Gas Market Roadmap

July 2026

NESO
National Energy
System Operator

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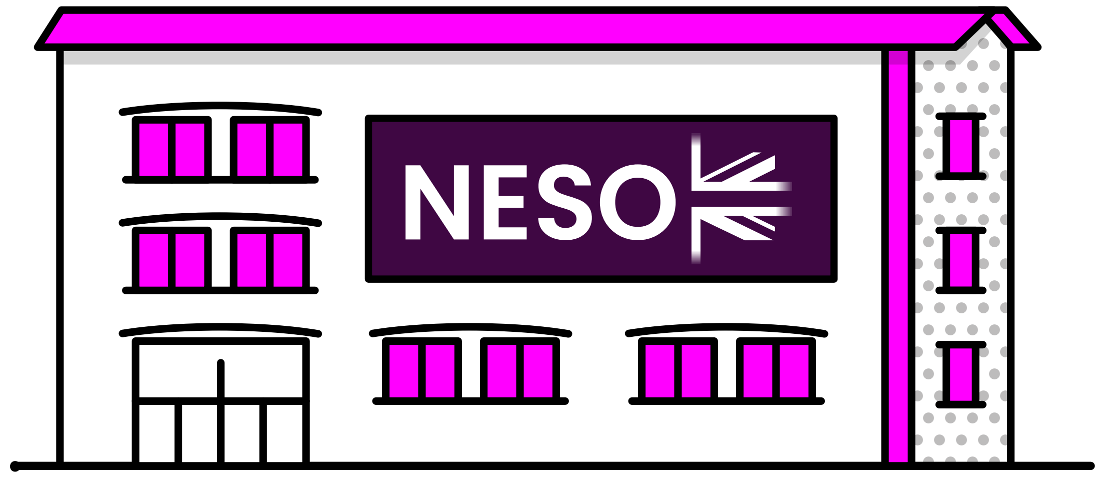
Welcome

Welcome to NESO's first Gas Market Roadmap, which sets out our view of how gas market arrangements may need to evolve in Great Britain.

Gas continues to play a critical role in Great Britain's energy system especially as the system transitions to a cleaner, more secure and affordable energy future.

The Gas Market Roadmap (GMR) marks an important milestone in NESO's role as Gas System Planner. We coordinate long term market strategy by identifying where change is needed and aligning this with our wider responsibilities particularly in strategic energy planning. Future gas market strategy will need to consider whole system interactions as the energy mix becomes more complex.



Alongside the GMR, we are publishing additional insights on the role of biomethane and the potential for a hydrogen backbone for Great Britain. Together, these publications build a clearer picture of how Great Britain's energy system may evolve.

The GMR is intended to open and support an ongoing conversation with government, regulators, and industry on how gas market arrangements may need to evolve. It intends to inform, not determine policy decisions and future detailed reforms.

I would like to thank the Gas Advisory Council,[1] the Department for Energy Security and Net Zero (DESNZ), Ofgem, National Gas, distribution networks, industry participants and consumer representatives for their input and challenge during the development of this first publication. Continued engagement will be essential as NESO works with stakeholders to support a gas market that remains affordable, clean and reliable.

Rebecca Beresford
Director of Markets

1 The Gas Advisory Council (GAC) is NESO's cross gas sector advisory body for gas market strategy and development.

Executive Summary

Gas will remain important to Great Britain's energy system for many years to come. It plays a critical role in meeting peak energy demand, supporting heating and industrial activity, enabling electricity system flexibility and maintaining wider energy security. While gas market arrangements support today's operations, these will need to adapt as the energy system transitions.

This first Gas Market Roadmap sets out NESO's view of the challenges facing the gas market and further work that could help to ensure that market frameworks continue to support an affordable, reliable and clean energy system. Our analysis is informed by our Future Energy Scenarios (FES) pathways[2], exploring what needs to happen within the gas market to drive toward a decarbonised energy system.

The GMR has identified three Central Challenges:

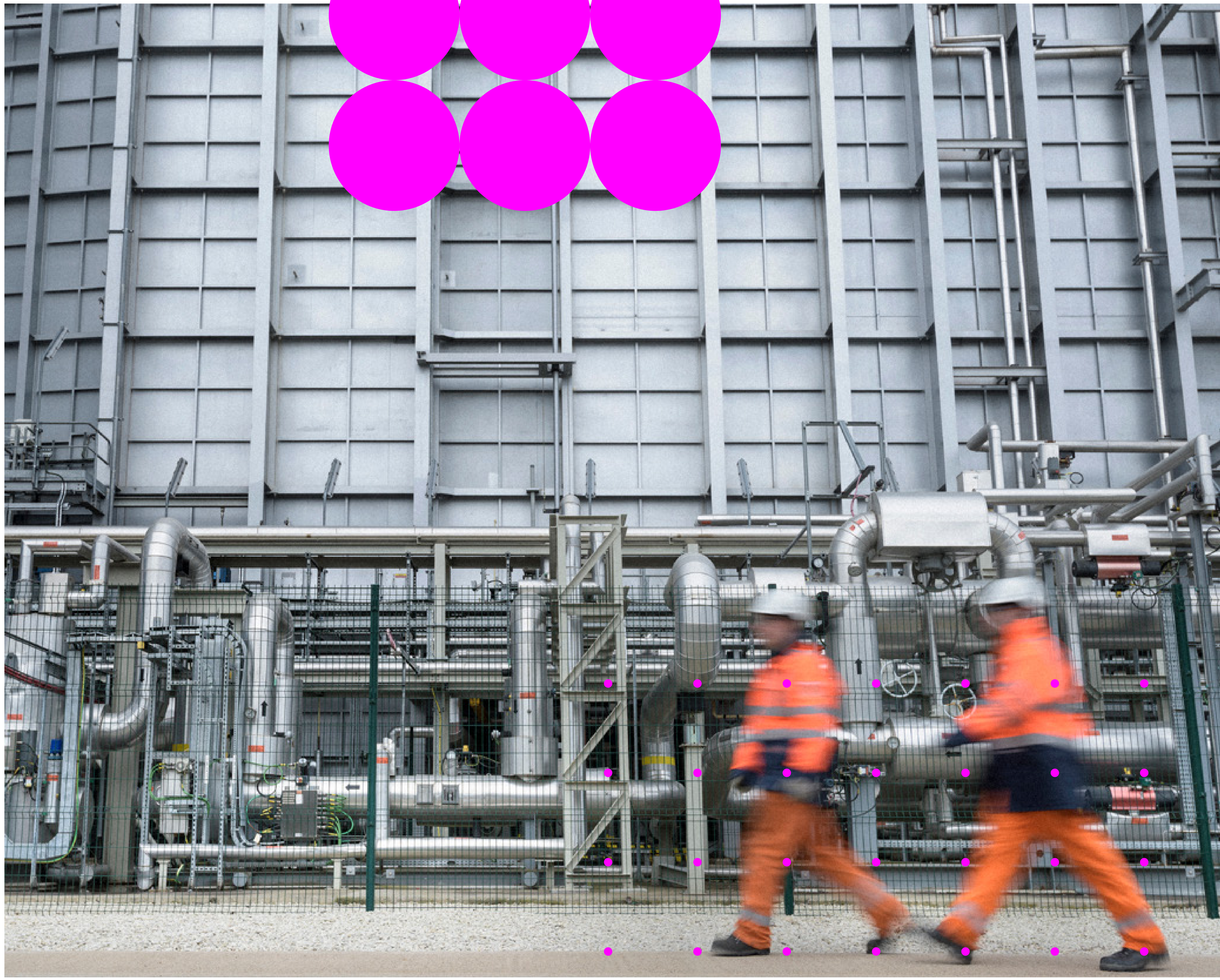
- Gas Market Transition, which focuses on how charging, cost recovery and regulation evolve as gas demand declines and the consumer base is anticipated to change.
- Market Resilience, which focuses on market arrangements to support security of supply and meeting peak energy demand as the supply and demand of gas changes in the future.
- Emerging Markets, which focuses on the development of biomethane, hydrogen and CCUS markets as well as the impacts on the gas market.

Taken together, these challenges show that the future evolution of gas markets will require coordinated action across a connected set of economic, regulatory and structural issues, as set out within the GMR. These issues form the basis for NESO's areas for further work.

The GMR will be updated on a regular cycle, with future publications produced every two years. These cycles will build progressively on this first publication, deepening the evidence base, tracking developments in policy and regulation, and refining areas for further work as the energy system evolves. Future GMR cycles will move from identifying challenges to testing options and supporting more informed, coordinated decision making.

2 Future Energy Scenarios (FES) provides an independent view of a range of future pathways for the whole energy system to reach Net Zero.

1. Introduction



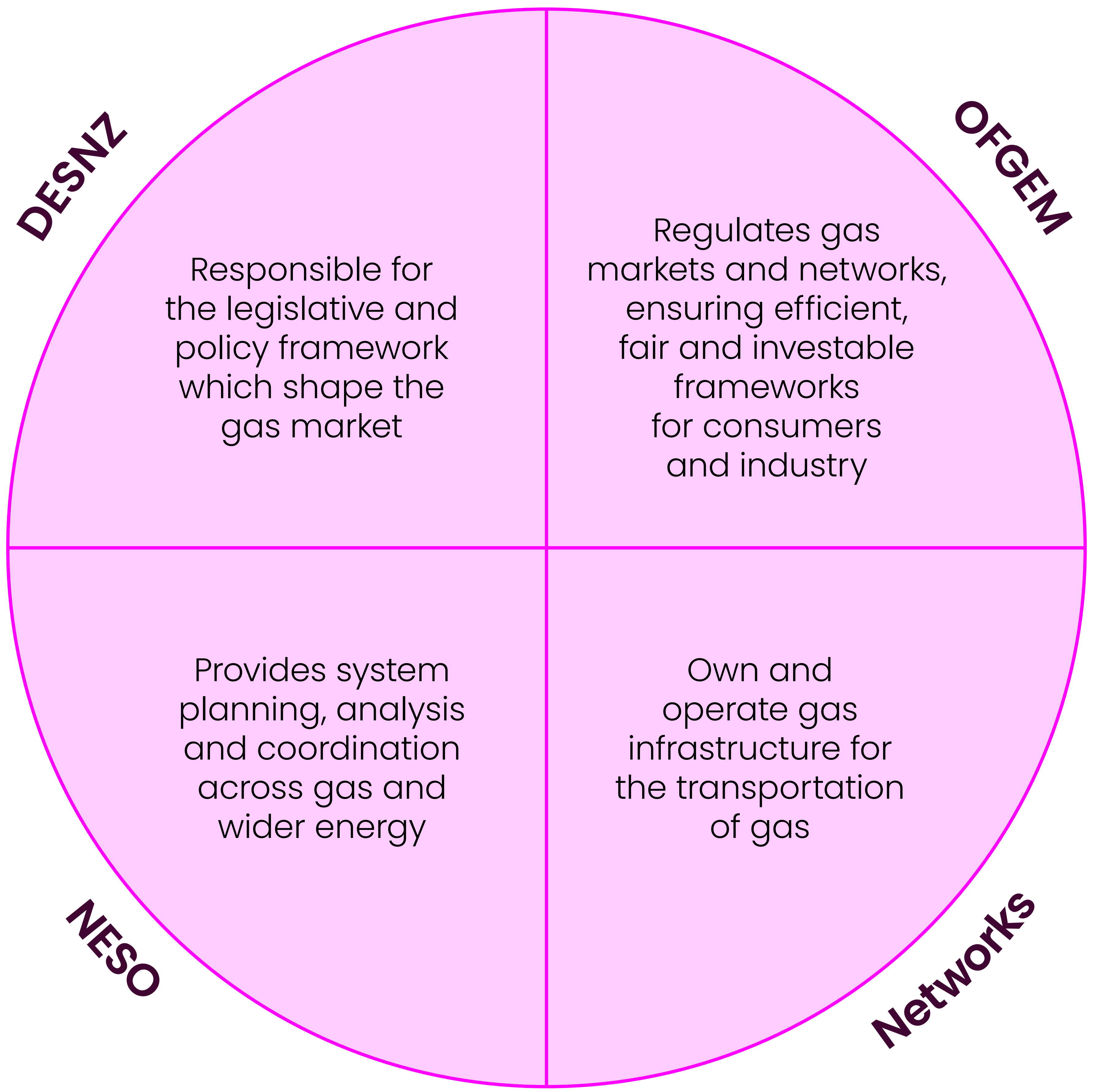
Introduction

NESO is supporting progress towards the government's objectives for a Clean Power system by 2030 and net zero by 2050. As the wider energy system changes, gas market arrangements will also need to adapt to support an orderly, secure and efficient transition.

The Gas Market Roadmap's (GMR) objective is to set out NESO's strategic view of how gas market arrangements in Great Britain may need to evolve through the energy transition, and areas for further work to progress. It supports a more coordinated understanding of future gas market challenges across government, regulators, networks and market participants out to 2050.

It is not intended to prescribe government policy, determine legislative change or set detailed delivery plans. Instead, it identifies areas for further work that could support decision making and the transition of gas market arrangements to 2050. The GMR is produced under NESO's Gas System Planner Licence (as the obligation to develop a Future Market Plan). This requires NESO to develop this document at least once every two regulatory years, in cooperation with relevant gas market participants.

Figure 1: Gas market strategy roles and responsibilities



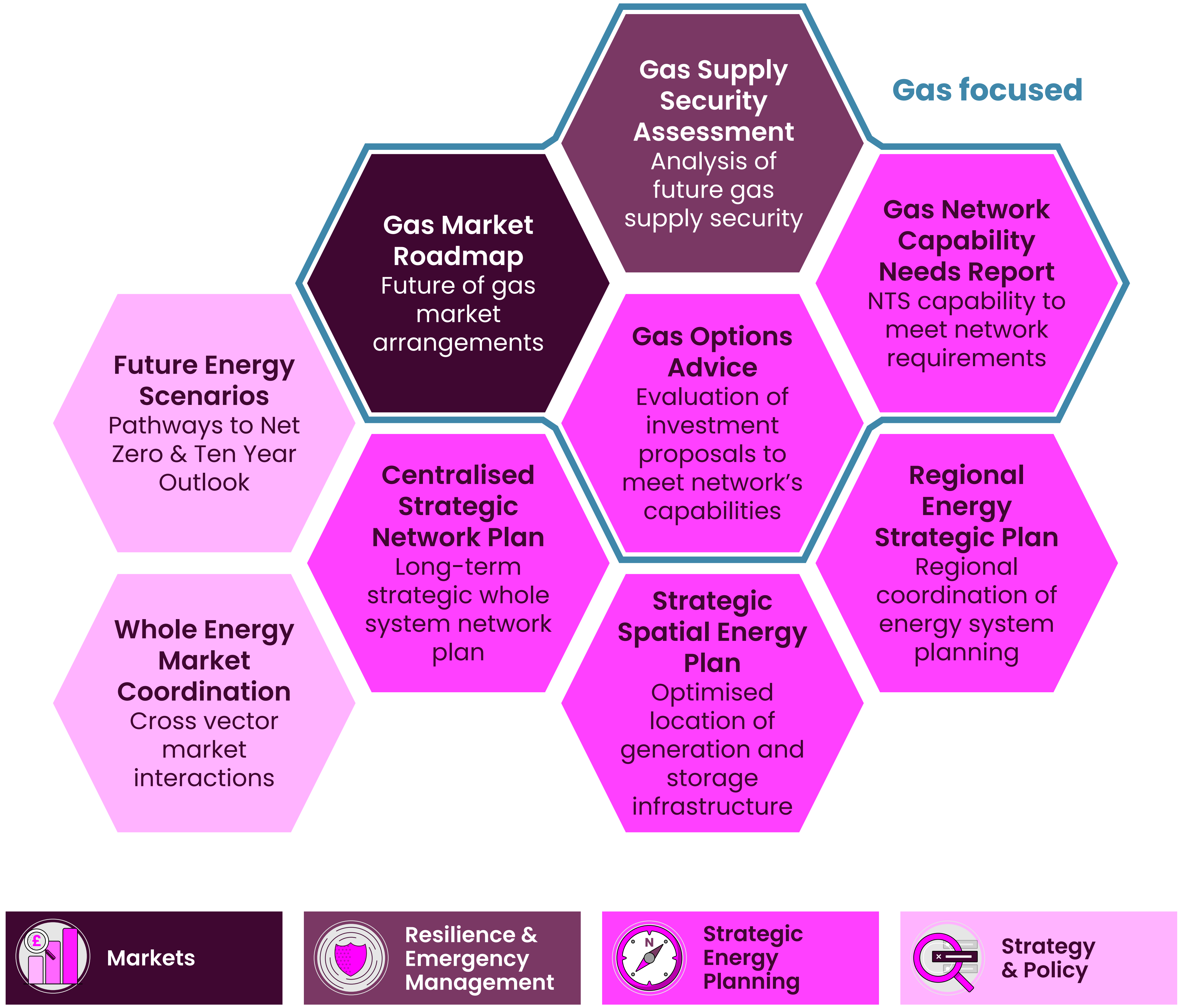
NESO's wider role in gas

NESO's gas market strategy builds on our wider programme of analysis and publications across gas and whole energy system activity, ensuring market considerations are aligned with future system needs.

As Gas System Planner, NESO brings together evidence across gas supply security, resilience, strategic network planning, future energy pathways and whole system market development.

This first GMR, and its proposed areas for further work, have been developed in this wider context as NESO continues to build its role in strategic whole energy planning.

Figure 2: Gas and whole energy system analysis and publications



GMR 2026 development process

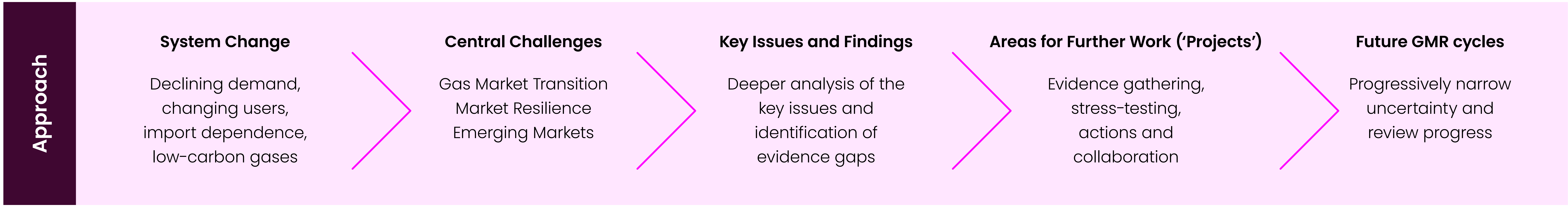
This first GMR forms part of an ongoing cycle to assess how gas market arrangements may need to evolve as the energy system transitions. It establishes a framework for identifying the main challenges, building evidence and supporting coordination across the gas market.

Our analysis has drawn on NESO's whole system work, including the Future Energy Scenarios and the Ten Year Outlook, alongside structured engagement with stakeholders, including through the Gas Advisory Council (GAC).

The development process brings together analysis, stakeholder insight and market design considerations to identify the most significant challenges facing the gas market. These are structured into three Central Challenges, which form the core of this GMR and are explored in detail in the following sections.

Future GMR cycles will build on this approach, deepening the evidence base and refining areas for further work as the system evolves.

Figure 3: Overview of the GMR 2026 development approach



Central Challenges

To frame our work and assess the scale of change required in the gas market out to 2050, we have developed our view of three Central Challenges and identified related areas for further work.

These challenges are interlinked and overlap across some important issues and areas for further work.

