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UK Gas Security: Managing Energy Security Challenges and Transition Risks

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Executive Summary

Gas production on the UK Continental Shelf is forecast to fall faster than the UK's demand for gas. Given the basin's maturity, policy can do little to change this fact (Section 4). This means that, going forward, while the UK will require less gas in absolute terms, a greater share of the gas it does consume will have to be sourced from imports.

Given that gas production in the UK's regional neighbours is also declining (Section 2), it is Liquefied Natural Gas (LNG) that will fill the gap. Global LNG export capacity is expected to increase 60% by 2030 (Section 3), but the dangers of the UK's reliance on market prices to attract spot LNG cargoes were painfully exposed in 2022-2023 (Section 5). Greater reliance on LNG would also increase the carbon intensity of the gas consumed in the UK in the short-to-medium term.

This unpalatable supply-side picture gives the UK every reason to expedite gas demand reduction and make good on its net zero commitments. Recent modelling suggests, with ambition, it is possible to do this significantly faster than envisioned by the Climate Change Committee in the balanced pathway it used to model the UK's 6th carbon budget (Section 8). Yet this is not easily done.

Bold policy is now required by the new government to bring down gas demand at pace. Prevarication on the technology mix for decarbonising home heating, and under-funding of the Boiler Upgrade Scheme, saw just 19,000 heat pumps installed over the year and half to 2023 (Section 9). Gas-to-electricity switching, across home heating, industry and other sectors, will depend on the ability of policy to bring down the current 1:4 ratio of gas-to-electricity prices per unit of energy (Section 10). Another key variable is the scale of flexible hydrogen needed to offset the intermittency of renewables, and the proportion of this which will be 'blue hydrogen', i.e., produced with natural gas and carbon capture and storage (Section 11).

The Climate Change Committee have warned that on forecasted build rates there may not be enough renewable electricity on the grid to meet hydrogen demand through electrolysis. The more blue hydrogen we use, the longer our reliance on gas. At the same time, absent low carbon sources of grid-scale flexibility (Section 11), the government may turn to unabated gas to balance the grid, including through the construction of new gas-fired power stations to replace retiring capacity.

Yet the accelerated phase-out of gas required on both climate and security of supply grounds could, if poorly managed, bring forward security of demand risks. Falling gas throughput will undermine the commercial and technical viability of critical infrastructure on which the UK will continue to rely over the medium-term. In the case of the UK's gas pipeline network, there are large outstanding investment costs, and tens of billions in decommissioning costs, that have to be met despite a shrinking customer base (Section 6). The UK's gas storage capacity may expand in anticipation of government support for hydrogen storage, but for the foreseeable future, the two UK-European interconnectors will rely upon the uncertain economics of the gas trade (Section 7).

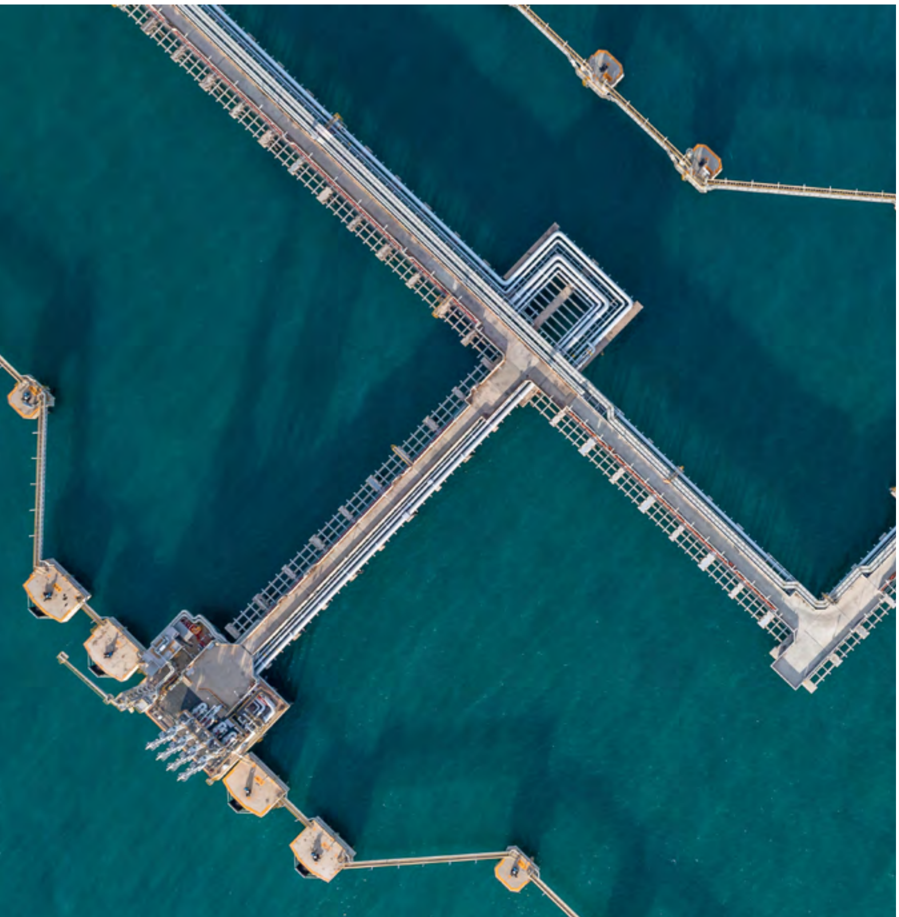
Overall, this means that gas demand reduction will be both the pivotal solution to supply-side exposure to volatile LNG imports, and a source of energy security risk in its own right, endangering the economic viability of critical gas infrastructure and bringing forward its decommissioning costs. The driving concern in both cases is the energy transition, and not the traditional preoccupation of energy security: physical security of supply. This necessitates a major reorientation of perspective and strategy.

