gas (gas) will continue to play a vital role in the energy system for the foreseeable future, and reliable supplies will remain essential for consumers in heating homes, powering industry and generating electricity. Over the next decade, we expect a continued decline in gas production from the United Kingdom Continental Shelf (UKCS), which will increase our reliance on imported gas to meet our needs. While overall gas demand throughout the year is expected to decrease due to decarbonisation, the amount of gas used on a cold day (the 'peak' gas demand) is expected to fall more slowly. This presents emerging risks that we will need to understand to ensure reliable supplies are maintained for consumers.

This new report – NESO's first annual Gas Supply Security Assessment – sets out our analysis of the risks to gas security of supply five and ten years from now, covering winters 2030/31 and 2035/36. Our report will help identify emerging risks and mitigation options that, if needed, can be implemented ahead of time to maintain reliable energy supplies as the energy landscape evolves. As well as our assessment, government has published a consultation on gas system supply and capacity that is seeking views on the need for government action and proposed interventions.

Collaboration will be essential to ensuring reliable supplies for consumers. We will work in partnership with key strategic partners including government, Ofgem, National Gas Transmission and the energy industry, to ensure reliable energy supplies. We warmly welcome engagement and encourage feedback from stakeholders on our first Gas Supply Security Assessment, which we will continue to build and develop collaboratively over the coming months.



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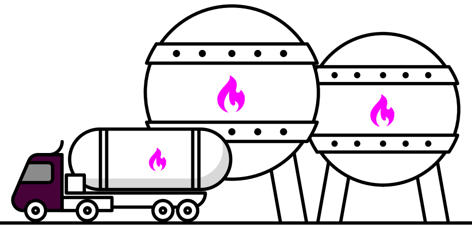
Director of Resilience and Emergency Management



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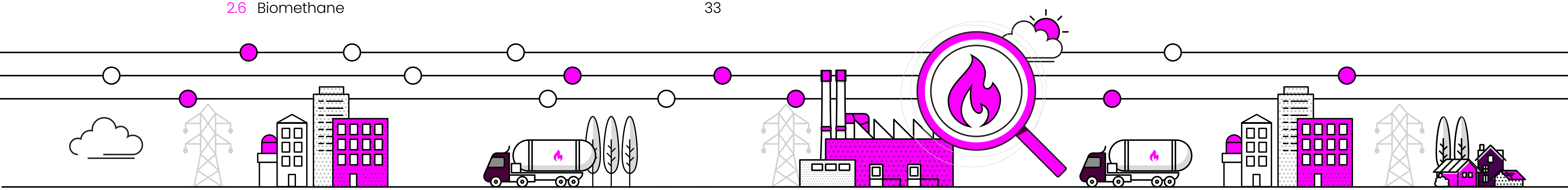

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Executive Summary

Security of supply is fundamental to the resilience of the energy system in Great Britain. Through its new responsibility as Great Britain's (GB's) Gas System Planner, NESO has a licence obligation to assess gas supply security at the five- and ten-year-ahead horizons[1]. In this *Gas Supply Security Assessment* (the Assessment), NESO delivers its first analysis under this licence obligation, considering the availability, reliability and deliverability of gas volumes needed to meet a range of GB demand scenarios. The Assessment focuses on winters 2030/31 and 2035/36 and also considers the intervening years to provide a clearer view of gas supply security across this period.

The future of GB gas demand is uncertain and depends on the rate of decarbonisation in key sectors such as domestic heating, power generation and industry. To ensure the analysis appropriately reflects this uncertainty, we have assessed gas supply security against each pathway in our 2025 *Future Energy Scenarios* (FES)[2]. Our Ten Year Forecast (10YF) represents the base case, with the four other pathways representing higher and lower demand scenarios, characterised by varying rates of decarbonisation.

For each scenario, gas supply security is assessed against seasonal normal weather conditions and a severe cold weather event, during which peak day demand reaches a level statistically likely to be exceeded once every 20 years (1-in-20). Gas supply security is further assessed under the same severe cold weather event conditions coinciding with the loss of the single largest piece of gas infrastructure (N-1 test).

Our Assessment shows that GB is expected to continue benefiting from a diverse range of gas supply sources in the 2030s. These sources include the United Kingdom Continental Shelf (UKCS), Norwegian Continental Shelf (NCS), Liquefied Natural Gas (LNG), pipeline imports from Europe, gas storage and biomethane. The relative contribution of these sources will evolve over time, primarily driven by the long-term natural decline of UKCS production – a trend evident since the early 2000s.

Deliveries from the NCS could also become more uncertain as overall production declines and producers retain the flexibility to supply multiple markets through the NCS system. As a result, we expect GB to become increasingly reliant on LNG, with sufficient global availability expected to enable high utilisation rates at GB terminals. Interconnector imports from mainland Europe and withdrawals from gas storage facilities will also continue to play a crucial role each winter. However, recent reductions in technical capacity mean the realistic maximum supply could be lower than in previous winters. Biomethane production is also expected to grow, delivering small but consistent volumes each year.

The Assessment shows that gas supply is expected to be sufficient to meet demand under seasonal normal weather conditions. When testing against a range of 1-in-20-year peak demand scenarios for 2030/31 to 2035/36, the analysis identifies an emerging risk to GB gas supply security. In scenarios where all gas supply and network infrastructure are operational (intact), this risk is evident only where decarbonisation is slowest – where peak gas demand is expected to remain close to, or even exceed, current expectations. However, in the unlikely event of the loss of the single largest piece of gas infrastructure (the N-1 test), gas supply falls short of demand expectations for all pathways in 2030/31. In 2035/36, this shortfall is apparent only in pathways where gas demand remains high due to slower progress towards net zero targets.

Given the risks identified, this Assessment shows that a combination of measures will likely be required to mitigate emerging security of supply risks. Mitigation options identified include reducing peak day gas demand through decarbonisation, maximising peak day supply from existing infrastructure, and developing new gas supply infrastructure. Delivering any action will require coordinated effort across the four organisations responsible for gas supply security – NESO, government, Ofgem and National Gas Transmission – to ensure the timely delivery of the most effective options for GB consumers.

1 *Annex G – Gas System Planner Licence Conditions – see Condition C4*, Ofgem.

2 *Future Energy Scenarios (FES)*, National Energy System Operator.

Key Messages

1 Gas Supply Outlook

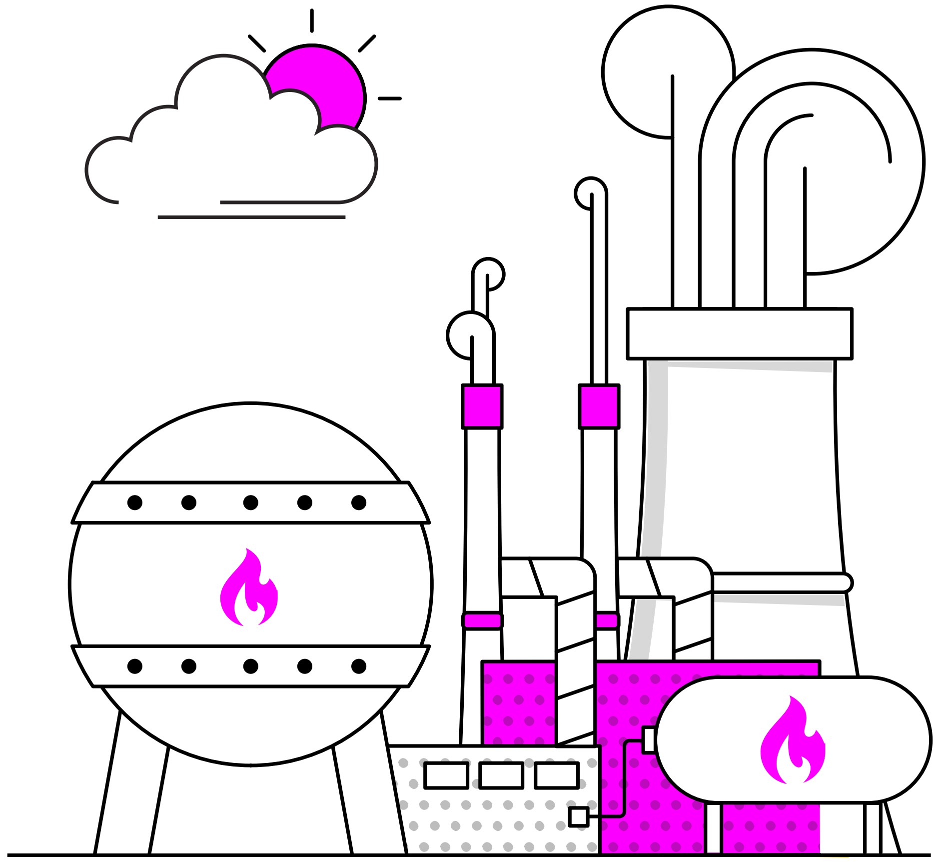
We expect Great Britain to continue benefiting from a diverse range of gas supply sources into the 2030s. As production from the United Kingdom Continental Shelf declines, we will become more reliant on Liquefied Natural Gas, interconnector imports from Europe and gas storage – alongside continued supply from the Norwegian Continental Shelf – to meet demand throughout each winter, particularly during cold spells.

2 Gas Supply Margins Outlook

Our analysis shows that gas supply margins are expected to become tighter by 2030, indicating an emerging risk to gas supply security. Based on expected demand levels for the period assessed (covering winters 2030/31 and 2035/36), the analysis shows that on a very cold day (during a 1-in-20-year cold snap) and following a failure of the single largest piece of infrastructure (the N-1 test), the system would not have sufficient gas to meet demand without mitigating action(s) being taken.

3 Mitigation Options

Options are available to mitigate the identified risks. NESO is committed to working with government, Ofgem, National Gas Transmission and industry to ensure continued security of gas supply. The mitigations identified in this Assessment, together with the consultation announced by government – which sets out its assessment of priorities for gas security of supply during the transition – provide a suite of options capable of addressing these risks. This will require a coordinated approach to ensure timely delivery of the most effective options for Great Britain.



A Changing Context

Gas supply security in GB has historically been delivered and maintained, even during times of elevated demand or system stress. Initially, this security was achieved through sufficient production from the UKCS. More recently, however, the system has evolved to rely on a diverse and flexible supply market (Figure 1). The NCS, LNG deliveries, gas interconnectors with Belgium and the Netherlands, and underground storage sites all now contribute to GB's gas supply security.

For almost a decade, UKCS production was sufficient to meet both GB's demand and to export gas to European markets (Figure 2). GB was a net exporter between 1997 and 2004, meaning the UKCS produced more gas annually than was consumed domestically. UKCS production is still assumed to flow most reliably relative to other sources – hence it is described as baseload supply – but it has naturally declined from its peak in the 2000s and is now considered a mature basin. UKCS fields are now experiencing a rapid decline in the delivery of molecules at an approximate rate of 12–13% winter-on-winter until 2035. As flows decline, terminals – which receive and process gas from offshore fields before injecting into the gas network – are either being actively decommissioned or are planned to be in the coming decades. Burton Point UKCS was decommissioned in 2023, with UKCS flows projected to cease into two other terminals over the next decade.

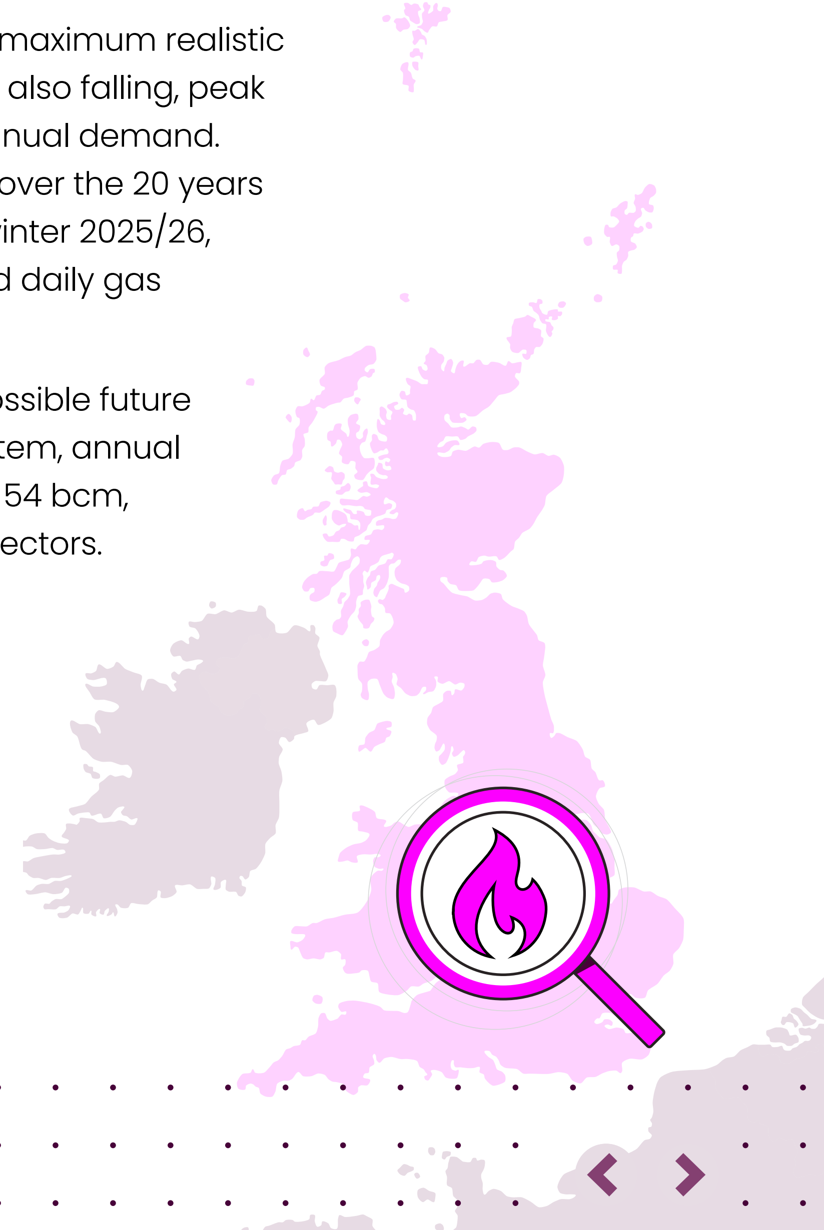
This will require GB to attract the necessary volumes of imported supply, which may also be subject to European and wider international market competition. During periods of peak demand in the 2030s, we expect GB's import dependency could rise above 90%.

NCS supply, imports from Europe and underground storage are also expected to have lower availability than in previous years. NCS production is projected to decline in the coming years, with the rate dependent on the delivery of any new production opportunities.

Rough gas storage in the North Sea did not reinject ahead of this winter, and there has been reduced import capacity on both interconnector pipelines connecting GB with mainland Europe due to reductions in long-term capacity bookings for winter 2025/26. Moreover, while we forecast that there will continue to be sufficient levels of LNG available globally, constraints on the National Transmission System (NTS) may prevent this from fully offsetting any shortfalls from other sources.

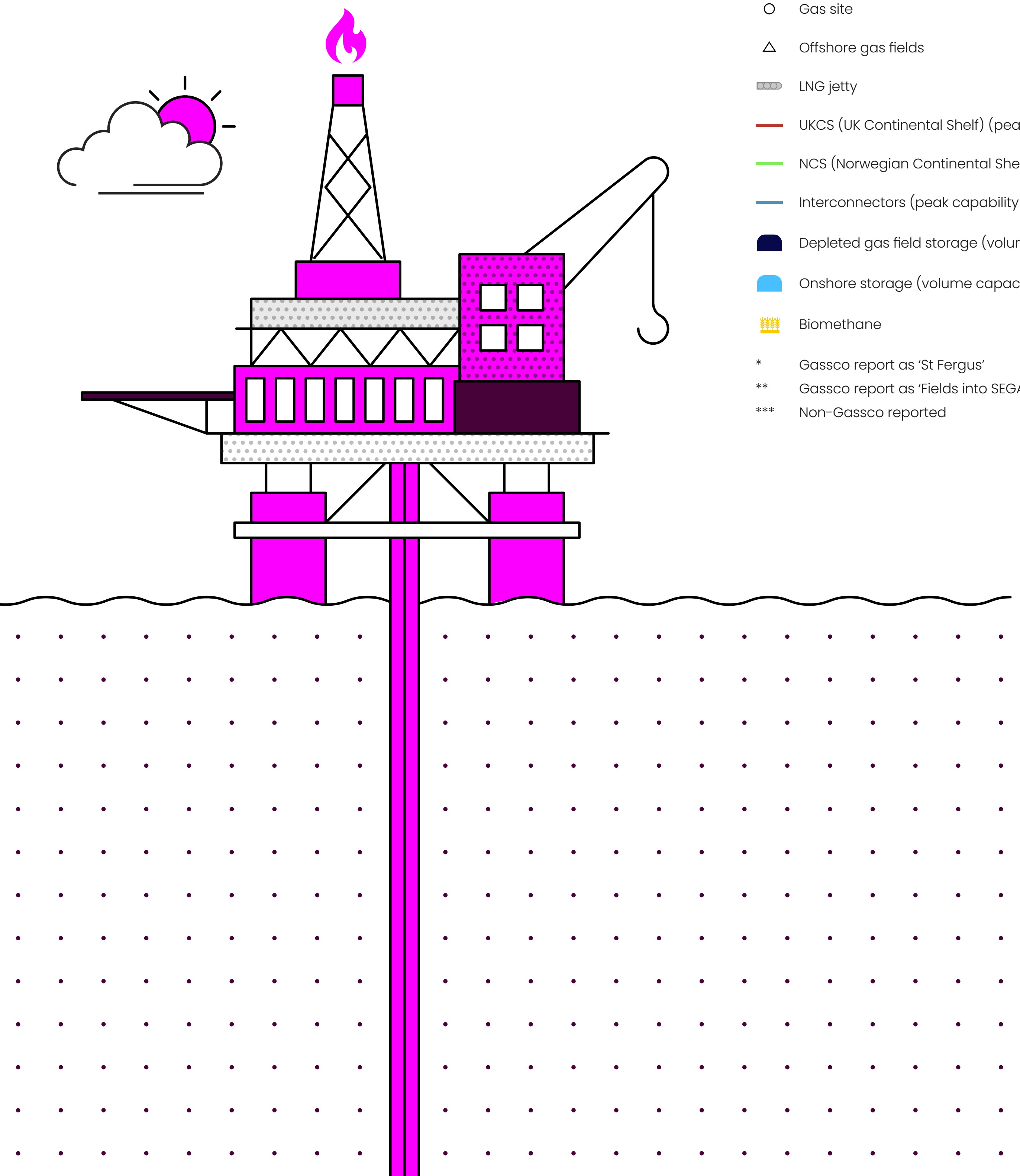
The combination of these factors means that the maximum realistic supply of gas to GB is falling. While gas demand is also falling, peak day gas demand is declining more slowly than annual demand. Annual gas demand has fallen by 40% to 62 bcm over the 20 years to 2024. However, the peak day gas demand for winter 2025/26, at 482 mcm,[3] remains above the highest observed daily gas demand of 465 mcm, recorded in January 2010.

Using our FES publication[4] to identify a range of possible future gas demand pathways within a whole energy system, annual gas demand in 2035 could range from 39 bcm to 54 bcm, depending on the rate of decarbonisation in key sectors. Peak day gas demand declines more moderately across all FES pathways. Even by 2050, the highest 1-in-20-year peak day gas demand considered feasible remains at 427 mcm, around 92% of the highest demand recorded on the NTS.



3 *Gas Winter Outlook* (October 2025), National Gas.

4 *Future Energy Scenarios (FES)*, National Energy System Operator.



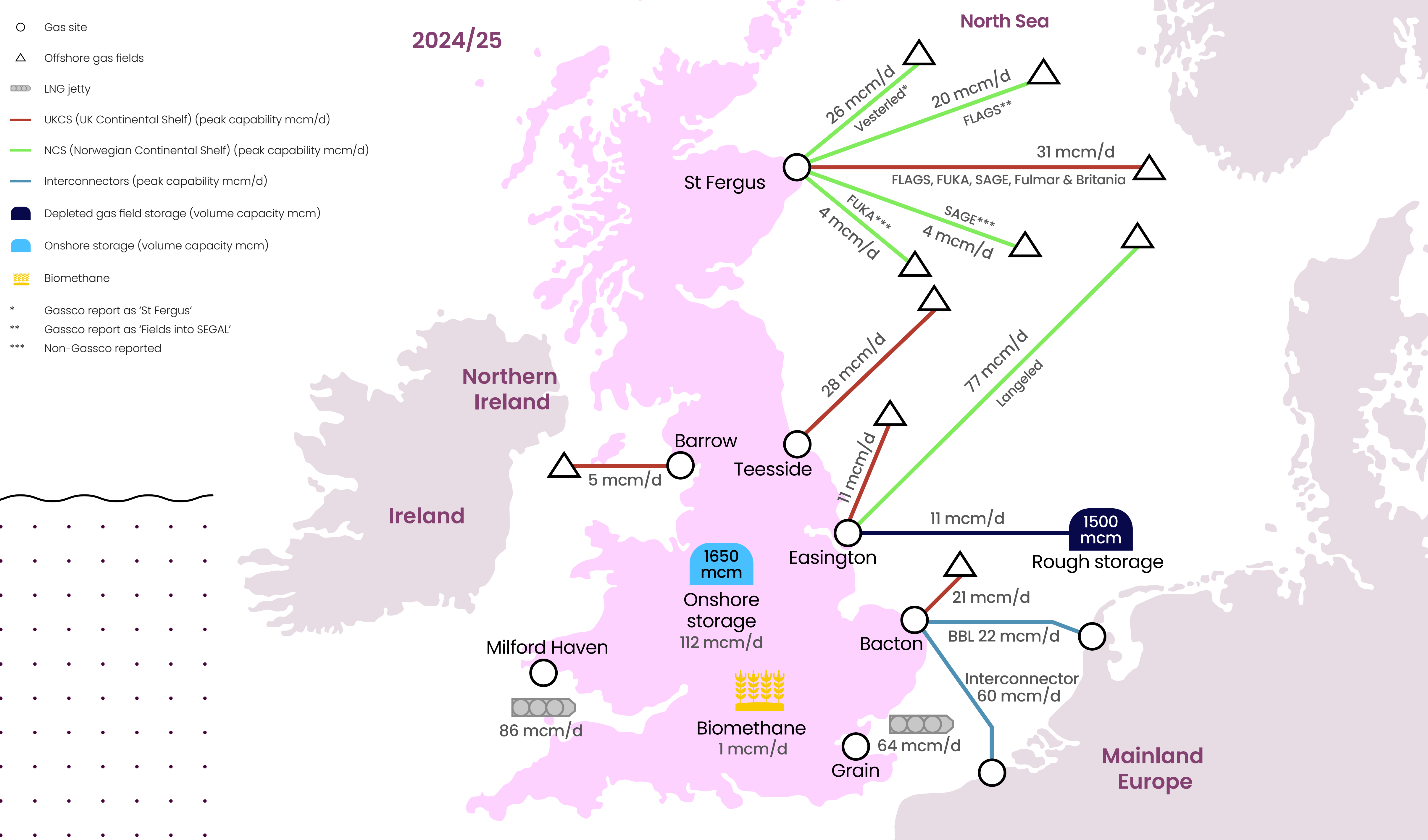


Figure 1: GB's 2024/25 gas supply map showing observed maximum deliverable capabilities

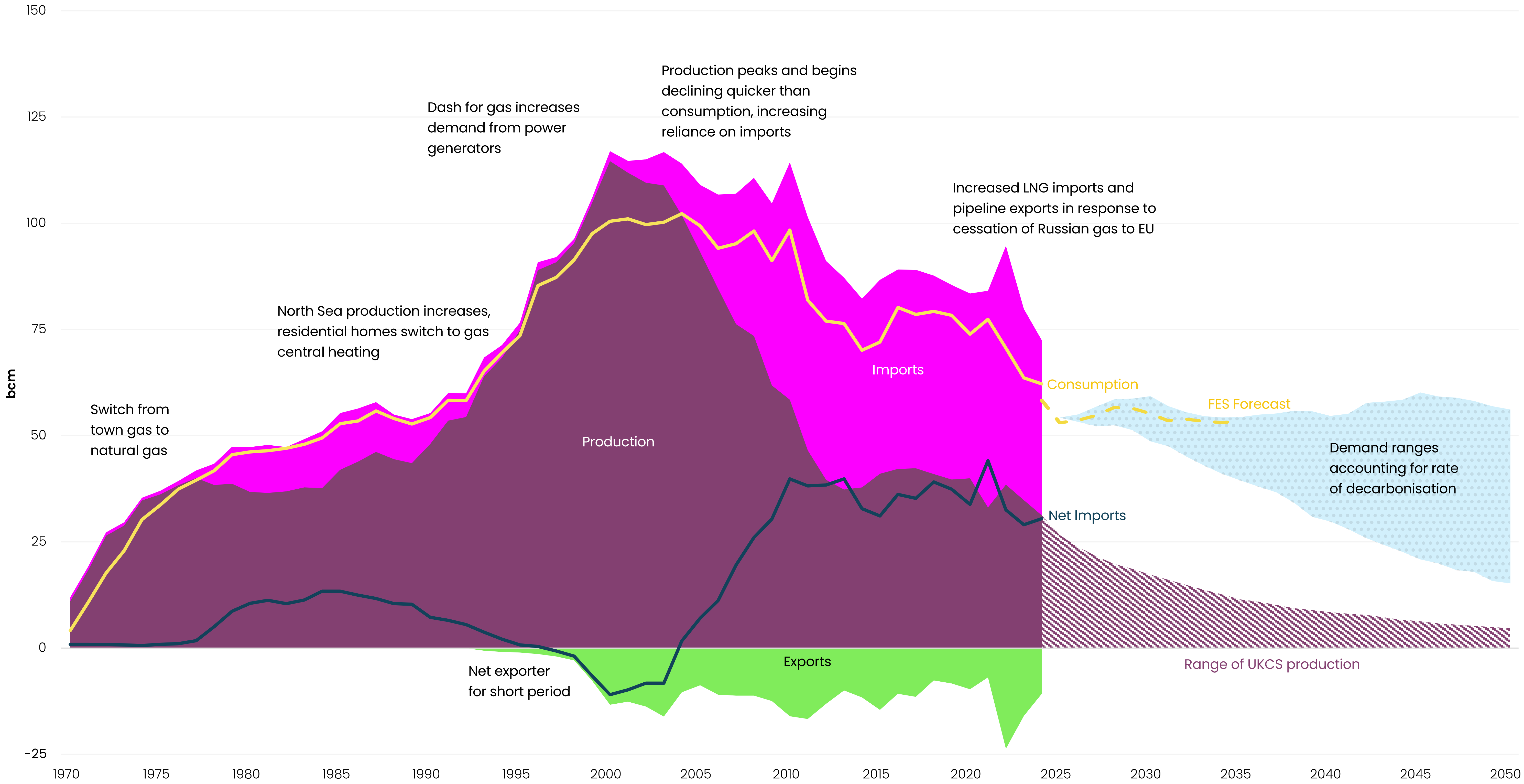


Figure 2: Total annual GB natural gas production and net imports compared with consumption, based on March 2025 North Sea Transition Authority (net) projections, including possible higher range from the FES UKCS high case. The difference between projected production and demand will be met by net imports.