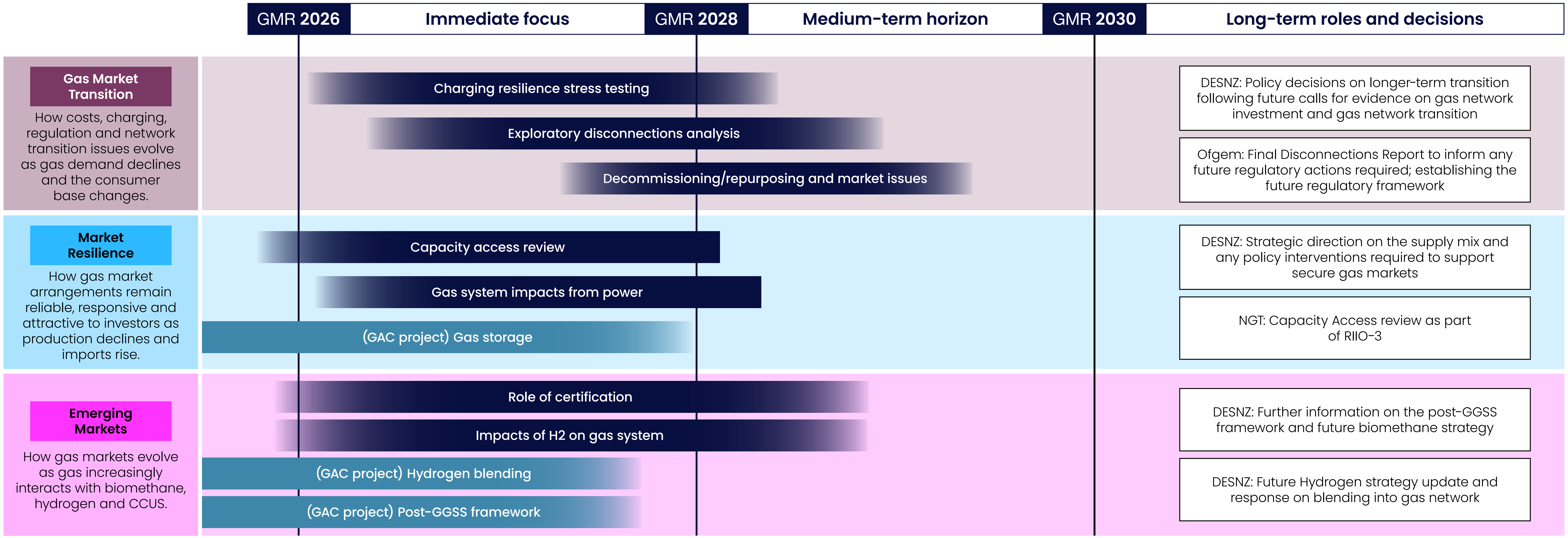
Figure 4: Central Challenges for the Gas Market Roadmap 2026

	Gas Market Transition	Market Resilience	Emerging Markets
Central Challenge	• Investment, asset recovery and regulation • Charging and cost recovery • Network transition, disconnections and decommissioning	• Supply resilience • Operational market design • Gas and power interactions	• Certificates and the UK Emissions Trading Scheme • Biomethane • Hydrogen markets • Carbon capture, utilisation and storage
Key findings	• Significant network investment will need to be recovered from an anticipated declining customer base, while regulatory frameworks may also need to evolve alongside changing system use • Declining gas throughput will affect existing charging mechanisms and wider cost recovery models • Gas disconnections and potential asset repurposing or decommissioning will have implications for costs, liabilities, sequencing and long-term market strategy.	• Declining domestic production and greater reliance on imported gas is reshaping the supply mix which may require policy intervention to maintain market attractiveness and liquidity • Existing operational market design arrangements (e.g. capacity access) were designed for a stable, high throughput system and may need to evolve as conditions change • Shifting demand patterns and stronger interdependencies with the power sector will require changes to gas market arrangements.	• Carbon pricing and certification will increasingly shape market signals • Biomethane growth depends on clear policy direction, continued production support and resolving gas network constraints • Hydrogen market development will require maturing support frameworks, infrastructure decisions and system coordination across production, transport, storage and demand.
Areas for further work this cycle	• Charging resilience stress testing • Exploratory disconnections analysis • Decommissioning/repurposing & market issues	• Capacity access review • Gas system impacts from power	• Role of certification • Impacts of H2 on gas system

Next stages of the GMR

Having identified the Central Challenges, this GMR sets out an initial view of areas for further work that will help build the evidence base, support coordination and inform future decisions on gas market arrangements. These areas are indicative and will be refined through engagement with DESNZ, Ofgem, the GAC, and other relevant gas market stakeholders. Future GMR cycles will build on this first publication by deepening the evidence base, tracking relevant policy and regulatory developments, and clarifying where further analysis or coordinated action may be required.

Figure 5: Indicative areas for further work across future Gas Market Roadmap cycles



2. Methodology for Identifying the Central Challenges

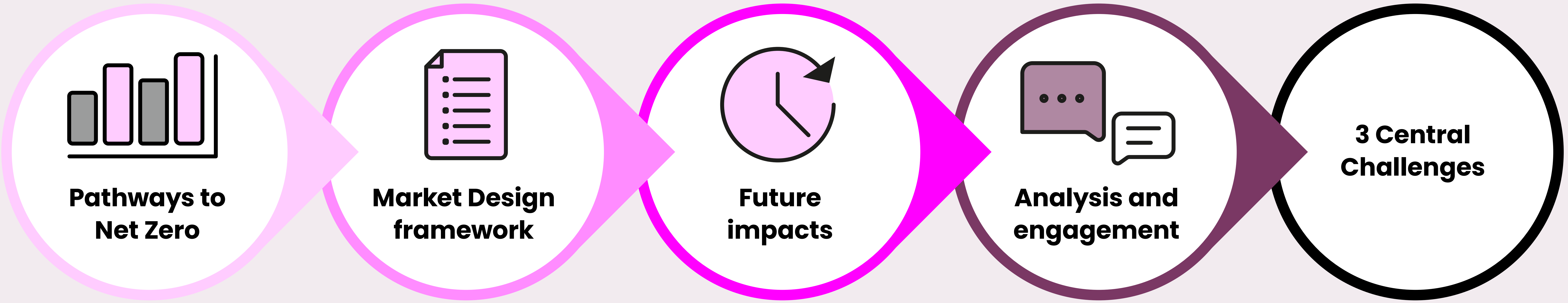
Identifying Central Challenges

Figure 6: Methodology for identifying the Central Challenges for the 2026 Gas Market Roadmap

For this inaugural GMR, we have developed a clear process to understand the Central Challenges for the gas market from now out to 2050.

Pathway assumptions were mapped against NESO's Market Design Framework to assess which parts of gas market design may need to adapt as the system changes.

We tested these findings against wider NESO gas analysis, the broader policy and regulatory landscape, and engagement with stakeholders and the Gas Advisory Council.



FES 2025 pathways were reviewed to understand how gas supply and demand could evolve across sectors to 2050, including natural gas, hydrogen, biomethane and CCUS.

From this, the main areas of change were identified, including where pathways show common trends and where uncertainty or divergence remains.

This process informs the three central challenges that structure the 2026 Gas Market Roadmap.

FES 2025: Pathways to Net Zero

The Gas Market Roadmap (GMR) is informed by NESO's wider whole system analysis and decarbonisation pathways, including the *Future Energy Scenarios 2025: Pathways to Net Zero*.

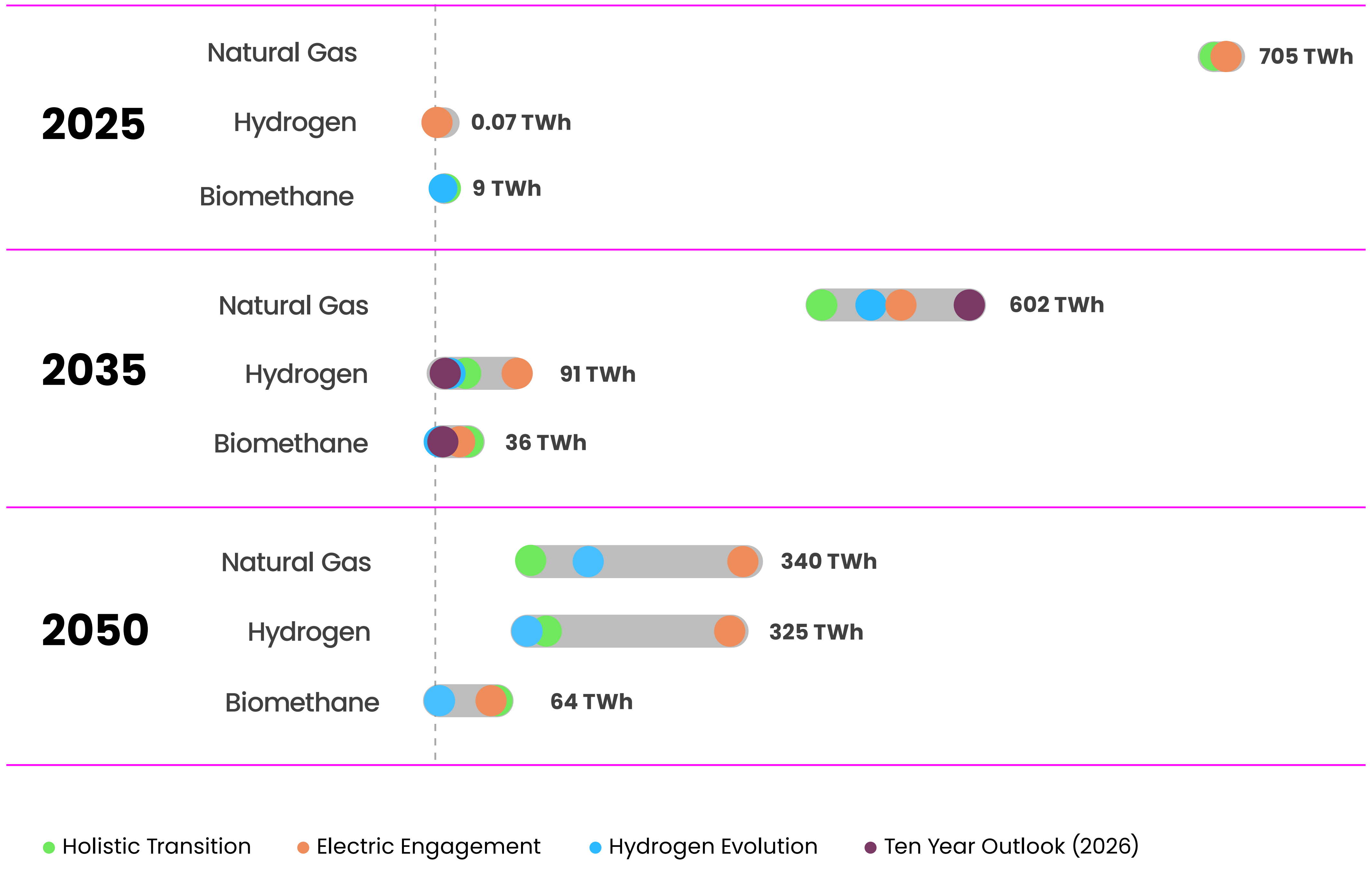
Future Energy Scenarios 2025 (FES 2025) provides long-term pathways that show how supply, demand and the mix of gases could evolve to meet net zero by 2050. This helps us understand the potential effects on existing gas market arrangements and identify future challenges. The scale of change across the energy system varies between the FES pathways, but all pathways indicate that existing gas market arrangements will need to evolve.

2026 Ten Year Outlook: action to decarbonise

NESO will also provide the updated FES Ten Year Outlook following this GMR. The Ten Year Outlook outlines our view of gas supply and demand to 2036 based on the current trajectory of known or expected policy and sector developments. It does not account for planned or proposed government intervention that are not yet defined and is not a pathway to net zero. It shows a decline in gas demand, but at a slower pace than in the FES 2025 pathways, with slower growth in low carbon gases over the next decade.

This outlook reinforces the importance of the GMR in building evidence, improving understanding and driving action across government, regulators and industry.

Figure 7: Key pathway assumptions for gas from the Future Energy Scenarios 2025 and 2026 Ten Year Outlook



(2026 Ten Year Outlook to be made available)

Market Design Framework

To identify where gas market arrangements may be affected up to 2050, we assessed FES 2025 assumptions against the Market Design Framework used in NESO's *Whole Energy Markets Coordination* (WEMC) report. The framework provides a structured way to assess how energy markets are designed and how they may need to evolve.

The Market Design Framework breaks down the concept of an 'energy market' into four categories, as shown in Table 1. This has allowed us to develop a comprehensive understanding of current market arrangements including which elements may need to change under different future pathways, resulting in three Central Challenges.

Table 1: Market Design Framework dimensions, elements and explanations

Market dimensions	Market design elements	Explainer
A. Economic Regulation	Structure of the energy market across vectors, value chains and market participants	The structure of the energy market across vectors, value chains and market participants, considering governance, regulation, industry codes and standards, and the roles and responsibilities in place to support the foundations of the market. E.g. Licensed activities, codes, standards, roles and governance, certification
B. Investment policy	Market interventions employed to achieve specific policy objectives	Market interventions employed to achieve specific policy objectives, such as decarbonisation or development of first-of-a-kind technologies. E.g. Supply decarbonisation support mechanisms (like Contracts for Difference)
C. Operational market design	The structure of wholesale and short-term operational energy markets to match physical supply and demand	The structure of wholesale and short-term operational energy markets to match physical supply and demand, including system operation frameworks, gas quality, capacity and balancing and settlement charging. E.g. Settlement period, energy balancing mechanism design
D. Cost allocation	Cost recovery for networks and investment policy	Cost recovery for networks and investment policy, and the structure of what costs are allocated and how these are recovered. E.g. Investment policy cost allocation, network cost allocation

(source: NESO WEMC Report)

3. Central Challenge: Gas Market Transition

How costs, charging, regulation and network transition issues will evolve as gas demand declines and the consumer base changes

Introduction

Gas market arrangements in Great Britain were developed for a system with relatively consistent natural gas throughput, a large consumer base and predictable patterns of use. Across the Future Energy Scenarios 2025 (FES 2025) pathways and the 2026 Ten Year Outlook, overall gas demand declines, although the pace and scale of this reduction vary (Figure 8).

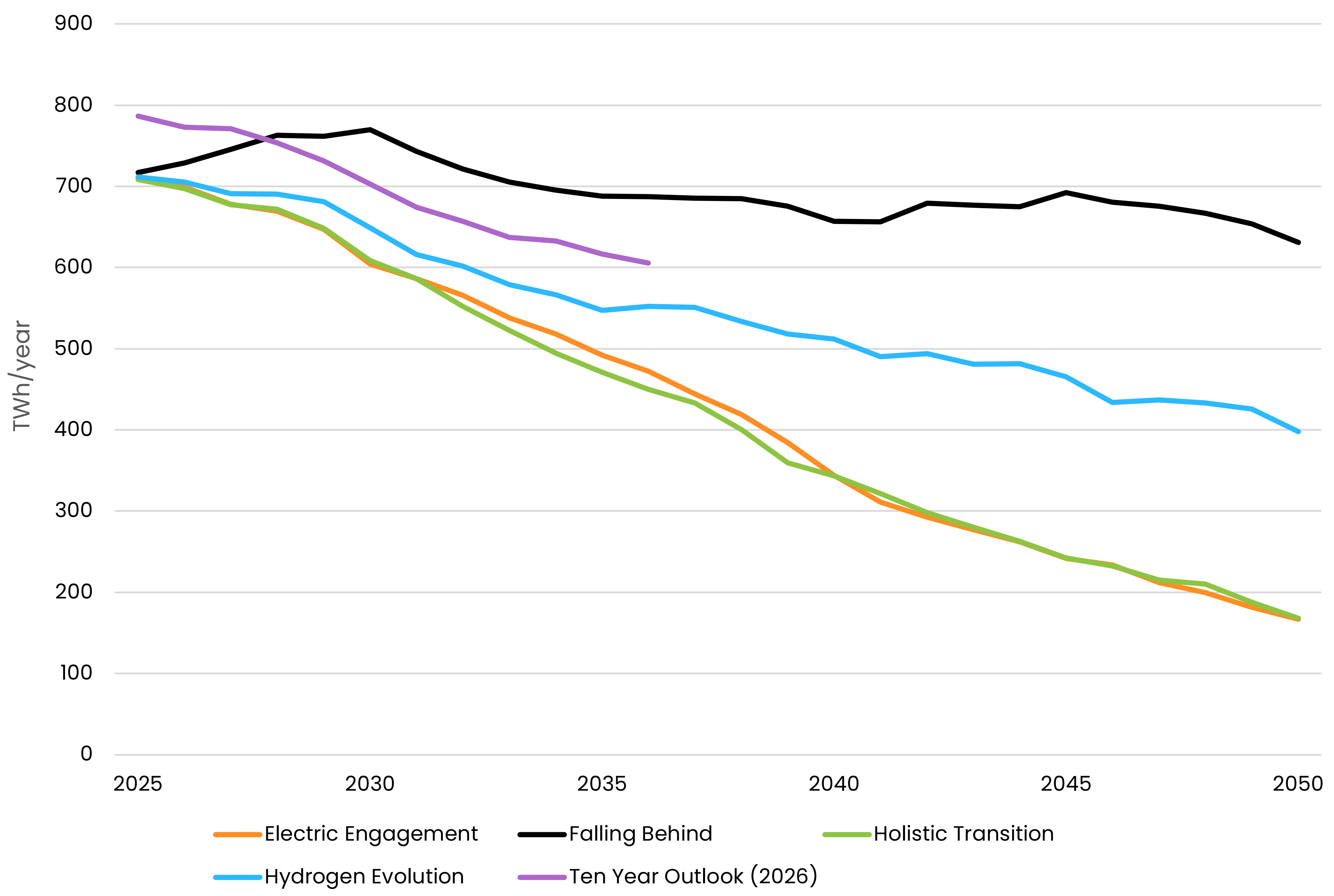
As NESO's Ten Year Outlook reflects current policies and market arrangements, it does not take into account future government interventions that are not yet defined to be incorporated in the analysis. As a result, the 2026 Ten Year Outlook differs compared to the FES pathways, which are developed to meet net zero targets. The difference also highlights uncertainty around heat decarbonisation, industrial demand, consumer choices and the timing of wider system change.

Why this matters

Charging, cost recovery, and regulation will all need to remain fair, efficient and workable as demand declines and the gas user base evolves. These arrangements must also support decarbonisation while recognising uncertainty around the pace of change and future asset use.

This section considers how these issues may develop, where existing arrangements may be impacted and where further evidence and coordination may be needed to support understanding of the future gas market transition as wider policy, regulation and whole system planning progress.

Figure 8: Gas demand per year across FES 2025 pathways, Falling Behind scenario and the 2026 Ten Year Outlook, 2025–2050



(2026 Ten Year Outlook to be made available. Unlike the FES pathways shown, the 2026 Ten Year Outlook includes an estimate of additional gas demand for power generation arising from electricity network constraints. The pathways and 2026 Ten Year Outlook shown include gas exports and shrinkage).

Investment, asset recovery and regulation

Gas network investment and costs will need to be recovered from an anticipated declining customer base.