1. Introduction

Michael Bradshaw & Louis Fletcher, Warwick Business School

The UK Energy Research Centre (UKERC) has been researching the question of UK gas security for over a decade. Back in 2014, as the second phase of UKERC came to an end, we published a research report entitled 'The UK's Global Gas Challenge', summarising the findings of a flexible fund project on 'The Geopolitical Economy of Global Gas Security and Governance: Implications for the UK.'[1] The central thesis of that study was that as the UK's gas import dependence was growing it was effectively 'globalising' its gas security and consumers were more and more exposed to events in the global gas market.

This initial project had three aims: first, to develop a framework for analysis of the UK's gas security; second, to identify the geopolitical drivers, actors, issues and risks shaping global gas security to the late 2020s; and third, to consider the implications of our findings for the UK's energy strategy and low carbon transition policy.



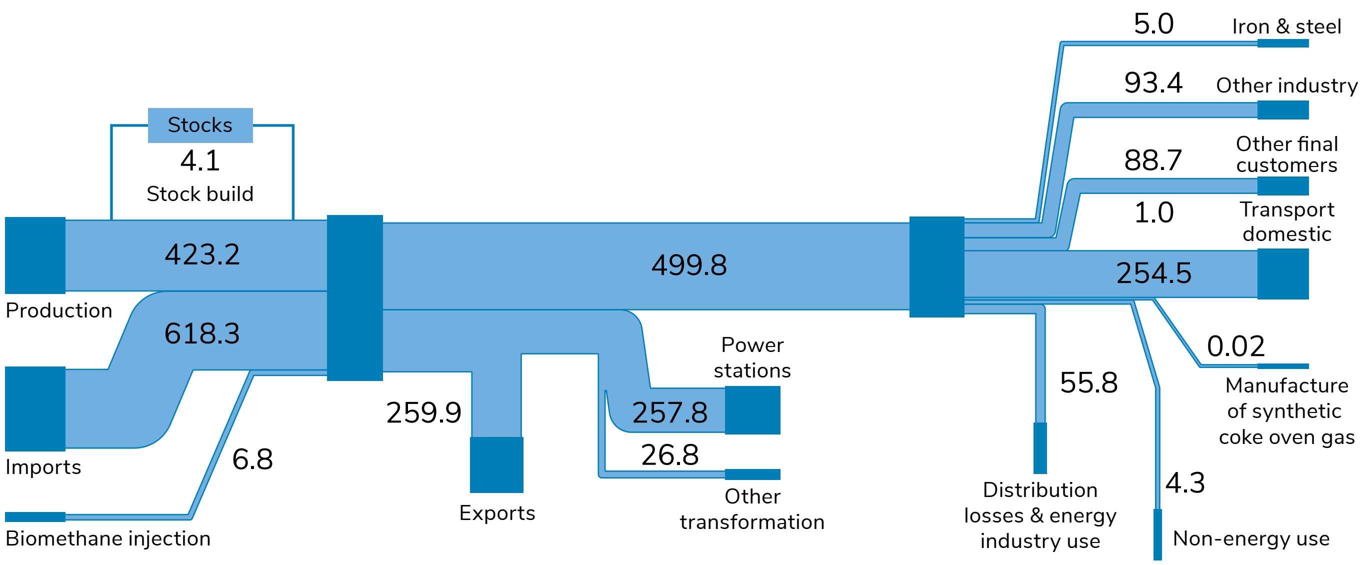
Our research continued through the third phase of UKERC, located in the 'Resources and Vectors' theme. In 2017-18 we conducted a series of gas security workshops in London and co-produced a series of short briefings that we then consolidated into our 2018 report, 'Future UK Gas Security: A Position Paper'.[2] That research sought to identify the potential impact of Brexit and the key issues that should be addressed in a post-Brexit 'UK Gas Security Strategy.' It deployed the supply chain approach developed in our earlier research and reached the conclusion that: "*Gas will continue to flow post-Brexit, but consumers may have to pay more for it to guarantee security. Longer term, it is not the outcome of Brexit that poses a threat to gas security, but the failure of the Government to provide a clear roadmap for the role of gas in the low carbon transition.*" This was a theme developed in various contributions to UKERC's annual *Energy Policy Review* by contrasting two approaches: 'gas by default' versus 'gas by design.' As the name suggests, 'gas by default' describes the Government's assumption that UK consumers will always have access to the gas that they need at a price that they can afford. Over the years the Statutory Security of Supply Reports produced for the Government had concluded that the UK has more than sufficient infrastructure to meet gas demand in all eventualities and benefits from a diversity of sources of supply; however, it also noted that we rely on market mechanisms – on paying enough to attract the gas we need – to ensure security of supply.

The post-Covid energy crisis and the gas supply crisis provoked by Russia's invasion of Ukraine in late February 2022 both exposed the dangers inherent in such a market-based approach. New problems also now loom. As the UK's energy transition gains pace, falling demand and the changing role of natural gas in the UK energy system will threaten the economic viability of its supporting infrastructure, much of which is aging. This is the notion of 'transition risk,' the fact the energy transition itself creates uncertainty and poses risks to the continued economic and technical viability of critical gas infrastructures. A 'gas by design' approach is required to manage these risks, and secure affordable access to natural gas as demand falls and the role of gas in the economy and energy system changes.