Roles and Responsibilities

Gas supply security is a shared responsibility, shaped by the distinct roles and outputs across four organisations: NESO, the Department for Energy Security and Net Zero (DESNZ), the Office of Gas and Electricity Markets (Ofgem) and National Gas Transmission (NGT, also known as National Gas).

As the independent system planner for GB's energy system, NESO has recently taken on strategic planning and advisory responsibilities for gas security of supply. This includes this new Assessment at the five- and ten-year-ahead timeframe, in line with obligations under our Gas System Planner Licence[5]. It supports the delivery of existing duties by providing a system-wide view of gas supply through analysis of the availability, reliability and deliverability of gas molecules.

Other relevant NESO activities includes the *Gas Network Capability Needs Report* (GNCNR)[6], which assesses whether the NTS has the capability to meet current and future gas flow requirements, and the *Gas Options Advisory* (GOA) document[7], which evaluates the commercial value of new gas infrastructure under typical market conditions. NESO also produces the FES[8], which sets out potential future pathways for the whole energy system that informs the assumptions used in these activities.

Under UK legislation (transposed from former European legislation[9]), the Secretary of State at DESNZ has ultimate responsibility for ensuring the security of GB's gas supply. This includes meeting the N-1 infrastructure standard, which assesses whether the gas system can meet demand on a statistically rare peak day (1-in-20-year event) even if the single largest gas supply infrastructure asset is unavailable. This test ensures the system is resilient to major supply disruptions under periods of elevated demand. DESNZ committed, in its *Midstream Gas System*: *Update to the Market*[10], to publish a consultation on gas security of supply and seek views on a range of proposed policy options that the government is considering to address these priorities. The *Gas System in Transition*: *Security of Supply* consultation was published in November 2025.[11] NESO and DESNZ have worked closely to compare modelling assumptions throughout the development of this Assessment and the government consultation.

Ofgem ensures that market regulations are consistent with the Secretary of State's mandate and is the Uniform Network Code authority, which governs the transportation and supply of gas in the UK.

NGT is the owner and operator of the gas NTS in GB. It is required to develop, maintain and operate economic and efficient networks, and to facilitate competition in the supply of gas in GB. In relation to security of supply, NGT has three main duties as:

- infrastructure provider, to ensure the NTS can accommodate the required flows to meet peak demand
- residual balancer, to ensure supply and demand are balanced daily
- market facilitator, to inform the market both daily through its data portal and through annual publications such as the *Winter Outlook* and *Gas Ten Year Statement*

Finally, each part of the gas supply system is privately operated, with gas shippers responsible for the purchase, transportation and delivery of gas to consumers. Market participants are incentivised to deliver gas in line with consumer demand through established market signals and commercial arrangements.

5 *Annex G – Gas System Planner Licence Condition C4*, National Energy System Operator.
6 *Gas Network Capability Needs Report (GNCNR)*, National Energy System Operator.
7 *Gas Options Advice (GOA)*, National Energy System Operator.
8 *Future Energy Scenarios (FES)*, National Energy System Operator.
9 Regulation (EU) 2017/1938 of the European Parliament and of the Council of 25 October 2017 concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010 (Text with EEA relevance), GOV.UK.
10 *Midstream Gas System: Update to the Market*, GOV.UK.
11 *The Gas System in Transition: Security of Supply*, November 2025, GOV.UK.

Modelling Approach

How has Gas Supply Security been assessed?

This Assessment is a new approach to assessing the capability of projected gas supply to meet differing levels of national demand, five and ten years from now.

Central to this Assessment is the understanding that the stated technical maximum capability of each supply source may not accurately represent the realistic maximum volumes of gas deliverable to GB's NTS on any given day. Consequently, a 'de-rating' methodology has been developed and applied to calculate the realistic maximum volume of gas that each supply source is likely to be able to deliver each day for the periods assessed. The concept of de-rating is widely used for electricity security of supply assessments and can also be applied to gas security of supply to better estimate the actual availability, reliability and deliverability of gas volumes over the specified time horizon.

De-rating criteria

Availability	Reliability	Deliverability
Are the physical quantities of gas that GB will need available from supply sources?	**Can these quantities be purchased by, and delivered to, GB market participants?**	**Is there sufficient infrastructure capacity to receive and transfer the quantities of natural gas required onto the NTS?**

These criteria have been used to evaluate each of GB's gas supply sources, through examination of historic supply onto the NTS and expected capability in the 2030s. The output of this process is the aggregated maximum deliverable supply volume that can meet NTS demand, measured in million cubic metres a day (mcm/d).

As cold spells tend to last for several days at a time, it is important that we assess the potential for gas supplies to meet demand over multi-day periods. We have chosen to assess how gas supplies can meet demand over an 11-day cold snap. This reflects our work with the Met Office, which identified a prolonged period of elevated gas demand that GB could experience in the coming years. This approach is intended to capture the increased security of supply risk over extended durations, as the volumes of some available supply sources gradually decline over the cold snap period.

Using the FES pathways, we identify a base case scenario alongside upper and lower demand expectations. For each scenario, two demand profiles have been considered:

- **Peak demand profiles:** Characterised by a period of low temperatures and wind speeds, culminating in the 1-in-20-year gas demand day, as reported in FES.
- **Seasonal normal demand profiles:** Reflecting the level of demand that would be expected to prevail under weather conditions considered normal for the time of year.

Margins are then calculated by balancing de-rated supply against these demand profiles for each day of the cold snap period. A positive margin indicates supply sources are expected to be capable of meeting demand, whereas a negative margin signals a supply deficit. Margins were evaluated under both an intact network – that is, where all gas supply and network infrastructure is fully operational – and when industry standard security of supply tests are applied by removing the largest single piece of supply infrastructure, known as N-1.

Options to mitigate identified risks have been considered and are outlined in this Assessment. However, the need for action and potential intervention is a matter for government.

The following sections present the main findings from applying the Assessment methodology, including future demand expectations, supply projections, margins and mitigation options.

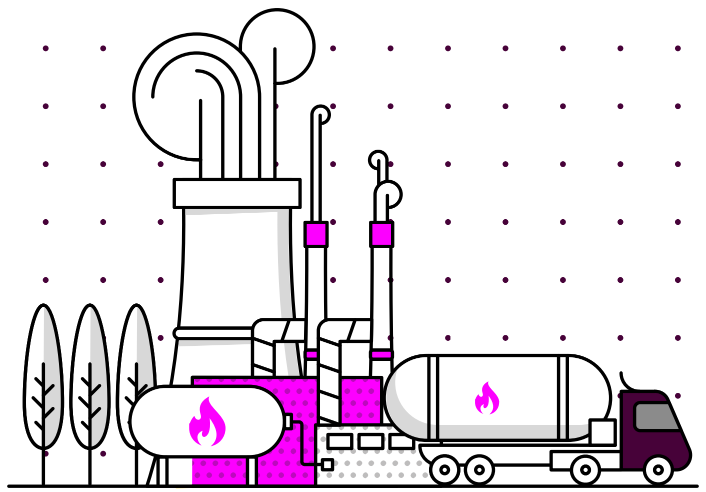
Stakeholder Engagement

We have engaged extensively with stakeholders in developing this Assessment. This includes our well-established stakeholder engagement program, undertaken as part of our FES[12], as well as more focused engagement across all areas of the GB gas supply industry to test some of our assumptions and the modelling approach specific to this Assessment.

Table 1 summarises our engagement and the number of operators we have worked with. This includes all LNG, storage and interconnector import operators, as well as a selection of North Sea operators where our analysis has highlighted reductions in the coming years across both the Norwegian and UKCS basins.

We have also engaged with a wider community of experts in developing this work. Most notably, this includes academic review of our modelling approach and input from the Met Office on our assumptions and approach to modelling a prolonged cold snap.

We warmly welcome further engagement and encourage feedback from stakeholders on our first *Gas Supply Security Assessment*, which we will continue to build on and develop collaboratively over the coming months.



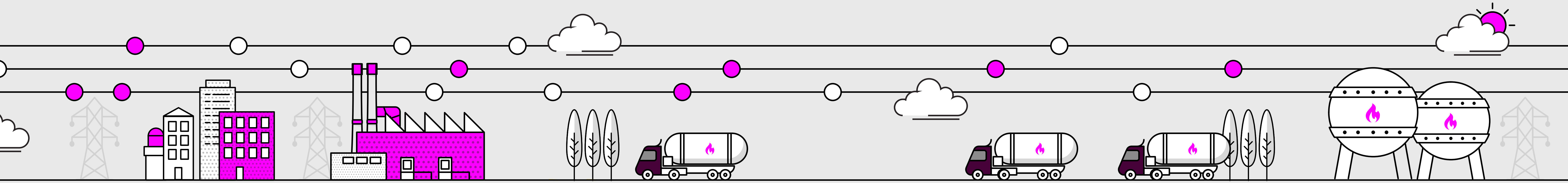
Please contact us at:
box.gassupplysecurity@neso.energy.

Table 1: Summary of stakeholder engagement

Stakeholder Group	Number of Participants
Government departments and regulators	3
Network operators	2
UKCS operators	2
NCS import operators and regulators	3
LNG import operators	3
Interconnector import operators	2
Storage operators	9
Academic institutes & weather forecasters	2

12 *Summary of Stakeholder Engagement FES 2025*, National Energy System Operator.

01 The Future of Gas Demand



GB's gas demand is comprised of four primary components: the heating, power generation, industrial and commercial (I&C) sectors and exports. In 2024, 80% of households in GB used natural gas to heat their homes; gas-fired power stations used gas to meet 26%[13] of annual electricity consumption; and the industrial sector used gas to fuel its processes.

GB's interconnectors also export gas to Ireland, Northern Ireland, the Isle of Man and mainland Europe. A small proportion of demand is also attributed to shrinkage, which covers leakage, metering errors and the gas used in the transmission system.

Decarbonisation will be the driving force behind lower annual and peak day gas demand in the future. Nevertheless, in the 2030/31 and 2035/36 assessment years, GB will continue to rely on natural gas to meet at least part of its energy needs. However, the rate and nature of decarbonisation in each sector, both domestically and in export markets, remains highly uncertain. To account for this, the demand methodology used for this Assessment is underpinned by modelling developed for NESO's 2025 FES. This ensures that an appropriate base case, together with a range of higher and lower demand possibilities, is captured to assess gas supply security:

- **Ten Year Forecast (10YF):** NESO's base case, reflecting our current best view of future demand for gas and power over the next ten years. It considers existing project development and policy action.
- **Holistic Transition (HT):** Net zero is met through a mix of electrification and hydrogen, with hydrogen mainly used around industrial clusters. A high-renewable capacity pathway, with lower unabated gas-fired generation.
- **Electric Engagement (EE):** Net zero is met mainly through electrified demand. Consumers are highly engaged in the transition through smart technologies that reduce energy demand, such as electric heat pumps and electric vehicles.
- **Hydrogen Evolution (HE):** Net zero is met through rapid progress for hydrogen in industry and heat. Widespread access to a national hydrogen network is assumed. Some consumers will have hydrogen boilers, although most heat is electrified.
- **Falling Behind (FB):** Net zero emission reductions by 2050 are not met. Falling Behind represents the slowest credible rate of decarbonisation in the heating, power generation and I&C sectors, and therefore the highest credible gas security of supply risks can be assessed. Compared with our base case of the Ten Year Forecast, Falling Behind has lower engagement in clean heat technology from consumers, lower electricity demand flexibility and slower power system decarbonisation.

Each FES pathway provides a 1-in-20-year peak demand day for each year (during which peak-day demand reaches a level that is statistically likely to be exceeded once every 20 years), together with daily seasonal normal demand expectations and a total annual demand figure. Seasonal normal is the expected demand under weather conditions considered statistically normal for the time of year.

13 Britain's Electricity Explained: 2024 Review, National Energy System Operator.

Future demand expectations

Gas demand is highly seasonal, with around 60% of annual demand occurring during the winter months (October–March). The periods of highest demand generally result from low temperatures and low wind speeds occurring simultaneously. The 50 highest demand days of the past five winters had an average wind speed and temperature of 5.5 m/s and -3.1°C, compared with a five-year winter average of 7.5 m/s and +3.8°C.

During these peak demand periods, the gas supply system needs to respond to elevated demand for heating, alongside an increase in gas-fired generation to meet electricity demand. During such periods, GB generally does not export gas to mainland Europe, instead relying on imports to meet demand.

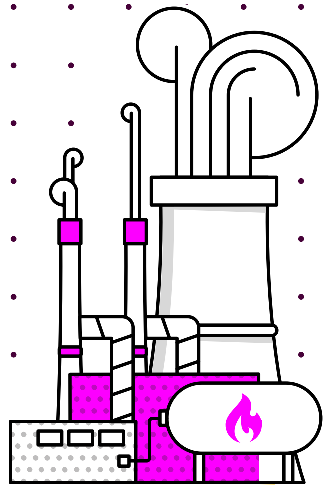
The peak gas demand profiles underpinning this Assessment correspond to plausible future incidences of very low temperatures and minimal wind, referred to as a cold snap. Climatological modelling carried out in partnership with the Met Office identified an appropriate peak demand profile duration to be 11 days.

During this 11-day period, demand increases from seasonal normal expectations on the first day to the calculated 1-in-20-year peak day gas demand figure – as reported in FES for the corresponding year and pathway – on the middle day. Demand then falls from its peak to seasonal normal expectations throughout the remainder of the 11-day period. 11-day profiles are also generated under seasonal normal demand expectations to assess how gas supply could meet demand under weather conditions considered normal for the time of year.

A cold snap could begin at any point in the winter, so to further test gas system resilience, the peak demand day is assumed to fall on a Wednesday. This represents a worst-case scenario, as the most severe weather conditions are experienced during the working week, when overall demand tends to be higher due to greater economic activity.

Under the Ten Year Forecast – NESO's base case for this Assessment and our best view of future gas demand – the 1-in-20-year peak day demand in 2030/31 and 2035/36 is expected to be 461 mcm (Figure 3) and 422 mcm (Figure 4). This compares with the highest observed daily demand of 465 mcm (Figure 5), recorded in January 2010. Local Distribution Zones (LDZs), which include residential and smaller industrial and commercial facilities, make up over 70% of this 1-in-20-year peak day demand. Meanwhile, 81 mcm and 82 mcm are attributed to NTS-connected gas-fired power stations in 2030/31 and 2035/36. This compares with the highest recorded daily power station gas demand of 107 mcm[14], recorded in winter 2010.

The 11-day demand profiles are assumed to fall in late February for each assessment year. Before this point, there is greater confidence that European and GB storage levels are fuller, allowing the gas system to respond more effectively to a cold snap. This compares with the end of the winter period, when European and GB storage stocks have historically approached their lowest level. In March, total European demand is also generally lower due to warmer weather in parts of Europe. Additionally, climatological modelling indicates that weather conditions precipitating a 1-in-20-year demand event are more likely to occur in February than in March. The confluence of these factors suggests that late February is the 'expected period of least resilience'.



14 *Winter Outlook Report 2010/11*, National Grid.

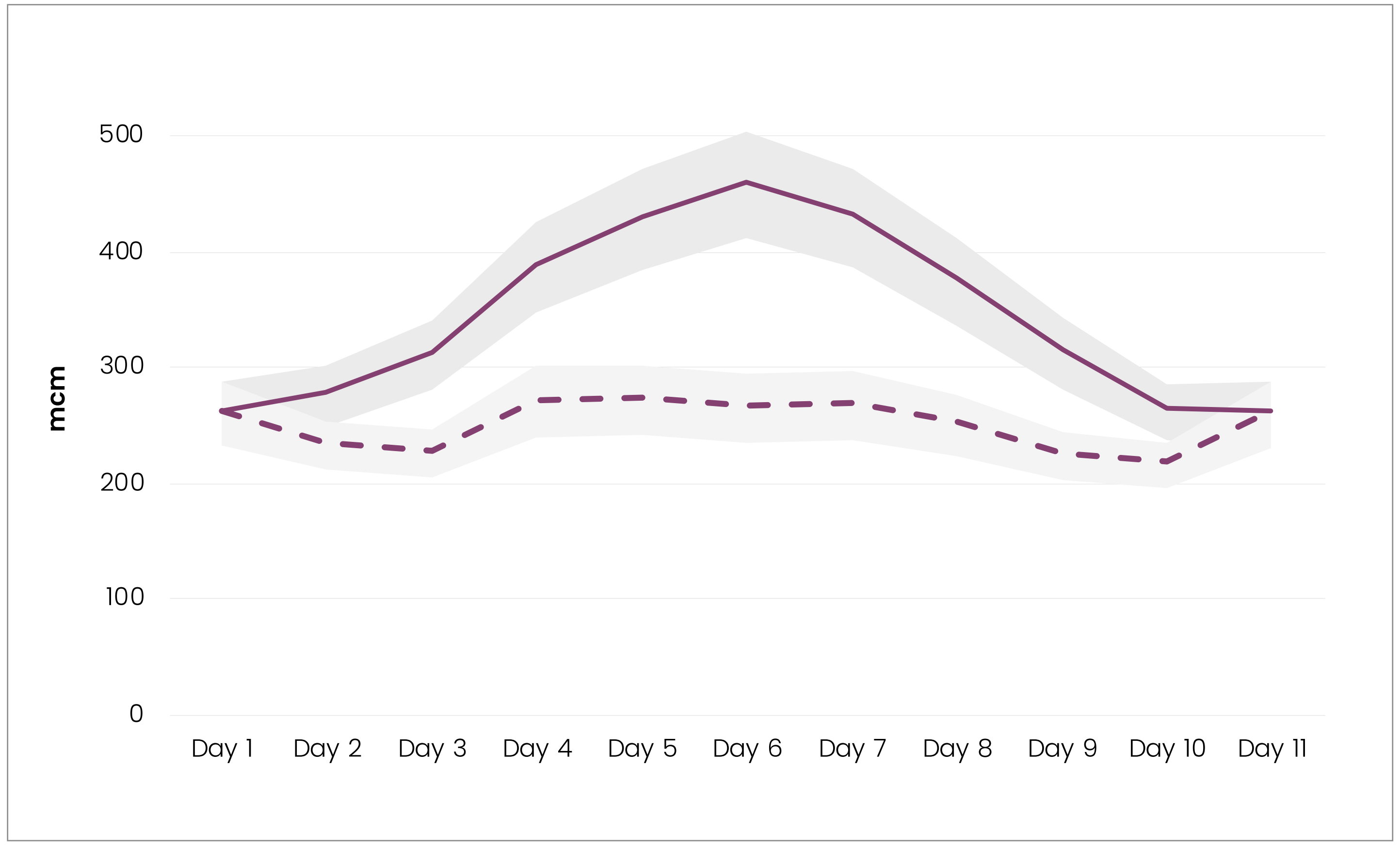


Figure 3: 2030/31 Ten Year Forecast cold snap and seasonal normal demand curves within upper and lower ranges based on possible decarbonisation pathways

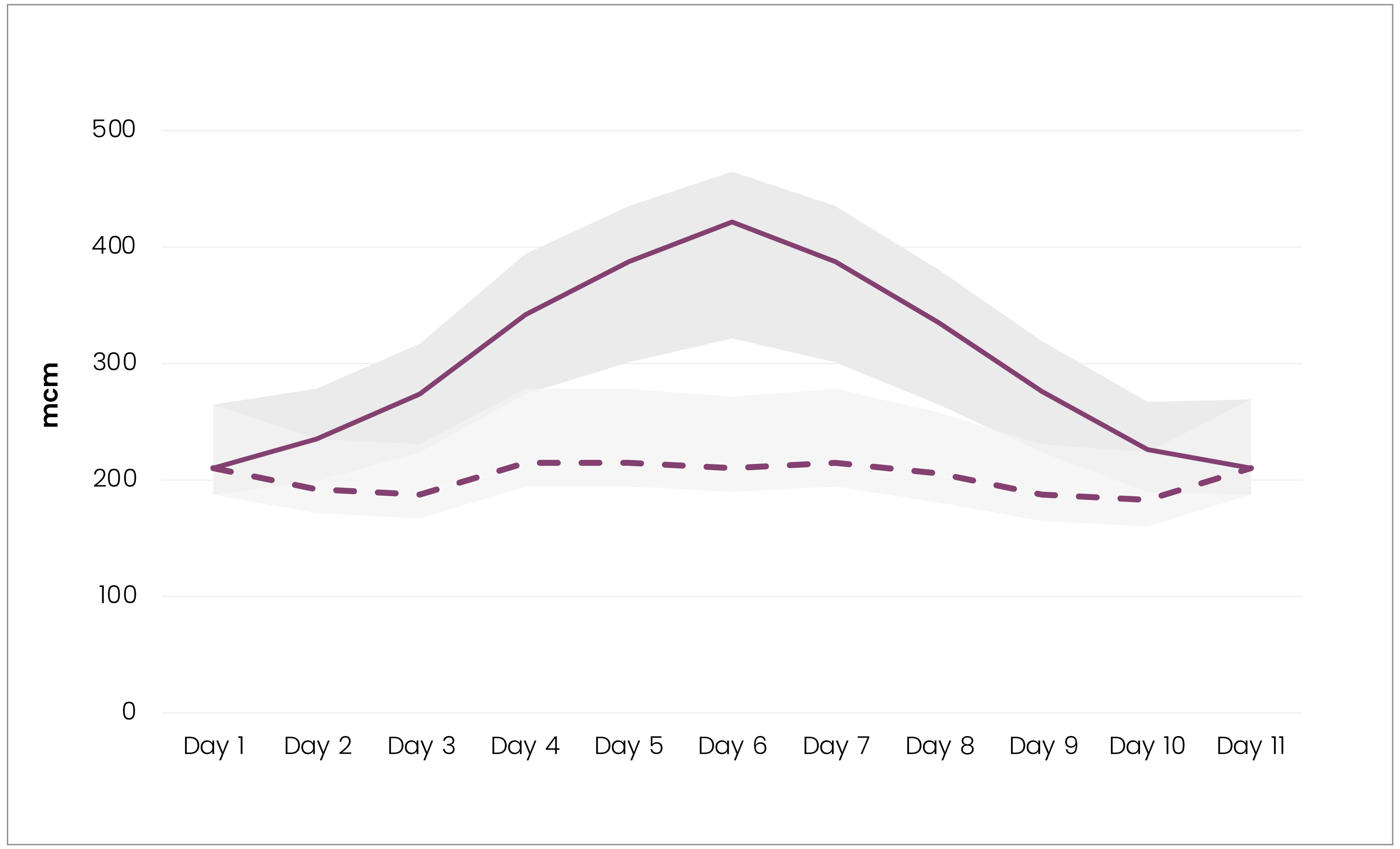


Figure 4: 2035/36 Ten Year Forecast cold snap and seasonal normal demand curves within upper and lower ranges based on possible decarbonisation pathways