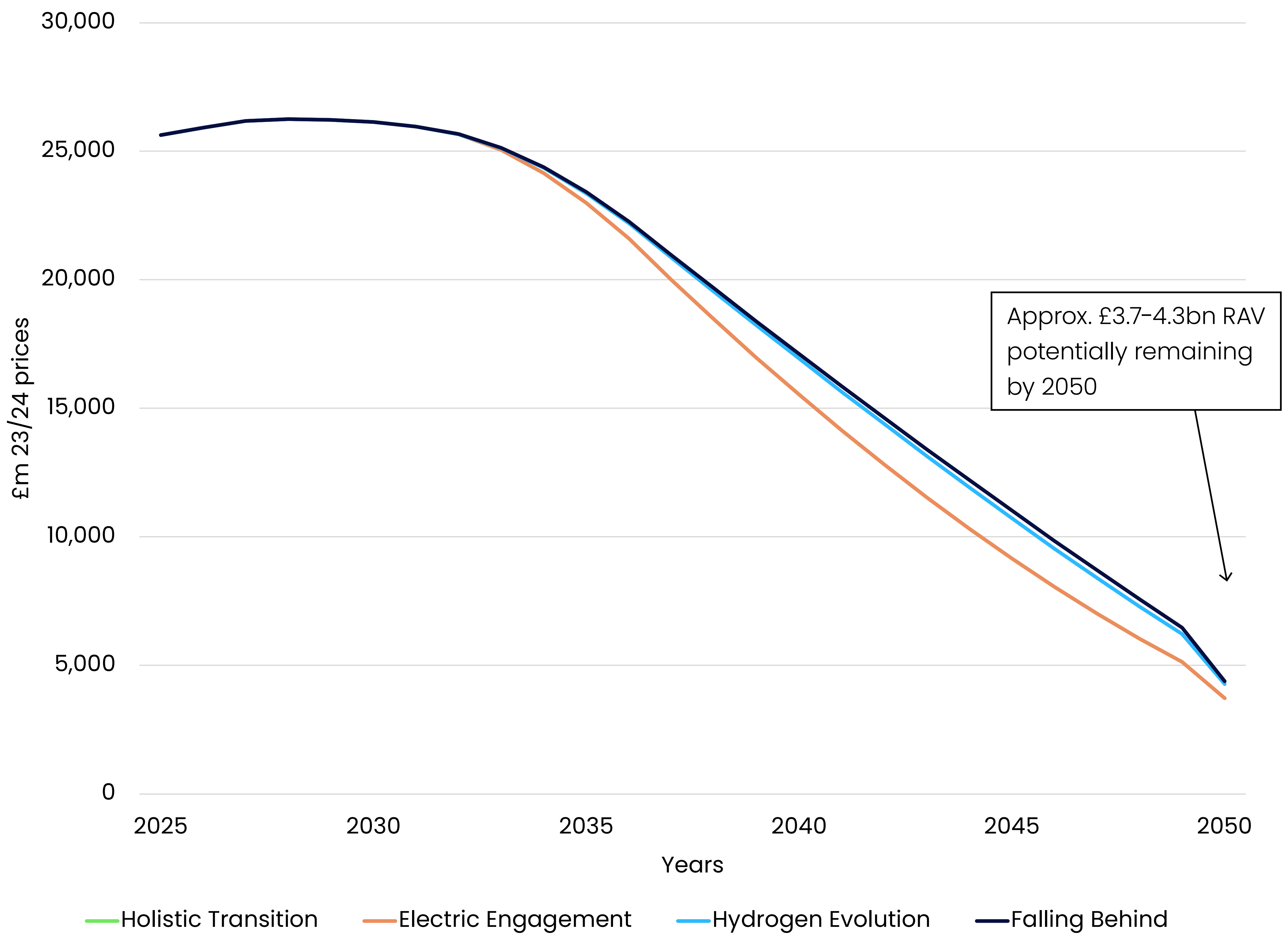
Gas networks are regulated by Ofgem through the RIIO price control framework.[3] Under this model, National Gas Transmission (NGT) and Gas Distribution Networks (GDNs) recover investment and operating costs from network users over time. A significant proportion of these costs is capitalised into the Regulatory Asset Value (RAV) and recovered through network charges paid by consumers.

As the number of gas users falls, the network costs recovered from each remaining user will increase. This could have implications for affordability, investor confidence and the long-term design of gas market arrangements.

Ofgem has already taken steps to accelerate depreciation for new GDN investments from 2026 onwards to ensure they are paid off by 2050 and reduce the risk of recovering new network investment. However, even with accelerated depreciation, some RAV may remain across the gas networks by 2050 (Figure 9).

The government has committed to reviewing current gas network cost recovery arrangements and intends to publish a call for evidence in 2026. This will seek views on how best to recover these future costs, balancing investor confidence with consumer affordability. This will inform whether further work is needed during the next Gas Market Roadmap (GMR) cycle.

Figure 9: **Projected closing gas distribution Regulatory Asset Value (RAV) by 2050, in £ million at 2023/24 prices, across FES 2025 pathways and Falling Behind scenario**



(sources: FES 2025 Pathways and hypothetical cost percentages based on SGN's long-term total expenditure assumptions in its *RIIO-3 Business Plan: Finance Annex* Figure shown also assumes that Ofgem's proposed accelerated depreciation of new investment continues beyond RIIO-3.)

3 RIIO (Revenue = Incentives + Innovation + Outputs) is Ofgem's price control framework for gas and electricity networks. It sets allowances for what network companies can spend and recover, including investment costs, as well as performance incentives and revenue adjustment mechanisms that affect their final allowed revenue.

Regulatory and remuneration frameworks should become more flexible over time to reflect changing patterns of system use and the role of gas networks in the future.

As part of its Future Systems and Network Regulation (FSNR) programme, Ofgem indicated that regulatory frameworks may need to become more adaptable as the role of gas changes through the transition.[4] This is likely to affect both gas distribution and transmission networks, although the nature of the challenge for each may differ.

Ofgem's FSNR work informed its *RIIO-3 Final Determinations*, in which it signalled that RIIO-3 is likely to be the last 'steady-state' price control for gas distribution, focused on maintenance and stability. Over time, costs, outputs and incentives may need to change further to reflect changes in gas demand, network utilisation and the future role of gas distribution networks. Future gas distribution price controls should also continue to support innovation and the efficient use of existing and future assets.

At the gas transmission level, FES 2025 suggests that while overall gas demand declines, peak demand and gas use for power generation may remain significant. This will impact future gas system operator incentives, network investment and the regulatory framework for gas transmission assets.

Gas transmission price controls should continue to align with relevant strategic planning outcomes (including the Centralised Strategic Network Plans). Future regulatory frameworks will depend on decisions by DESNZ and Ofgem and remain highly dependent on the scale and pace of changes in gas demand.

FSNR recognised the uncertainty about the future role of gas and indicated that a more flexible regulatory approach may be needed after RIIO-3. Further work may be considered in future GMR cycles to support changes to the regulatory framework.

4 Ofgem, Consultation on frameworks for future systems and network regulation: enabling an energy system for the future.

Charging and cost recovery

Declining gas throughput will affect existing network charging mechanisms and wider cost-recovery models.

Gas transmission and distribution networks recover their allowed revenues under the RIIO framework through charges on network users. These charges form part of gas consumer bills, alongside wholesale costs, supplier operating costs, VAT and policy costs, including levies such as the Green Gas Levy, which supports biomethane investment.

Charging mechanisms are structured differently across gas transmission and distribution. For gas transmission, cost recovery will increasingly depend on capacity booking behaviour and on how fixed and operational costs are recovered in a future market with potentially more variable usage and future capacity access reform. There are ongoing proposals for near-term charging reforms, including Uniform Network Code (UNC) Modification 0903,[5] but wider questions are likely to remain as demand declines and usage patterns change.

At the distribution level, the balance between charging components may also need to be reviewed if the number of connected users declines over time. A smaller customer base will increase the costs recovered from each remaining user, with potential implications for affordability, network requirements and the incentives for consumers considering low-carbon alternatives. Future proposals for gas distribution charging are also currently being discussed as part of the UNC modification review 0937R.[6]

In this context, there may be value in reviewing the principles that should underpin future gas charging arrangements. This could include how network costs, policy costs and wider levies are applied across the whole energy system and whether current arrangements support efficient, fair and coordinated decarbonisation.

NESO proposes further stress testing of current charging arrangements against future forecasts to help identify potential pressure points and the resilience of the existing framework, ahead of any wider policy decisions or charging review.

5 Uniform Network Code modification 0903, The Introduction of a Single NTS Capacity Reference Price proposes to introduce a single price across capacity charging on the National Transmission System (NTS) for entry and exit capacity and is currently awaiting an Ofgem decision.

6 Uniform Network Code modification 0937R, *Aligning LDZ Charges with Actual Gas Usage for All Customers* which explores the balance between capacity and commodity charges at gas distribution level.

Network transition, disconnections and decommissioning

Gas disconnections are likely to become more significant as demand declines, with implications for consumers, networks and market frameworks.

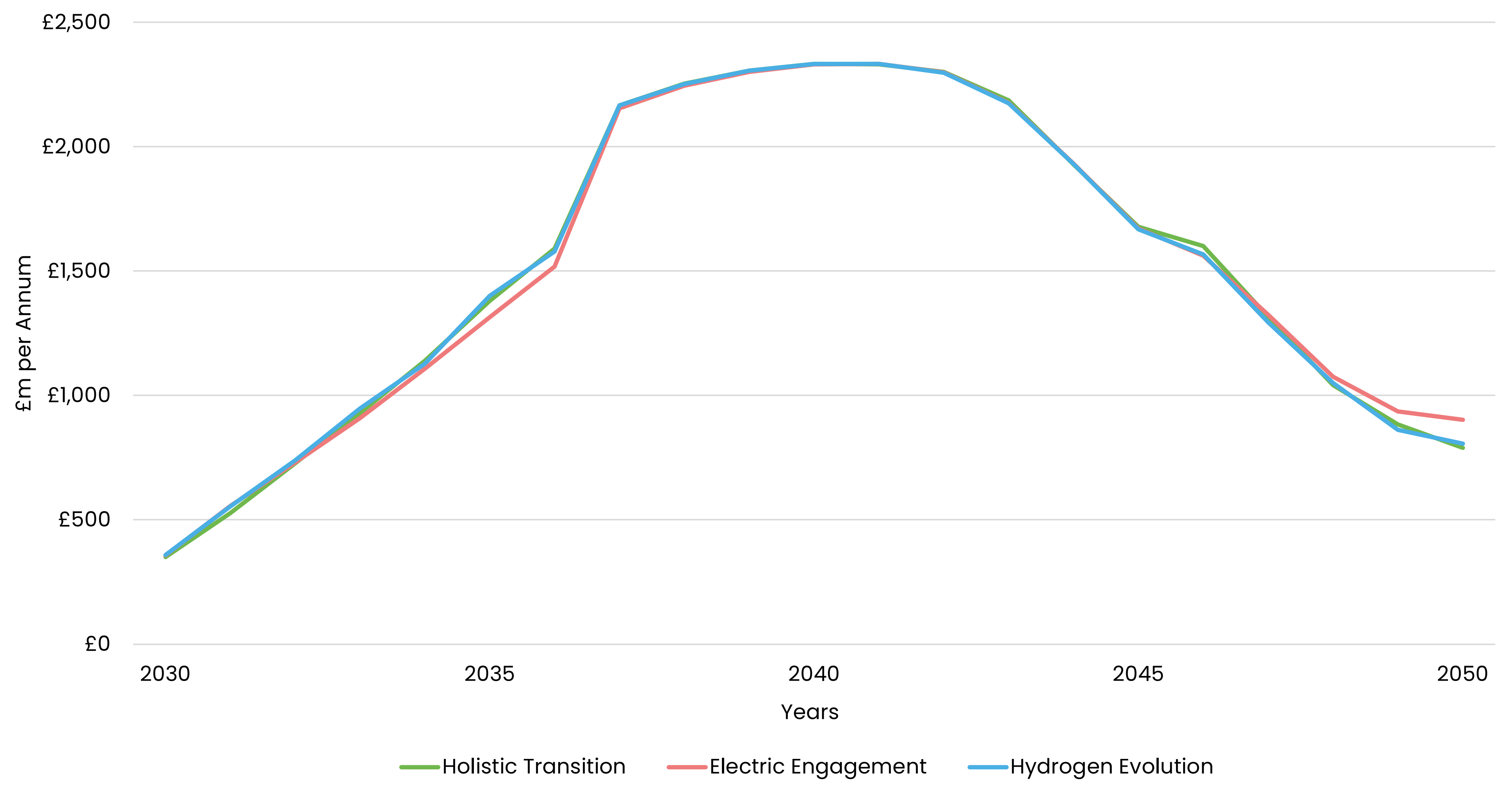
Gas network disconnections will likely increase as more consumers move away from gas as part of the decarbonisation of heat. This raises questions about whether the current disconnection framework and associated processes and costs remain fit for purpose.

Under current arrangements, consumers can request gas meter removal through their gas supplier, after which the Gas Distribution Network (GDN) complete disconnection works for health and safety reasons.[7] This type of work accounts for around 77% of disconnections, with an average disconnection cost of £712 recovered from gas consumers through their gas bills.[8] Consumers can also voluntarily request and pay directly for a gas disconnection from their GDN. These parallel routes can create uncertainty for consumers and industry about processes, responsibilities and cost-recovery frameworks when applied at scale.

Ofgem's recent review of gas disconnections highlighted the need for a more coherent long-term approach to future low-carbon heat deployment. In NESO's response to Ofgem's review, we noted that whole system approaches to cost recovery should be considered and highlighted the potential efficiencies through more coordinated delivery of disconnections.

Ofgem has also been engaging with the gas networks on the future disconnection processes following its review. We are proposing additional exploratory work in the next GMR cycle to support Ofgem, DESNZ and wider industry in analysing these future disconnection costs, potential efficiencies and process requirements.

Figure 10: Indicative disconnection annual costs, for health and safety disconnections (under GSIUR 1998) and voluntary disconnections across FES 2025 pathways



(sources: FES 2025 Pathways. Average forecast disconnection costs and assumed split between voluntary and health & safety disconnections sourced from Ofgem's ***Summary of Responses: Gas Disconnections Framework Review***. These annual costs (in nominal terms) are based on an individualised approach without cost savings from coordinated action or reduced network expenditure. Disconnection numbers are derived from the FES pathway assumptions and should be interpreted as illustrative net zero compliant pathway outputs rather than forecasts of actual future disconnections.)

7 Disconnections are carried out in accordance with the Gas Safety (Installation and Use) Regulations 1998, (GSIUR 1998).
8 Figures are set out in Ofgem's *Summary of Responses: Gas Disconnections Framework Review*, September 2025.

Any repurposing and decommissioning of gas assets will have implications for future cost recovery, sequencing and long-term gas market strategy.

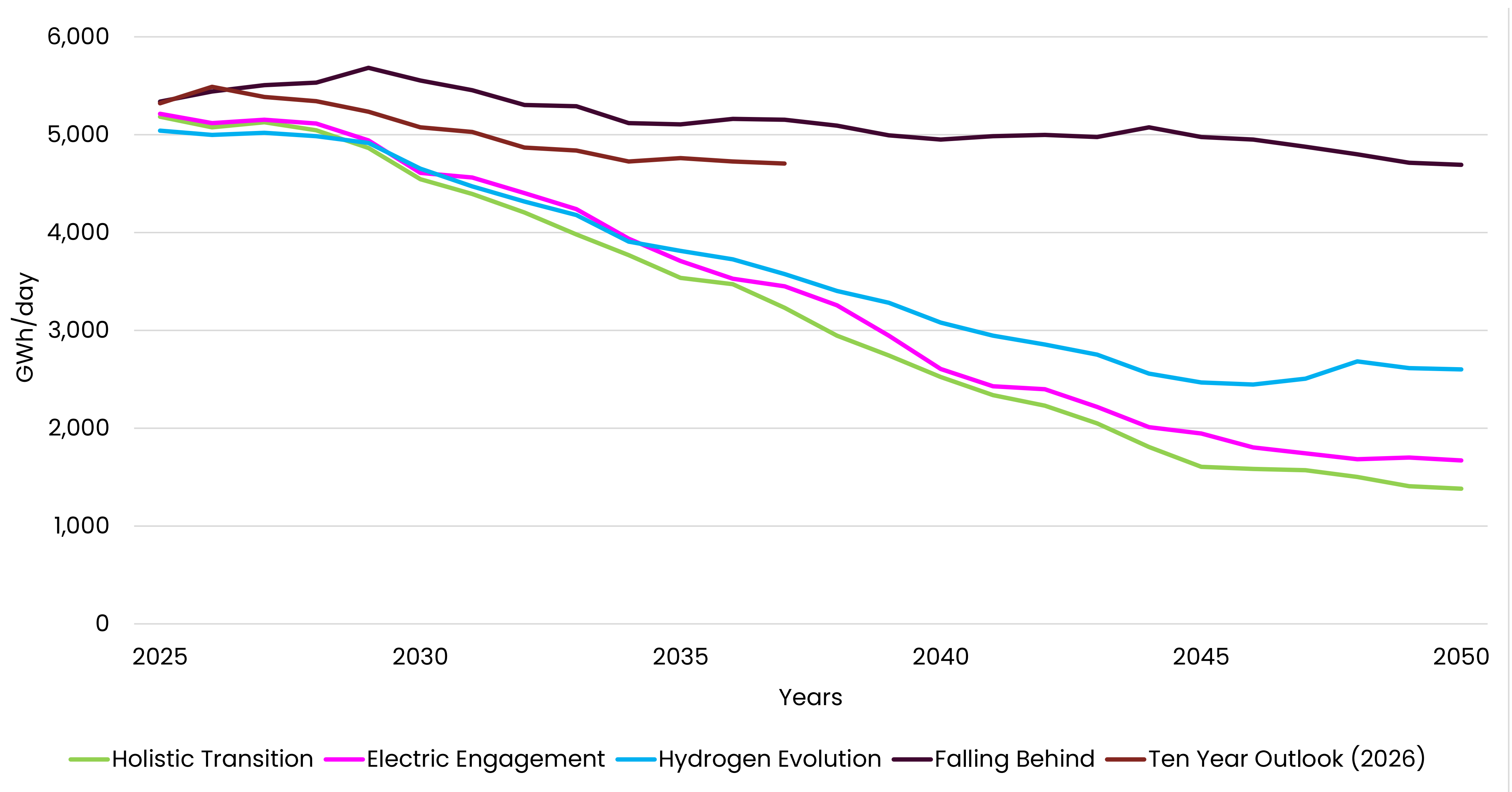
Future repurposing or decommissioning will be linked to how gas demand develops over the long term. FES 2025 illustrates overall gas demand ranging from around 166 to 398 TWh in 2050[9] compared with almost 787 TWh in 2025. Under current obligations, gas networks must also be maintained to meet peak demand levels.[10] These show similar decline and variation across the FES 2025 pathways (Figure 11), raising questions about future gas network requirements and asset use.

The government has committed to publishing a call for evidence on gas network transition in 2026. This will seek views on how to plan and deliver an effective transition of the gas network as demand declines, while protecting consumers and workers. Any significant decommissioning or repurposing of gas networks would be a long-term transition requiring planning and coordination across multiple organisations.

Given the ongoing uncertainty about the decline in gas demand, growing insights from NESO's Centralised Strategic Network Plan and Regional Energy Strategic Plans will help provide greater visibility of how gas demand and network requirements could evolve alongside wider interactions with electricity and hydrogen systems.