While there have been signs of an emerging gas by design approach, the recent gas crisis has seen security of supply concerns take precedence at the expense of a more strategic approach to managing the transition. The new government's ambitions to accelerate the transition are to be welcomed, but perhaps understandably, have focused upon building new low-carbon infrastructure. Less attention is being given to the question of how to manage the decline of incumbent systems.

It is in this context that this briefing seeks to assess the current status of the gas security challenges and transition risks that the UK faces to the end of this decade and beyond to 2035. Figure 1 presents a useful starting point as it demonstrates the role that natural gas plays in the UK energy system today.

Figure 1: Natural Gas Flow Chart 2022 (TWh)



Source: DUKES 2023

The data in Figure 1 are for 2022, which was far from a normal year. In the midst of the gas security crisis of 2022-23 the UK played a critical role as a 'gas bridge' to Europe. It imported LNG via its three terminals, transiting that gas through the national transmission system (NTS) to the two interconnector pipelines on the east coast, to be exported to Belgium and the Netherlands and beyond to compensate for falling supplies of Russian pipeline gas to Europe. Thus, the level of gas in the system in 2022 was inflated over previous (and likely subsequent) years.

Data for 2023 shows that gas exports fell by 32% compared to 2022.[3] Notwithstanding the unusual situation in 2022, when it comes to the domestic energy system, we can see gas playing a crucial role in three ways. First, in generating electricity, but more and more as flexible backup to intermittent renewables; second, as the most important source of domestic heating, a fact that leads to a distinct seasonal pattern to gas demand; and third, as a critical input into industry as a source of process heat and power and as a raw material.

With the benefit of hindsight, we know that the 'dash for gas' and the switch from coal to gas played a critical role in decarbonising the domestic energy system, but this autumn the last remaining coal-fired power station will close. At that point gas will be the most carbon-intensive element of the power generation mix, and future power sector decarbonisation will require the removal of 'unabated gas power generation'. Equally, meeting the country's ambitious carbon budgets will require the decarbonisation of domestic heating and industrial activity. The pace of these changes will determine the level of future gas demand, while continuing decline on the UK Continental Shelf (UKCS) will mean increasing import dependence.

Depending on the rate of gas demand reduction, less gas will need to be imported in absolute terms, but it will be a growing share of total consumption. A faster rate of demand reduction (including efficiency savings) will ease the security of supply challenge as less gas will need to be imported. However, in part, it is uncertainty over the pace of decline that generates transition risk as fewer and fewer customers will have to carry the cost of maintaining the gas system's infrastructure. This is a challenge made all the more difficult because some of that infrastructure may need replacing in the medium-term to maintain the resilience of the system even as demand falls. Therefore, we can propose that, in relative terms, as gas demand falls security of supply becomes less of a challenge – dependent on the state of the global LNG market – and transition risk becomes the major issue that requires strategic management. The purpose of this briefing is to assess the current situation vis-à-vis security of supply and transition risk to aid in the development of a much-needed 'Gas Security Strategy.'

As before, we deploy our supply chain approach to structure and deliver our analysis.

Table 1: Supply Chain Approach to UK Gas Security

	Geopolitics	Dimensions	Issues
Upstream	Security of supply	• Resource base • Technology • Investment	• Future of UK Continental Shelf Production • Future of Norwegian Continental Shelf exports to UK • EU import capacity • Global LNG market dynamics • Prospects for biomethane and bioSNG
Midstream	Security of transmission (transit)	• Processing • Storage • Transportation	• UK Continental Shelf infrastructure • Utilisation of LNG terminals • Domestic storage capacity • Status of interconnectors • Status of National Transmission System • Status of Gas Distribution Networks • Status of National Balancing Point • UK/EU Gas Governance
Downstream	Security of demand	• Power generation • Domestic use • Industrial use	• Ratio of electricity to gas prices • Domestic heat decarbonisation • Intermittency and capacity markets • Future of the UK ETS • Hydrogen strategy • Role of CCS in industry

This briefing is one of three 'integration' projects completed in completed in 2024. It has its origins in a day-long workshop that took place at WBS-Shard in May 2023. It integrates in four senses. First, it called on expertise across UKERC to assess the implications of the three major decarbonisation challenges – power, heat and industry – that will impact future gas demand (it did not consider transport). Second, it drew on a longstanding collaboration between UKERC's gas security research and the Gas Programme at the Oxford Institute for Energy Studies (OIES).

Third, it connected to other UKRI funded projects such as the NERC-ESRC Research Programme on 'Unconventional Hydrocarbon in the UK Energy System' (UHUK), the ESRC 'Fraying Ties' project and the Centre for Research into Energy Demand Solutions (CREDS). Finally, our research benefitted from continued interaction with the UK Government, think-tanks and key industry players. The report was prepared ahead of the 4th July 2024 General Election and the installation of the new Labour Government; however, our findings remain valid and can serve to inform a coherent 'gas security strategy' that looks beyond security of supply.

2. European Context

Jack Sharples, Oxford Institute for Energy Studies

Natural gas is a fuel of strategic importance to the UK. It provides heating to almost 80% of households in England, Wales, and Scotland,[4] which profoundly influences the seasonality of UK gas demand. In 2023, natural gas also accounted for 38% of final energy consumption in the industrial sector and 35% of UK electricity generation.[5] Gas therefore provides consistent baseload energy supply to all three sectors.