FES scenario range   Peak demand profile 10YF   Seasonal normal demand 10YF

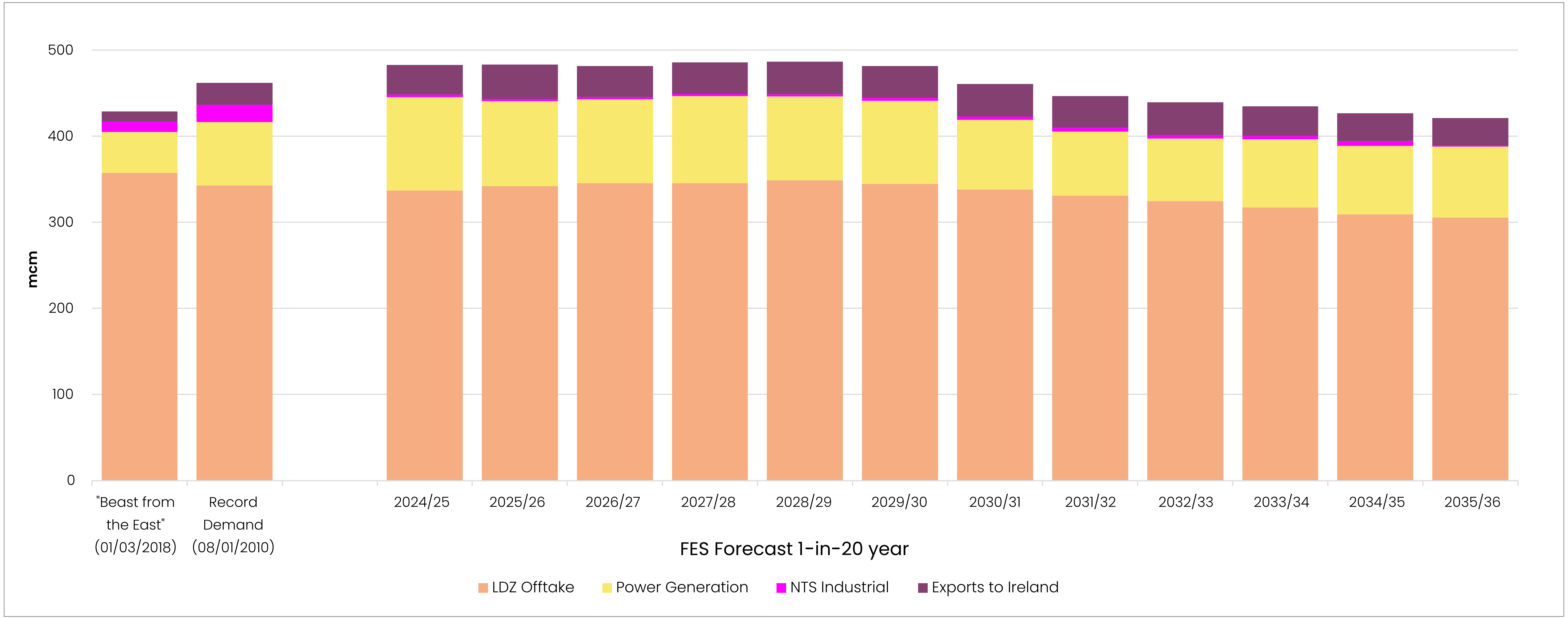
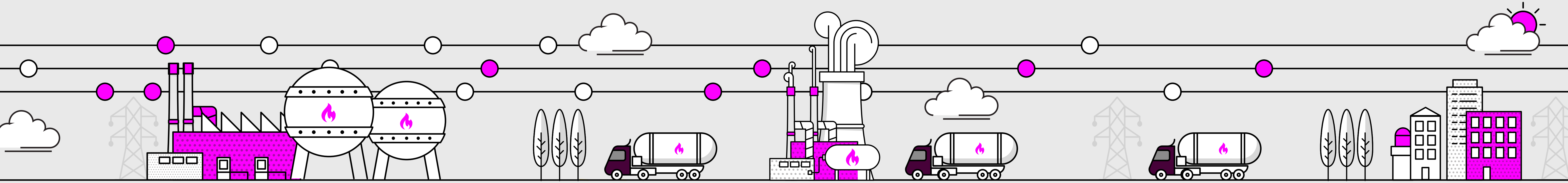


Figure 5: FES Forecast 1-in-20-year peak day demand by year compared with record and 'Beast from the East' demand

02 Gas Supply Outlook

Key Message 1



We expect Great Britain to continue benefiting from a diverse range of gas supply sources into the 2030s. As production from the United Kingdom Continental Shelf declines, we will become more reliant on Liquefied Natural Gas, interconnector imports from Europe and gas storage – alongside continued supply from the Norwegian Continental Shelf – to meet demand throughout each winter, particularly during cold spells

Continental Shelf (UKCS)

The UKCS comprises gas reserves in fields predominately under the North Sea and other waters surrounding the UK. As the basin naturally matures and reserves are depleted, supplies to GB are declining at a rate of around 12–13% each year. Its contribution to the supply mix is expected to drop from a maximum last winter of around 85 mcm/d, observed in January 2025, to around 30 mcm/d in the early 2030s and around 15 mcm/d by 2035.

Future UKCS supply expectations are significantly below even our lowest demand projections for winters in the 2030s. This means that imported supply sources could be required to deliver up to 261 mcm/d to meet total demand during seasonal normal winter weather conditions, or up to 452 mcm/d to meet peak day demand during a cold snap in 2030/31.

Norwegian Continental Shelf (NCS)

The NCS still contains substantial gas reserves. However, based on public projections from the Norwegian Offshore Directorate and NESO analysis of field-level data set out in our workbook, supply to GB is expected to decrease by 3–7% each year in the 2030s, accounting for field discoveries yet to be approved. Although overall Norwegian production has increased in recent years, declining production from fields linked to GB infrastructure and increased European competition mean that both annual total and peak single-day supply into GB are projected to decrease compared with historic maximums.

Liquefied natural gas (LNG)

GB has three import terminals at which LNG cargoes can be delivered onto the GB gas system. Almost 70% of cargoes arrived from the United States of America (USA) in 2024, with the remaining 30% originating from nine other nations. We expect LNG to play an increasingly important role in GB's gas supply security, taking advantage of the increased supply in international LNG markets as new export facilities come online. Recognising the growing international availability and the greater role LNG is likely to play in meeting GB's demand, GB terminals have increased their import capacity in recent years.

Interconnectors

GB is connected to Belgium via Interconnector Ltd (INT)[15] and to the Netherlands via the Balgzand Bacton Line (BBL), with both gas interconnectors offering bidirectional flows. We expect both interconnectors to continue enabling bidirectional flows between mainland Europe and GB during the assessment period. However, both INT and BBL are expected to reduce their import capacity from mainland Europe to GB ahead of winter 2025/26. Historically interconnectors have been relied upon to balance the GB gas system during periods of elevated demand. While this is likely to remain the case, interconnectors may increasingly provide more frequent supply to GB as UKCS and NCS deliverability decline further.

Storage sites

In winter 2024/25, there were eight storage sites connected to the NTS, allowing users to inject gas into their facilities during periods of lower prices and withdraw it when prices are higher. We have assumed that Rough will not be available in the 2030s, as it has not refilled ahead of winter 2025/26. The remaining storage sites are expected to allow shippers to take advantage of day-to-day, week-to-week and month-to-month price spreads.

Table 2 and Figure 6 provide a summary of the projections from the different supply sources for GB in the assessed period of 2030/31 and 2035/36.

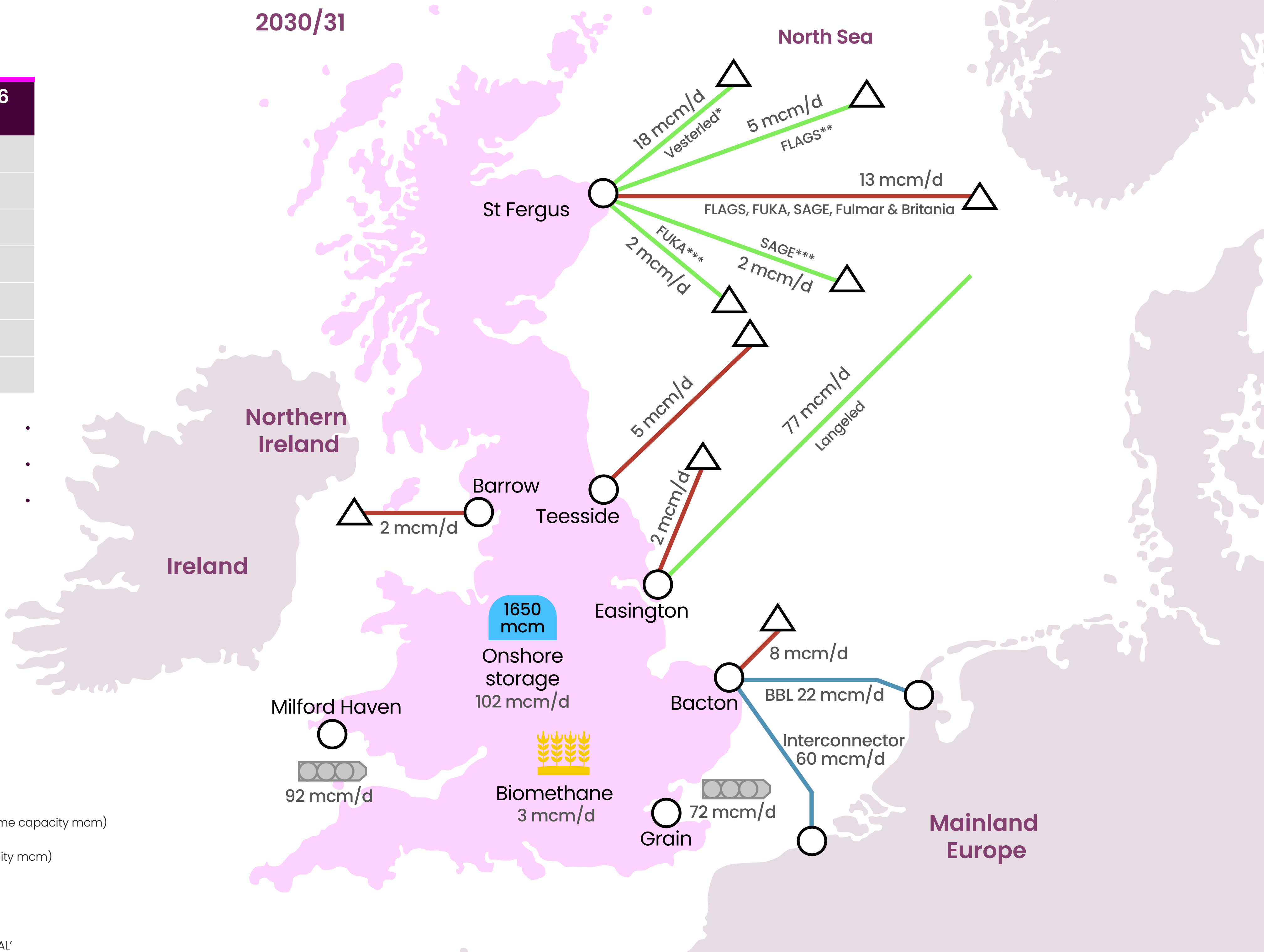
15 Interconnector Ltd is also widely known as IUK; this Assessment uses INT in line with the pipeline operator's official name.

Table 2: Comparison of historic and forecast maximum daily gas supply by source

mcm/d	Ten Year Maximum	Winter 30/31 De-Rated	Winter 35/36 De-Rated
Total NTS Supply	419	482	452
UKCS	153	30	15
NCS	146	104	89
LNG	138	164	164
Storage	101	102	102
Interconnectors	107	82	82
Biomethane	2	3	5

The availability, deliverability and reliability of each supply source are detailed on the following pages.

The circles in the top left corner of each section provide an at-a-glance view of the volume of gas delivered on a peak day from that source during the last winter, along with the projected peak day volume for winter 2030/31 and winter 2035/36.



Gas site
Offshore gas fields
LNG jetty
UKCS (UK Continental Shelf) (peak capability mcm/d)
NCS (Norwegian Continental Shelf) (peak capability mcm/d)
Interconnectors (peak capability mcm/d)
Depleted gas field storage (volume capacity mcm)
Onshore storage (volume capacity mcm)
Biomethane
* Gassco report as 'St Fergus'
** Gassco report as 'Fields into SEGAL'
*** Non-Gassco reported

Figure 6: Map of Great Britain showing the outcome of de-rating analysis, with the realistic maximum volumes that could be expected to flow onto the gas network during a cold snap in winter 2030/31.

2.1 UK Continental Shelf

Gas production from UKCS fields currently flows into five terminals: Bacton, Barrow, Easington, St Fergus and Teesside. Most of these terminals comprise up to three sub-terminals, which receive and process gas transported via different pipeline systems and gas fields, including those in Norwegian territorial waters. UKCS flows are considered a baseload supply source, as volumes are expected to be delivered directly to terminals with a high level of certainty over the next decade.

Availability

The North Sea Transition Authority (NSTA) assesses the availability of UKCS reserves and publish biannual Projections of *UK Oil and Gas Production and Expenditure*[16], which include projected total production from UKCS into the GB market for each year out to 2050[17]. By 2035, there is a projected 78% reduction in gas availability compared with 2025, broadly equivalent to a long-term decline of around 12–13% each year. For comparison, total availability of UKCS volumes throughout 2025 has been projected at 24.5 bcm, dropping to 10.4 bcm in 2031 and 5.4 bcm in 2036 (Figure 7[18]), illustrating the long-term decline of the UKCS.

Deliverability

The pipeline network connecting offshore gas fields to onshore terminals has a current technical capacity of approximately 330 mcm/d, which will reduce as planned decommissioning occurs.

Due to the integrated nature of UKCS and NCS infrastructure, a proportion the 330 mcm/d pipeline capacity is shared between UK and Norwegian gas fields. Of the five terminals that receive UKCS volumes, four receive volumes exclusively from UKCS fields, while some pipelines into St Fergus carry both UKCS and NCS volumes (Figure 6). Britannia exclusively carries UKCS volumes, with shared capacity with NCS through the Far North Liquids and Associated Gas System (FLAGS), Scottish Area Gas Evacuation (SAGE), Frigg UK Association (FUKA) and Fulmar pipelines, as it connects to the Shell Esso Gas and Associated Liquids (SEGAL) system.

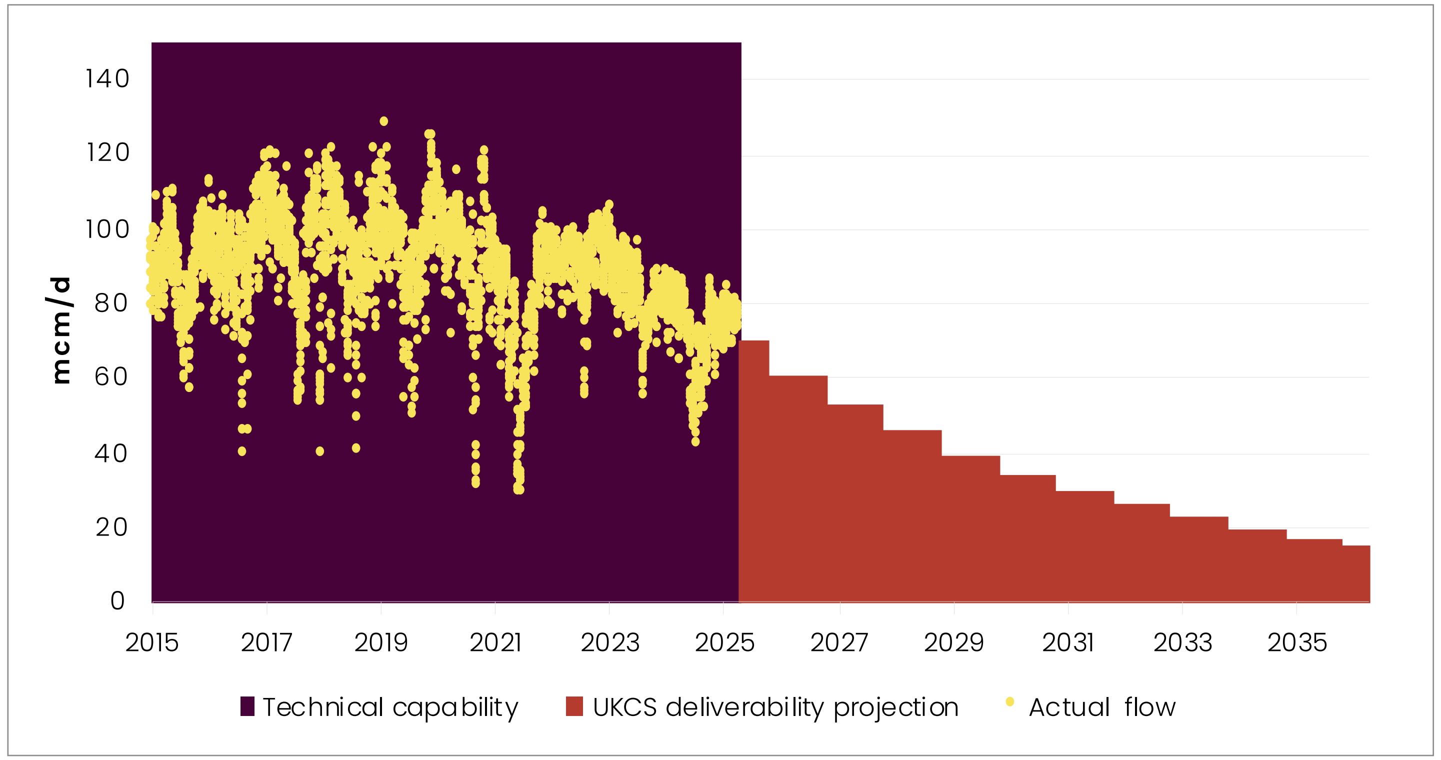


Figure 7: UKCS historic capability and deliverability with NESO's de-rated supply projections

Reliability of supply

Working with the NSTA, we have used its latest annual production projections to develop daily, de-rated supply figures for our assessment periods. We have done this by analysing the seasonality of UKCS supply and its propensity to respond to short-run changes in GB gas demand. This analysis shows that, once maintenance requirements are considered, UKCS supply is highly reliable. UKCS supply typically exhibits only small day-to-day fluctuations during winter periods, even where there are large day-to-day changes in demand.

16 *Data and insights - Production and expenditure projections*, North Sea Transition Authority.

17 This Assessment uses the March 2025 publication rather than the August 2025 publication.

18 For clarity, full technical capacity is not shown.

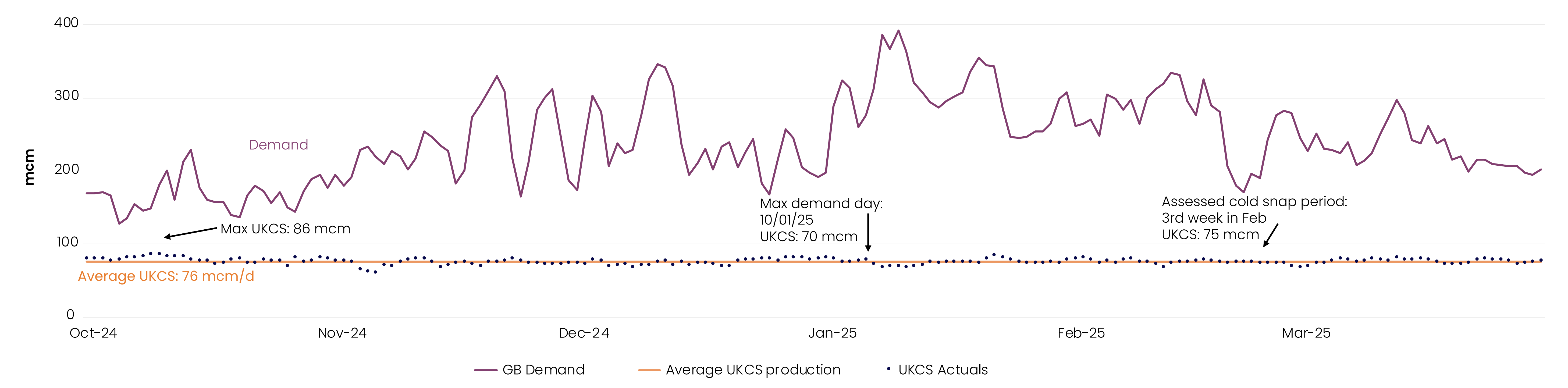


Figure 8: Winter 2024/25 UKCS deliveries with GB demand, showing limited variation in deliverability despite demand fluctuations

There is limited seasonality in UKCS supply: around 52% of the annual supply typically occurs during the winter season, that is, the six-month period from 1 October to 31 March. There is also limited variability in UKCS supply within winters, even amid substantial short-run changes in demand, as illustrated in Figure 8.

As such, we assume that a constant level of UKCS production and supply is maintained throughout each assessment period in winter 2030/31 and winter 2035/36. The level of supply is calculated as the seasonality-adjusted (0.52) annual NSTA projected volume for the assessment year, averaged over the 182-day assessment winter. For the 10.4 bcm availability in 2030/31 and 5.4 bcm in 2035/36, we therefore expect that the UKCS will deliver daily figures of 30 mcm/d and 15 mcm/d, respectively.

Reliability of projections

The NSTA's production projections include some uncertainties. Physical supply in a particular year could be higher or lower than projected, which may indicate a different long-term decline rate to the 12–13% assumed in this Assessment.

Total production in 2025 was expected to be 24.5 bcm, based on NSTA's March 2025 projections. Actual annual production could miss this projection, given that production between January and September 2025 was recorded at 17.3 bcm[19], equating to an annual run rate of 23 bcm, although this could increase by the end of 2025. As the UKCS is a mature basin, lower production in a given year could lead to higher production in later years relative to their projected figures.

Extended maintenance periods could also result in lower annual production relative to NSTA projections. This was the case in 2021 following delayed maintenance after the 2020 pandemic. However, we do not consider the impacts of extended or unplanned maintenance in this Assessment.

19 Based on terminal flows using NGT's data portal, accounting for shared infrastructure delivering production from Norwegian Continental Shelf fields.

2.2 Norwegian Continental Shelf

2024/25 **122** mcm/d

2030/31 **104** mcm/d

2035/36 **89** mcm/d

NCS production is delivered from gas reserves in fields within the North Sea, Norwegian Sea and Barents Sea surrounding Norway. Gas assets including pipelines, offshore terminals and processing plants are owned by the Norwegian state, with most of the infrastructure operated by the state-owned Gassco.

Although many fields are geographically close to UKCS fields, the basin has developed separately. There is also greater flexibility in NCS production, with options to export to multiple markets including GB, Germany, France, Belgium and Denmark, with onward delivery to the Netherlands and Poland.

Annual NCS production is currently close to what is expected to be its peak lifetime production before it begins to decline. Norway increased NCS production to respond to Europe's need to source alternative gas supplies following the cessation of Russian flows after its full illegal invasion of Ukraine. NCS reached a historic maximum production volume in 2024 of 124 bcm and a single-day maximum production of 359 mcm. This peak production is expected to be maintained in the coming years before beginning to decline by the 2030s, albeit at a slower rate than UKCS.

The maximum one-day supply to GB terminals was recorded in February 2017 at 147 mcm/d (Figure 9)[20], despite total annual NCS production capacity being lower than it is today. The five pipeline system that delivered NCS volumes to GB in 2017 all continue to be available: the Langeled pipeline into Easington, and three routes into sub-terminals at St Fergus via the Vesterled pipeline, SEGAL system, and production not reported by Gassco via the SAGE and FUKA pipelines (Figure 6).