We are proposing early evidence gathering and exploratory assessment of the market issues from any potential repurposing or decommissioning activities. This will enable a greater understanding of how market arrangements may need to evolve from any future network transition as we simultaneously develop our strategic planning capabilities.

Figure 11: Total annual Great Britain 1-in-20 peak demand across FES 2025 pathways and the 2026 Ten Year Outlook, 2025–2050



(Figure 11 in gas years, where 2025 refers to Gas Year 2025/26, which is 01/10/2025-30/09/2026.)

9 Gas demand in 2050 varies across the FES 2025 pathways from 166 TWh in the Electric Engagement pathway to 398 TWh in Hydrogen Evolution, excluding Falling Behind. Overall gas demand in 2025 was around 787 TWh as identified in the 2026 Ten Year Outlook.

10 Gas networks must be maintained to meet 1-in-20 peak demand conditions. Under these conditions, peak daily gas demand, measured in GWh/day, would be exceeded only once every 20 years, in accordance with licence obligations.

Areas for further work

Within the gas market transition challenge, we are proposing four key areas of further work. These aim to support long term decisions, which will be made through government, Ofgem and relevant policy and regulatory processes.

Figure 12: Areas for further work for Gas Market Transition Central Challenge

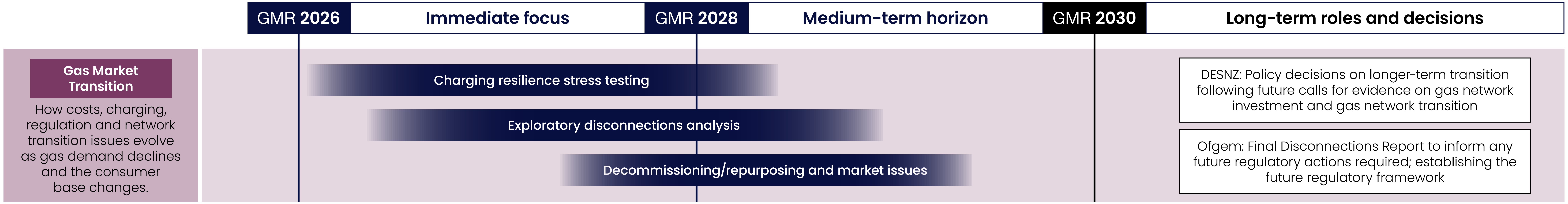
	Areas for further work		Owner and Timeline
Investment, asset depreciation and regulation	**Call for evidence on gas network investment** Call for evidence on affordability and network investment recovery, including how best to recover the costs of gas network investment as demand declines	**DESNZ**	DESNZ will publish its call for evidence on gas network investment with a decision expected in this GMR cycle
Charging and cost recovery	**Charging resilience stress testing** Review and stress testing of charging frameworks to understand how existing gas charging and cost-recovery arrangements may be impacted as gas demand and network usage change	**NESO**	Area of immediate focus to stress test the resilience of charging arrangements, and support any future charging review and Ofgem regulation
Network transition, disconnections and decommissioning	**Exploratory disconnections analysis** Assessing and building the evidence base for delivering gas disconnections at greater scale and what this could mean for costs and changes to processes and market arrangements	**NESO**	Area of work to commence following publication of final Ofgem disconnections report
	Decommissioning/repurposing and market issues assessment Exploring market design, cost, sequencing and process implications of any future gas network decommissioning or repurposing	**NESO**	Project to begin on exploring future decommissioning/ repurposing costs & market issues later in this GMR cycle

Summary

The Gas Market Transition Central Challenge discusses how charging, regulation and wider network transition arrangements remain fair, affordable and workable as the gas system changes. These issues are closely linked to wider policy, regulatory and strategic planning decisions and require further work in this GMR cycle.

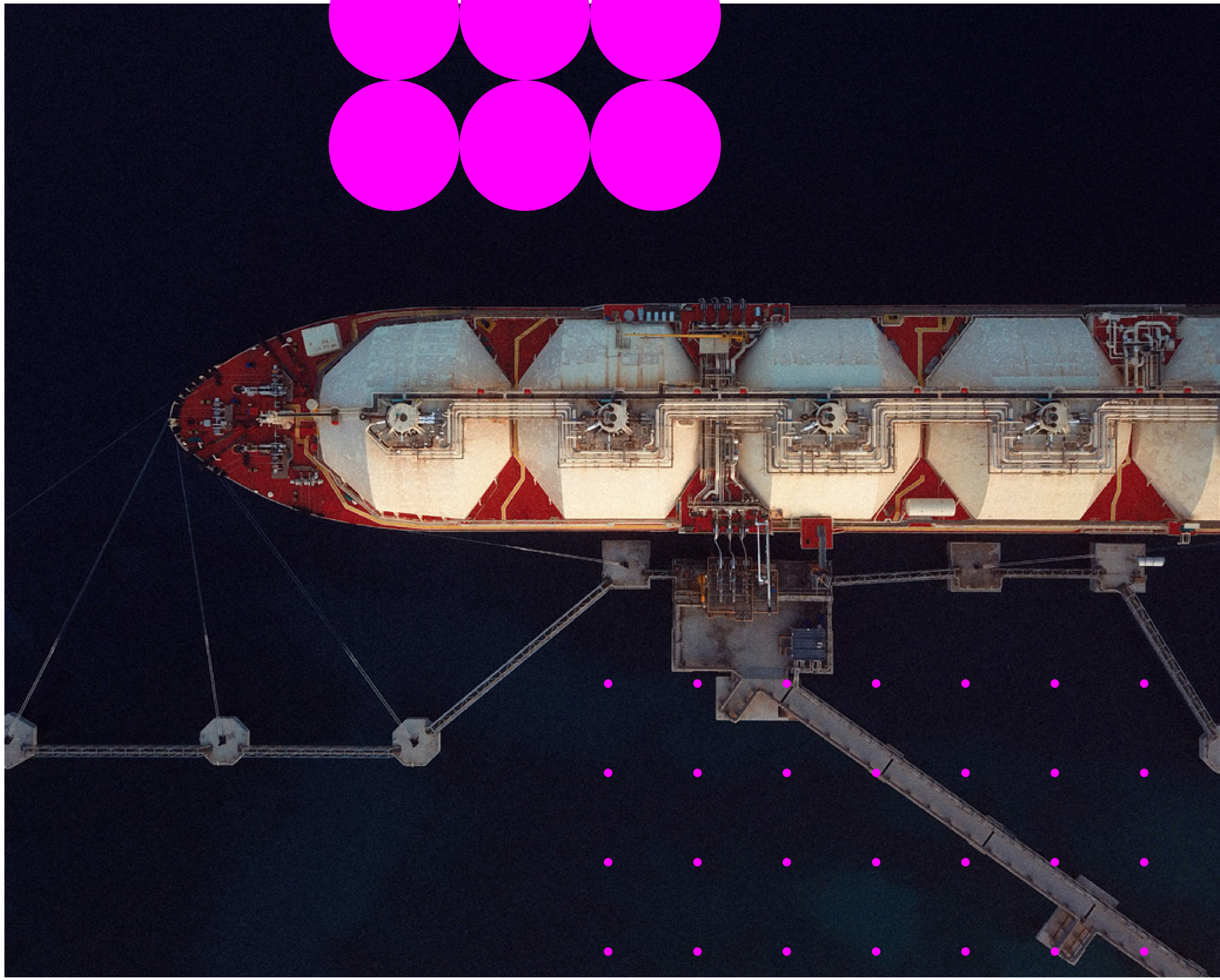
Even as annual demand declines, gas will remain important for energy security. The next section considers whether gas market arrangements will remain fit for a more import-dependent, operationally variable and increasingly stress-driven system.

Figure 13: Gas Market Transition areas for further work and long-term questions timeline



4. Central Challenge: Market Resilience

How gas market arrangements remain reliable, responsive and attractive to investors as production declines and imports rise



Introduction

FES 2025 pathways demonstrate that UK Continental Shelf (UKCS) production will decline (Figure 14), with other sources including imported gas and LNG playing an important role in the supply mix.

As Great Britain decarbonises, the way we consume gas will change. The drive to targets like Clean Power 2030 will see changing operational patterns impacting where and when we need gas.

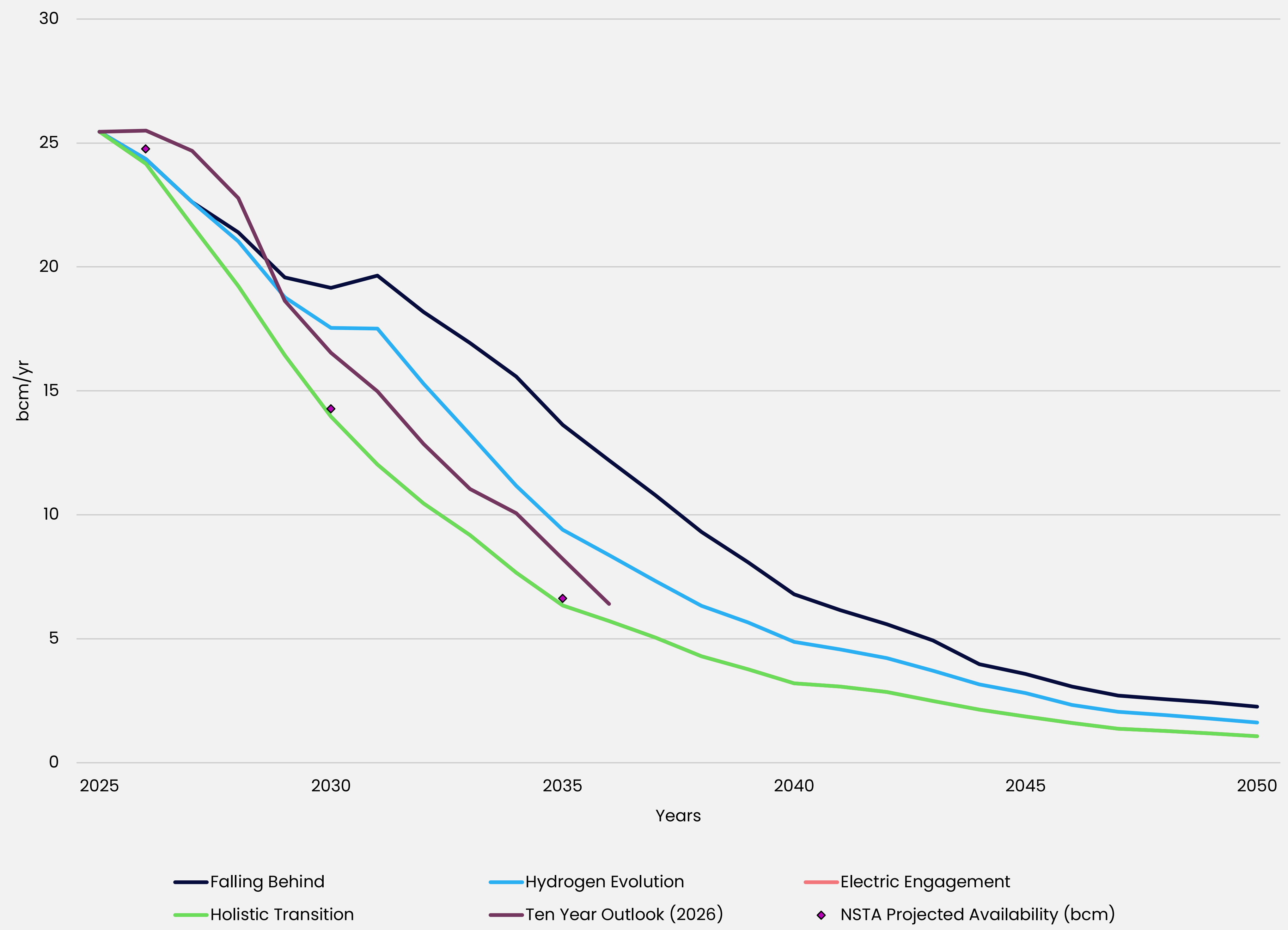
Why this matters

Market resilience refers to the ability of gas market arrangements being able to signal and source supply when needed, maintain sufficient liquidity and operability, and support effective coordination with the wider energy system as flexibility requirements evolve.

Maintaining reliable access to gas during peak energy demand will remain essential. Gas-fired generation will continue to provide flexibility to the electricity system during periods of stress, therefore, gas market resilience will remain a core component of wider energy security.

This section considers the market arrangements that focus on supply resilience, operational market design and gas–electricity interactions.

Figure 14: UK Continental Shelf (UKCS) gas production across FES 2025 pathways and North Sea Transition Authority (NSTA) February 2026 projections, 2025–2050



(NSTA projections inform NESO's *Gas Supply Security Assessment* (GSSA) publications.)

Supply resilience

Declining domestic production and greater reliance on imported gas are reshaping the supply mix.

Across all FES pathways, gas supply sources are expected to change to 2050 (Figure 15). DESNZ's Gas System in Transition: Security of Supply consultation examined how Great Britain could maintain a reliable gas supply as this shift occurs. The consultation highlighted the importance of resilient infrastructure, clear commercial and regulatory frameworks and coordinated whole system planning. It also recognised that policy intervention may be needed where market mechanisms alone are unlikely to sustain critical assets. It also sought evidence on the scale, timing and nature of any interventions required to support a flexible gas system through the transition to net zero.

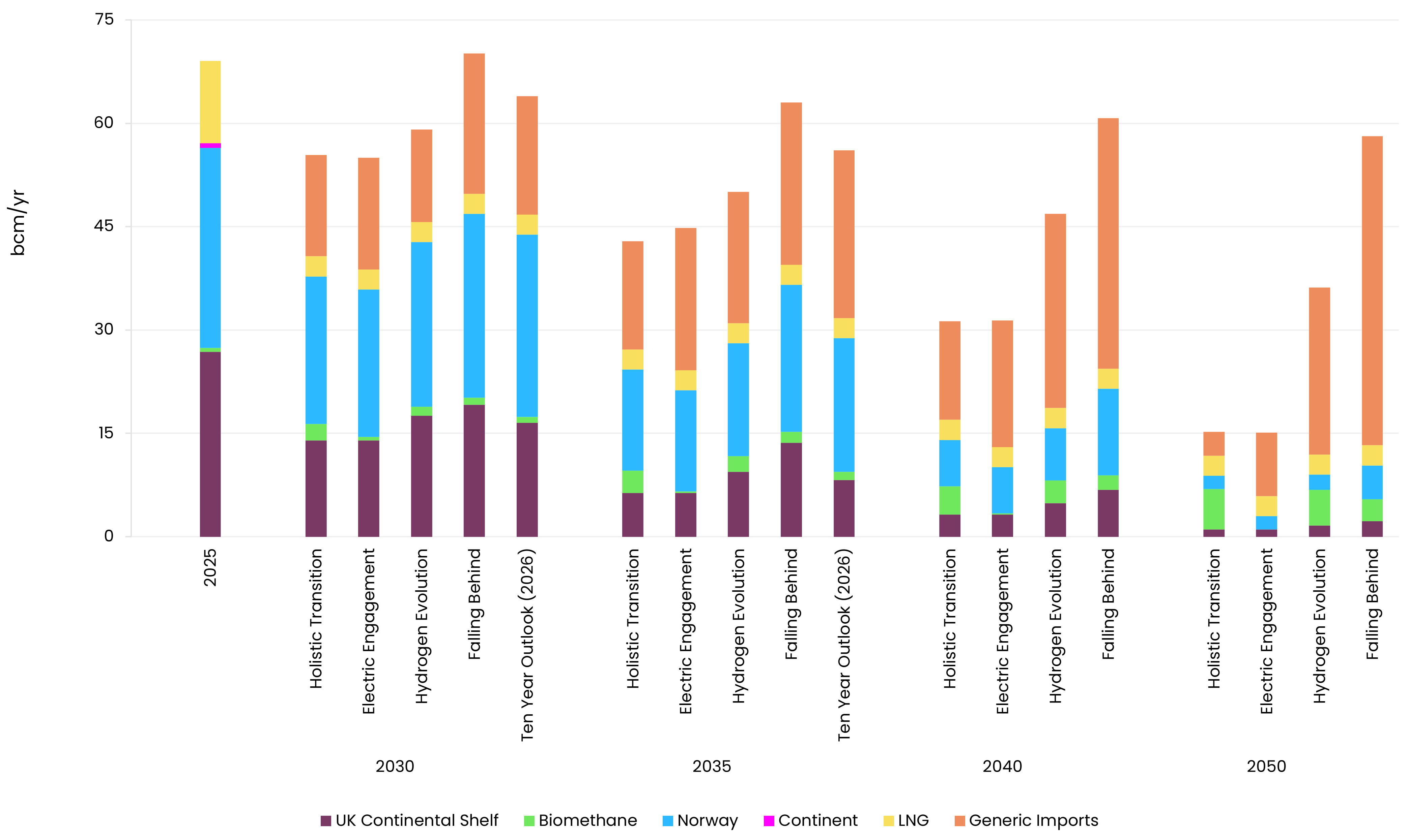
The UKCS has historically provided resilient supply, but annual production has not exceeded demand since 2004. As domestic supply continues to decline, a higher proportion of Great Britain's gas is expected to be imported from Norway, continental European interconnectors and liquefied natural gas (LNG). Market arrangements must ensure that Great Britain remains attractive for imported gas supply.

Gas is traded in competitive international markets, with flows to Great Britain driven by price, capacity availability and wider European demand. As imports become more price-sensitive and competition with North-West Europe increases, flexible and timely access to Norwegian supply is likely to become more important.

Biomethane may contribute to supply resilience by increasing the volume of domestically produced gas. Increasing production may require further market developments. These issues are explored in Section 5.

The National Balancing Point (NBP) is Great Britain's virtual wholesale gas trading hub and benchmark price for gas. It enables gas from multiple sources to be traded through a single market at a national reference price. High liquidity allows participants to trade significant volumes quickly and at relatively low transaction cost. Spot and short-term trades provide an important price signal for attracting flexible gas supply into Great Britain, especially during periods of tight global supply.

Figure 15: Supply Source Diversity across FES 2025 Pathways



'Generic Imports' represents the combination of price driven flows of both LNG imports and pipeline imports through interconnectors ('continent'). LNG in yellow represents minimum LNG from 'boil off' processes.

Imported gas

Interconnectors are likely to remain important to system resilience, supporting peak-day deliverability and system balancing. As overall gas demand declines, existing interconnector operating models may need to adapt to changing utilisation patterns.

LNG will play an important role, offering flexibility and access to global supply, while increasing exposure to geopolitical risk and price volatility. Maintaining Great Britain's competitiveness as a destination for LNG will be important, alongside addressing technical and infrastructure constraints such as gas quality requirements and import capacity. Uniform Network Code (UNC) Modification 0903 has already considered whether lower entry tariffs could make Great Britain more attractive to LNG cargoes by aligning entry charges more closely with European markets.

However, heightened geopolitical risk may increase freight and insurance costs. There are also additional costs due to requirements for LNG cargoes to be ballasted to meet gas quality levels in Great Britain compared with neighbouring markets. This increases the delivered cost of LNG injected onto the National Transmission System (NTS).

As the supply mix changes to 2050, it will be important to monitor and understand how price formation and price spreads against other trading hubs may affect flows to Great Britain, with implications for NBP liquidity and competitiveness.

NESO's Gas Supply Security Assessment (December 2025)

NESO's **Gas Supply Security Assessment (GSSA)**, published in December 2025, assessed supply and demand margins using future 11-day peak demand profiles at 5 and 10 years ahead. These profiles were tested against both an intact network scenario and a scenario involving the loss of the single largest piece of infrastructure.