With nuclear power generation not particularly variable, and coal all but eliminated from the UK power generation mix (the last power station will close autumn 2024), gas also plays a vital role in balancing the variability of renewable power supply and the variations in electricity demand. On days of low wind power and high demand, gas can provide up to 60% of UK electricity supply, while on days of low demand and high supply from other sources, the share of gas can fall below 10%.[6]

Therefore, UK gas supply must be flexible enough to match the volatility in hourly and daily gas demand for power generation, in addition to the seasonality of gas demand for space heating. UK gross gas supply[7] in 2023 totalled 75.7 billion cubic metres (bcm) and was divided between domestic production (40%), pipeline imports from Norway (34%), and LNG imports (26%). UK gas production is almost entirely offshore in the North Sea, while pipeline imports from Norway also originate in the North Sea and make landfall at St Fergus (Scotland) and Easington (Yorkshire). LNG is imported via three terminals: Dragon and South Hook in Milford Haven, and the Isle of Grain in Kent.

The UK is connected to the Netherlands and Belgium by the BBL and Interconnector pipelines, which are used for market balancing. When the UK is oversupplied, volumes are re-exported to Europe, and when the UK is undersupplied, volumes can be imported from Europe.

Between June 2021 and February 2024, the UK was a net exporter every month via these pipelines, given the prevailing market tightness in northwest continental Europe. In 2023, the UK exported a net volume of 11.8 bcm to the Netherlands and Belgium, plus another 4.0 bcm to the Republic of Ireland and Isle of Man, leaving 59.9 bcm for domestic consumption. Given the ongoing dynamic of the UK as a consistent net exporter via the Interconnector and BBL, those pipelines cannot be considered sources of substantial UK gas imports.

The UK's largest gas storage facility, Rough, was closed in 2017, reopened in 2022, and now provides half of all UK storage capacity. It can store 1.53 bcm[8] – the equivalent of 2.6% of UK demand in 2023. The UK's relatively small storage facilities are used for continuous injections and withdrawals to balance the market on a daily basis, rather than to accumulate large stocks to balance the peaks and troughs of winter and summer demand.

Overall, the UK is dependent on two sources. First, gas production in the North Sea from the UK and Norwegian sectors and imports of LNG cargoes from the global market to provide ongoing baseload gas supply. And second, the flexibility offered by storage withdrawals, sendout from LNG regasification terminals, and flows on the BBL and Interconnector pipelines, to meet short-run fluctuations in UK gas demand.

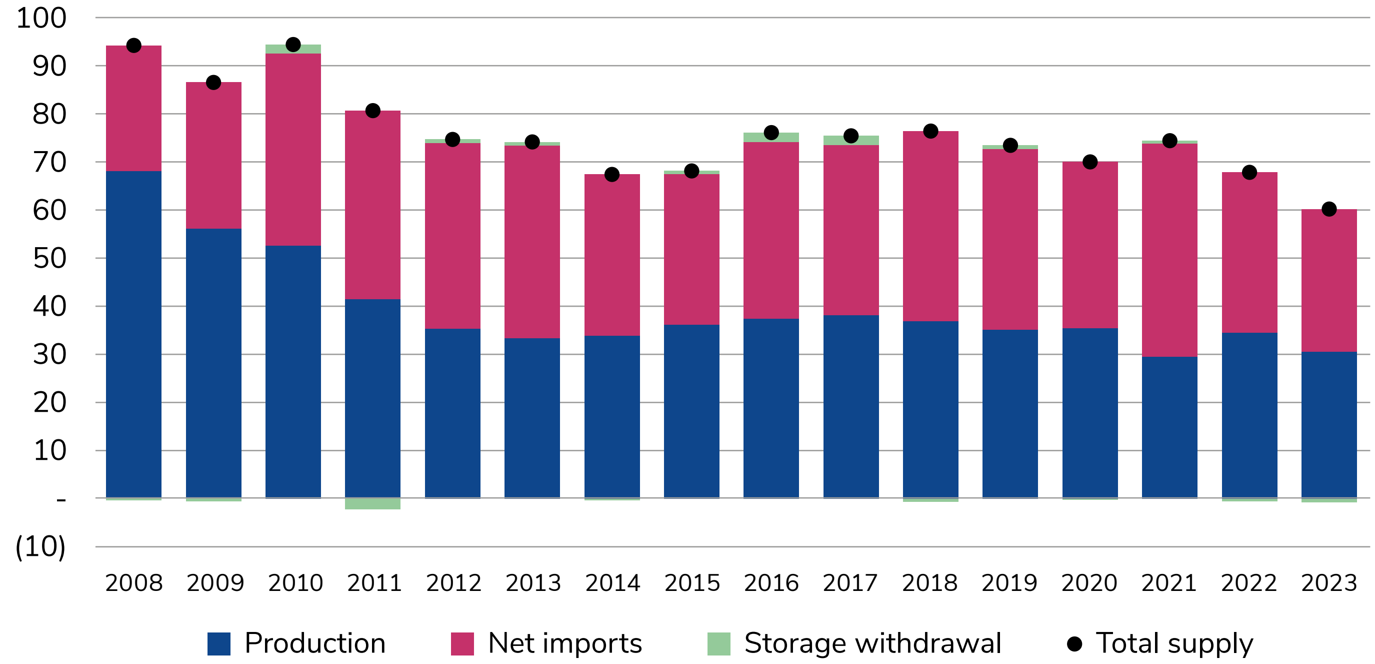
Currently, the UK is embedded in the gas market of North-West Europe. Norwegian gas has some optionality over whether to flow to the UK or to the continental EU, and LNG cargoes arriving in North-West Europe certainly have that optionality.[9] While the ability of traders to flow gas between the UK and Belgium/Netherlands will also ensure that outside times of capacity constraints (as seen in 2022), UK wholesale prices will not diverge substantially from those on the benchmark for North-West Europe, the TTF.