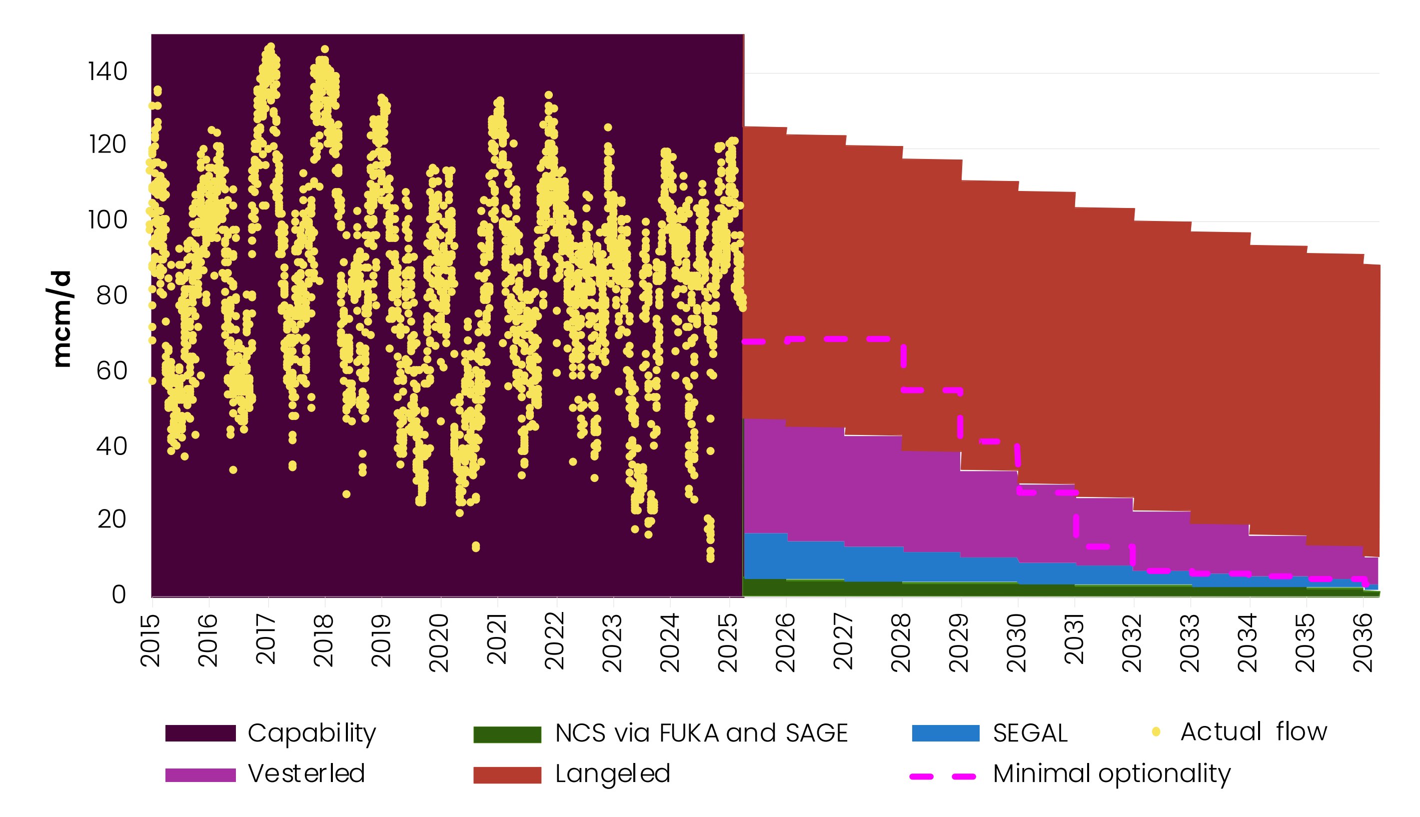


Figure 9: Historic GB imports of NCS production against total NCS capability with NESO's cold snap de-rated deliverability projections

Availability

The Norwegian Offshore Directorate publishes the availability of known NCS reserves, as well as future additional fields and possible discoveries. Total NCS production could fall from around 118 bcm in 2025 to around 102 bcm and 61 bcm in 2030 and 2035, respectively[21]. This represents a decline of around 48% over the next decade. While there could be additional gas field discoveries that increase NCS production above projections, most undiscovered fields are expected to be in the Barents Sea, which is geographically isolated from the current NCS system. This creates uncertainty about whether these fields would be tied into the current NCS network or exported via the geographically closer Hammerfest LNG terminal.

A small number of NCS fields can deliver only to GB and operate in much the same way as UKCS fields. These fields generally supply gas at a consistent rate, with limited capability to increase production in response to changing demand.

20 The combined flows through the Segal system, Vesterled and Langeled were 142.3 mcm on 10 February 2017, with a further 5 mcm assumed to have flowed through FUKA and SAGE.

21 Expected Volumes of Sales Gas from Norwegian Fields, 1995-2035, Norwegian Petroleum.

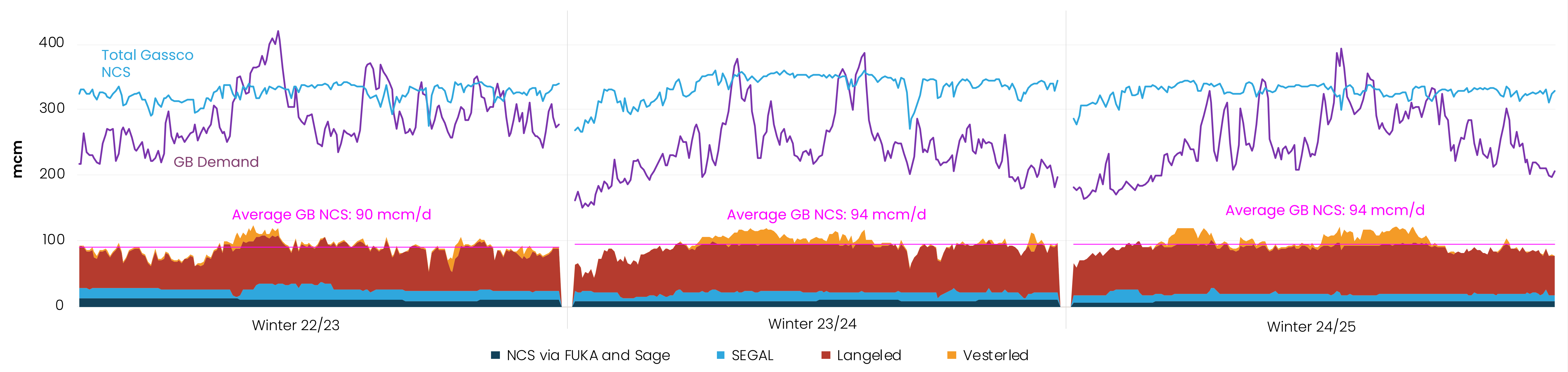


Figure 10: NCS production against GB pipeline import patterns and overall GB demand, demonstrating consistent imports with some flexibility during peak demand periods

Deliverability

The total technical capacity of the pipeline network capable of transporting NCS gas to GB terminals is around 158 mcm/d. However, due to declining flows through the SEGAL system and Vesterled, not all of this capacity can be utilised. The maximum daily flow in winter 2024/25 was 122 mcm/d (Figure 10), though NGT recently reported this could be up to 135 mcm/d[22] for winter 2025/26.

We project that the maximum daily supply could drop to around 104 mcm/d in 2030/31 and 89 mcm/d in 2035/36. These figures have been derived through the following pipeline analysis.

- **Langeled pipeline:** has a maximum capacity of 77 mcm/d, connecting at Easington. Subject to cross-border price spreads, we expect these volumes to remain high over the assessment period. This is because gas can flow to Langeled via two separate Norwegian gas processing terminals (Nyhamna and Kollsnes), which in turn can receive gas from multiple fields within the wider NCS system.
- **Vesterled pipeline:** has a current technical capacity of 35 mcm/d, flowing into St Fergus. Historically it has delivered volumes above 40 mcm/d when directly connected with NCS fields. Changes to the NCS system mean it is now tied into the Oseberg Gas Transport (OGT) system, which has optionality to transport to multiple European terminals. NESO's field-level analysis identifies five fields with 62 bcm of remaining gas reserves that could service Vesterled. These five fields are: Oseberg (main field, ØST and SØR), Tune and Valemon. Declining production from these fields means we expect peak deliverability into Vesterled to reduce over the next decade unless new infrastructure is developed to connect it to the wider NCS system.

  Annual utilisation of Vesterled is the lowest of all five NCS entry points, ranging from 14% to 32% between 2021 and 2024. This results from a number of factors, including optionality to divert flows to multiple markets and higher landing costs compared with other GB terminals. A potential requirement for nitogren ballasting in the future to ensure that gas is compliant with the Wobbe Index (used to measure gas quality) could decrease utilisation further.

22 *Gas Winter Outlook* (October 2025), National Gas.

- **SEGAL system:** production from fields connected to SEGAL can only be delivered into St Fergus through the FLAGS pipeline. This limited optionality increases the certainty that available gas reserves will be delivered into St Fergus and, like UKCS, is therefore considered a baseload supply source. The SEGAL system exhibits similar characteristics to UKCS production, which is declining year-on-year. At its peak in 2016, maximum supply through FLAGS was above 35 mcm/d, but production volumes have steadily reduced over the last decade and now deliver a maximum of 20 mcm/d. NESO's field-level analysis identifies eight fields with around 20.2 bcm of remaining gas reserves that can deliver exclusively through SEGAL. These eight fields are: Duva, Gjøa, Islay, Nova, Statfjord (including the main field, Nord and Øst) and Vega. At current production levels, flows to GB through this system could drop to 5 mcm/d by 2030/31 and 2 mcm/d by 2035/36.
- **FUKA and SAGE pipelines:** multiple NCS fields are included in the Gassco system that can only be transported via FUKA and SAGE, meaning they are also considered a baseload supply source. Production volumes from Norwegian fields are mixed with UKCS production, with third-party operators transporting gas from both UKCS and these NCS fields. Based on recent Norwegian production estimates and field analysis, these fields produced around 13 mcm/d in 2022 and are expected to decline to 4 mcm/d in 2030/31 and 2 mcm/d by 2035/36.

Reliability

There is uncertainty in the reliability of future NCS supply to GB. Currently, NCS production often exceeds the import capacity at terminals in mainland Europe capable of receiving NCS supply. This means mainland Europe can receive maximum NCS supply with additional volumes available to service the GB market, regardless of the price disparity between GB and European markets. As NCS production falls, the frequency of instances where NCS production exceeds the capacity of the pipeline system supplying mainland Europe will fall, making NCS supply more price-sensitive.

European import terminals capable of receiving NCS supply have a capacity of 273 mcm/d. This compares with a maximum NCS production of 359 mcm/d, of which 339 mcm/d of which is not tied to a specific pipeline system (for example, SEGAL). Provided Norwegian production exceeds the 273 mcm/d European terminal capacity, a proportion of NCS production must be supplied to GB. This certainty will diminish as NCS production falls, and EU-GB price spreads will become far more significant in determining the level of NCS supply to GB. The exception to this is NCS fields tied exclusively to GB terminals (pink dashed line, Figure 9).

2.3 GB storage

2024/25 94 mcm/d | 2030/31 102 mcm/d | 2035/36 102 mcm/d

There are seven active onshore storage sites connected to the NTS ahead of winter 2025/26. We assume that these seven sites will continue to be operational in winters 2030/31 and 2035/36. Each storage site has individual characteristics that determine the volume of gas it can store and deliver onto the NTS, and for how long. This depends on the geological nature of the site and the compressor capacity to inject and withdraw gas to and from storage.

Gas storage in GB is typically considered to be medium-range storage because it can empty and refill in a matter of days. This differs from storage in European system, which is typically long-range storage, refilling during the summer and withdrawing gas throughout winter. The flexibility of GB storage means that sites regularly respond to changes in gas prices on different timescales, such as between working days and weekends, or changes between one week and the next.

The main change to GB's storage capacity since 2015 was the ceasing of operations at the Rough facility in 2018 (Figure 11). Rough is GB's only offshore long-range storage site and operates in a similar way to European sites – refilling during longer periods of lower demand and delivering over extended periods. The site returned to commercial operation in 2022, albeit with reduced technical capability. Since returning, Rough's maximum withdrawal rate has been 11 mcm/d, or 9% of total storage withdrawal capability, decreasing as fullness falls to around 5 mcm/d. For this Assessment, we have assumed that Rough is unavailable over the assessment period on the basis that it has not refilled during summer 2025 ahead of winter 2025/26.

Availability

Working with GB gas storage operators, we have identified that the total working volume of gas that can be stored in GB onshore storage is 1,650 mcm. This does not include additional cushion gas, which is used to ensure the integrity of storage sites and to support deliverability. There is uncertainty about how much gas would be in GB gas storage at the start the cold snap we are assessing. This depends on the supply and demand patterns leading up to the cold snap and the commercial operations of each operator.

For this Assessment, we analysed historic levels of gas storage that were available during both average winter periods and ahead of anticipated periods of high demand. This analysis identified that storage operators typically take preparatory actions to increase stocks above seasonal averages to take advantage of upcoming elevated demand. For this Assessment, we have assumed that available storage stocks will be in line with the average levels observed at the start of the last five cold snaps. This is equivalent to 1,174 mcm, or around 71% of total storage capacity.

Deliverability

GB storage sites have a combined technical maximum deliverability of 112 mcm/d (Figure 12). In winter 2024/25, the maximum single-day of deliverability was 94 mcm/d, excluding Rough. The true deliverability on a single day depends on the relationship between stock

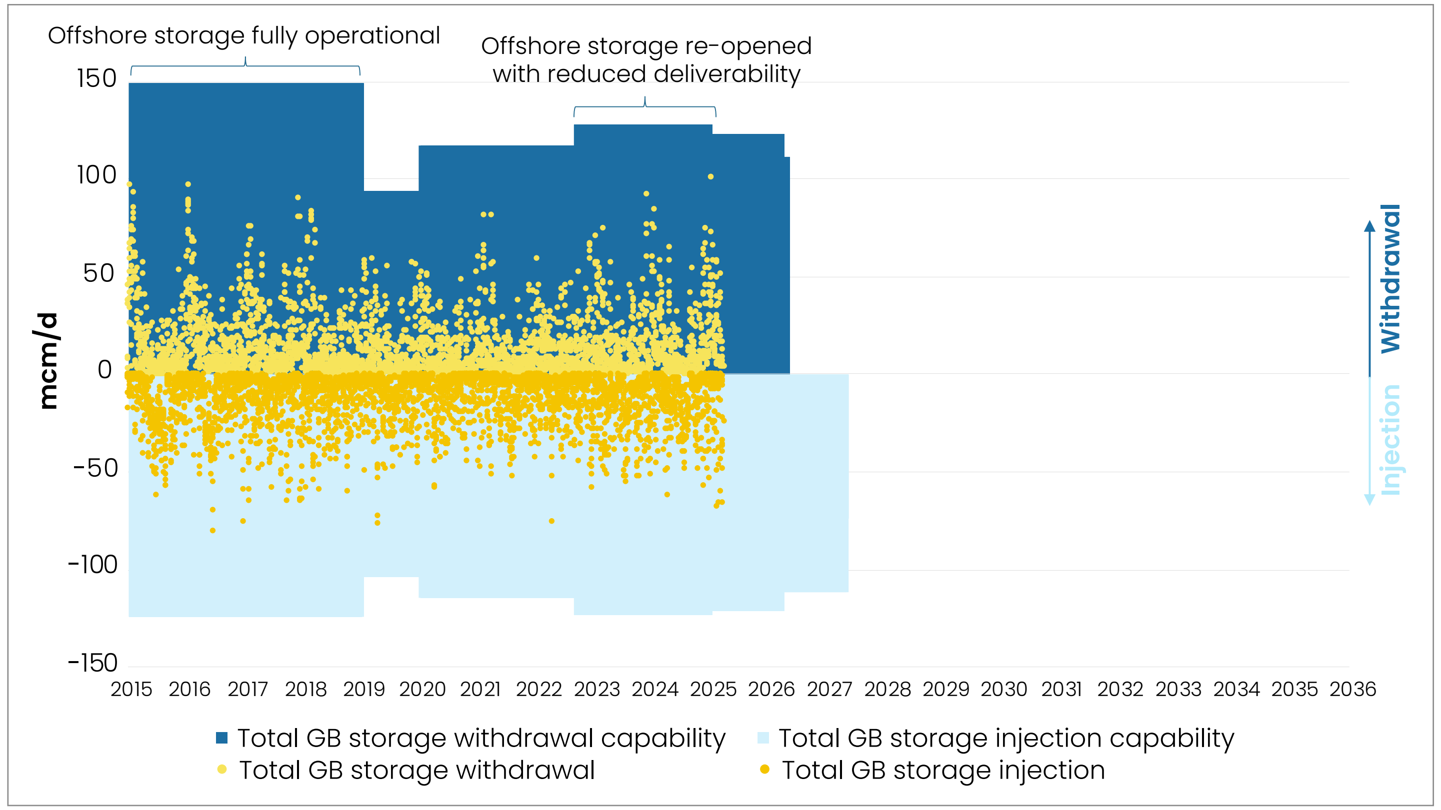


Figure 11: Maximum technical capacity and historic injection and deliverability patterns of onshore and offshore gas storage sites, and current future technical deliverability

level, cavern pressure and the maximum withdrawal rate for each site. As such, maximum deliverability changes daily following withdrawals and the pressure inside caverns drops.

Typically, as stocks deplete, so too does the maximum withdrawal rate. However, some storage sites have more complex characteristics due to asset capability and pressure conditions within the caverns. Working with storage site operators, we have identified that the maximum expected withdrawal rate if sites were 100% full on the first day of a cold snap is 95 mcm/d. This withdrawal rate can then be maintained within a range of 10 mcm/d for seven days before declining. Analysis also shows that starting stock levels lower than 100% can increase deliverability.

Reliability

Gas in GB storage is reliable during a cold snap because, once in storage, this gas can only be withdrawn and injected into the GB system. Historic behaviour has shown that each site has been able to provide at least 95% utilisation for multiple days of its technical withdrawal capacity, with most achieving 100%.

If lower volumes are required to support GB demand and starting stocks are high, the reliability of flows will extend beyond the 11-day cold snap tested. Starting storage stocks are highly dependent on shippers and operators taking proactive decisions ahead of high-demand periods, and there is a risk that starting stocks are lower than anticipated. Should this occur, and starting stocks are lower than assumed in this analysis, deliverability would be reduced (Figure 13).

If starting fullness is less than 50% across all storage sites, deliverability is reduced to just above 70 mcm on day one before dropping quickly to almost 10 mcm by day five (Figure 13).

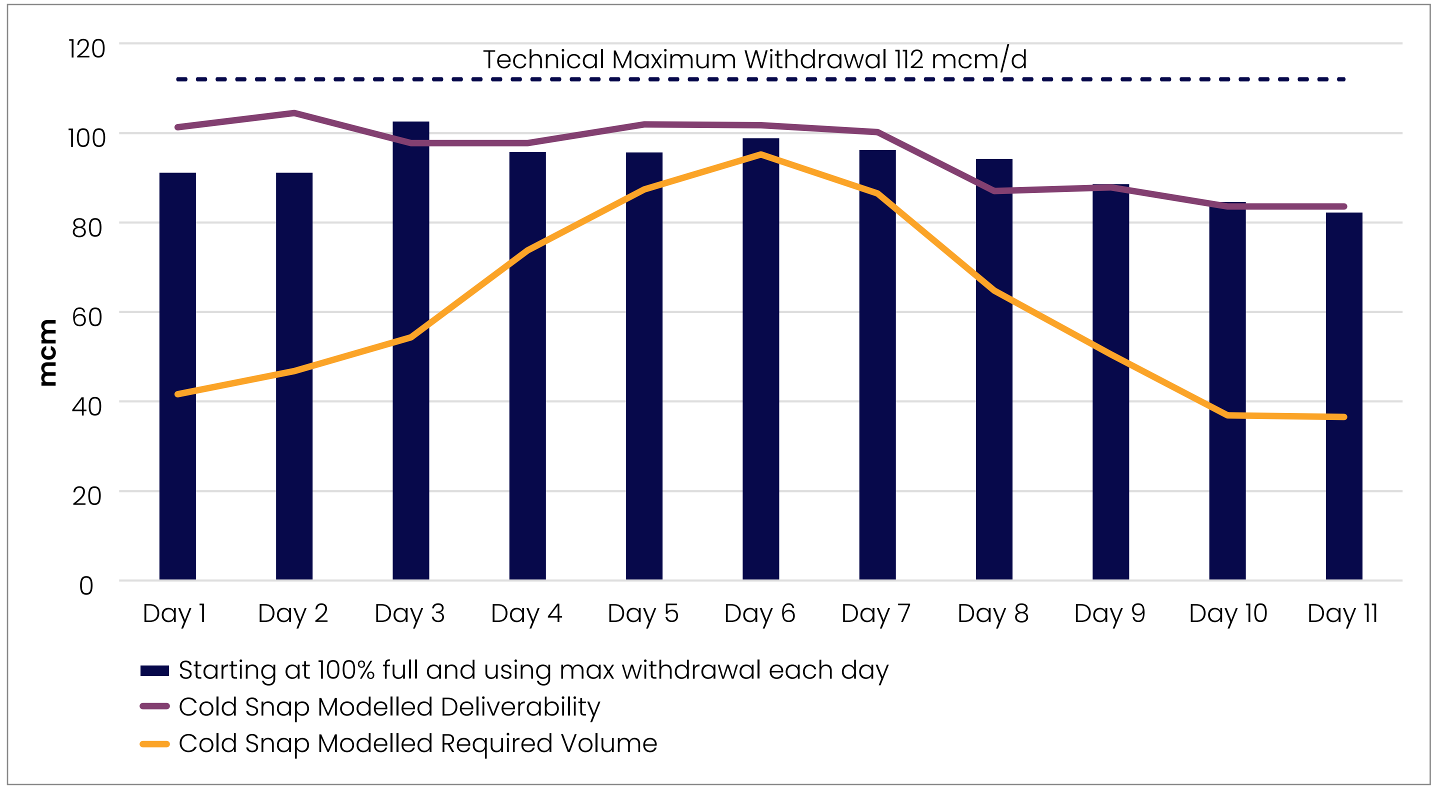


Figure 12: Deliverability at 100% fullness (blue bars) compared with higher deliverability using lower starting stock assumptions of average fullness ahead of the last five cold snaps (purple line) – the orange line shows how storage sites could increase deliverability to help meet higher demand throughout a cold snap in the Ten Year Forecast

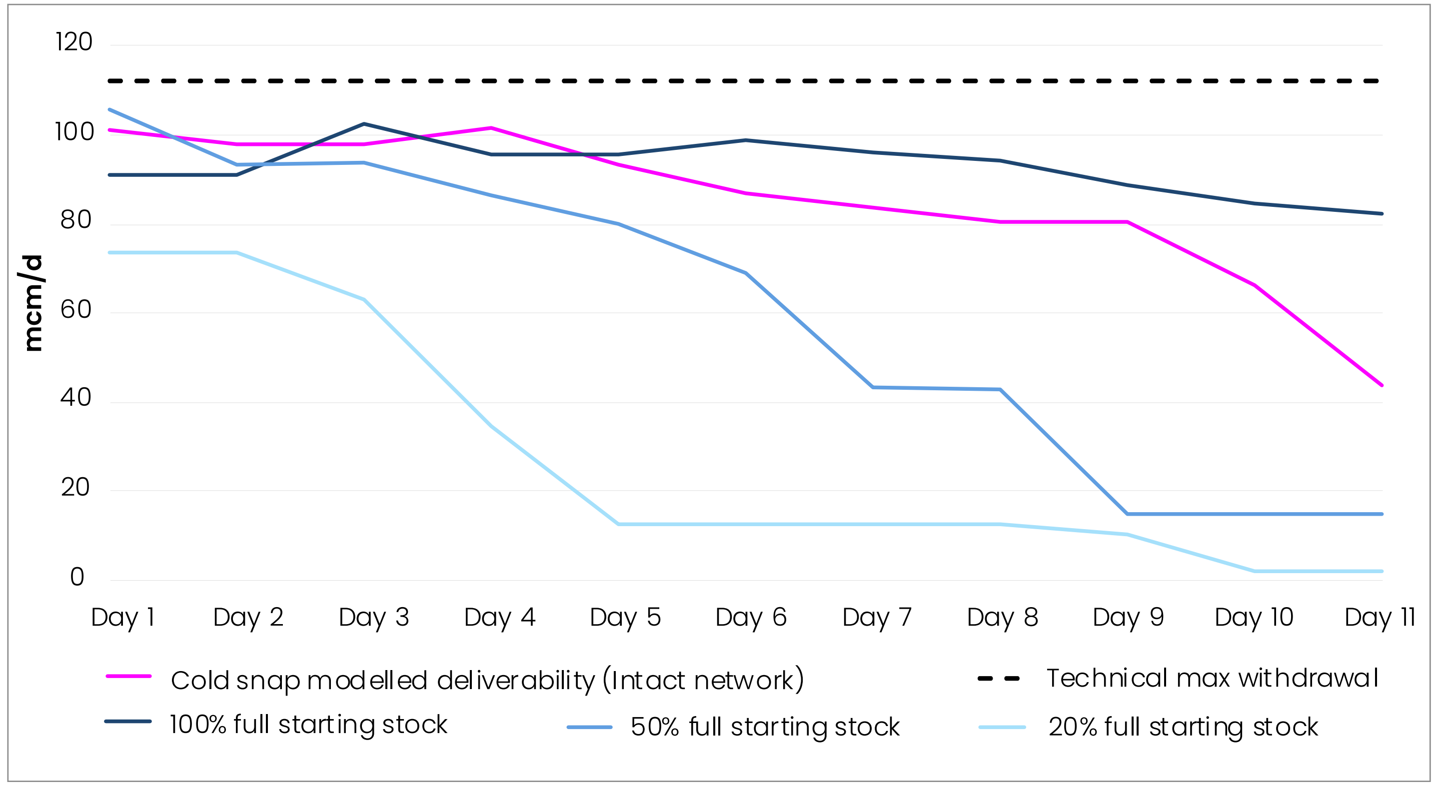


Figure 13: Relationship between the percentage fullness of all storage sites and withdrawal deliverability, with starting percentages of 100, 50, and 20 applied equally to all sites

2.4 Liquefied Natural Gas import

There are three LNG import terminals in GB: South Hook and Dragon in Milford Haven, South Wales, and Grain LNG on the Isle of Grain, southeast England. The two Milford Haven terminals share an aggregated system entry point because a single feeder connects both terminals to the wider NTS.