The GSSA also made recommendations to support future security of supply. It considered the role of gas infrastructure, supply sources and broader cross-vector coordination, to provide advice on future policy and market arrangements.

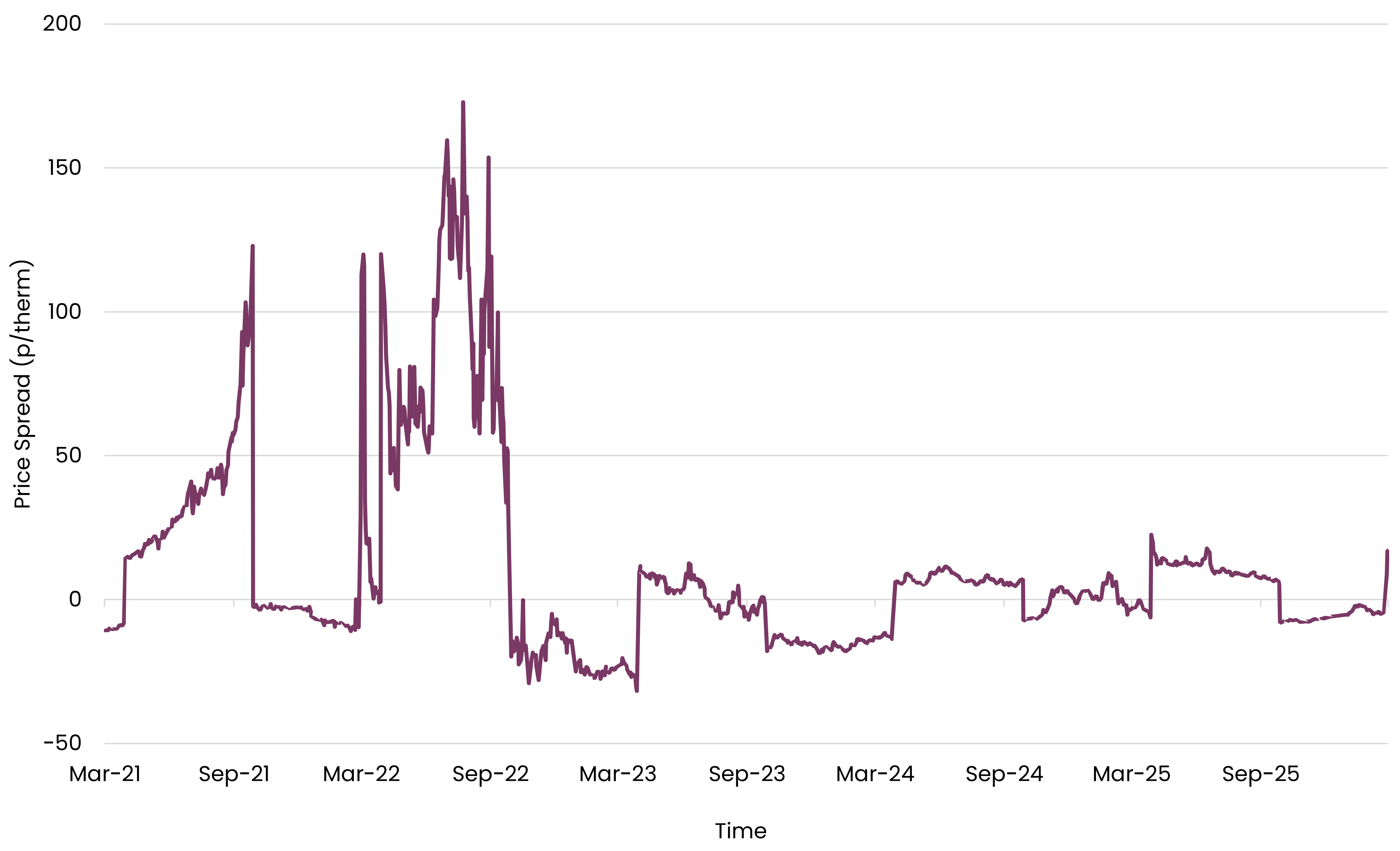
Domestic storage

Gas storage in Great Britain is privately owned and operated and is based on a merchant model. This relies on price spreads to incentivise storage filling, while short-term price signals drive dispatch to meet immediate system balancing requirements.

Figure 16 shows near-zero or negative spreads in recent years, suggesting that seasonal storage arbitrage has largely disappeared, significantly reducing the commercial value of storage, particularly for medium-term (seasonal) facilities. Greater import dependence and the growing role of LNG appear to have contributed to this compression.

The Gas Advisory Council (GAC) identified a potential project on the resilience of gas storage arrangements beyond the mid-2030s. This is separate from DESNZ's *Gas System in Transition: Security of Supply Consultation*, which addresses broader system security issues. Any further storage analysis will be considered by the GAC in line with any decision from the DESNZ consultation.

Figure 16: NBP price seasonal spreads, March 2021 to September 2025



(source: Independent Commodity Intelligence Services (ICIS))

Operational market design

Existing operational market design arrangements were designed for a stable system with consistent throughput and may need to evolve as the system changes.

Operational market design sets the framework for how users access the gas system, how physical balance is maintained and how risks to system integrity are managed. In Great Britain, price signals play the primary role in ensuring gas is available when and where it is needed.

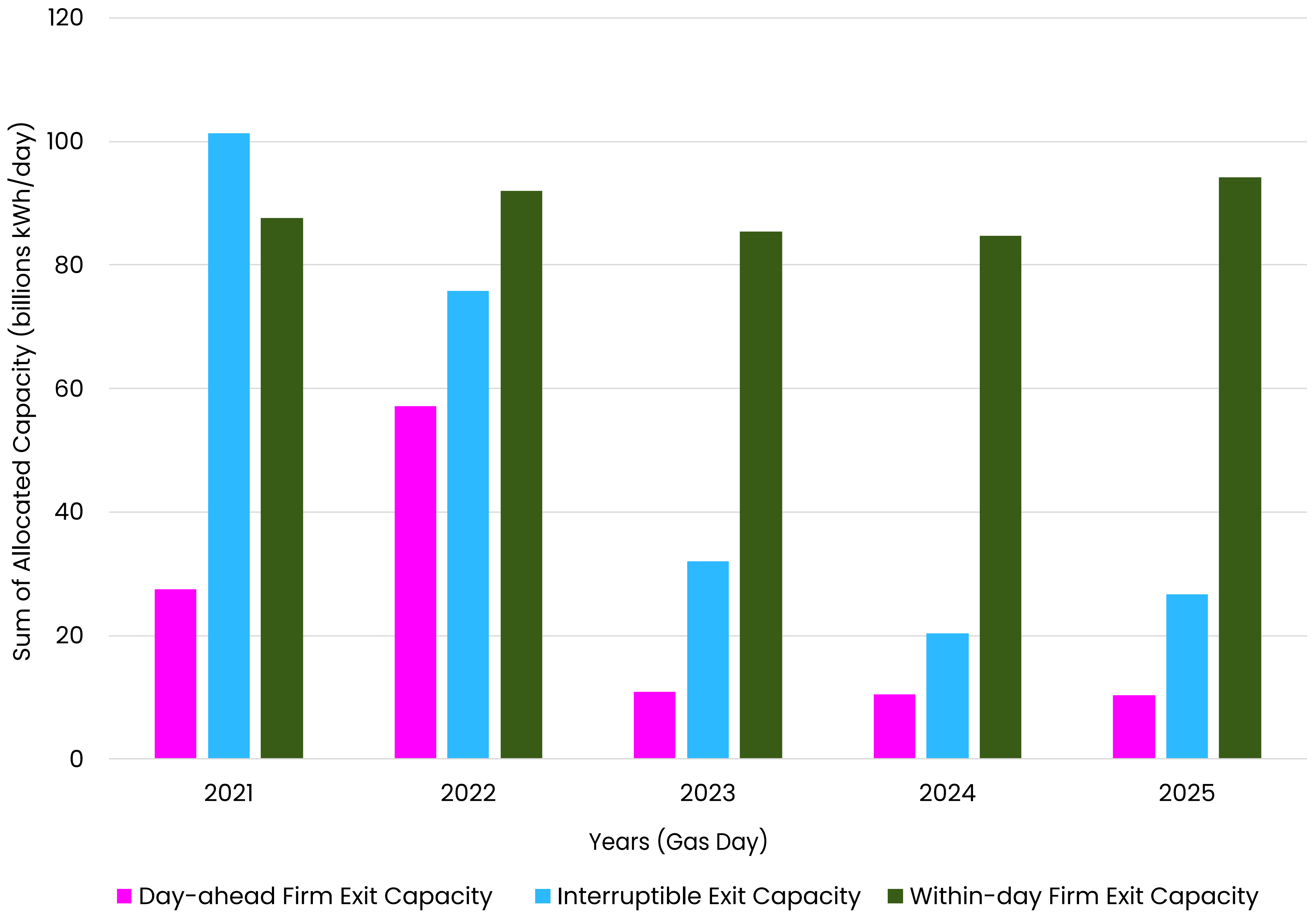
National Gas Transmission (NGT) is the licensed Gas System Operator (GSO) for the National Transmission System (NTS). It is responsible for maintaining safe pressures, acting as the residual balancer of the network[11] and protecting priority customers in emergencies.

Capacity access

To move gas on or off the NTS, users book capacity that covers their flows through a range of long-term and short-term, firm and interruptible entry and exit products.[12] NGT recovers revenue through these capacity arrangements to support the investment in, and operation of, the NTS.

Figure 17 shows that exit users (excluding Gas Distribution Networks)[13] have increasingly booked shorter-term exit capacity closer to real time, rather than long-term products. Similar patterns are also emerging on entry. The entry-exit regime uses capacity as a signal for future demand, access requirements and investment needs. Market participants are increasingly booking the capacity they need closer to real time, reducing reliance on long-term capacity products and weakening long term investment signals.

Figure 17: Capacity booking behaviour over time for exit users excluding gas distribution networks, 2021 to 2025



(source: National Gas Transmission, 2026)

11 As residual balancer, NGT can enter the market to take centralised actions and buy or sell gas on the On-the-Day Commodity Market (OCM) to ensure stability of the NTS and send signals to market participants to balance their positions.
12 Commercial rights held by shippers to inject gas into (entry) or withdraw gas from (exit) the National Transmission System at specified points, which can be secured on a firm basis or capacity that can be withdrawn by NGT (interruptible, off-peak).
13 GDNs are required to book capacity on the NTS to meet their 1-in-20 peak demand forecasts, and so have less flexibility to book capacity as close to flows compared to other exit users.

In 2021, NGT completed a *Long-Term Access Review* to assess whether capacity access arrangements would remain fit for purpose through to 2030 and beyond. The review reached no firm conclusions on major reform to the capacity regime due to the uncertainty about how the gas industry would develop.

With evolving operational behaviours, capacity access arrangements should be reviewed. NGT has indicated it will review the capacity access regime in RIIO-3,[14] and we propose this review should form an important area for further work over the next GMR cycle across NGT, NESO and the GAC.

Balancing and settlement

The gas system in Great Britain must remain physically balanced, with shippers acting as the primary balancers. Where shippers are out of balance, their positions are settled through the cash-out mechanism,[15] which provides a financial incentive to balance inputs and offtakes during the gas day.

In a liquid market, such as the NBP, imbalances can be priced quickly, allowing shippers to rebalance, redirect flows and source gas at short notice during periods of system stress.

The current balancing regime was designed for a relatively stable, production-led system. As the system becomes more variable, particularly through more intermittent gas-fired generation and greater reliance on imported gas, the speed and responsiveness of balancing arrangements may become more important.

Ofgem identified that NGT entered the market more frequently in RIIO-2, on 70% of days from April 2021 to March 2026, compared with 58% of days during RIIO-1 from April 2013 to March 2021.[16] This indicates that within-day system conditions are becoming increasingly variable with more residual balancing on the NTS.

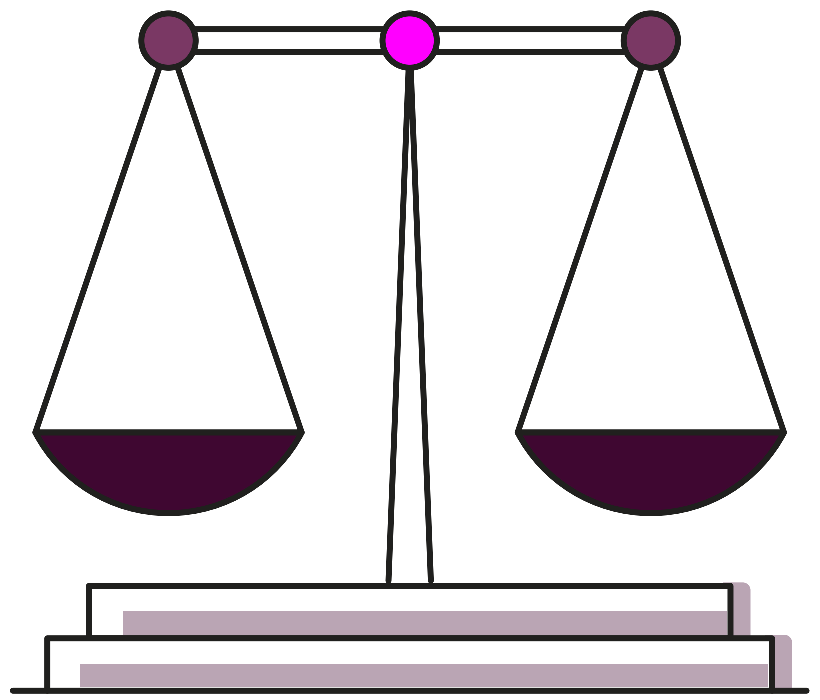
More volatile within-day conditions could test whether existing balancing tools, incentives and information flows remain well aligned with future system needs.

In 2022, NGT reviewed the gas balancing regime as part of the Gas Market Action Plan. The review explored potential reforms to the balancing regime, particularly in anticipation of gas-fired generation moving from more stable baseload operation towards a peaking role. The review showed that the regime remained fit for purpose in the near term. However, as gas and power interactions become more pronounced in a clean power system, the gas balancing regime may need to be reviewed again.

Linepack and operational flexibility

Linepack is the volume of gas contained within the pipeline system and is directly linked to operating pressures. It provides an important source of operational flexibility with NGT varying pressures within safe limits in response to changing system requirements.[17]

The transition towards a more import-dependent gas system, coupled with the changing role of gas-fired generation in supporting the electricity system, will increase within-day swings in linepack to manage these operational patterns. As these trends continue, alternative sources of within-day flexibility may be required to maintain system resilience. Market arrangements may also need to provide clearer signals for how this operational flexibility is accessed, valued and coordinated.



14 National Gas Transmission, System Operator Annex (RIIO-GT3 Business Plan), December 2024.
15 Where shippers are imbalanced, they must either pay for their shortfall at a price higher than the average daily gas price or sell their excess gas for less than the average price, incentivising shippers to balance rather than being subject to this cash-out system.
16 Ofgem, *RIIO-3 Draft Determinations: National Gas Transmission*, July 2025.
17 Provides around 100TWh per year compared to the total volume ~ 15% of total annual gas demand in GB.

Gas and power interactions

Shifting demand patterns and stronger interdependencies with the power sector will require changes to gas market arrangements.

As the energy system decarbonises, interactions between gas and electricity markets will remain critical.

The way in which gas is being used for power is changing. Gas-fired generation continues to shift from steady baseload to a flexible role to respond to electricity demand fluctuations and renewable generation.

With Clean Power 2030 and beyond, gas demand profiles for power will change. Reliable and timely access to gas will remain critical in these periods to support whole system resilience across all FES 2025 pathways.

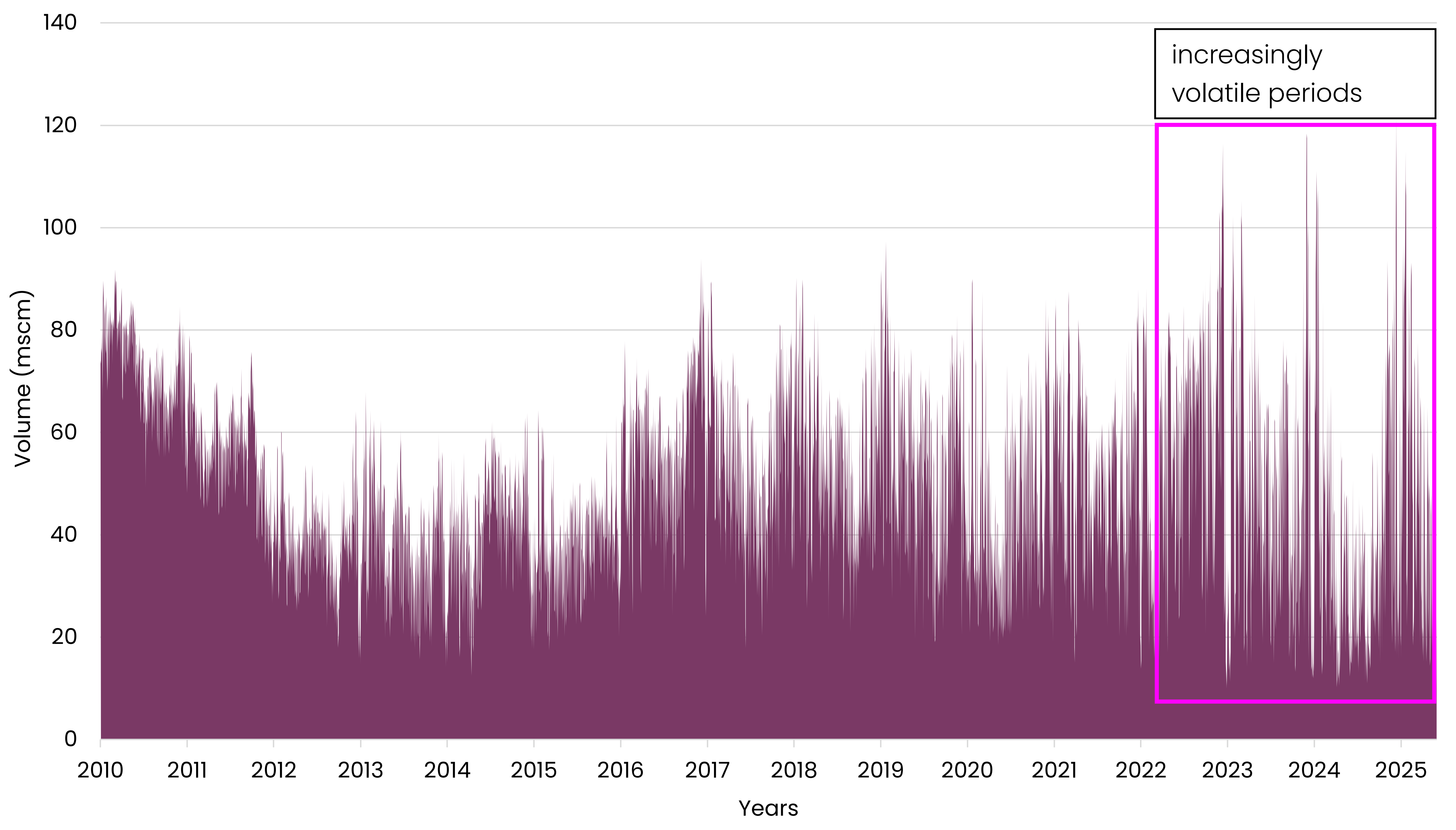
As the system changes, there may be a need to reassess whether post 2030 market arrangements, including flexible mechanisms and secuirty of supply metrics need to change.