The main challenge for the UK over the coming decade will be to accommodate the forecast decline in gas production both in the North Sea (affecting both the UK and Norway) and in the UK's regional neighbours (Ireland, the Netherlands, Germany, and Denmark in particular), which will curb both UK gas production and the ability to import by pipeline from regional neighbours, while simultaneously increasing regional competition for LNG cargoes.

If the policy-driven decline in regional gas demand does not keep pace with the decline in regional gas production, the result will be increased dependence on LNG imports. This implies increased exposure to the global LNG market, which, although set for a large wave of new supply in the late 2020s, faces a more uncertain supply-demand balance (and prevailing price level) post-2030.

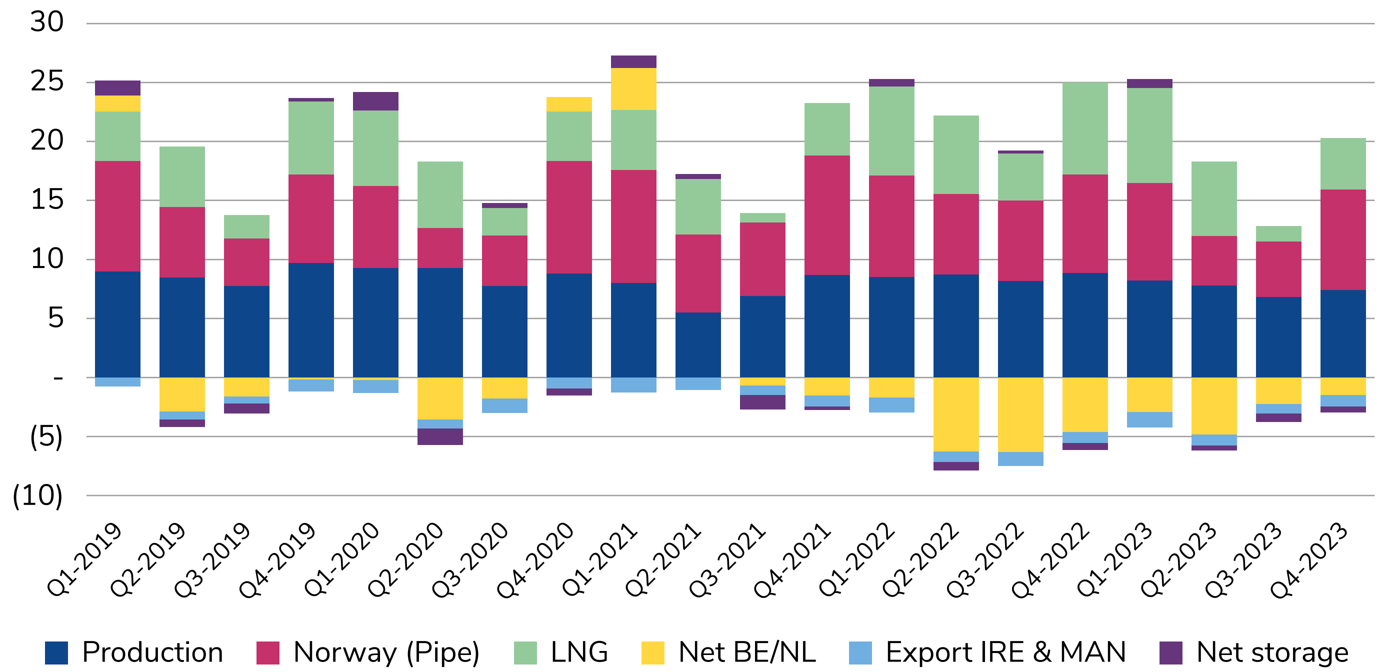
Given that the dynamic of declining regional production and increasing regional LNG imports has already begun, it is noteworthy that the UK LNG import capacity is currently being expanded.

Figure 2: UK Gas Supply from Production, Net Imports, and Net Storage Withdrawals Since 2008 (bcm per year)



Source: UK Government Energy Trends 2024

Figure 3: UK Quarterly Gas Supply by Source Since 2019 (bcm)



Source: UK Government Energy Trends 2024

3. Global LNG Supply

Mike Fulwood, Oxford Institute for Energy Studies

Global LNG supply has seen rapid growth since 2016, when the new wave of US LNG export capacity began to come onstream. In 2015, available LNG export capacity[10] averaged some 355 bcm. By 2023, the average available capacity had risen to some 560 bcm – an increase of over 55%. Over half of this increase was from the USA, supplemented by Russia (the Yamal project) and Australian expansions. By 2023, the USA had the most LNG export capacity, just beating Qatar and Australia.