LNG is gas that is cooled to -162°C, reducing its volume by a factor of 600 and making it possible to transport around the world using specialised tankers. Once LNG arrives in GB, it is stored in liquid form in tanks at the import terminals before going through a regasification process and being delivered onto the NTS when required.

Availability

To assess the availability of LNG, it is necessary to consider both the international LNG markets and LNG stored at GB terminals.

International markets

LNG is traded on the international market, meaning GB competes with other countries for cargoes, particularly during periods of market tightness. Nonetheless, the GB market has historically attracted sufficient volumes to meet demand (Figure 14). This held true even in 2022, when reduced pipeline flows to Europe following Russia's full illegal invasion of Ukraine required increased financial incentives for cargoes to deliver LNG to GB terminals.

Recently, almost 70% of GB LNG was delivered from the USA, with nine other countries providing the remainder: USA (68%), Qatar (8%), Trinidad (7%), Algeria (5%), Angola (3%), Peru (3%), Norway (2%), Nigeria (2%), Guinea (1%) and Egypt (1%)[23].

We have considered future global LNG supply capacities against total international LNG demand expectations for 2030/31 and 2035/36. The outcome indicates increased LNG availability compared with today, as global supply is expected to outpace the corresponding growth in demand between the upcoming winter and these assessment years.

2024/25 111 mcm/d

2030/31 164 mcm/d

2035/36 164 mcm/d

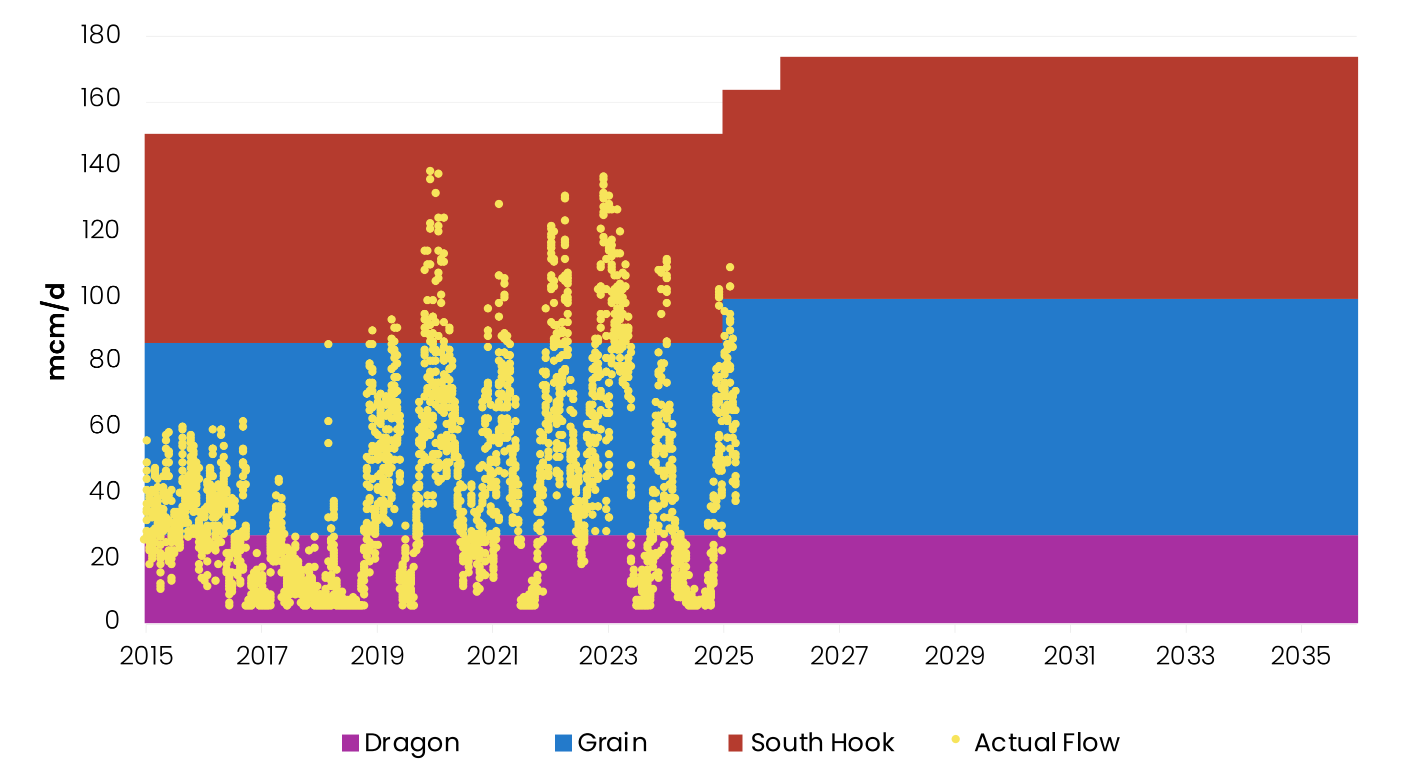


Figure 14: LNG volumes delivered onto the NTS against historic and future terminal availability

The majority of this growth is expected to come from the USA and Qatar, already the world's largest LNG exporters by volume[24]. Both countries have made Final Investment Decisions (FIDs) on projects that, if delivered, will increase nameplate capacity over the next five years by 150 bcm/y and 65 bcm/y[25], respectively. This compares with a projected increase in global LNG demand of 200 bcm/y over the same period[26].

During 2025, total export capacity increased by 33 bcm/yr. Global LNG export capability is projected to continue growing steadily throughout the remainder of the 2020s and into the beginning of the assessment period. By 2035/36, further FIDs will still be required to deliver sufficient export capacity to meet projected global demand. However, this is expected to occur, as the number of potential projects significantly exceeds the anticipated increase in demand.

23 *Digest of UK Energy Statistics (DUKES) 2025*, GOV.UK.

24 Argus LNG Daily, Argus.

25 Global LNG Capacity Tracker, International Energy Agency (IEA).

26 *Global LNG Market Outlook 2030*, Bloomberg Professional Services.

LNG storage

Each LNG terminal has a series of cryogenic tanks used to store LNG before it is regasified and delivered onto the NTS. These tanks can store a combined 1,239 mcm of gas equivalent, rising to 1,353 mcm following completion of a new tank at the Isle of Grain in 2025. Unlike underground storage, LNG storage from terminals can be delivered onto the NTS at a near-constant rate until empty, if required.

If full, LNG storage could maintain maximum deliverability for between eight and nine days, depending on the terminal, before additional LNG cargoes are needed. For a more accurate assessment, we applied the same availability approach to LNG storage as that used for underground gas storage sites. This showed that the average stock at the start of the last five cold snaps was 722 mcm, slightly less than 60% full.

Deliverability: international market

At 60% full, a new LNG cargo would be required to begin delivering as early as day four for the de-rated LNG figure to be maintained (Figure 15). During a cold snap, where demand increases from a lower seasonal normal starting point, a new cargo delivery would be required slightly later – by day six – due to lower regasification of LNG from storage in the preceding period.

Deliverability: NTS

The technical regasification capacity from all three terminals is expected to be 180 mcm/d by 2030, with the de-rated figure being lower. This reduction reflects observed terminal utilisation over the past five years, NTS constraints, and a continuous process of delivering a small volume from two terminals – known as 'boil-off' – which must be delivered to maintain LNG storage tank safety. This flow results from unavoidable heat transfer between the cryogenic tanks and higher external temperatures, which raises the temperature of LNG in storage above its boiling point and creates a minimum daily send-out requirement. While South Hook delivers its boil-off through its main entry point to the NTS and Dragon can re-liquefy its boil-off, Grain is unique in delivering its boil-off to the LDZ. This means Grain's overall deliverability comprises its regasification capability plus the volume of gas boiled off to the LDZ.

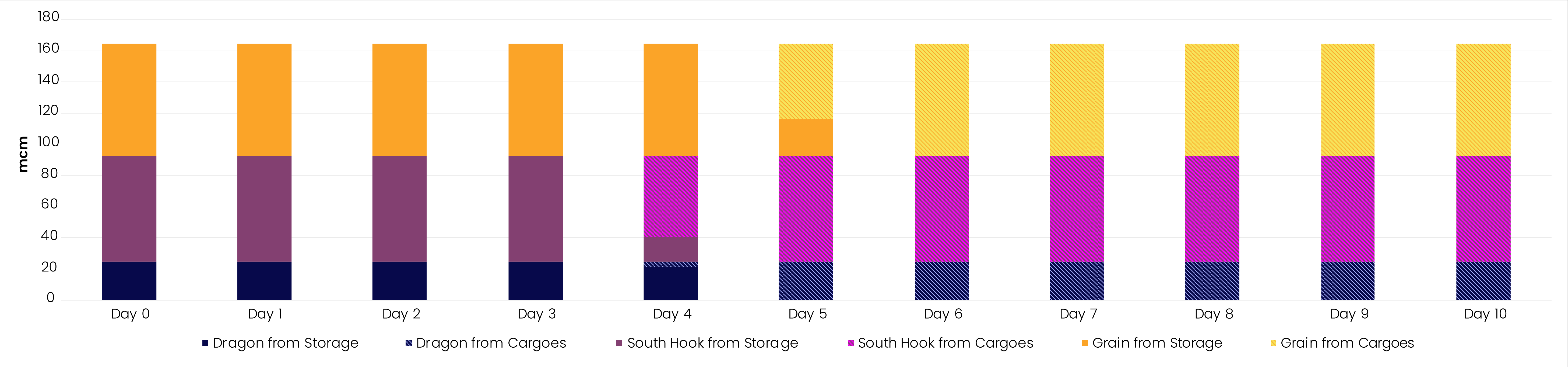


Figure 15: Representative graph of maximum de-rated deliverability based on average LNG storage starting stocks delivering maximum send-out, demonstrating that additional LNG cargoes would need to have arrived to maintain de-rated deliverability

After accounting for the historic utilisation rate of 91%, maximum deliverability onto the NTS of 174 mcm/d is reduced to a de-rated figure of 158 mcm/d. This is calculated by dividing total NTS deliveries from LNG terminals on the highest day over the past five years by the total technical regasification capability of LNG terminals on the same day.

A further 6 mcm/d is provided through boil-off from the Isle of Grain into the South East LDZ, helping to meet part of the LDZ demand requirement.

The de-rated 164 mcm/d deliverability split in both 2030/31 and winter 2035/36 is subsequently 92 mcm/d from Milford Haven and 72mcm/d from the Isle of Grain.

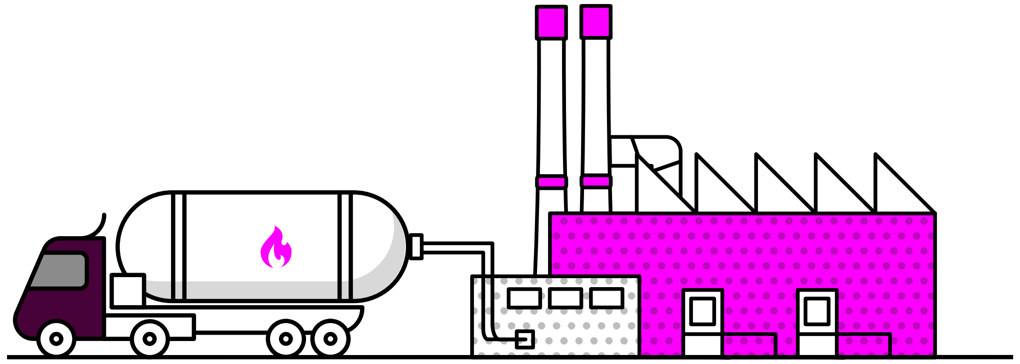
This figure can only be achieved if total NTS demand is at a sufficient level, as network constraints can prevent deliverability from terminals. As set out in NESO's *Gas Network Capability Needs Report*[27], in a base case Ten Year Forecast seasonal normal demand profile, the NTS can only accept 133 mcm/d of LNG. For maximum de-rated entry capacity from Milford Haven, total NTS demand must exceed 470 mcm/d, due to there being a single feeder from Dragon and South Hook into the NTS.

As part of NESO's upcoming *Gas Options Advisory* publication, due later this year, NGT's proposals to increase network capability at Milford Haven are being considered. If delivered, the NTS demand required to meet peak de-rated deliverability would be expected to fall.

For the Isle of Grain to deliver its de-rated volume, NTS demand must exceed a lower figure of 375 mcm/d. This reflects network constraints in the east of England due to the Bacton terminal's deliverability of 90 mcm/d, from a combination of UKCS production and the two interconnectors. All three of these supply sources are expected to reduce in availability by 2030, lowering the NTS demand level required for the Isle of Grain to deliver its de-rated capacity.

Reliability

In addition to the small volume of continuously delivered boil-off from the Isle of Grain, GB has historically attracted LNG cargoes to meet varying demand profiles through market price signals. We consider future LNG delivery onto the NTS to be reliable on the basis that, due to prior preparation from operators, we would expect there to be a minimum of four days (Figure 15) of LNG storage in GB terminals before a new cargo would need to have been delivered. This cargo could then be attracted through sufficient LNG availability globally during the period assessed.



27 *Gas Network Capability Needs Report (GNCR)*, National Energy System Operator.

2.5 Interconnector Imports

2024/25 32 mcm/d

2030/31 82 mcm/d

2035/36 82 mcm/d

There are three interconnector systems connecting GB to other markets. BBL and INT are bidirectional pipelines connecting GB with the Netherlands and Belgium, respectively. The Moffat interconnector system is unidirectional and can export gas from GB to the Republic of Ireland, Northern Ireland and the Isle of Man.

Availability

The availability of gas through the Bacton interconnectors depends on sufficiently wide price spreads between markets, which encourage merchant shippers to purchase interconnector capacity to flow gas volumes in either direction. This depends on three main factors:

- the ability of the importer to bring molecules within gas safety specifications
- a surplus of gas in one market (GB or continental Europe) that can be exported to the other
- the availability of network capacity in each market to transport gas from a supply source to interconnector terminals

Annual interconnector imports to GB have decreased by 89% since Russia's illegal invasion of Ukraine in 2022, which reduced surplus European capacity (Figure 16). Compared with pre-2022 highs of over 100 mcm/d, the highest combined interconnector volume imported to GB was 32 mcm/d in winter 2024/25. The two interconnectors have instead been used to export higher volumes from GB to Europe during summer months to support European storage refill targets.

Deliverability

In 2024, the two continental European interconnectors had a combined EU-to-GB import capacity of 112 mcm/d. This has fallen to 82 mcm/d ahead of winter 2025/26, which we assume will be maintained throughout the assessment period.

The operator of the BBL interconnector announced in June 2024 that EU-to-GB import capacity would be reduced from 45 mcm/d to 40 mcm/d[28]. In December 2024, a further reduction was announced, indicating that import capacity would fall to 22 mcm/d[29].

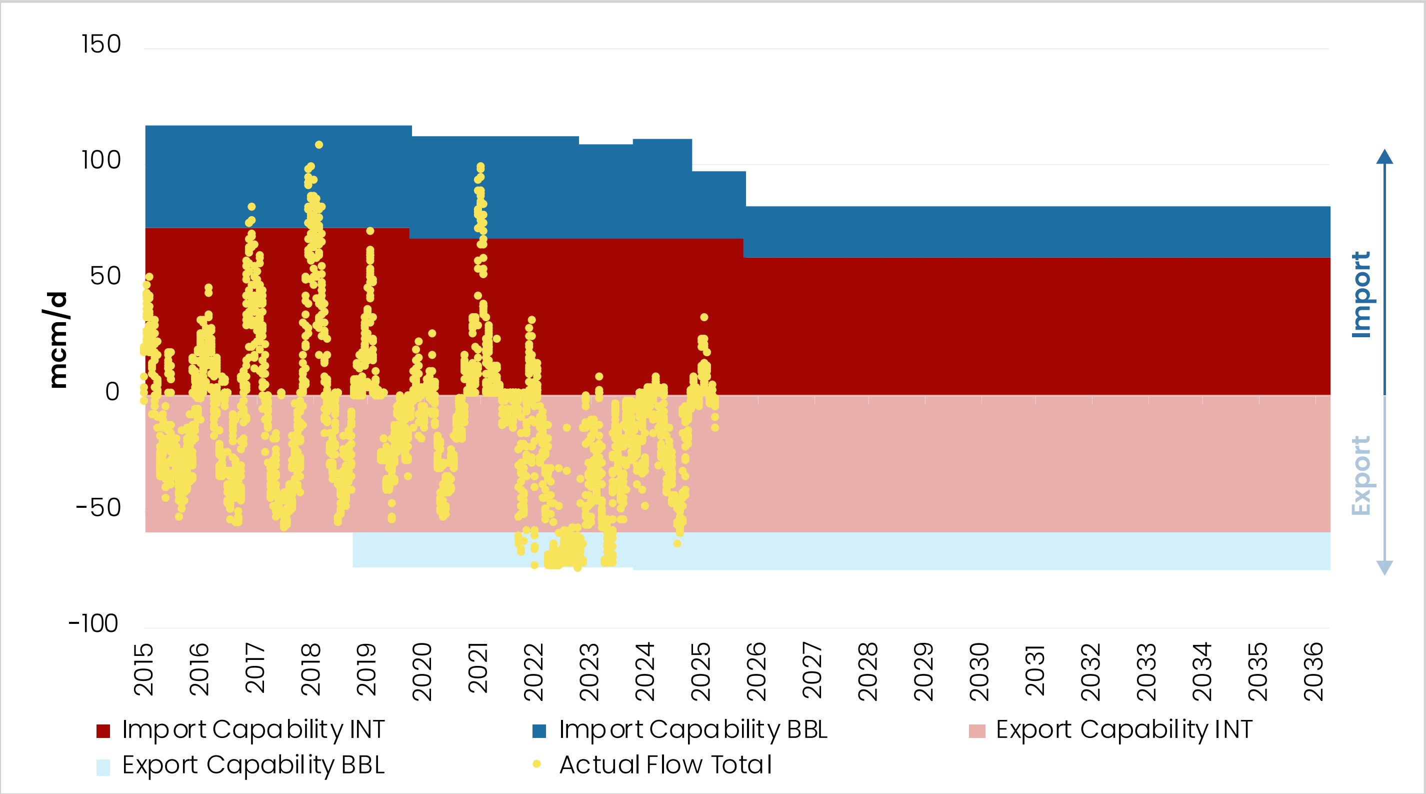


Figure 16: Interconnector actual flows and import and export capabilities for BBL and INT, showing historic performance and projected capability to 2026 assuming availability remains static

The import capacity of INT is expected to reduce from 73 mcm/d to 60 mcm/d[30] based on provisional indications of the capacity booking Open Season outcome outlined in NGT's most recent *Gas Winter Outlook*[31]. Should this trend persist, future import capacity could be reduced further in line with weaker interest in capacity bookings.

Reliability

When refilled, European storage stocks have enabled both the Netherlands and Belgium to be sufficiently well supplied to meet their domestic demand and to support exports to

28 Changes in available technical capacities, BBL Company.

29 Change in Forward Flow Technical Capacity, BBL Company.

30 INT availability is expected to be 667 GWh/d. NGT has published 61mcm/d for INT for a total interconnector availability of 83 mcm/d. The difference between the two publications is due to different Calorific Values used in the conversion between kWh/d and mcm/d.

31 *Gas Winter Outlook* (October 2025), National Gas.

neighbouring markets if required during each winter[32,33].

Unless there are network changes by 2030/31 and 2035/36, on a GB peak day the Netherlands could meet its peak domestic demand, export to GB at the maximum available capacity on the BBL interconnector, and still have sufficient technical capacity to export an additional 177 mcm/d to other European markets (Figure 17). Similarly, Belgium could meet its peak domestic demand, export to GB at the maximum available capacity on the INT interconnector, and still export an additional 23 mcm/d to neighbouring European markets (Figure 18).

GB and continental Europe have different standards for gas quality specification. The requirements in GB are generally more restrictive than those in Europe, and some of these parameters are defined through the Wobbe Index. GB gas quality is increasingly influenced by external factors such as LNG imports, Norwegian flows and the decline of UKCS production, which are beyond direct government control.

Ofgem has identified potential risks to GB's security of supply associated with the current upper limit of the Wobbe Index. To avoid supply disruptions and ensure continued system resilience, Ofgem is working with the Health and Safety Executive (HSE) to consider reviewing the Wobbe Upper Index limit. As part of any review, safeguard measures would be introduced to protect system stability while addressing urgent supply challenges. For the purpose of this Assessment, we assume that gas from connected European markets complies with GB specification.[34]

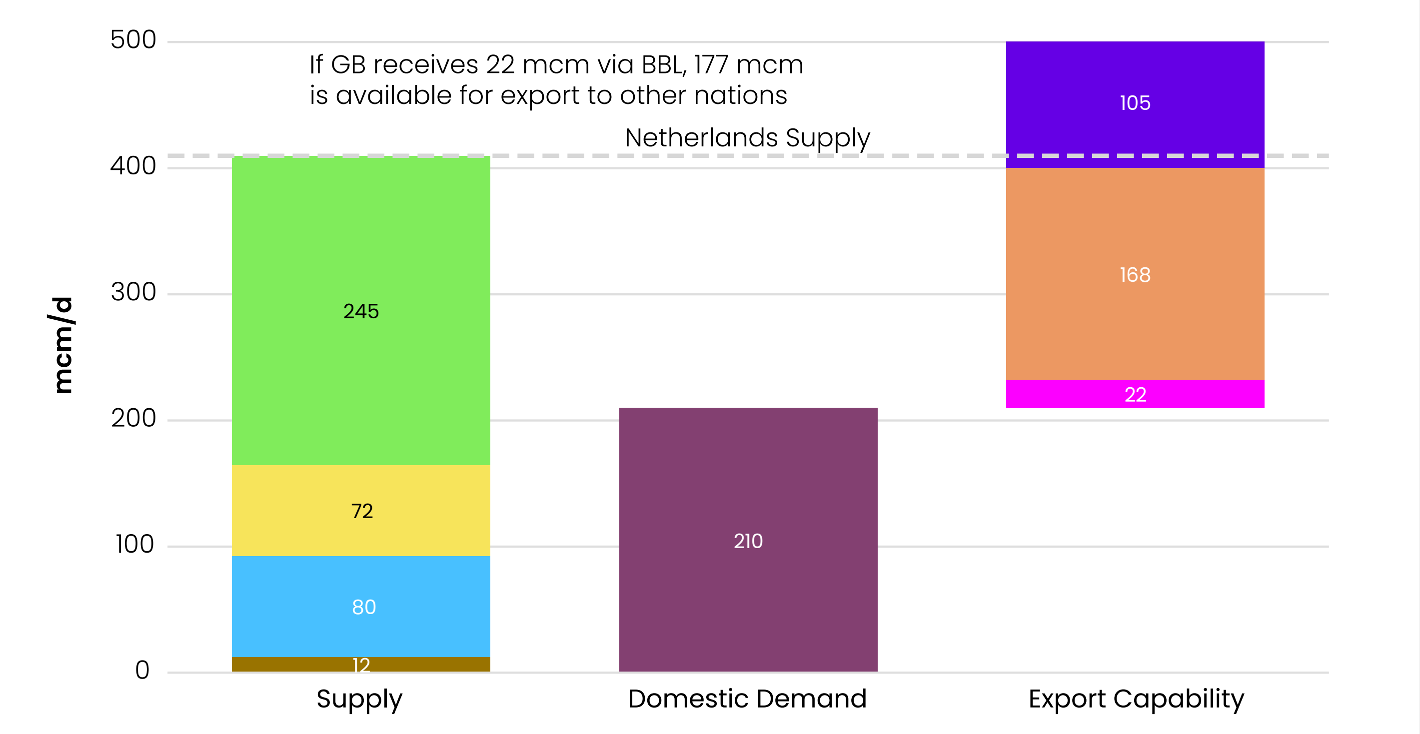


Figure 17: Netherlands peak supply and demand scenario assuming no imports from Belgium or Germany. Data by ENTSOG

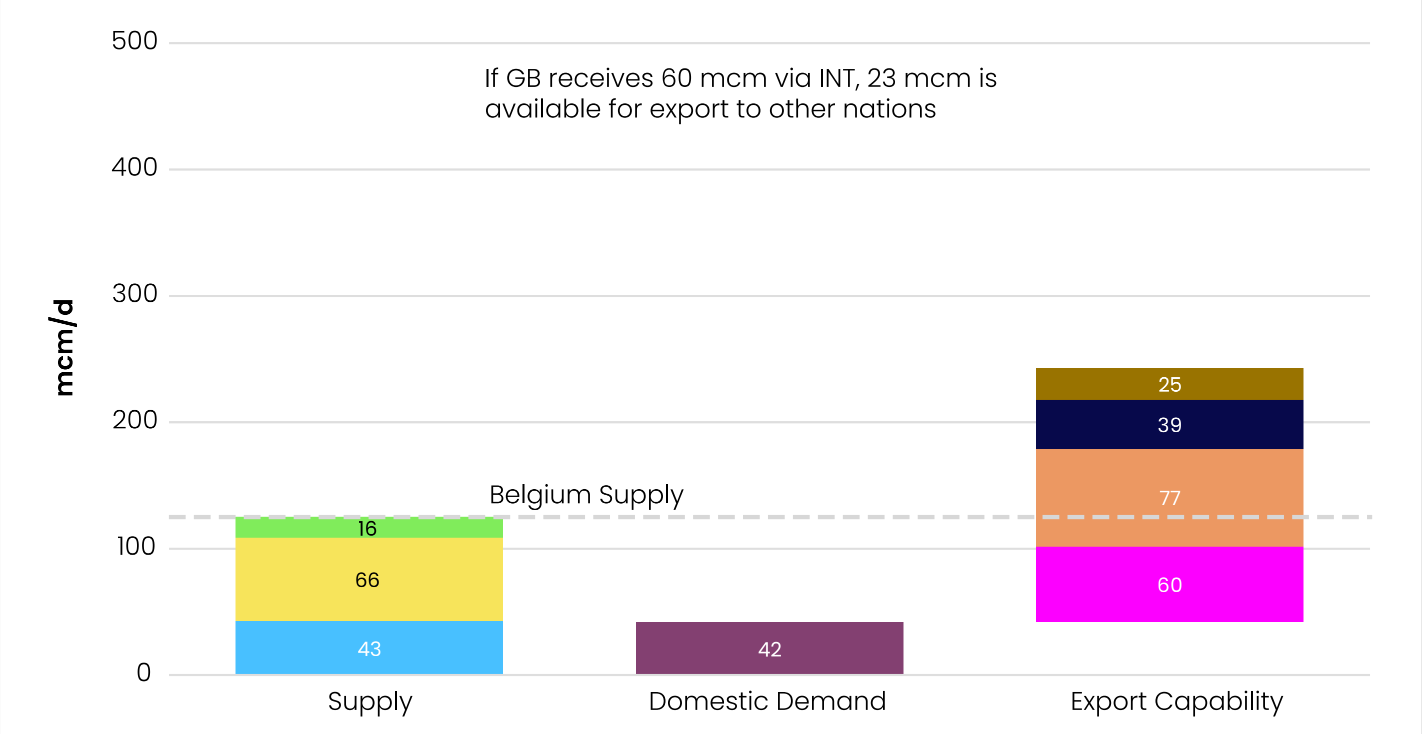


Figure 18: Belgium peak supply and demand scenario assuming no imports from France, the Netherlands or Germany. Data by ENTSOG

- Storage Withdrawal
- LNG Imports
- Norway Imports
- Exports to FR
- Exports to NL
- Exports to DE
- Exports to GB
- Domestic Demand
- Exports to BE

32 *Security of Supply Simulation*, ENTSOG (annex V – Capacities).