Figure 18 shows that power station gas usage is becoming more variable over time, with higher peaks and greater volatility. These changes could increase the operational value of linepack, while also making it more challenging for shippers and the system operator to balance the system within-day. The gas system will need to deliver rapid, short-duration flexibility rather than simply meeting aggregate annual demand.

Declining overall gas demand may also lead to more localised and variable flows across transmission and distribution networks. This could reduce the effectiveness of balancing approaches and increase the value of other flexibility sources, including linepack, storage, LNG, interconnector flows and demand-side flexibility where available.

We are proposing further work to understand whether existing gas market arrangements appropriately support system operation in a clean power system and whether changes to market design are required to maintain gas system flexibility under more variable operating conditions.

Figure 18: Total power station gas usage Jan 2010-May 2025



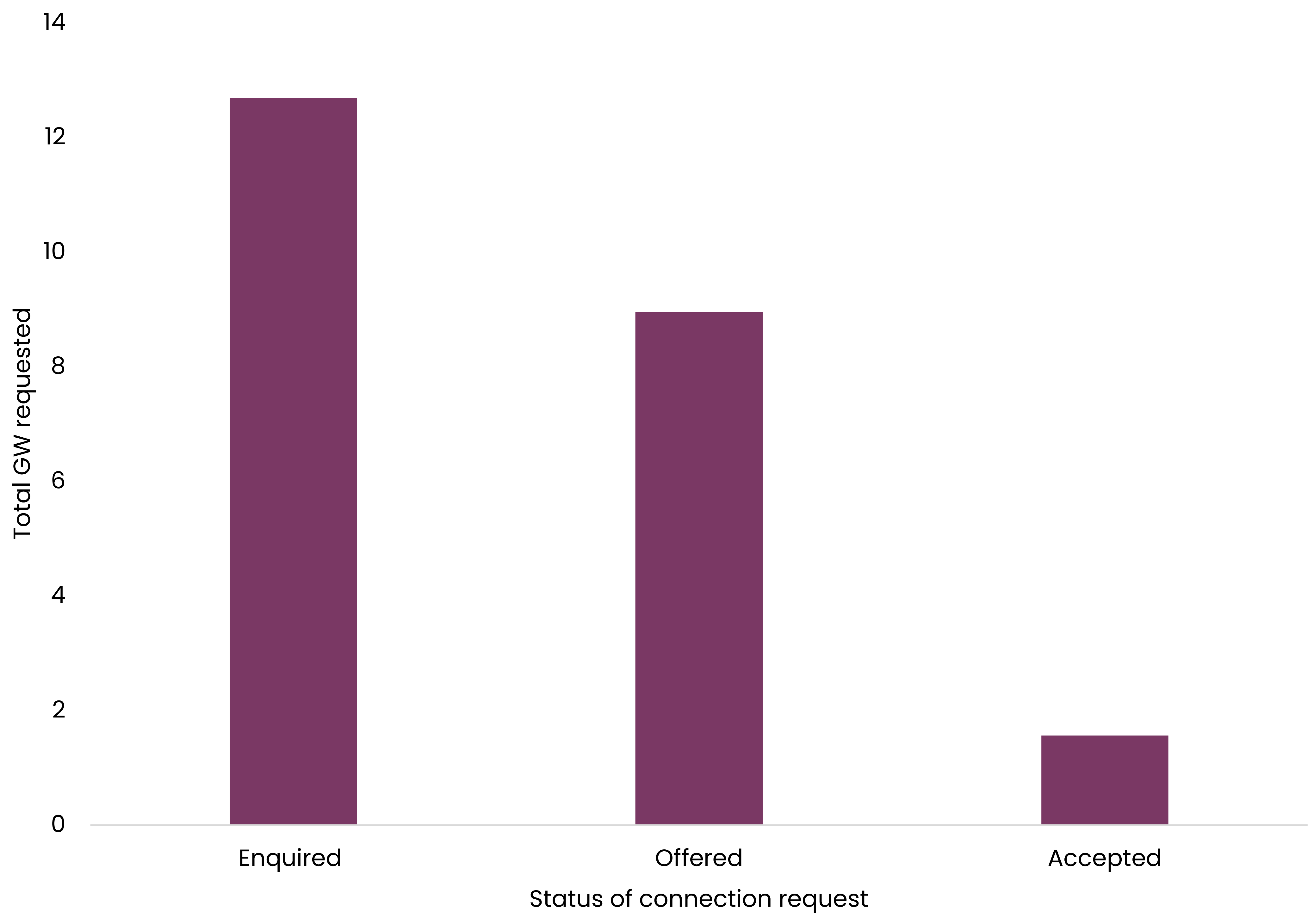
(source: National Gas Transmission (NGT) 2025)

Emerging demand uncertainty – data centres

Data centres are becoming an increasingly significant source of energy demand. While around 2 GW of data centre load is currently connected to the electricity network, delays in securing electricity connections have led some developers to consider on-site solutions, including gas-fired generation on an interim or backup basis. While current gas connection requests remain limited, concentrations of new loads could affect local gas demand, network operation and planning. Figure 19 shows grid connection requests between 2024 and 2027 (as of September 2025).

In a system with declining baseline gas demand, uncertainties around future data centre gas connections may make future demand patterns harder to anticipate. This reinforces the need for flexible and adaptive market arrangements and for strategic planning processes to continue to consider the interaction between electricity demand growth, gas network use and whole system resilience. We will continue to monitor the impacts that data centres are having on the energy system.

Figure 19: Data centre gas grid connection requests by gas volume, 2024 to 2027



(source: provided by Gas Distribution Networks as of September 2025)

Areas for further work

Within the Market Resilience challenge, we are proposing three key areas for further work. Longer-term decisions on the supply mix will be made through government, Ofgem and the market.

Given the responsibilities of DESNZ, NGT and NESO, we have highlighted where they will carry out further work in this Central Challenge. We will put forward the coordinated findings in the next GMR cycle.

Figure 20: Areas for further work for the Market Resilience Central Challenge

Areas for further work		Owner and Timeline	
Supply Resilience	**Strategic direction on the supply mix** Strategic direction on the supply mix and where market mechanisms may require policy intervention to support supply source diversity	**DESNZ**	DESNZ *gas system in transition: Security of supply* consultation response pending. The need for any additional further work will be reassessed in future cycles
Operational Market Design	**Capacity access review** Review of how capacity access market design may need to change to remain fit for purpose	**NGT**	NGT has proposed to review the purpose and principles of the capacity regime in RIIO-3. Wider review and input will be included in this cycle
Gas and Power Interaction	**Gas system impacts from power** Assessing how gas and power interactions are likely to change and how this may impact gas market operation	**NESO**	Area of immediate focus following GMR publication (2026 onwards)

Summary

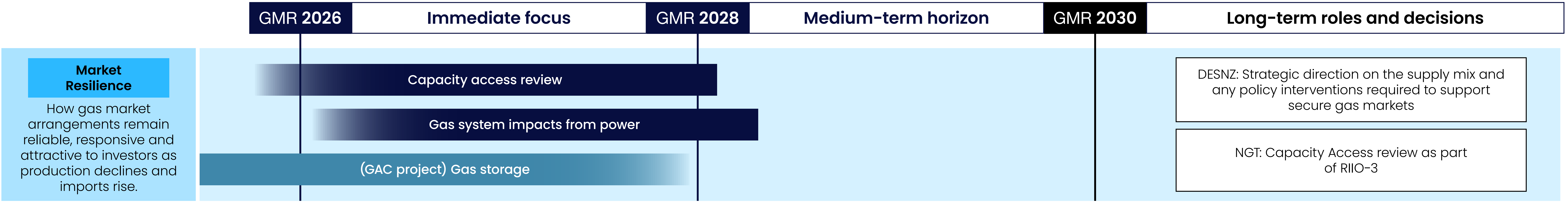
The Market Resilience Central Challenge focuses on ensuring that gas market arrangements continue to support a flexible and reliable network as domestic production declines, import dependence increases and operational patterns become more variable.

This includes ensuring access and balancing arrangements remain responsive to changing system needs, maintaining NBP liquidity and understanding the growing value of operational flexibility, including linepack, storage, LNG and interconnector flows. It also requires closer coordination between gas and electricity markets as gas-fired generation increasingly supports a low-carbon electricity system during periods of stress.

These issues show that resilience will remain a core consideration even as overall gas demand declines. The challenge is not simply whether there is enough gas in aggregate, but whether market arrangements continue to provide the right signals, incentives and operational tools to support a reliable and responsive system.

The next section turns to the Emerging Markets Central Challenge. As biomethane, hydrogen, CCUS and their interactions with the wider system become more significant, gas market arrangements will need to interact with support frameworks, certification arrangements, and market access requirements.

Figure 21: **Market Resilience areas for further work and long-term questions timeline**



5. Central Challenge: Emerging Markets

How gas markets may need to evolve as they increasingly interact with biomethane, hydrogen, and CCUS.

Introduction

The first two challenges in this GMR focus on how existing gas market arrangements may need to adapt during the transition. The third challenge examines emerging markets and their role in the system.

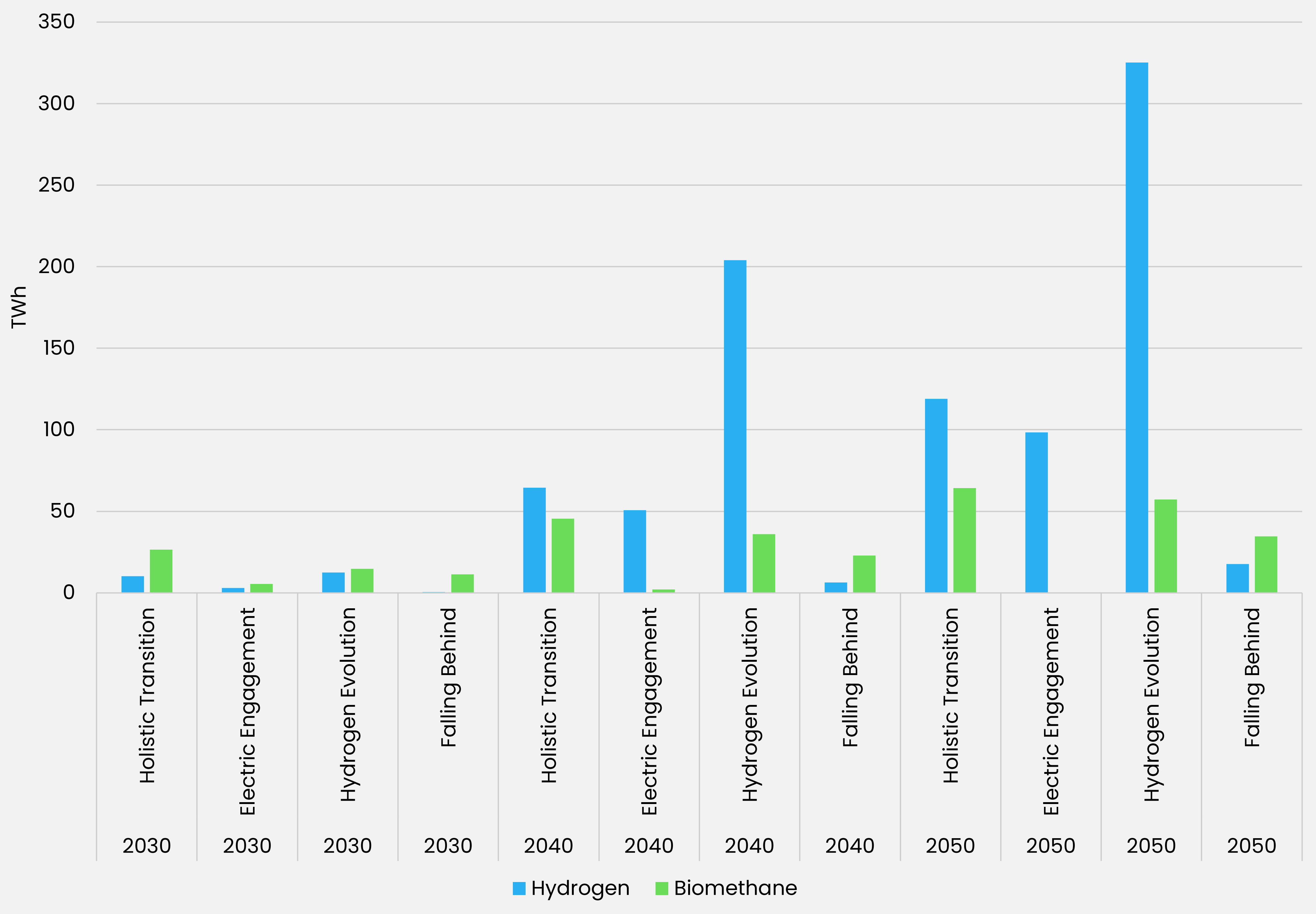
Historically, gas and electricity markets developed largely in isolation, with distinct roles and market arrangements. Their primary point of interaction has been gas-fired power generation. As the system transitions to net zero, these interactions will become increasingly prominent. Low-carbon gases, carbon capture, certification frameworks and changing patterns of industrial and consumer demand could all affect how gas markets operate over time.

Why this matters

The development of emerging markets will not be uniform across Great Britain. Hydrogen, carbon capture, utilisation and storage (CCUS) and biomethane deployment will be driven by location-specific factors, including industrial clusters, resource availability and infrastructure constraints. Strategic spatial planning will therefore be critical in coordinating these developments and ensuring efficient integration with the gas system.

This section considers the market design questions raised by these developments. The focus is not to prescribe the future role of any technology, but to identify where gas market arrangements may need to adapt as low-carbon gases and their respective markets develop.

Figure 22: Hydrogen and biomethane production across FES 2025 pathways, 2030–2050



Certification and the UK Emissions Trading Scheme

Certification and carbon pricing will increasingly shape the relative economics of gas and its alternatives, and therefore the pace of demand reduction.

Certification

Certificates are an important accounting tool in energy markets, acting not as physical commodities but as mechanisms to verify the origin and characteristics of energy where physical traceability is not possible. They enable biomethane and other low-carbon gases to be accounted for once they are injected into the gas grid, supporting compliance with policy frameworks in the absence of physical traceability. Beyond accountability, certification can also influence market behaviour by making carbon characteristics visible where gas competes with electrification or other low-carbon alternatives.

UK Emissions Trading Scheme

The UK Emissions Trading Scheme (ETS) is a cap-and-trade scheme covering power, energy-intensive industry, maritime transport and parts of aviation. As the cap tightens over time and allowances fall, decarbonisation incentives rise. Despite price volatility, carbon pricing continues to shape the competitiveness of gas-fired generation relative to lower-carbon alternatives.

The scheme does not apply directly to residential gas consumption and, for domestic use, has only an indirect effect via electricity markets through gas-fired generation. It also does not currently allow grid-injected biomethane to offset emissions. However, demand across ETS-covered sectors could increase if such recognition were introduced. This creates an important interaction between gas, electricity and carbon markets, influencing technology choices and fuel use across the wider energy system.

The interaction is more nuanced for hydrogen. While production that generates carbon emissions and exceeds the ETS threshold is subject to carbon pricing, on-site hydrogen combustion produces no carbon emissions and therefore incurs no ETS obligations.

Differences in carbon price exposure across fuels and end-use sectors can influence the relative economics of gas, electricity and alternative gases, shaping the pace and extent of demand reduction.

We are proposing further work to analyse the interactions and overall contribution of certificate schemes to decarbonisation, given the number currently in use and the potential for additional schemes to emerge.

Biomethane

Biomethane growth depends on clear policy direction, continued production support and resolving gas network constraints.

Current and future biomethane production in Great Britain

Biomethane is a low-carbon gas that can be domestically produced from sustainable biological material, such as agricultural and food waste, sewage and crops, via anaerobic digestion. Biomethane can be injected into the existing gas grid without changes for end users who are already using natural gas. There are more than 120 biomethane production plants connected to the gas grid in Great Britain, injecting around 6 TWh of gas in 2025[18] – less than 1% of current gas demand.

Scaling up biomethane production in Great Britain beyond current levels could deliver considerable benefits across the energy system. Using it for dispatchable generation could lower the cost of the future power system compared to not having biomethane available. It could also provide a viable option to reduce emissions for hard-to-electrify industry that may not have alternative solutions, such as dispersed sites outside of industrial clusters without access to hydrogen or carbon capture and storage (CCS). CO_2 capture from biomethane production also provides a route to achieving permanent greenhouse gas removals.

Sustainable biomethane production can increase substantially beyond current levels. To scale production, increased use of sustainable feedstocks from the agriculture and waste sectors would be required, which comes with a growing number of dependencies, trade-offs and risks. Cross-sector assessment is needed to determine the level of biomethane production that strikes the right balance between the benefits and these wider challenges. We expect that these wider challenges may only start to materially emerge beyond an ambition of around 30 TWh of annual production by 2050. Any growth in biomethane production is reliant on policy support at least in the short-to-medium term. We discuss these issues further in our insight piece, *Exploring the Role of Biomethane*, which considers biomethane in the energy system to 2050.

Greater collaboration across the energy, agriculture, environmental and waste sectors would help define an ambition that balances cross-sector objectives and identifies the actions needed to deliver it, including consideration of the necessary gas market arrangements.

Enabling biomethane deployment

Production of biomethane has grown significantly with subsidy support through the Renewable Heat Incentive and the Green Gas Support Scheme (GGSS), which closes to new applicants in 2028.[19] The government has various options for a future scheme, including continuing tariff-based schemes, Contracts for Difference (CfD), an obligation-style scheme, or a combination of these. Biomethane producers have indicated an ambition for biomethane to transition to a more self-sufficient market over the next few decades.

The government is planning to consult on support for the biomethane sector after 2028 and is also examining how to address a range of investment barriers. It is also exploring the potential integration of grid-injected biomethane into the UK Emissions Trading Scheme. This could support the growth of long-term offtake arrangements with users covered by the UK ETS.

Producers are also exploring additional revenue streams that could help reduce the level of support needed in the future. Various biomethane plants currently capture their CO_2 during the biogas upgrading process and sell it into utilisation markets. A scale-up of CO_2 transport options, including non-pipeline transport, and greater competitiveness in the CO_2 market could drive further growth in the sector. There are also potential revenue opportunities from storing CO_2 to achieve greenhouse gas removals, as well as from selling digestate (a by-product of biomethane production) as a fertiliser, both of which have the potential to contribute to reducing the need for subsidy for biomethane producers.

Further detail on our assessment of the role of biomethane in the energy system is published in *Exploring the Role of Biomethane.*

18 Future Energy Scenarios (FES) 2026 Ten Year Outlook.
19 GOV.UK, *Green Gas Support Scheme (GGSS): open to applications*.

Gas networks and the role of biomethane

There are a number of barriers to entry for biomethane to the gas grid, with projects currently under way aimed at providing solutions to these challenges. During NESO's engagement with industry, stakeholders identified three core grid issues affecting the scale-up of biomethane: the pace, cost and complexity of obtaining gas grid connections, the potential for gas grid constraints to curtail biomethane injection on distribution networks, rather than the National Transmission System (NTS), and the expense of needing to propanate biomethane when injecting into the distribution network.

Historically, connection timeframes have been slow and complex, with each GDN setting different requirements and processes. Work by gas network operators, in partnership with wider industry, is seeking to overcome such barriers by standardising processes and equipment.