The rapid expansion of LNG export capacity is expected to continue through to 2030, with a further increase to some 890 bcm – a further rise over 2023 of some 60%. Much of this increase is already under construction or has taken a final investment decision (FID) and is predominantly from North America (principally the USA, but also Canada and Mexico), plus large Qatari expansions, supplemented by smaller expansions in Australia, Russia, Papua New Guinea, Senegal/Mauritania, Nigeria and Mozambique.

In January 2024, the Biden administration announced that there would be a pause on the approvals of LNG exports to non-Free Trade Agreement (FTA) countries[11]. This pause, driven by election-year politics as an effort to placate the left of the Democratic Party, does not affect most of the projects in the US that have already taken FID, as they already have received approval for non-FTA exports. In any case it seems highly likely that the pause will be abandoned in 2025 or even before, regardless of whoever forms the next administration.

The destination of the LNG exports has been predominantly Asian and European[12] markets. In 2023 Asia and Europe accounted for some 95% of total LNG imports globally. This trend is expected to continue through to 2030, with Europe needing more LNG if demand does not decline as expected, with production and pipeline imports falling, and rapid growth in the Asian markets, especially China and Southeast Asia, plus India, Pakistan and Bangladesh.

Prior to 2019, Europe's LNG imports averaged some 55 bcm a year (2012 to 2018). In 2019, as almost 80 bcm of new LNG export capacity came online, LNG imports into Europe surged to some 116 bcm. This was not in response to rising European gas demand, but the LNG principally ended up in European storage, as well as offsetting declining production and pipeline imports. In 2020, Covid-19 hit, and Europe demand and LNG imports fell back a little. In 2021 the recovery from Covid and the cold winter in the northern hemisphere saw a sharp rise in Asia's demand for LNG, with Europe's ability to drawdown on storage, allowing more LNG to flow to Asia.

In 2022 the Russian invasion of Ukraine resulted in a sharp fall in pipeline imports from Russia. While European demand was reduced, a large rise in LNG imports was also required, both to meet the remaining demand but also to rebuild gas storage. In 2022, total LNG imports into Europe rose to just under 170 bcm from 100 bcm in 2021.

The large change in the flows of LNG between Europe and Asia was made possible because of the increasing flexibility in the global LNG market. The traditional LNG business model was a heavily contracted market with so-called destination clauses linking specific export plants to specific import markets, and even import terminals. The contracts were also mostly oil indexed.

This model was already beginning to change as Europe's gas markets were liberalised and competition in gas supply was introduced. However, with the advent of US LNG exports in 2016, the global LNG market became much more flexible. The US LNG export contract structure is very different from the traditional LNG contract structure. The offtakers are contracting for capacity at the US LNG export terminals separately from the gas supply and their only obligation is to pay a capacity charge if they choose not to lift the LNG – with no obligation to pay for the gas supply. These free-on-board (FOB) contracts also have no specific destination for the LNG, which can be directed to any import terminal capable of receiving the LNG tanker.

Prior to 2016 the volume of spot LNG in total LNG imports averaged some 18%, with much of the rest being oil indexed under specific destination-linked contracts.[13] The introduction of more flexible US LNG contracts, which also spread to other suppliers, has greatly increased the flexibility in the LNG market. In addition, the use of oil indexation is also in decline. The latest IGU Wholesale Gas Price Survey shows that over 50% of the pricing of LNG in 2023 was gas-on-gas competition (either LNG sold into traded markets, such as the UK, spot LNG or contracted LNG linked to hub prices), with the rest being oil indexed.[14] The author also estimates, using the database of LNG contracts from the NexantECA World Gas Model, together with information on spot LNG cargoes, that some 60% of global LNG trade is now flexible, with most of it coming from Atlantic Basin export facilities, particularly the USA.

This flexibility was of crucial importance in 2022 for Europe, as pipe imports from Russia fell sharply. Substantial volumes of LNG were diverted from Asian markets towards Europe. In 2021 only one-third of US LNG exports went to Europe, while in 2022 this rose to two-thirds, with total US LNG exports also rising. If the LNG market in 2022 had remained more like the destination-restricted market of 10 or 15 years earlier, then Europe's ability to meet its even reduced gas demand would have been severely compromised. This would likely have led to extensive blackouts and even industrial curtailments.

The anticipated rapid growth in LNG supply and a continuation of more and more flexible LNG, suggests that any possible constraints on LNG supply to Europe generally, and the UK in particular, appear unlikely in the absence of any major supply disruption.