33 *Aggregated Gas Storage Inventory (AGSI)*, GIE (Gas Infrastructure Europe).

34 *Call for input: evidence on the upper limit of the Wobbe Index*, Ofgem.

2.6 Biomethane

Biomethane is produced from the anaerobic digestion of biomass – such as food waste, agricultural waste, crops or sewage – into biogas, which is a mixture of methane and CO_2. The CO_2 is separated and removed, and the methane is conditioned to meet standards for injection into Local Distribution Networks (LDZ) or the NTS. This provides a low-carbon alternative to natural gas, as the CO_2 emissions arising from biomethane production are derived from biogenic waste that would otherwise have decomposed into methane.

Availability

There are currently over 100 operational biomethane sites in GB. Our assumptions for biomethane availability are based on the FES 2025 base case of the Ten Year Forecast as the best view of future availability.[35]

Deliverability

Biomethane sites are currently capable of delivering nearly 2 mcm/d onto the GB Market. This could rise to 3 mcm/d in 2030/31 and 5 mcm/d in 2035/36 (Figure 19).

Reliability

Biomethane sites are unable to adjust their output in response to short-term demand changes due to the nature of the production process. As a result, they provide a consistent volume throughout the year.

The daily deliverability volume may be lower than expected if there is low demand at either the LDZ or NTS level, creating congestion that prevents injection onto the networks and movement away from the production site. In such cases, excess biomethane would either be vented or flared. This typically occurs during summer months and is not expected to affect how biomethane contributes to the overall supply mix during elevated demand periods – such as cold snaps – between 2030/31 and 2035/36 or beyond.

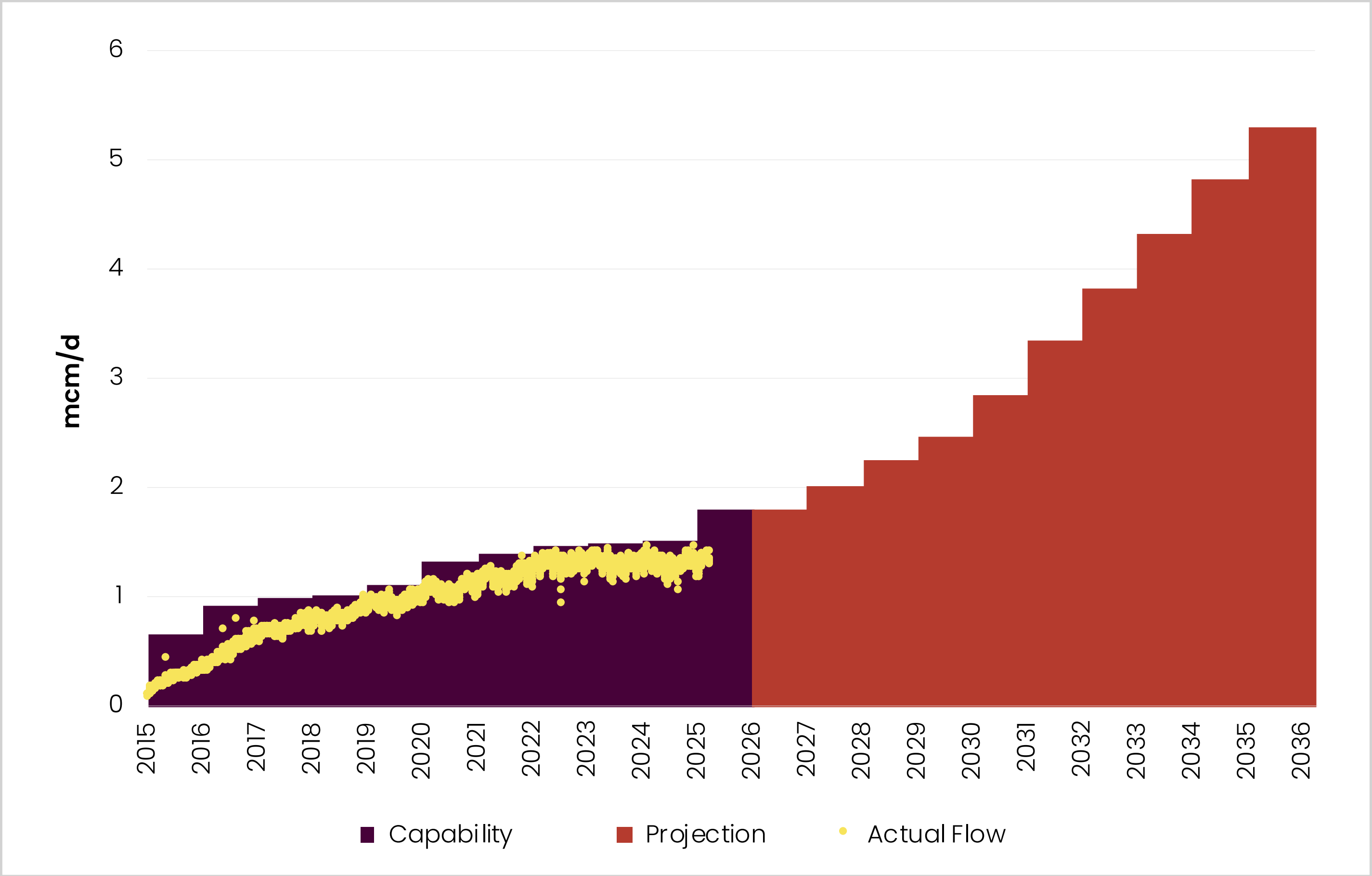
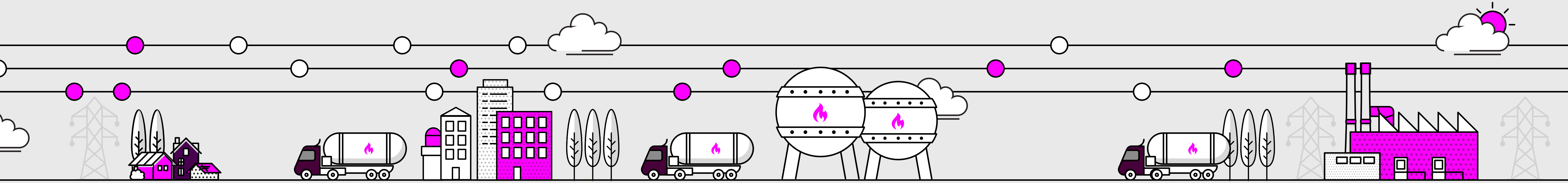


Figure 19: Biomethane capability, actual flow and projections of future deliverability to 2036 based on NESO's FES Ten Year Forecast base case

35 *Future Energy Scenarios: Pathways to Net Zero* (July 2025), National Energy System Operator.

03 Gas Supply Margins Outlook

Key Message 2



Our analysis shows that gas supply margins are expected to become tighter by 2030, indicating an emerging risk to gas supply security. Based on expected demand levels for the period assessed (covering winters 2030/31 and 2035/36), the analysis shows that on a very cold day (during a 1-in-20-year cold snap) and following a failure of the single largest piece of infrastructure (the N-1 test), the system would not have sufficient gas to meet demand without mitigating action(s) being taken.

3.1 How risk emerges

Margins represent the difference between expected de-rated supply and expected demand under a given scenario. Smaller margins indicate a greater risk to security of supply, as the system has less capability to respond to unexpected outages or price spreads between market hubs that do not encourage flows to GB. Negative margins indicate a shortfall in supplies that, if realised in real time, may require within-day management by NGT as the gas system operator. We also consider how this risk can be tested and potentially mitigated.

Our Assessment shows that gas supply margins under seasonal normal demand conditions are adequate, though smaller than today. However, it also shows that risks to gas supply security emerge due to one or more of the following conditions:

- cold days when peak gas demand is higher than seasonal normal levels, in line with a 1-in-20-year cold weather period
- pathways in which peak gas demand remains high due to slower decarbonisation (for example, the Falling Behind pathway)
- loss of the largest piece of supply infrastructure (N-1)

This risk is present throughout the full horizon of this Assessment, from winter 2030/31 to 2035/36.

Table 3 summarises gas supply margins for both seasonal normal and peak demand conditions in winters 2030/31 and 2035/36 across the different FES pathways. It shows that negative margins exist in winter 2030/31 on a 1-in-20 peak day in the Falling Behind pathway. While the Ten Year Forecast and the remaining FES pathways show a positive margin for winter 2030/31, all margins would become negative in the event of the loss of the largest infrastructure (N-1).

The situation improves for winter 2035/36, particularly for the three pathways that meet net zero decarbonisation targets. The gas supply margin in these three pathways would remain positive on a 1-in-20 peak day, even in the case of the largest infrastructure loss.

The following sections present gas supply margins over the multi-day assessment period, first for seasonal normal conditions and then under security standards (1-in-20-year and N-1) to stress-test the gas supply system. We focus on the Ten Year Forecast, representing NESO's best view of future demand for both gas and power. However, uncertainties in the future trajectory of energy system decarbonisation are accounted for through modelling of all FES demand profiles, providing an upper and lower bound for gas demand.

Table 3: Supply margins under seasonal normal, 1-in-20 peak and N-1 reduced system conditions for each FES pathway, showing the lowest daily margin calculated over the 11-day cold snap

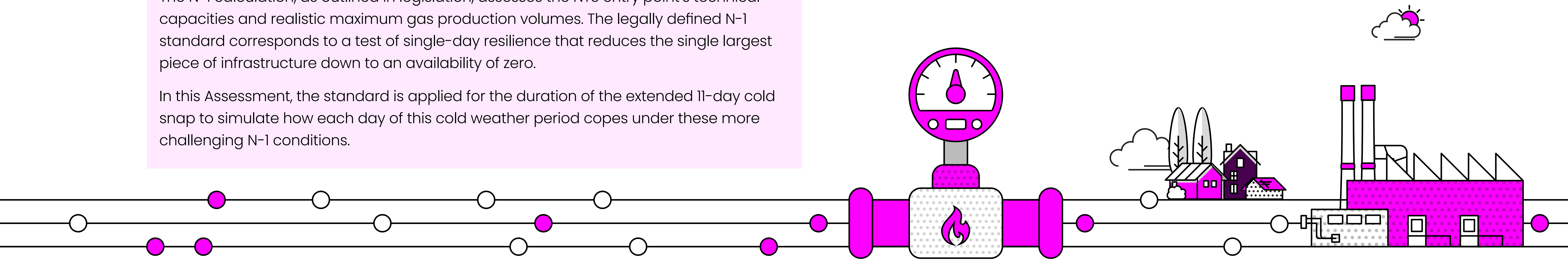
	2030/31			2035/36		
	Seasonal Normal Margin (mcm)	Peak Day Intact Margin (mcm)	N-1 Margin (mcm)	Seasonal Normal Margin (mcm)	Peak Day Intact Margin (mcm)	N-1 Margin (mcm)
Falling Behind	163	-20	-127	157	-9	-114
Forecast (10YF)	182	23	-76	207	32	-57
Hydrogen Evolution	205	60	-29	209	104	19
Electric Engagement	205	61	-28	208	106	23
Holistic Transition	211	73	-16	225	126	48

What is N-1?

Following the UK's departure from the European Union, EU regulation 2017/193822[36] was incorporated into UK law by the Gas (Security of Supply and Networks Codes) (Amendment) (EU Exit) regulations 201923[37]. The infrastructure standard outlined in the regulation requires that GB gas supply infrastructure is capable of meeting a 1-in-20-year peak day gas demand in the event of disruption to the single largest piece of gas infrastructure. This is known as the N-1 standard.

The N-1 calculation, as outlined in legislation, assesses the NTS entry point's technical capacities and realistic maximum gas production volumes. The legally defined N-1 standard corresponds to a test of single-day resilience that reduces the single largest piece of infrastructure down to an availability of zero.

In this Assessment, the standard is applied for the duration of the extended 11-day cold snap to simulate how each day of this cold weather period copes under these more challenging N-1 conditions.



36 Regulation (EU) 2017/1938 of the European Parliament and of the Council of 25 October 2017 concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010.

37 The Gas (Security of Supply and Network Codes) (Amendment) (EU Exit) Regulations 2019.

3.2 Supply margins: seasonal normal conditions

Under seasonal normal weather conditions, considered typical for the time of year, demand is expected to remain lower than de-rated supply. Figure 20 shows the seasonal normal demand profiles against expected de-rated supply levels over the multi-day assessment period.

The highest daily demand level reached under the Ten Year Forecast (10YF) is 274 mcm in 2030/31. This is substantially less than the aggregated de-rated supply capability of 456 mcm, resulting in a large positive margin of 182 mcm on day 5. This margin increases to 207 mcm in 2035/36, as shown in Figure 21.

A similar outcome is observed across all FES pathways, with maximum seasonal normal demand varying between 242 mcm/d to 302 mcm/d in 2030/31. As a result, the analysis consistently shows substantial positive daily supply margins, ranging from the narrowest margin of 163 mcm under the Falling Behind pathway to 211 mcm under the Holistic Transition pathway. This demonstrates that even the upper level of demand – experienced under the Falling Behind pathway – is unlikely to have a significant impact on supply margins during typical winter weather conditions.

In both winters 2030/31 and 2035/36, seasonal normal demand remains consistently below the de-rated supply levels for all evaluated future demand profiles. These results highlight that we expect there to be sufficient gas supply to meet demand under seasonal normal weather conditions, assuming a fully operational ('intact') supply network.

2030/31

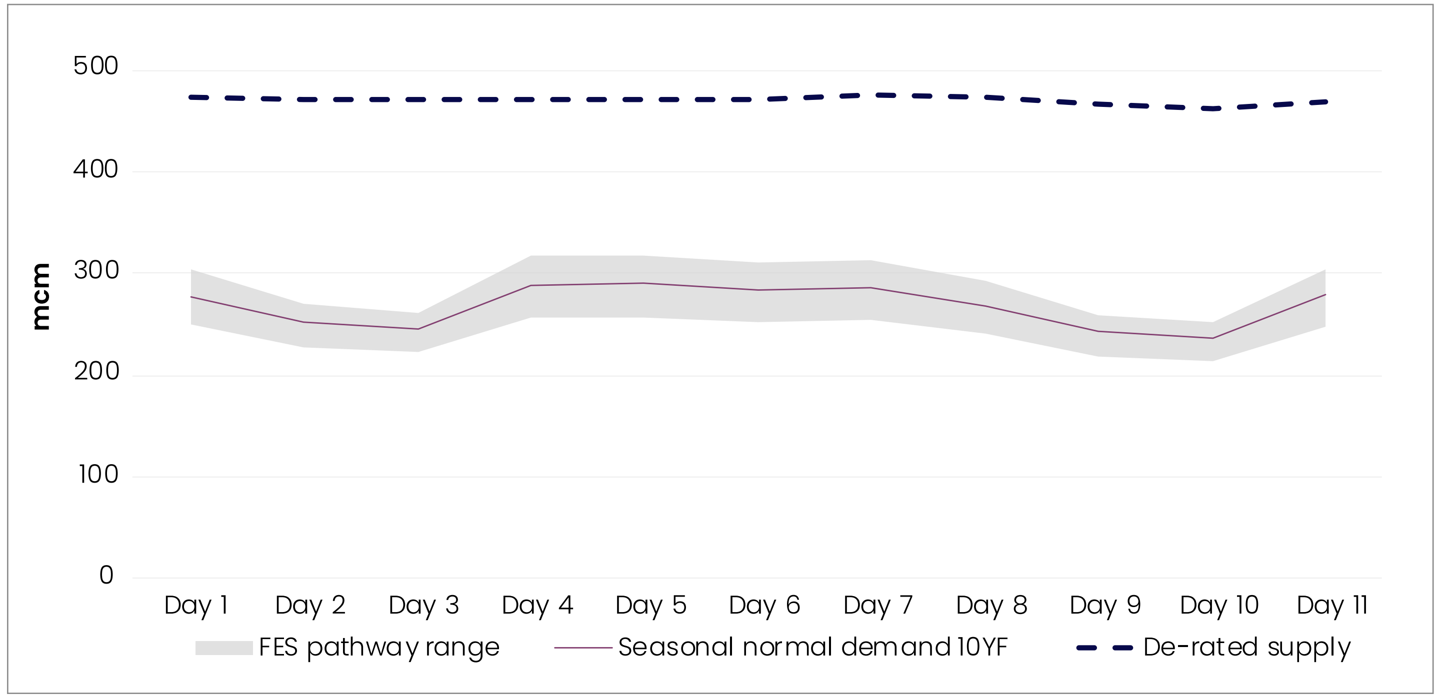


Figure 20: In winter 2030/31, seasonal normal demand is less than de-rated supply across the 11-day period, resulting in large positive margins

2035/36

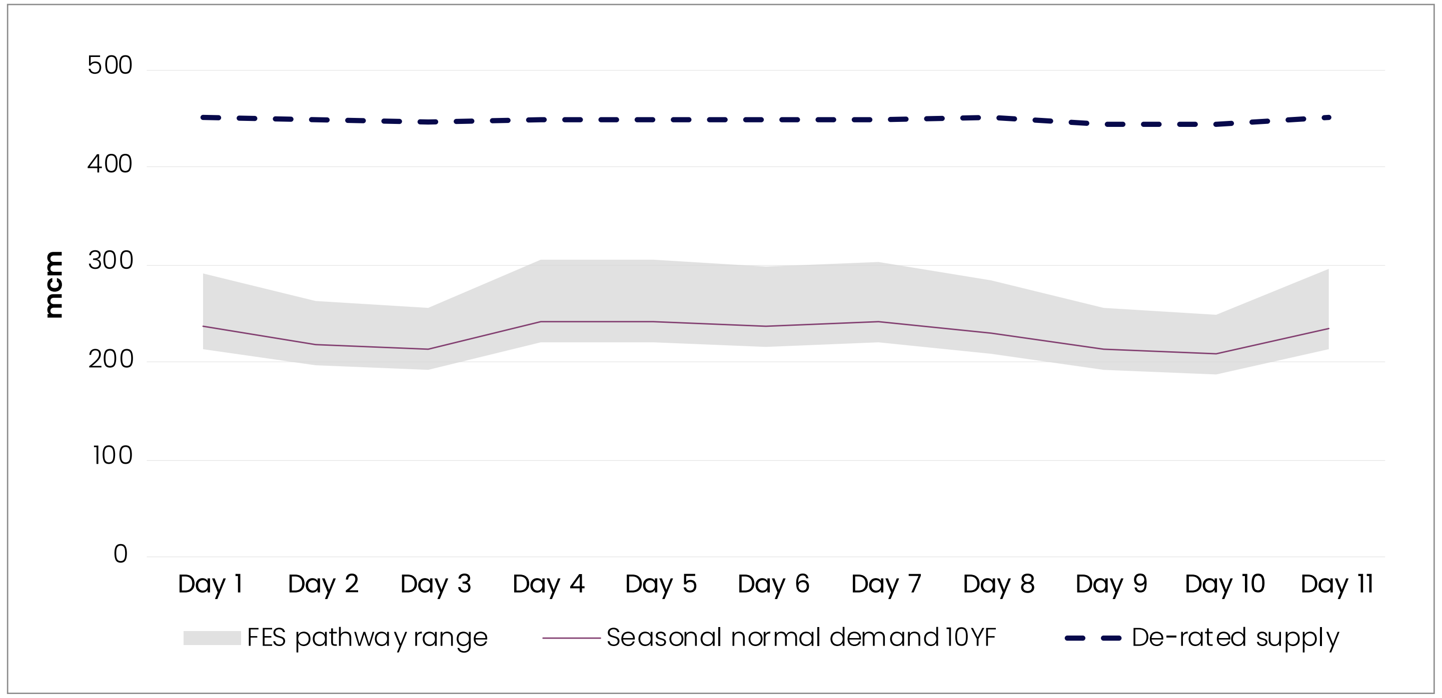


Figure 21: In winter 2035/36, seasonal normal demand remains less than de-rated supply, with margins increasing for our Ten Year Forecast relative to 2030/31

3.3 Supply margins: 1-in-20-year cold snap

The supply margins outlook changes when considering a 1-in-20-year cold snap period. This Assessment assumes a fully intact and operational gas supply network, and that a 1-in-20-year peak demand day is reached in the middle of the 11-day cold snap.

Figures 22 and 23 show the equivalent multi-day peak demand profiles against de-rated supply for winters 2030/31 to 2035/36, respectively. In 2030/31, under the base case – the Ten Year Forecast (10YF) – demand reaches 461 mcm on the peak day, resulting in a narrow but positive supply margin of 23 mcm, rising to 32 mcm in 2035/36. While these margins indicate that supply could meet peak day demand, their limited size leaves the system vulnerable to potential supply disruptions. Notably, outages exceeding 23 mcm have occurred during previous winters.

Figure 24 illustrates the relative contribution of each supply source in meeting peak demand under the base case 11-day cold snap in winter 2030/31. UKCS and biomethane supplies are expected to remain relatively stable, with additional volumes initially met by increasing NCS supply through Langeled or Vesterled, followed by increased contributions from LNG, storage and interconnectors. Due to the dynamic way in which supply sources deliver, there will be no fixed combination of contributions until demand reaches its highest level. At this point, all supply sources would be required to operate, simultaneously, at close to their de-rated maximum capacities, to prevent a gas supply shortfall. This has not previously been required and is therefore untested in real time. Even if this were achieved, there would be very limited spare capacity for the gas system to respond to higher demand or to compensate for lower-than-expected supply from another source – for example, if storage starting stocks were lower than assumed in this analysis.