Gas network barriers have also emerged, particularly during low-demand periods on GDNs, such as summer, where injection may be curtailed, affecting project economics and limiting emissions reductions. Addressing this will require targeted investment and solutions such as reverse compression and smart pressure control, with recent RIIO-3 'use it or lose it' (UIOLI)[20] funding providing a potential route to support this investment.

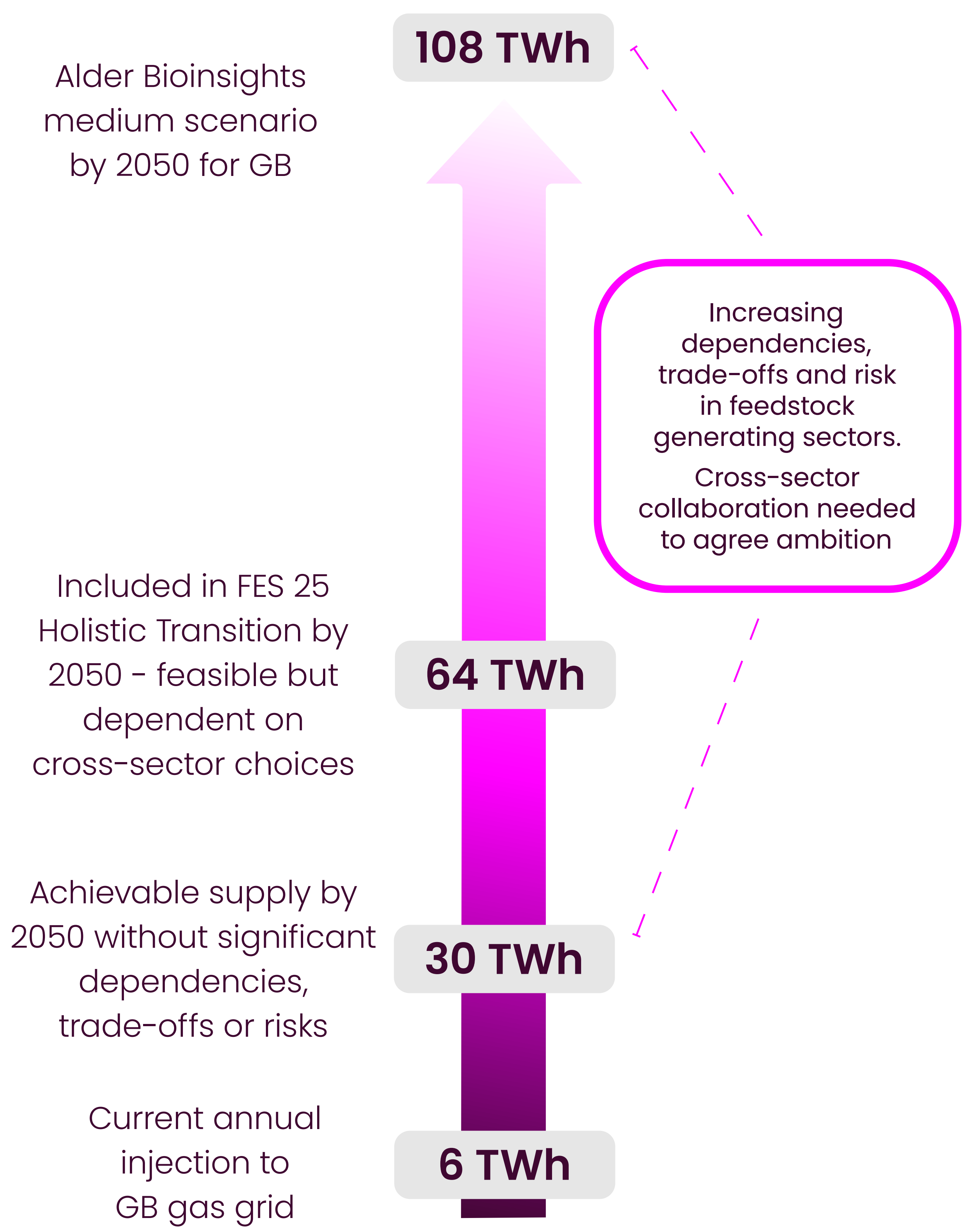
Biomethane typically has a lower calorific value than natural gas and must currently be supplemented with small quantities (3–6%) of propane to meet GDN requirements. This adds a cost to production and can act as a barrier to further deployment.

Addressing this will require changes to standards, measurement, billing and network operations, alongside efforts to reduce or eliminate the need for propanation, while ensuring the continued safe and efficient operation of the gas grid.

We are working with government to refine the vision for biomethane between 2030 and 2050, alongside natural gas and hydrogen, as set out in the Clean Flexibility Roadmap. Considerations in our biomethane insight piece are feeding into this work covering production ambition and end uses, with biomethane offering high value in hard-to-decarbonise sectors.

We have also worked in collaboration with the Gas Advisory Council (GAC) to explore post-2030 biomethane support, which has helped inform our findings within the GMR. Future activity with the GAC will depend on policy decisions about biomethane support. Where biomethane is used will also affect gas market operations and wider energy system planning. Greater certainty about volumes and end uses would support more cost-effective infrastructure decisions and help identify targeted future market requirements.

Figure 23: Biomethane Future Production Potential



(source: See NESO's ***Exploring the Role of Biomethane*** publication for underlying data and assessments)

20 Ofgem, *Biomethane Use It Or Lose It (UIOLI) Governance Document*

Hydrogen

Blue hydrogen production is expected to be concentrated in industrial clusters, creating localised gas demand.

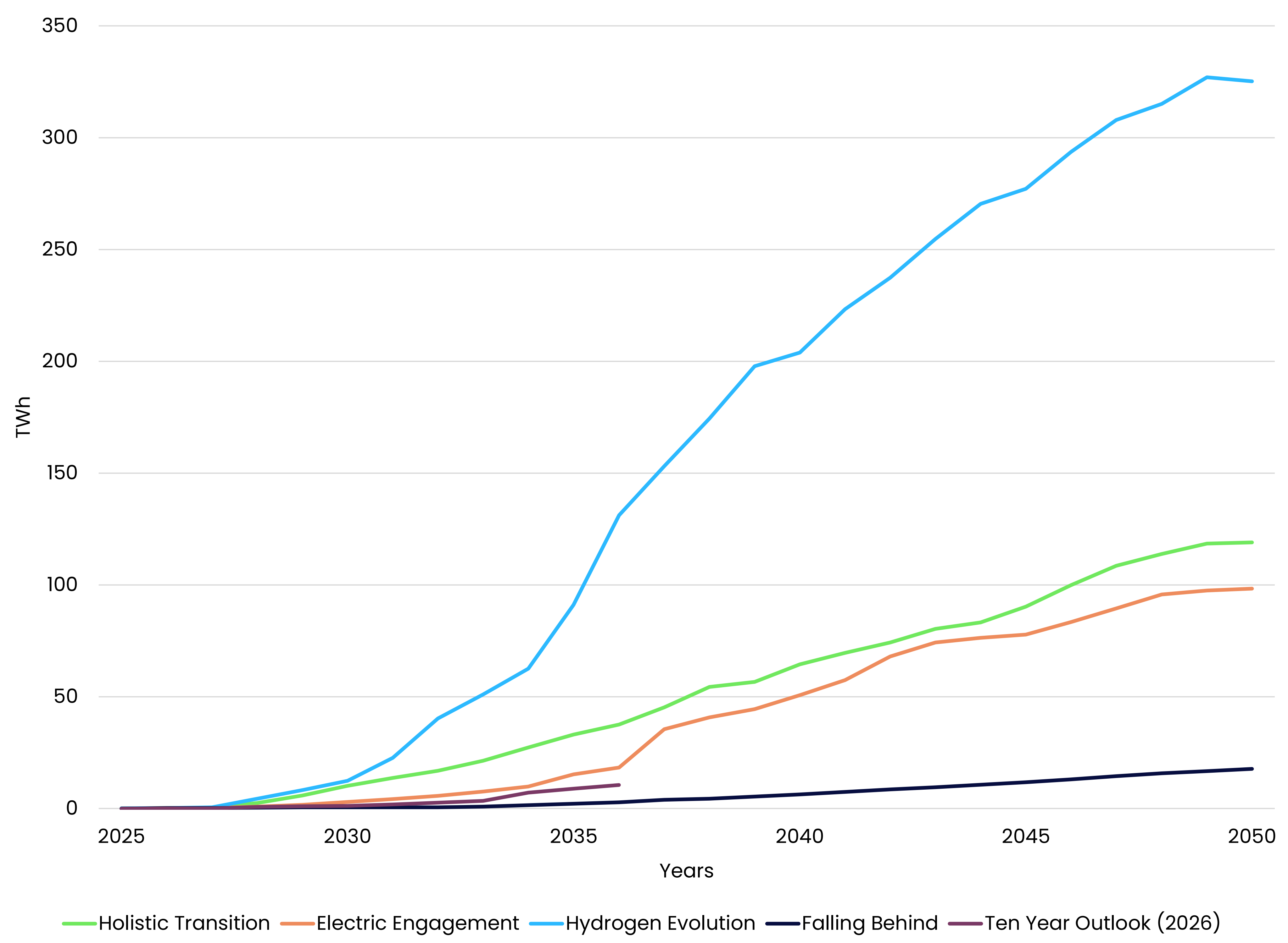
Hydrogen can provide a low-carbon fuel option where electrification is constrained or prohibitively costly. For parts of industry and some power system applications, it could offer a route to emissions reduction, particularly in hard-to-abate end uses. Hydrogen features across the FES 2025 pathways as a potential contributor to energy system decarbonisation (Figure 24).

Hydrogen produced from low-carbon electricity via electrolysis is green hydrogen. Blue hydrogen is produced from natural gas with carbon capture and requires the relevant infrastructure. Early blue hydrogen development is expected to be concentrated in industrial clusters, creating more localised gas demand where production assets connect to the gas system.

Support for low-carbon hydrogen production in the UK is delivered through the Hydrogen Production Business Model (HPBM). While electrolytic hydrogen production projects can receive HPBM support through Hydrogen Allocation Rounds (HAR), CCUS-enabled blue hydrogen projects can also access HPBM revenue support via the cluster sequencing programme, reflecting their reliance on shared carbon transport and storage infrastructure.

HAR1 projects are expected to be funded in the long term via the Gas Shipper Obligation,[21] subject to legislation, with costs expected to be passed through to gas consumers. Government analysis suggests this could add approximately £2.60–£4.50 per year to the average dual-fuel household bill for HAR1 projects alone, noting this reflects only green hydrogen deployment. This would increase as further projects are bought forward.

Figure 24: Hydrogen Production across FES 2025 pathways, Falling Behind scenario and 2026 Ten Year Outlook, 2025-2050



21 GOV.UK, *Funding Mechanism for Hydrogen Business Model*

Transport and storage

Hydrogen infrastructure will develop in stages, with larger networked systems evolving as volumes scale.

Hydrogen will impact future network configuration, requiring choices between repurposing existing gas pipelines and developing new, dedicated hydrogen infrastructure. These decisions will shape how gas and hydrogen systems operate over the long term.

Hydrogen storage will play a critical role, as production is unlikely to match demand in real time. This is particularly important where hydrogen is produced from electricity, as output will vary with power system conditions. Storage is therefore needed to balance supply and demand, provide flexibility, and support security of supply.

The development of hydrogen transport and storage increases the interaction between the electricity system, hydrogen production and the existing gas system. This makes planning and operation more complex and means these systems can no longer be considered in isolation.

There is significant uncertainty about the scale, location and timing of hydrogen infrastructure. If this is not managed carefully, there is a risk of building assets too early or too late, leading to inefficient investment or underused infrastructure.

An important challenge will be putting in place the right frameworks to support safe and efficient operation. This includes clear economic regulation, well-defined security standards, and appropriate codes governing how networks are planned and run. Hydrogen producers, as the primary balancers, and hydrogen transporters, as system operators with residual balancing responsibilities, will need to work closely with other parts of the energy system to ensure operational decisions are coordinated and deliver efficient whole-system outcomes.[22]

22 As proposed in *DESNZ publication on the hydrogen economic framework.*

Demand

Hydrogen-to-power and sustainable aviation fuel could anchor demand for hydrogen.

Hydrogen demand will develop across different sectors and locations, with implications for gas market arrangements, network use and whole system coordination.

Hydrogen-to-power

Hydrogen-to-power could provide a source of low-carbon dispatchable generation, supporting electricity system resilience during periods of high demand, low renewable output or wider system stress.

This creates specific market design and operational questions. Hydrogen-to-power is likely to have a low load factor and intermittent demand profile, and would require close coordination between electricity dispatch signals, hydrogen fuel availability, storage and network operation.

Hydrogen-to-power will likely depend heavily on hydrogen storage rather than real-time production. This raises questions about how hydrogen storage is funded, accessed, valued and operated, and how its role in electricity system resilience is reflected in market arrangements. Where hydrogen is produced from natural gas with CCUS, hydrogen-to-power could also sustain localised gas demand in industrial clusters or other connected locations, even as overall gas demand declines.

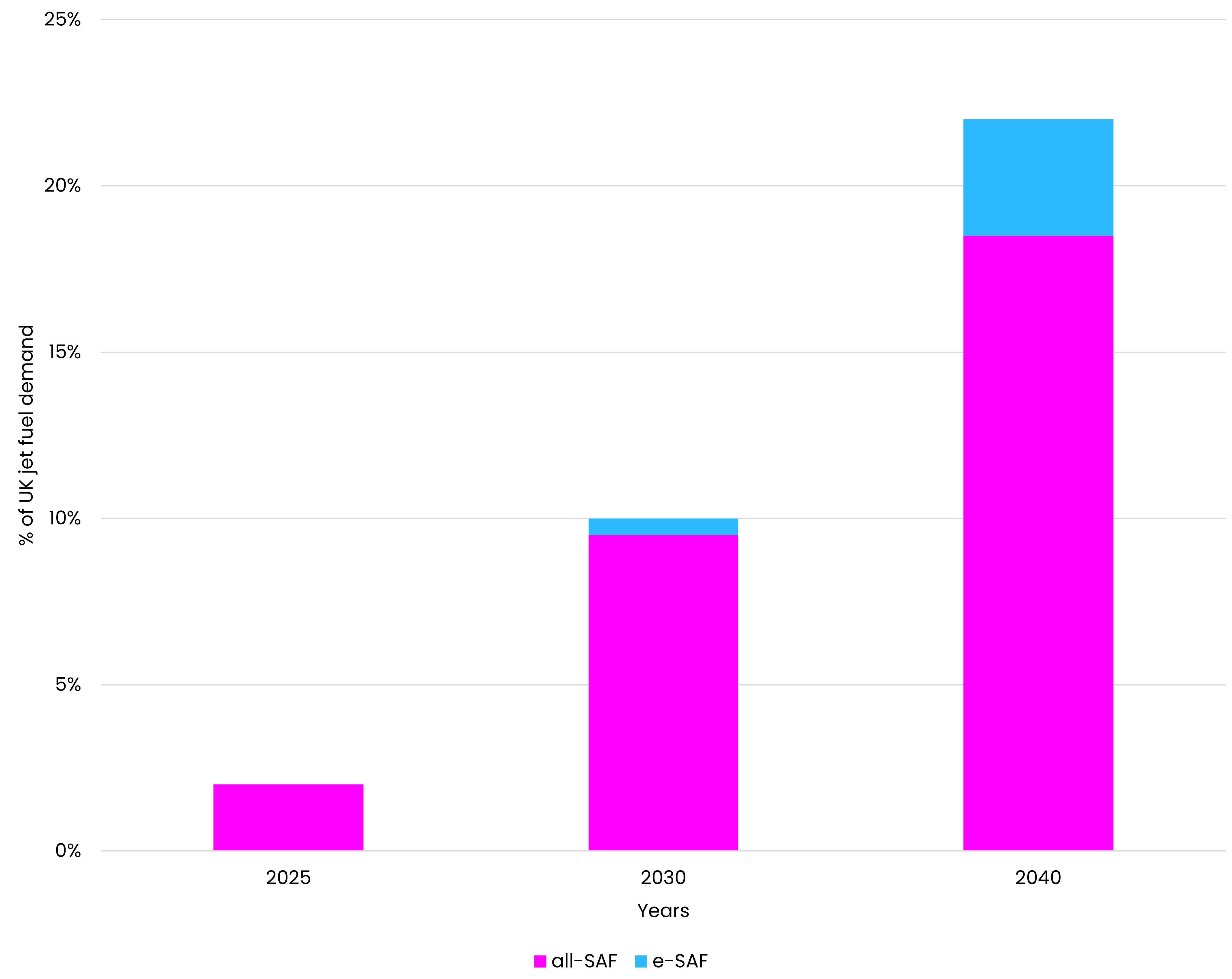
Recognising the potential role of hydrogen-to-power, the government confirmed through its *Hydrogen to Power: Market Intervention Need and Design* consultation in December 2024 that a Dispatchable Power Agreement-style mechanism is its preferred approach for supporting early projects. As policy and market arrangements develop, it will be important to understand how hydrogen-to-power interacts with gas, hydrogen and electricity markets, and whether existing frameworks provide the right signals for investment, operation and resilience.

Sustainable Aviation Fuel

Sustainable Aviation Fuel (SAF) represents a potential anchor source of hydrogen demand. SAF mandates in the UK and EU create a growing, policy-driven requirement for low carbon fuels, with Power-to-Liquid (PtL)[23] explicitly intended to scale beyond the limits of bio-based feedstocks. PtL production relies on hydrogen and captured carbon, and the lifecycle emissions requirements strongly favour green hydrogen. Blue hydrogen could contribute where it meets emissions thresholds, but may be less competitive or ineligible for certain policy targets.

As a result, SAF demand is likely to drive sustained hydrogen demand growth, with implications for electricity demand, system coordination and infrastructure planning.

Figure 25: SAF mandates for the UK



(source: Department for Transport – Sustainable Aviation Fuel mandate: Compliance Guidance)

23 Power-to-Liquid is a process for producing electro-Sustainable Aviation Fuel (e-SAF) combining hydrogen with captured carbon dioxide.

Hydrogen for heat and industry

Hydrogen is likely to play an important role in industrial processes that are hard to or prohibitively costly to electrify. Therefore, demand is expected to be spatially concentrated, linked to industrial clusters, infrastructure availability and local decarbonisation pathways. Depending on the production route, hydrogen could either sustain residual gas demand (where produced from gas with CCUS) or reduce it (where it displaces direct gas use).

As set out in the *Warm Homes Plan,* hydrogen is not yet a proven technology for domestic heat at scale. Any role in heat is likely to emerge later, but would require significant changes to consumer protection, retail arrangements, billing and safety frameworks.

Hydrogen blending

Hydrogen blending is a potential transitional pathway to support early hydrogen market development. However, blending introduces system impacts across gas quality, calorific value, billing and settlement, as well as end-use compatibility. These impacts are particularly relevant for sensitive or gas-dependent users, where changes in gas composition may affect operational and commercial decisions, equipment integrity or regulatory compliance.