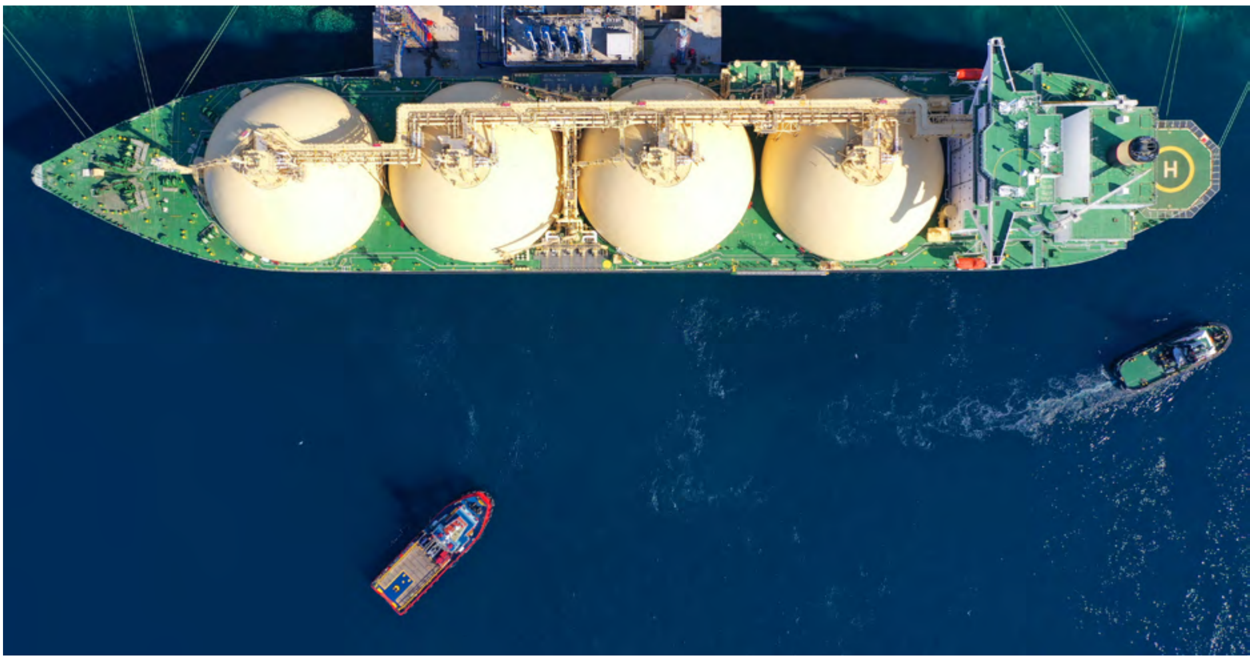
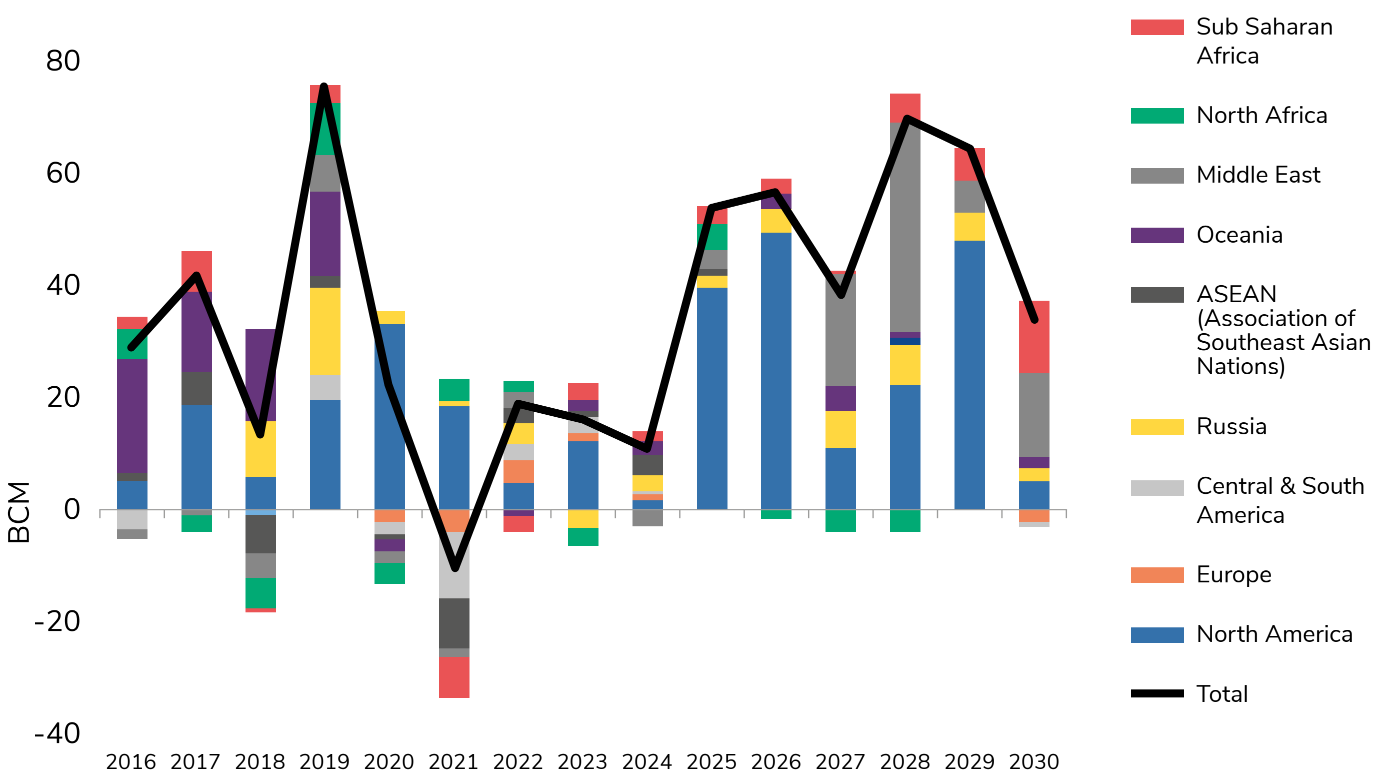