2030/31

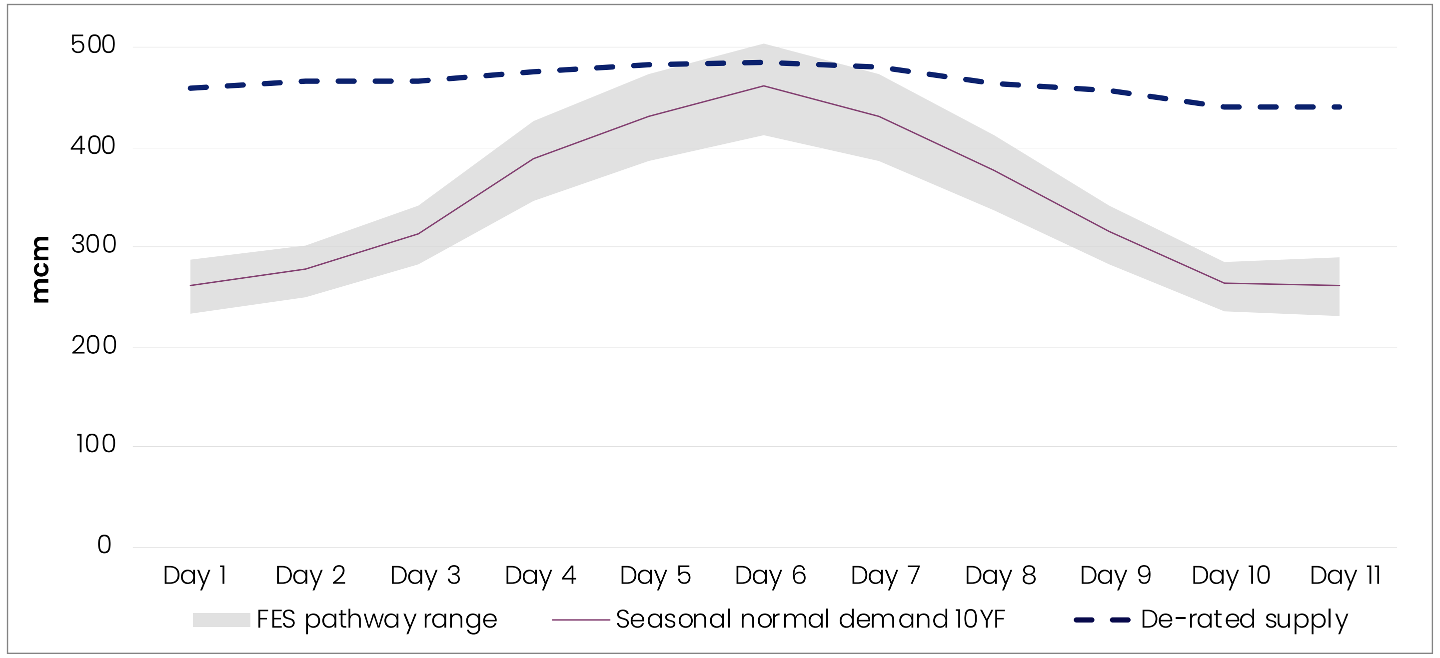


Figure 22: Margins narrow under an 11-day cold snap, with 10YF peak day demand only 23 mcm less than de-rated supply in winter 2030/31

2035/36

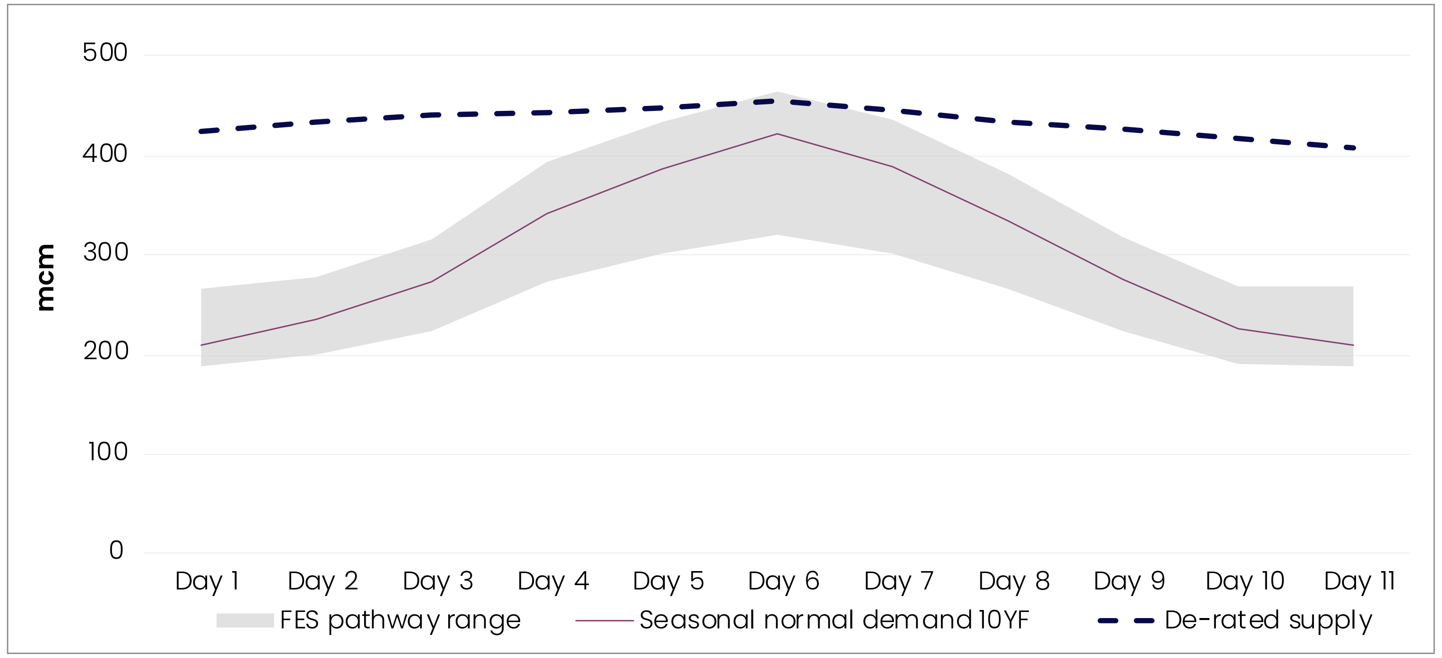


Figure 23: Margins narrow under an 11-day cold snap, with 10YF peak day demand only 32 mcm less than de-rated supply in winter 2035/36

When considering the three pathways compliant with net zero decarbonisation targets – all with demand levels below the Ten Year Forecast profiles in Figures 23 and 24 – the gas supply system is expected to deliver sufficient volumes to meet elevated demand. The margins in these pathways are higher than those in the Ten Year Forecast due to increased electrification across the energy system, which reduces peak day gas demand. Projected peak day margins could range from 60 to 73 mcm/d in winter 2030/31, increasing to between 104 mcm/d and 126 mcm/d in 2035/36. We would expect this trend to continue beyond 2035/36 if the long-term decarbonisation trajectory continues.

The Holistic Transition pathway represents the most rapid reduction in gas demand, driven by high electrification and hydrogen adoption, mainly in industry. In winter 2030/31, we expect peak day demand of 413 mcm/d to be met partly by flows from UKCS, NCS and biomethane, with the remaining 272 mcm/d supplied through a combination of LNG, storage and interconnector capacity. This scenario demonstrates how achieving more ambitious decarbonisation targets could strengthen gas security of supply.

However, this is not the case for Falling Behind, the slowest decarbonisation scenario, represented by the upper limit of the FES pathway range in Figures 23 and 24. Under this pathway, demand reaches 505 mcm on the peak day, exceeding expected supply levels by 20 mcm and resulting in a negative margin.

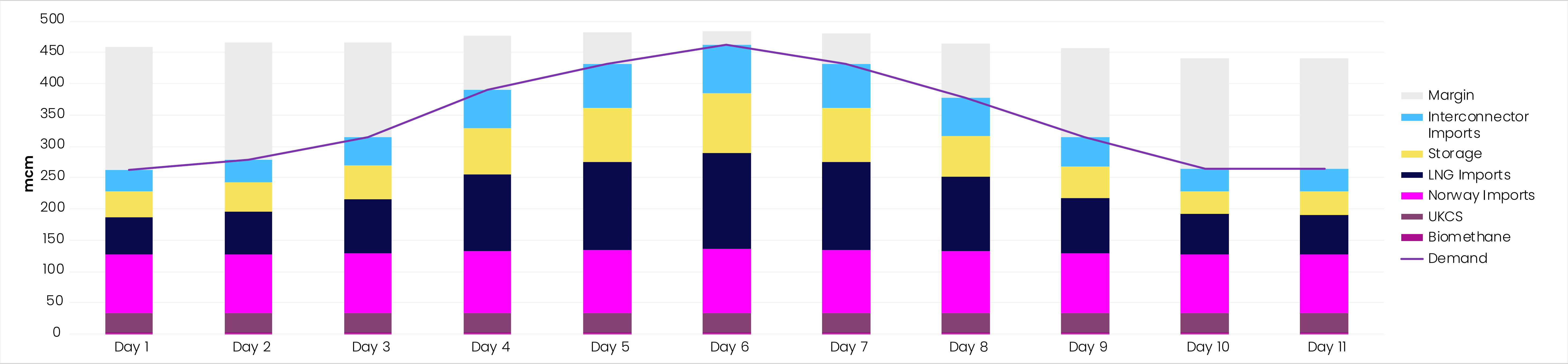


Figure 24: Base case (10YF) breakdown showing how different GB gas supply sources could meet 1-in-20-year peak demand during an 11-day cold snap, assuming an intact network in winter 2030/31

3.4 Supply margins: N-1 reduced supply

Potential shortfalls would be greater in the event of an N-1 supply loss. Although the total loss of the single largest piece of infrastructure is considered a rare event, negative margins could materialise during a cold snap even with a small reduction in deliverability across the gas supply system. This is not the case under seasonal normal weather conditions, where lower demand expectations are likely to be met even under N-1 conditions.

Assuming the loss of the single largest piece of supply infrastructure – peak demand in winter 2030/31 would not be met under any of the FES pathways, resulting in a failure to meet the N-1 security of supply standard. Focusing on the Ten Year Forecast (10YF) base case, Figure 25 shows that peak day demand in winter 2030/31 is projected to reach 461 mcm. Under N-1 conditions, de-rated supply would fall to 385 mcm, resulting in a supply deficit of 76 mcm. Figure 26 demonstrates how a deficit of 57 mcm would still exist in 2035/36.

Under N-1 conditions, storage would need to deliver at its maximum rate to offset the initial supply shortfall. However, due to the natural decline in deliverability over time, it cannot sustain this peak output for multiple days. As a result, storage performance deteriorates from maximum delivery on day five, with a reduction of 18 mcm (-18%) by day eight. Figure 27 illustrates this dynamic, showing how reduced LNG deliverability under N-1 conditions increases reliance on storage from day one of the cold snap, ultimately leading to a supply shortfall by day five – even with all available sources operating at their de-rated maximum capacity. This effectively simulates a scenario, where both the largest infrastructure and storage deliverability are constrained, leading to supply reductions that exceed the technical capacity of any single supply source.

2030/31

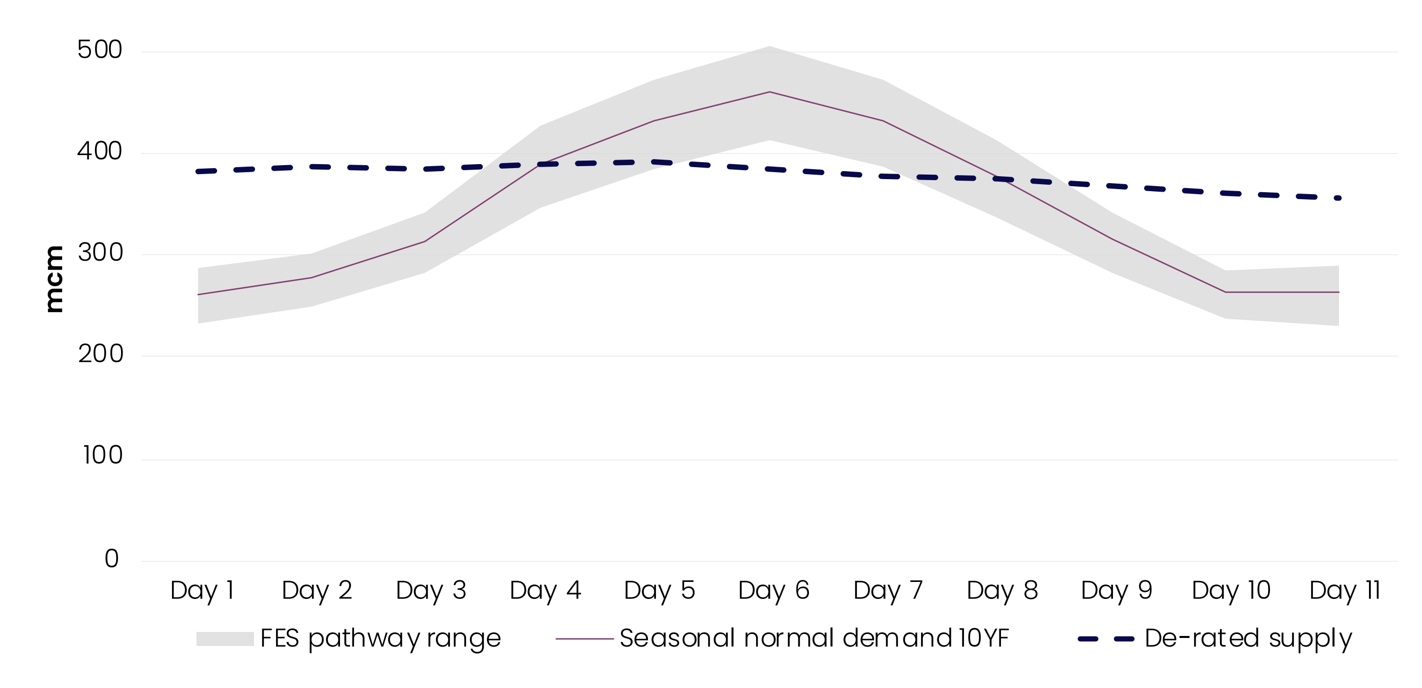


Figure 25: In winter 2030/31, N-1 supply fails to meet peak day demand under a cold snap, across all FES pathways

2035/36

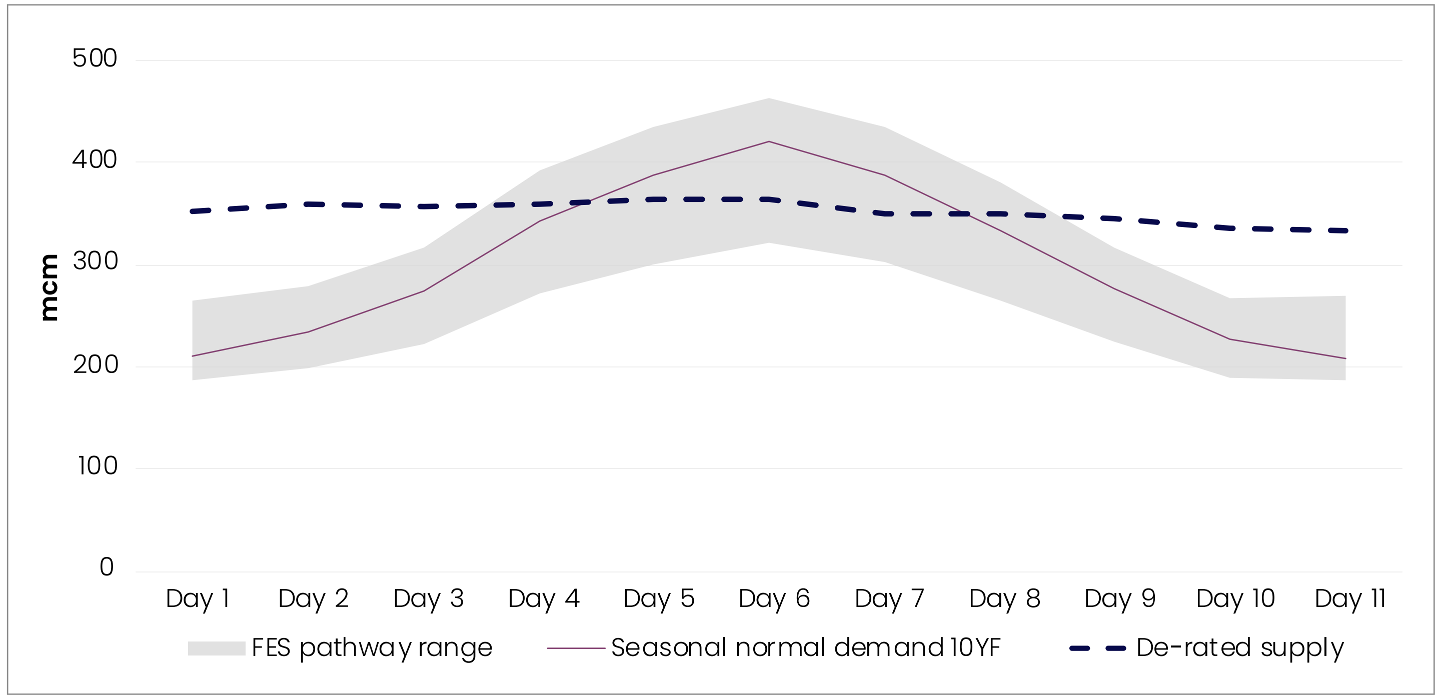


Figure 26: In winter 2035/36, N-1 supply fails to meet peak day demand for the 10YF and Falling Behind pathways but meets the standard under net zero compliant pathways

The analysis shows that, in addition to failing the N-1 test for the loss of the single largest piece of infrastructure, there may also be insufficient supply to maintain a positive margin if smaller losses occur elsewhere in the gas supply system. This suggests that the N-1 threshold is not the only critical point; smaller or combined losses across multiple assets could also compromise gas security of supply.

Under net zero compliant pathways, lower projected peak demand levels – illustrated by the shaded area beneath the Ten Year Forecast in Figure 25 – are expected to result in more favourable supply margins. However, these pathways still fail to meet the N-1 security of supply test for the loss of the largest piece of infrastructure, with at least one day of negative margins projected during the cold snap period in 2030/31. For example, under the Holistic Transition pathway, demand reaches 413 mcm during the peak day of the cold snap, exceeding the N-1 de-rated supply capability by 16 mcm.

In winter 2035/36, the same infrastructure loss would result in unmet demand and a failure to meet the N-1 standard for the Falling Behind pathway. However, margins under net zero pathways are expected to become positive, as peak demand falls to levels that offset the risk and meet the N-1 standard.

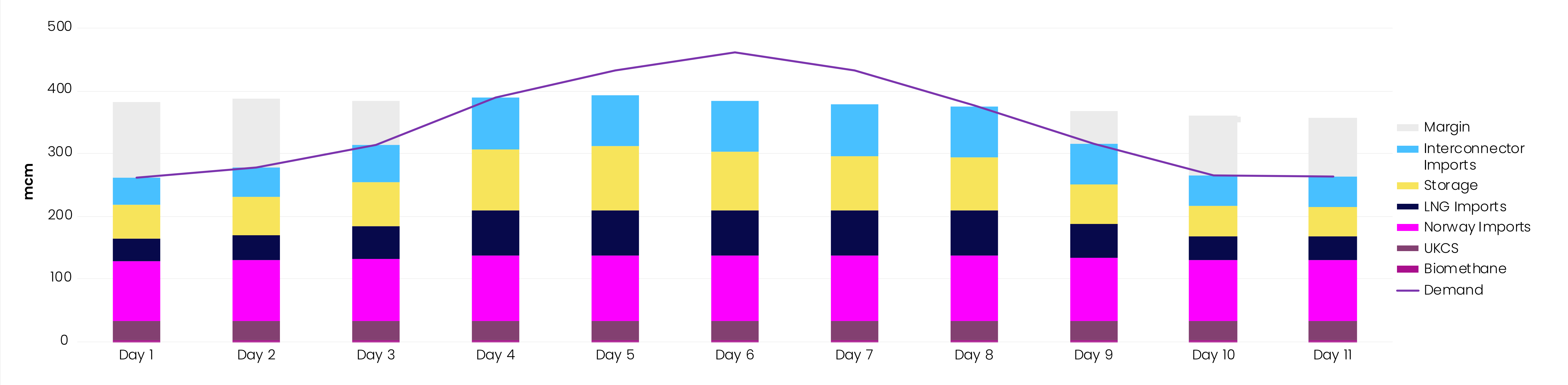
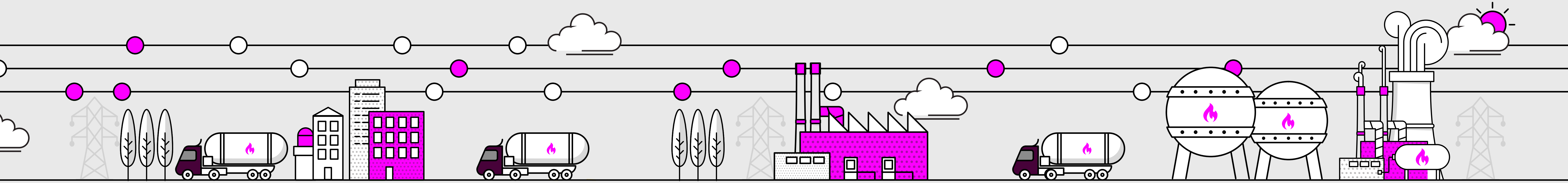


Figure 27: Base case (10YF) breakdown showing how different GB gas supply sources could meet 1-in-20-year peak demand during an 11-day cold snap, assuming an N-1 reduced supply network in winter 2030/31

04 Mitigation Options

Key Message 3



Options are available to mitigate the identified risks. NESO is committed to working with government, Ofgem, National Gas Transmission and industry to ensure continued security of gas supply. The mitigations identified in this Assessment, together with the consultation published by government – which sets out its assessment of priorities for gas security of supply during the transition – provide a suite of options capable of addressing these risks. This will require a coordinated approach to ensure the timely delivery of the most effective options for Great Britain.

Our Assessment shows that there are emerging risks to gas supply security over the period covering winters 2030/31 to 2035/36. In this section we consider some of the potential options that could help mitigate these identified risks to security of supply. These options have been identified based on their potential impact on gas security of supply for the time period considered. While we are not advocating for any particular option, our Assessment indicates that a combination of options may be needed to mitigate the identified risks. This will require a coordinated approach to ensure timely delivery of the most effective options.

Alongside this Assessment, the government has launched a consultation outlining its view on the key priorities for gas security of supply during the transition[38]. The consultation presents a range of proposed policy options under consideration to address these priorities. While our Assessment identifies that options are available to mitigate the identified risks, the need for action or intervention is a matter for government. Other factors – such as maximising consumer value, minimising market disruption and determining the mechanisms or frameworks by which any identified measures would be delivered – are beyond the scope of this Assessment but will need to be considered. We will continue to work in partnership with government, providing technical expertise and impartial advice to support its consultation process.

We have identified mitigation options that can be grouped into four main categories:

1. Reducing gas demand on a peak day
2. Maximising existing gas supply infrastructure
3. Developing new gas supply infrastructure
4. Developing National Transmission System (NTS) infrastructure to support gas supply security

38 *The Gas System in Transition: Security of Supply*, November 2025, GOV.UK.

4.1 Reducing gas demand on a peak day

NESO's FES sets out three net zero pathways in which peak day gas demand is lower than in both the Ten Year Forecast and Falling Behind. The numerous drivers of reduced peak day gas demand across these three pathways indicate ways in which demand-side policy could be shaped to support gas security of supply. In this Assessment, we have chosen to focus on clean heat technology as domestic heating represents the largest single source of peak day gas demand under all FES pathways.

Although NESO recognises the challenges and costs associated with domestic consumers switching to electrified heating systems and improving insulation standards, government financial support schemes already exist, providing an established framework through which further progress could be achieved. In addition to clean heat technology, we also consider how decarbonisation of the power system could reduce peak day gas demand from gas-fired generation, and the opportunities for growth in demand-side response in the gas market.

Clean heat technology

Increasing the uptake of clean heat technology can reduce gas demand from domestic gas-fired boilers. The difference between peak day domestic boiler demand in the Ten Year Forecast and the net zero pathways is 17 mcm in winter 2030/31, increasing to 47 mcm in winter 2035/36.

The difference in peak day gas boiler demand under the net zero pathways is predominantly explained by greater uptake of air-source and ground-source heat pumps (Figure 28), and improved insulation standards in households. Heat pumps, in addition to being electrified, require around three to four times less energy input to achieve the same indoor temperature as gas-fired boilers. Improved insulation increases energy efficiency in all homes, including those still using gas-fired heating, by reducing gas consumption while maintaining the same interior temperatures.