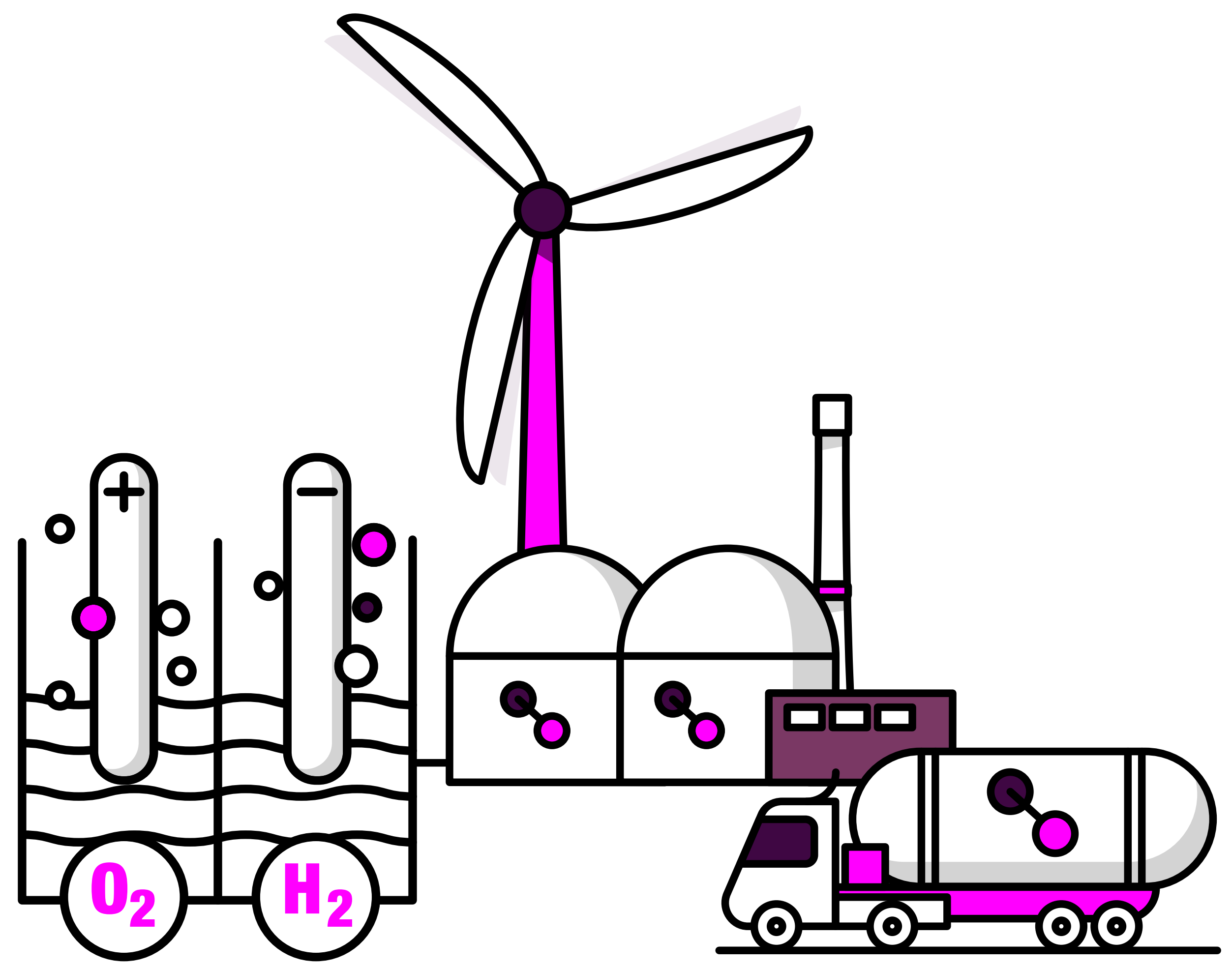
Understanding and mitigating these impacts will be critical, including through work to identify sensitive end user groups and assess system-wide implications. Work is already under way across the gas networks, through programmes such as the Blending Implementation Programme, to assess these impacts and the changes required to enable safe and efficient operation at scale.

The government has taken a positive decision to support *hydrogen blending into Gas Distribution Networks* of up to 20% by volume in certain circumstances, while continuing to consider more limited *blending into the NTS*. Any rollout remains subject to safety approvals and further regulatory and market framework changes.

Taken together, hydrogen-to-power, SAF, industrial hydrogen demand, potential heat use and hydrogen blending all point to the same strategic issue: hydrogen demand will not develop in isolation. Its growth will affect, and be affected by, gas market arrangements, electricity market operation, infrastructure planning, support frameworks and consumer-facing rules.

While some demand segments are likely to be location-specific, uncertain or transitional, others may provide more sustained, policy-driven signals. In particular, hydrogen-to-power and SAF could emerge as anchor sources of demand: hydrogen-to-power through its role in system resilience, and SAF through mandated volumes and stringent low-carbon requirements, which are likely to drive sustained demand for low-carbon hydrogen over time.

We are proposing further work to understand how hydrogen market development will impact the gas system in the future.



Carbon capture, utilisation and storage

If carbon capture, utilisation and storage (CCUS) develops at scale, gas market arrangements may need to adapt to more localised and enduring system interactions.

CCUS enables carbon dioxide from hard-to-abate industrial processes, blue hydrogen production and power generation to be captured, transported and either permanently stored or used in industrial applications. In the UK, initial deployment is focused on the Track-1 clusters, HyNet and the East Coast Cluster, with further development expected through Track-2 clusters, including Acorn in Scotland and Viking in the Humber.

CCUS is expected to play a role in decarbonising parts of industry and power where alternatives such as electrification or fuel switching may be more difficult or more costly. The transport and storage element of CCUS is supported by government, reflecting the need to develop shared infrastructure ahead of fully mature commercial markets.

CCUS could create new interactions with the gas system, particularly where natural gas continues to be used in industrial processes, CCUS-enabled hydrogen production or gas-fired generation fitted with carbon capture. In these cases, CCUS may support more localised and enduring gas demand even as overall gas demand declines.

For power generation, carbon capture can introduce an efficiency penalty, which may increase fuel use relative to unabated operation and affect dispatch patterns, fuel requirements and operational market arrangements. The Dispatchable Power Agreement is intended to support CCUS-enabled power by helping higher-cost, low-carbon dispatchable generation compete with unabated gas-fired generation in the electricity market.

DESNZ is also consulting on non-pipeline transport options for captured carbon. If developed, this could expand the potential use of CCUS beyond pipeline-connected clusters and create further interactions with gas demand outside the initial cluster areas.

These developments will also have implications for gas system operation and infrastructure use. Sites connected to CCUS infrastructure may retain strategic gas demand for longer, while the build-out of CO_2 transport and storage networks could create opportunities for asset repurposing in some locations. In Scotland, for example, National Gas Transmission's SCO_2T Connect project is intended to repurpose existing gas pipeline infrastructure to transport captured CO_2 to offshore storage.

At scale, CCUS is likely to require gas market arrangements to accommodate more geographically concentrated and enduring gas demand, changes in infrastructure use and closer coordination between gas, electricity, hydrogen and CO_2 transport networks.

We will continue to monitor CCUS development and assess implications for gas markets in subsequent GMR cycles.

Areas for further work

Within the Emerging Markets Central Challenge, we are proposing two key areas for further work. Longer-term decisions on emerging market development and their interactions with gas will be made through government, Ofgem and industry.

Figure 26: **Strategic questions and areas for further work for Central Challenge 3 – Emerging Markets**

Areas for further work		Owner and Timeline	
Certification and the UK Emissions Trading Scheme	**Role of certification** Review of certifications, how they interact and how they support decarbonisation	**NESO**	Area of immediate focus following GMR publication (2026 onwards)
Hydrogen	**Impacts of H2 on gas system** Understanding how hydrogen could impact gas through replacement and use for production	**NESO**	Area of focus during this GMR cycle following latest DESNZ hydrogen strategy update

Summary

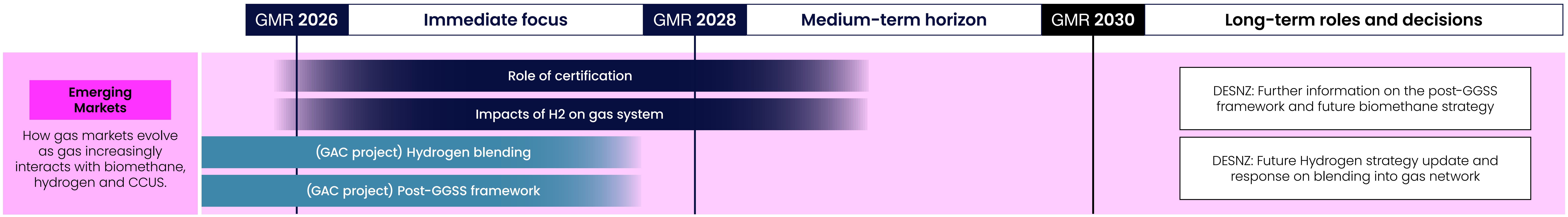
The Emerging Markets Central Challenge shows that the future of gas market arrangements will not be defined solely by adapting the existing methane system. As biomethane, hydrogen, and CCUS become more significant, gas markets may need to further consider support frameworks, certification arrangements, and operational interfaces.

These developments are likely to emerge unevenly across Great Britain, shaped by industrial clusters, network capacity, feedstock availability, storage potential, electricity system needs and wider infrastructure decisions. This means future market arrangements will need to work alongside strategic spatial planning and whole system coordination.

DESNZ and Ofgem will continue to make policy decisions across the different energy markets to support their development and growth. The purpose of this GMR is not to prescribe policy, but to identify where gas market arrangements may need to adapt.

Taken together, the three Central Challenges show that the future of gas markets must support an orderly transition, security and efficiency. Through this GMR and future iterations, NESO will continue to develop the evidence base and progress areas for further work to support coordinated decision-making and drive change in the gas market out to 2050.

Figure 27: **Emerging Markets areas for further work and long-term questions timeline**



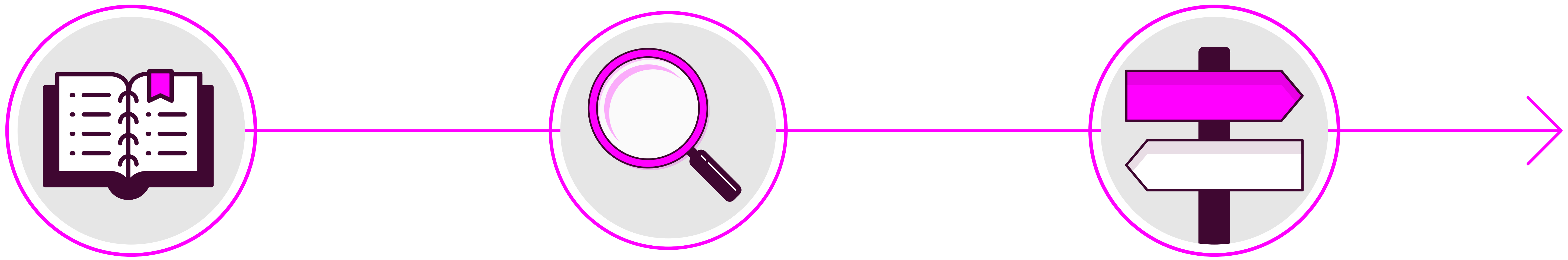
6. Conclusion and Future Cycles

This first Gas Market Roadmap (GMR) identifies how changing demand, increasing variability and emerging markets may impact existing gas market arrangements. While these arrangements continue to support system operation today, the challenge is how they adapt over time to maintain a market that is attractive to investors, resilient and affordable.

The GMR will be updated on a two year cycle. Future publications will build on this first assessment, strengthening the evidence base, tracking developments in policy and regulation, and refining areas of focus as the system evolves.

Over time, GMR cycles will move from identifying challenges to testing options and supporting more coordinated decision making across government, regulators and industry.

Figure 28: Focus areas for GMR 2026, GMR 2028 and GMR 2030



GMR 2026

Establish strategic baseline:

- Define Central Challenges
- Identify areas for further work
- Launch first projects

GMR 2028

Deepen evidence and test options:

- Track developments across the value chain, including policy and code changes
- Evaluate initial project findings
- Review and refine challenges

GMR 2030

Support longer-term direction:

- Report on project findings across cycles
- Review and refine challenges
- Drive progress toward post-2030 regulatory and policy decisions

Appendix 1: Gas Market Arrangements & Participants

Key: Market Arrangements | Market Participants

DESNZ	OFGEM	NESO	National Gas Transmission	Health and Safety Executive
Legislation, Policy, Subsidy Mechanisms and Strategic Direction	Licenses, Codes, Regulation & Price Control	Gas System Planner	Gas System Operator	Safety, Technical Standards and Emergency Framework

Supply

- Gas Terminals
- LNG Terminals
- Storage Operators
- Interconnectors
- Hydrogen Producers
- Biomethane Producers
- Carbon Emitters

Trading

NBP

National Balancing Point

price formation • balancing reference • wholesale hub

Wholesale Gas Market

- Traders
- Shippers

Transportation

Networks

- Transmission Network
- Distribution Networks
- Independent Gas Transporters Networks
- Carbon Networks
- Hydrogen Networks

System Operation

- System Balancing
- Capacity Allocation
- Linepack Management
- Security Standards
- Emergency Response

Demand

- Suppliers
- Residential
- Industrial
- Power Generation
- Commercial

Policy and economic levers

Supply

- Certification
- Policy Subsidies
- Licensing / permitting rules

Trading

- Carbon Markets
- Certification
- Network Codes
- Commercial Balancing

Transportation

- Infrastructure Investment Incentives
- Charging Frameworks
- Network Codes
- Market Access Rules

Demand

- End use subsidies/tariffs
- Energy efficiency / heat policy signals
- Consumer protection
- Cost recovery

Appendix 2: Role of the Gas Advisory Council

An advisory group comprising experts from across the gas market value chain.

The Gas Advisory Council (GAC) operates as an advisory body, providing strategic insight on the future evolution of gas markets to support affordability for consumers, fairness across market participants, and long-term sustainability.

The GAC take a cross-molecule view of the gas system—spanning methane, hydrogen, and biomethane and have helped us develop priorities for further analytical work.

Throughout the development of the Gas Market Roadmap (GMR), the GAC have been engaged and provided valuable feedback to help deliver a valuable final product.

Consumers

Industrial Consumers

Domestic Consumers

Transport and Storage

Storage Providers

Transmission Networks

Distribution Networks

Independent Gas Transporters

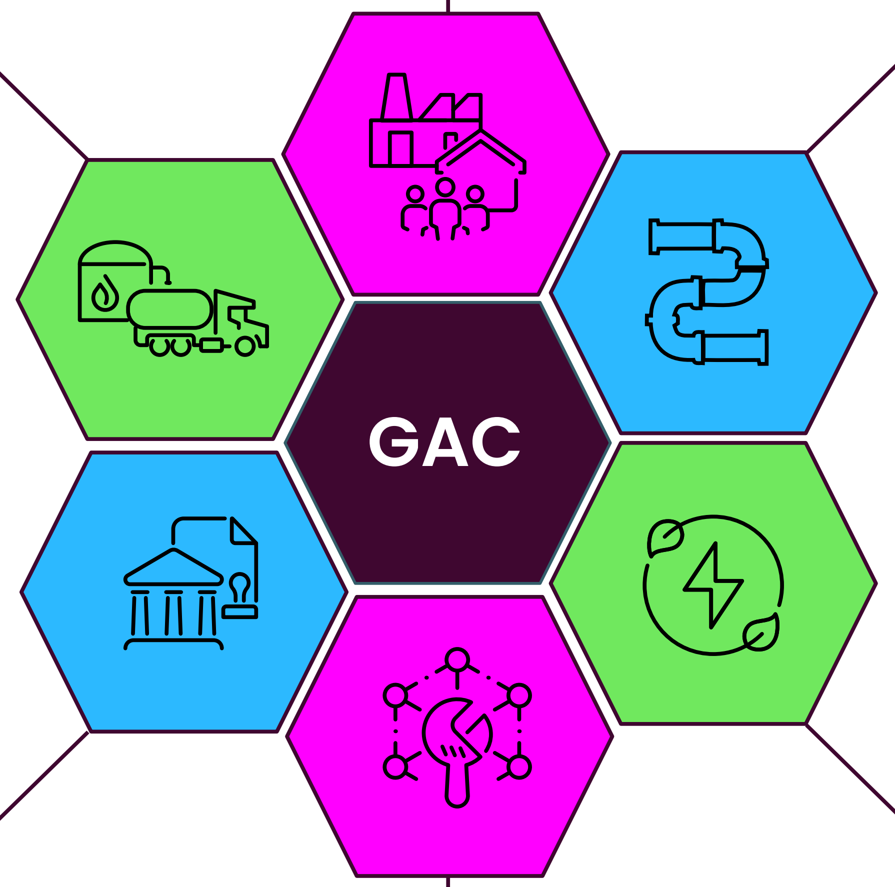
Interconnectors

Shippers and Suppliers

Large Shippers / Suppliers

Small – Medium Shippers / Suppliers

Industrial Shippers / Suppliers



Governance and Regulation

Government

Regulator

Code Administration

Billing, Settlement and Market Data

Cross Market

Skills and Jobs

Climate Change Advisory

Academia

Evolving Markets

Hydrogen Markets

Carbon Capture Utilization and Storage

Biomethane Markets

LNG Markets

Glossary

Acronym	Description
Capex	Capital expenditure
CCS	Carbon capture and storage
CCUS	Carbon capture, utilisation and storage
CFD	Contracts for Difference
CfE	Call for Evidence
CSNP	Centralised Strategic Network Plan
DESNZ	Department for Energy Security and Net Zero
ECO	Energy Company Obligation
ETS	Emissions Trading Scheme
e-SAF	electro-Sustainable Aviation Fuel
FES	Future Energy Scenarios
FSNR	Future Systems and Network Regulation (Ofgem programme)
GAC	Gas Advisory Council
GB	Great Britain
GD	Gas distribution
GDN	Gas Distribution Network
GGSS	Green Gas Support Scheme
GMR	Gas Market Roadmap
GMaP	Gas Market Action Plan

Acronym	Description
GNCNR	Gas Network Capability and Needs Report (NTS capabilities to meet network requirements)
GOA	Gas Options Advice (evaluation of investment proposals to meet the network's capabilities)
GSIUR	Gas Safety (Installation and Use) Regulations 1998
GS(M)R	Gas Safety (Management) Regulations
GSO	Gas system operator
GSSA	Gas Supply Security Assessment
GT	Gas transmission
H2	Hydrogen
HAR	Hydrogen Allocation Round
HSE	Health and Safety Executive
HPBM	Hydrogen Production Business Model
HT	Holistic Transition (FES pathway)
ICIS	Independent Commodity Intelligence Services
IGT	Independent Gas Transporter
LDZ	Local Distribution Zone
LNG	Liquefied Natural Gas
NBP	National Balancing Point

Acronym	Description
NCS	Norwegian Continental Shelf
NGT	National Gas Transmission
NPT	Non-pipeline transport
NSTA	North Sea Transition Authority
NTS	National Transmission System
Ofgem	Office of Gas and Electricity Markets
Opex	Operating expenditure
PtL	Power-to-Liquid
RAB	Regulated asset base
RAV	Regulatory asset value
RESP	Regional Energy Strategic Plan
RHI	Renewable Heat Incentive
RIIO	Revenue = Incentives + Innovation + Outputs (Ofgem price control framework)
SAF	Sustainable Aviation Fuel
SEP	Strategic Energy Planning
SO	System Operator

Acronym	Description
SSEP	Strategic Spatial Energy Plan (optimal location of generation and infrastructure)
UIOLI	Use It Or Lose It
UK	United Kingdom
UKCS	UK Continental Shelf
UNC	Uniform Network Code
UNC0903	Uniform Network Code Modification 0903
WEM	Whole Energy Market
WEMC	Whole Energy Market Coordination

NESO

National Energy
System Operator