39 Resource Adequacy in the 2030s (July 2025), National Energy System Operator.

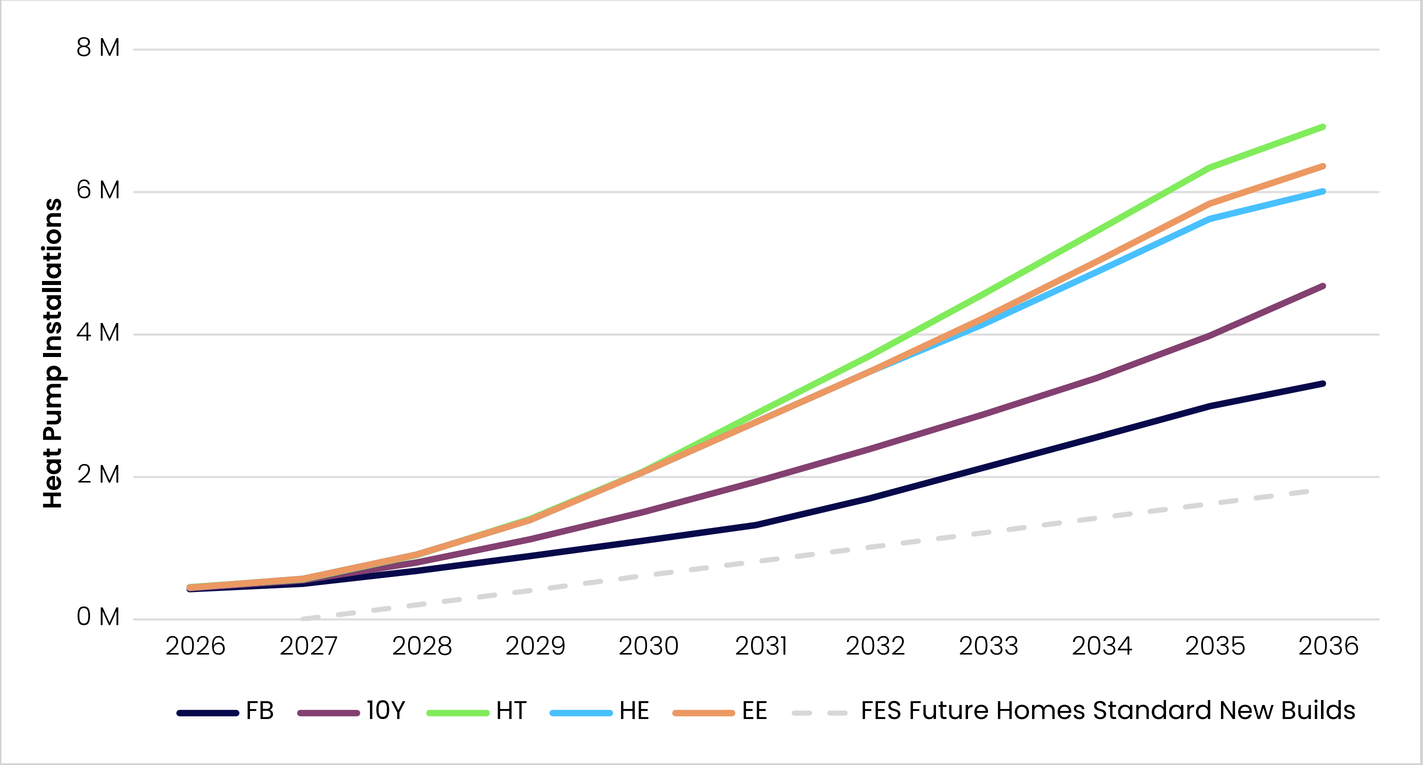


Figure 28: Heat pump uptake by FES pathway with post Future Homes Standard new build projections

Power sector decarbonisation

NESO's *Resource Adequacy in the 2030s* report[39], published in July 2025, showed how bringing forward new low-carbon electricity generation and storage capacity could reduce our reliance on unabated gas-fired generation while maintaining reliable electricity supplies. Reducing this dependence could also support gas security of supply by lowering peak day gas demand.

Demand-side response

Demand-side response (DSR) is a mechanism through which consumers can voluntarily reduce their energy consumption in response to price signals that reflect the level of scarcity in the energy system. DSR exists in both electricity and gas markets but, due to the differences in transmission, balancing and energy use between the two systems, the scope of DSR varies significantly.

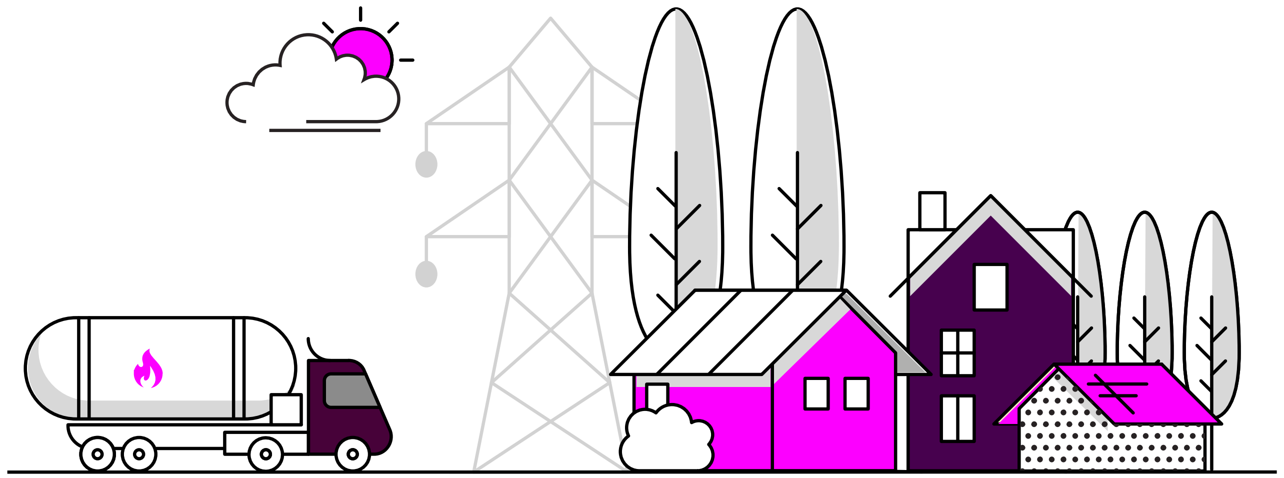
Non-daily metered

As detailed in Ofgem's determination on non-daily metered (NDM) DSR trials, residential demand-side response for gas posed risks to vulnerable consumers who may fail to adequately heat their homes in cold weather, and to those who are not in control of their heating and could therefore be exploited[40]. As such, NDM DSR is not currently regarded as an appropriate mitigation for the risks identified in this Assessment.

Daily metered

A Uniform Network Code (UNC) obligation mandates that National Gas Transmission (NGT) tenders annually for Industrial & Commercial (I&C) DSR. NGT is required to procure offers on an economic and efficient basis. Despite year-on-year growth, the current volumes offered remain below what NGT considers necessary to achieve its outcomes. Therefore, NGT did not accept any DSR Option Offers in the latest tender[41] but continues to seek further growth in the daily metered (DM) DSR market.

NESO, alongside NGT, will consider industry feedback to the government consultation and work with DESNZ, Ofgem and Industry to explore the effectiveness of DM DSR in supporting gas security of supply.



40 *UNC0856 Final decision letter*, Ofgem.

41 *DSR Annual Report 2024-25*, National Gas.

4.2 Increasing gas availability, reliability and deliverability

Even if clean heat technology helps transition GB from the base case to a faster decarbonisation pathway, there remains a risk of negative gas supply margins in 2030/31. This means a range of other options – including how gas supply infrastructure could further contribute to security of supply – should be considered.

Maximising existing supply infrastructure

Onshore storage

Further expansion of onshore storage capacity beyond that assumed in this Assessment could increase total storage deliverability and improve gas supply margins. In September 2025, Kistos plc announced that the Hole House gas storage facility would return to commercial operation for the first time since 2018[42]. This announcement, made after the analysis for this Assessment was completed, highlights that the gas supply market continues to evolve and that industry commercial decisions continue to influence the security of supply landscape.

Interconnectors (INT and BBL)

This Assessment assumed lower available import capacity to GB in line with the expected capacity reductions on both INT and BBL for winter 2025/26.[43] Working with the infrastructure owners – Fluxys and BBL Company – to understand what conditions would be required to reinstate and maintain maximum technical import capacity could deliver additional supply security without the need for new infrastructure.

Strategic collaboration on GB gas exports

GB has the capacity to export gas to neighbouring markets through three interconnector systems. There is agreement on the strategic importance of BBL, INT[44] and Moffat[45] for energy security. As Ireland (the Republic of Ireland and Northern Ireland), the Netherlands and Belgium assess their own future gas supply security, there may be scope to review how these interconnectors can best be used to support gas supply security for all consumers.

Storage refill targets

Mandated storage targets for existing capacity could be considered to ensure sufficient storage deliverability ahead of the expected period of least resilience. This mechanism was introduced for long-range European storage in 2022. However, its effectiveness for medium-range GB storage is more uncertain. Operators have historically taken preparatory action to maximise deliverability ahead of periods of elevated demand, indicating that storage targets have not previously been necessary. However, it is uncertain as to what extent this can be relied upon in future.

Additional LNG regasification capacity

Peak day deliverability from LNG terminals is limited by each site's regasification capacity – that is, the rate at which LNG can be taken from storage and injected onto the NTS. Two of GB's three LNG terminals are expected to have expanded regasification capacity before 2030. Additional expansion could further increase peak day deliverability. However, investment in associated gas transmission infrastructure may be necessary to ensure that the additional regasification capacity can be fully utilised during peak demand periods.

LNG delivery contracts

Our analysis assumes that the total de-rated capacity of each LNG terminal can be fully utilised during peak periods, as global LNG supply is expected to be greater into the mid-2030s than it has been in recent years. This means that agreeing LNG delivery contracts would not affect total availability, so would have negligible impact on margins. Because short-term gas prices would rise during a cold snap, delivery contracts could add certainty to future pricing. However, this lies outside the scope of this Assessment.

42 *Interim Results for the Six Months to 30 June 2025 & FID of Hole House Storage*, Kistos Holdings plc.

43 *Gas Winter Outlook 2025*, National Gas.

44 British and Belgian national gas transmission networks explore new cross-border links to progress a clean energy future, National Gas

45 Memorandum of Understanding between the Government of Ireland and the Government of the United Kingdom of Great Britain and Northern Ireland on Cooperation for Natural Gas Security of Supply, GOV.UK

Increasing UKCS production

There is a level of uncertainty over how much additional extraction of domestic fossil fuels could feasibly deliver – both in terms of the total additional volume and the timeframe in which they could be realised. Additional UKCS production could potentially be achieved through larger or more efficient output from existing fields. However, exploration of new fields is unlikely to deliver material new capacity within the required period. Notably, the government's *Building the North Sea's Energy Future* consultation[46], published in April 2025, explained that fewer than 10% of recently issued new licences have delivered new molecules.

For hydraulic fracturing (fracking), both the potential additional volumes and the delivery timescales are uncertain. Given concerns over seismicity and local opposition, a moratorium remains in place prohibiting the issuing of licences.

Biomethane

The biomethane sector could provide additional security of gas supply. Our Ten Year Forecast projects daily biomethane production could reach around 4 mcm/d by 2030/31. This could rise to 8 mcm/d under net zero pathways, while third-party analysis commissioned by NESO indicates that up to 12 mcm/d could be achievable, based on expectations of available feedstock. The Gas Advisory Council (GAC) is considering future support mechanisms and market frameworks that could introduce more biomethane into the gas supply mix. Both NESO, and NGT as the gas system operator, are supporting this ongoing work.

Development of new supply infrastructure

Additional LNG import capacity

Developing a new LNG facility in GB would take advantage of the significant expansion in global liquefaction capacity expected in the coming years and could utilise existing network infrastructure around UKCS terminals that might otherwise become obsolete. A Floating Storage Regassification Unit (FSRU) would likely become operational sooner than a permanent onshore LNG terminal and could be more easily decommissioned should the security of supply risk sufficiently diminish. Alternatively, a permanent LNG terminal would likely have a larger impact on aggregated gas deliverability onto the NTS.

Offshore storage

There is potential for offshore storage capacity to be developed in both the North Sea and the Irish Sea. Possible projects could involve redeveloping end-of-life storage infrastructure that has previously provided gas storage capacity, or developing new infrastructure to use depleted gas fields for storage.

Onshore storage

In addition to expanding existing onshore gas storage infrastructure, there are numerous geological resources – predominantly salt caverns – that could be developed into new onshore storage sites. This would need to be balanced against possible delivery timelines, which could extend to 8–10 years based on industry feedback.

Ensuring The National Transmission Network can meet supply security requirements

Constraints exist on the NTS where the transmission network cannot always facilitate full supply infrastructure deliverability. These constraints are not always fixed, as demonstrated by the reduced interconnector availability relieving other constraints in southeast England. Alleviating such constraints can have implications for security of supply, and appropriate network investment could facilitate additional gas supply without the need for new supply infrastructure. NESO's GNCNR and GOA assess the capability of the gas transmission network and identify where alleviating constraints could increase NTS capability under varying levels of national demand.

46 *Building the North Sea's Energy Future: Consultation* (April 2025), DESNZ.

South Wales

In response to the GNCNR, NGT has proposed a series of options to increase the capability of the NTS. NESO's GOA, which will be published in December 2025, assesses the commercial value of NGT's proposals under normal market conditions, rather than specifically considering the value of gas supply security during peak demand periods. Nonetheless, the options that will be considered in the GOA could improve gas supply security, particularly where they would alleviate key network constraints. This includes options that would bolster NTS entry capacity at the two LNG terminals at Milford Haven.

Improvements being considered include uprating gas pipelines to higher pressures, improving and debottlenecking gas junctions, modifying the technical characteristics of compressor stations, and constructing new gas pipelines. Network investment could enable both LNG terminals to simultaneously utilise their full regasification capacity, thereby increasing peak day deliverability. Appropriate network investment could also provide sufficient NTS entry capacity for either LNG terminal at Milford Haven to increase its regasification capacity.

Southeast England

Another section of the gas transmission network with security of supply implications is the NTS entry point at the Isle of Grain LNG terminal. Milford Haven deliverability is predominantly dictated by the volume of LNG in storage, technical regasification capacity and national demand. However, deliverability at Grain depends on several additional factors, including constraints related to the volume of gas entering the NTS at the Bacton terminal. Bacton receives gas from UKCS fields and mainland Europe via the interconnectors.

The reduction in EU-to-GB import capacity means that, during high-demand periods, Grain can now utilise its full regasification capacity. However, reinstating the technical import capacity of the interconnectors could reintroduce a constraint at Grain. As such, the impact of any supply-side mitigations on gas transmission infrastructure capability will be a key focus of ongoing work.

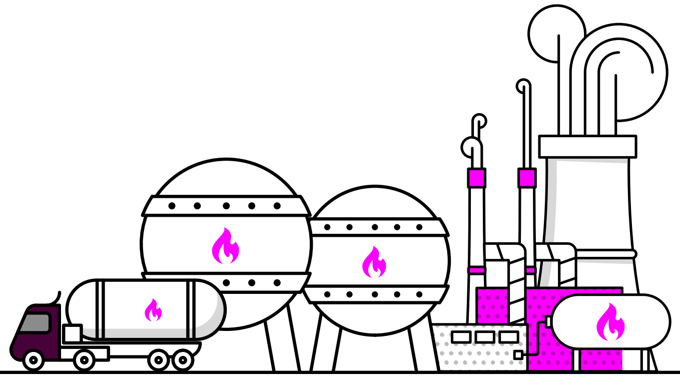
05

Next Steps

Following the completion of our first *Gas Supply Security Assessment*, we will continue to work with key strategic stakeholders – including government, Ofgem, NGT and the wider industry – to ensure reliable energy supplies for consumers. Alongside this Assessment, government has published a consultation that will seek views on the need for government action and potential intervention[47]. While this Assessment identifies that options are available to mitigate the identified risks, the need for action or intervention is a matter for government. Any future action will also need to consider how to maximise consumer value and minimise market disruption. We will continue to work in partnership with government, providing technical expertise and impartial advice to support its consultation process.

This Assessment has evaluated gas supply security at the five- and ten-year horizons, covering winters 2030/31 and 2035/36 in line with our licence requirements. In addition to this Assessment, NGT publishes its *Winter Outlook* report each autumn, providing a short-term view of gas supply security for the winter ahead. We consider there to be value in extending security of supply assessments to cover the intermediate period of two to five years, supported by greater clarification and transparency of roles and responsibilities. We will work with government, Ofgem and NGT on this.

As this is our first Assessment, we are committed to the continuous improvement of our modelling assumptions and approach. We have engaged with a wide range of stakeholders in developing this report and warmly welcome feedback on how we can further improve our modelling over the coming months. Please contact us at box.gassupplysecurity@neso.energy.



47 *The Gas System in Transition: Security of Supply*, November 2025, GOV.UK.

Glossary

Availability
Part of the de-rating calculation that considers whether the physical quantities of gas that GB will need are available from supply sources.

Baseload supply
Gas supply that is consistently available and not subject to short-term fluctuations.

bcm
Billion standard cubic metres under GB reference conditions (temperature: 15°C, Pressure: 1 atmosphere, or 1.01325 bar).

Boil-off
The continuous evaporation of LNG during storage, which maintains the -162°C temperature by preventing pressure from increasing. These volumes are either delivered into the NTS, sent directly to LDZs, or reliquefied and returned to the storage tanks as LNG.

Calorific Value (CV)
The measure of energy released when it is combusted. The CV used for converting energy (KWh) to volume (mcm) is 40 for interconnectors and 39.6 for other sources.

Cavern pressure
The internal pressure within underground gas storage caverns, which must be managed to ensure structural integrity and deliverability.

Cold snap
A sustained period of very low temperatures and minimal wind that drives up gas demand. Cold snaps are used in scenario testing to assess system resilience.

Compressor stations
Facilities equipped with gas turbine or electric drive units that increase the pressure and flow rate of natural gas to transport it through the NTS. They are strategically located along NTS pipelines to maintain pressures and ensure gas can be delivered over long distances.

Cushion gas
The volume of gas permanently retained in a storage facility to maintain adequate pressure, cavern integrity and ensure the deliverability of working gas.

De-rated supply
An adjusted estimate of supply capability that accounts for real-world constraints. Used to assess realistic physical supply during stress events.

Decommissioning
The process of safely retiring gas infrastructure that is no longer in use.

Deliverability
Part of the de-rating calculation that considers the capacity of infrastructure (for example, pipelines or terminals) to transport gas onto the NTS.

Flexible supply
Supply sources that can quickly adjust output in response to changes in demand. LNG and gas storage are key examples of flexible sources.

Future Energy Scenarios (FES)
NESO's view of a range of potential future pathways for the whole energy system, exploring routes to net zero by 2050 for both energy demand and supply. For the latest release, visit Future Energy Scenarios (FES) on our website.

Gas Network Capability Needs Report (GNCNR)
NESO's view of NTS's capability to meet current and future network requirements. For the latest release, visit *Gas Network Capability Needs Report (GNCNR)* on our website.

Gas Options Advice (GOA)
NESO's evaluation of investment proposals from NGT that aim to meet the gas network's capability requirements in GB. For the latest release, visit *Gas Options Advice (GOA)* on our website.

Gas shippers
Market participants who contract for gas transportation and delivery. They play a key role in commercial supply arrangements.

Gas system operator
The entity responsible for coordinating gas flows within the NTS, balancing daily supply and demand, and ensuring system integrity. NGT holds this role.

Gas Ten Year Statement (GTYS)
NGT's view of how it intends to operate and plan for the gas NTS over the next ten years. For the latest release, visit *Gas Ten Year Statement (GTYS)* on NGT's website.

Intact network
A scenario where all gas supply infrastructure – including onshore assets (NTS, terminals and sub-terminals) and upstream infrastructure – is operational, with no supply outages or failures limiting gas flows.

Interconnector
Transmission infrastructure linking GB to European gas markets to enable cross-border gas trade. Key import interconnectors include those to Belgium (Interconnector) and the Netherlands (BBL).

Local Distribution Zones (LDZs)
Regional zones across GB where gas is distributed locally by gas distribution network operators. LDZs serve residential, commercial and smaller industrial consumers.

Liquefied Natural Gas (LNG)
Natural gas cooled to -162°C for transport and storage in liquid form. LNG is transported on purpose-built vessels and delivered to GB at one of three terminals. LNG provides flexible and globally sourced supply options.

Margin
The difference between realistically available supply and expected demand. A positive margin indicates surplus supply; a negative margin signals a potential shortfall.

Market competition
The extent to which multiple shippers may wish to purchase the same gas molecule.

Mature basin
A gas-producing region where output is declining due to natural resource depletion. UKCS is considered a mature basin.

mcm
Million standard cubic metres under GB reference conditions (temperature: 15°C, pressure: 1 atmosphere, or 1.01325 bar).

Mitigations
Actions or strategies to reduce risks to gas supply security.

Molecules
A colloquial term referring to the physical units of natural gas.

N-1 standard
A key gas system resilience standard that assesses whether the gas supply system can meet demand if the largest single piece of supply infrastructure fails.

National Transmission System (NTS)
The high-pressure pipeline network that transports gas across GB. It is maintained and operated by NGT.

Net exporter
A country or region that exports more gas than it imports.

Net importer
A country or region that imports more gas than it exports.

Norwegian Continental Shelf (NCS)
Norway's offshore gas production zone. Supplies from the NCS are one of GB's main import sources, delivered via pipelines such as Langeled and SEGAL.

Reliability
Part of the de-rating calculation that considers whether the gas volumes identified through availability analysis can be purchased by, and delivered to, GB market participants.

Seasonal normal conditions
Expected weather and demand patterns based on long-term historical averages.

Security of supply
The ability of the gas system to meet demand reliably under all conditions.

System stress
Periods when the gas system is under pressure due to high demand, supply disruption or infrastructure constraints.

Technical maximum capability
The theoretical maximum volume of gas that infrastructure can deliver under ideal conditions.

Terminals
Facilities where gas is received, processed and delivered onto the transmission system. Includes both LNG and pipeline entry points.

UK Continental Shelf (UKCS)
The offshore area surrounding the UK where natural gas is extracted. It represents a domestic source of supply.

Uniform Network Code (UNC)
The regulatory framework that governs gas transportation and balancing in GB. It ensures fair access and consistent operational standards.

Wobbe Index
A measure of gas quality and interchangeability of fuel gases. It is calculated as the calorific value divided by the square root of the specific gravity. The Wobbe Index is used to ensure consistent combustion characteristics across different gas sources and is important for appliance safety and performance, as set out in the *Gas Safety (Management) Regulations* (GS(M)R).

Winter Outlook (NESO)
NESO's *Winter Outlook* report presents our view of security of supply for the electricity system for the winter ahead. For the latest release, visit *Winter Outlook* on our website.

Winter Outlook (NGT)
NGT's *Gas Winter Outlook* report examines the forecast supply and demand for the gas system in GB. For the latest release, visit *Gas Winter Outlook* on NGT's website.

1-in-20-year peak demand
A statistical benchmark representing the level of demand expected to occur on one day in every 20 years. Used in gas system planning and security of supply assessments.

Get in Touch

Email us with your views on the *Gas Supply Security Assessment* at box.gassupplysecurity@neso.energy, and we will get back to you.

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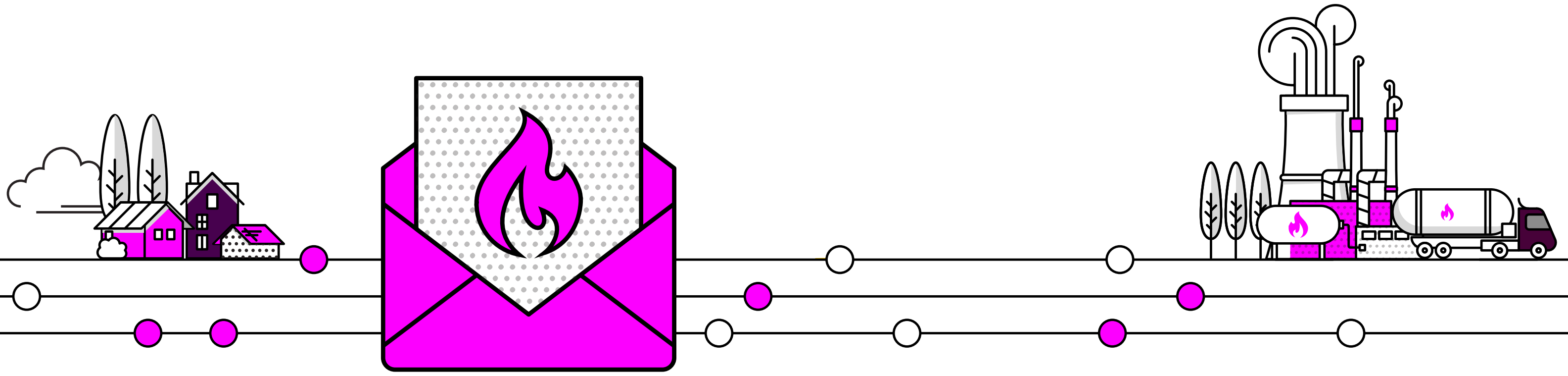
The *Gas Supply Security Assessment* is part of a suite of documents prepared by NESO. Visit neso.energy for more information.



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