Figure 4: Annual growth in LNG export capacity by region



Source: NexantECA World Gas Model

4. UK Gas Production

Gavin Bridge, Durham University & Gisa Weszkalnys, London School of Economics

Gas has been extracted from the UKCS for more than half a century.[15] Most of this gas has been used to heat UK homes, fuel industry and, since the 1990s, generate electricity. Domestic gas supply rose rapidly, matching growing demand, and peaked in 2000 (115 bcm) when the UKCS supplied nearly all the gas consumed in the UK. Gas demand has subsequently fallen, but UKCS production has declined more quickly. In 2022, it stood at 37.7 bcm, around half total gas supply in the UK (72 bcm).[16]

The prospects for gas production on the UKCS are constrained both by the maturity of the basin and by the climate consequences of gas production and consumption. Over half (53%) of the UK's territorial carbon dioxide emissions are attributable to using gas: gas accounts for most emissions from the residential sector, and 70% of those in the power sector, for example. Gas production also contributes to the UK's territorial emissions (oil and gas platforms account for 4% of total emissions) as does methane leakage from gas transmission and distribution networks. Gas is now the single largest contributor to UK territorial emissions, by fuel type.[17]

The shock to international energy markets following Russia's invasion of Ukraine starkly highlighted the economic and social costs of relying on gas, which accounts for two-fifths of the UK's total energy consumption.[18] Despite the UKCS providing the largest single source of UK supply, gas is bought and sold at international prices. The UK is thus mainly a 'price taker', and UK consumers were not insulated from surging international wholesale energy prices. Eye-watering gas prices – and the scale of public funds allocated to dampen their effect on consumers (estimated by the OBR at £51 billion, or 2% of GDP, when including both direct energy bill support and wider cost-of-living measures) – have exposed the UK's reliance on gas to be a strategic vulnerability.[19]

The previous (Conservative) government targeted new gas supply, rather than systematically tackling gas demand. Policy initiatives included an Energy Security and Affordability Partnership with the US (for LNG) and efforts to boost gas production from the UKCS. The British Energy Security Strategy (2022), for example, vowed to "*giv[e] the energy fields of the North Sea a new lease of life*" and establish 'regulatory accelerators' that would bring "*more domestic gas on the grid sooner.*"[20] Offshore licensing became a centrepiece of this supply-side strategy with government announcing in 2022 it would issue over 100 new licenses in the 33rd licensing round. It then upped the ante, introducing an Offshore Petroleum Licensing Bill (2024) requiring the regulator to increase the frequency of licensing, and claiming annual licensing rounds would encourage oil and gas production in UK waters. Passage of the Offshore Petroleum Licensing Bill was cut short by the government's decision to call a snap election in July 2024.

The new (Labour) government has promised to end new offshore licensing. After 60 years of making the UKCS available for new oil and gas exploration, the symbolism of this apparent 'reversal' of policy is significant. It does not affect, however, the large areas of the UKCS already licensed for oil and gas production. The incoming government has said these licenses will not be revoked and that existing fields can operate "*for the entirety of their lifespan.*"

Calling time on new licenses, then, does not address the climate concerns associated with developing already licensed fields or the long-standing obligation on the offshore regulator to maximise the economic recovery of hydrocarbons. It is, however, a pragmatic move that acknowledges relying on gas (regardless of where it is produced) is a source of economic insecurity, and it begins to shift UK policy closer towards the objective (agreed at COP28) of transitioning away from fossil fuels.

Given the maturity of the UKCS and its steady rate of production decline, the material consequences for UK gas supply of no longer licensing new areas for gas production are likely to be limited. Production has fallen by about two-thirds since 2000. Developing undeveloped resources on the UKCS would slow this downward slope but only marginally – production in 2040 would fall to 14% of current output, rather than 10% – and come nowhere close to making up for long-term decline.[21] Previous licensing rounds appear to have added only relatively small volumes to UKCS gas reserves.

Analysis by Uplift suggests the six licensing rounds between 2010 and 2023 yielded only five new hydrocarbon discoveries, with a further seven previously known fields also licensed and brought into development. Were all 12 fields to be brought into production, their total output would equate to only a fraction of UK oil and gas consumption (16 weeks and 9 weeks, respectively).[22] And, as noted earlier, an increase in production from the UKCS would do little, if anything, to change the UK's ability to influence prices.

Efforts to boost domestic gas production in the name of energy security reflect a sustained failure to substantially drive down gas demand. The Climate Change Committee (CCC) and the Skidmore Review of the UK's net zero plans both made clear that the most effective method of ensuring energy security is to "*cut fossil fuel consumption [by] … improving energy efficiency, shifting to a renewables-based power system and electrifying end uses in transport, industry and heating*".

The CCC has sought more ambition from upstream producers in decarbonising oil and gas production, comparing the industry's target of halving operational greenhouse gas emissions by 2030 – agreed as part of the North Sea Transition Deal (2021) – with the 68% reduction envisaged as part of the CCC's Balanced Net Zero Pathway.[23]

The emission intensity of UKCS gas production is increasingly in the spotlight. The UK currently occupies a 'mid table' position internationally on emissions intensity with a carbon dioxide intensity of 19.8 $kgCO_2$/boe.[24] Proponents of UKCS gas tend to contrast its emissions intensity with imported LNG (e.g., 78 $kgCO_2$/boe for US LNG) – rather than Norwegian pipeline gas which, due to the comprehensive electrification of Norway's offshore platforms, has a substantially lower GHG intensity (8$kgCO_2e$/boe) than UKCS production.[25] Static side-by-side comparison also ignores the lock-in effects over time of developing new gas infrastructures on the UKCS and in the UK: with a life span of decades, these infrastructures have cumulative emission consequences far greater than a short-to-medium term increase in emissions via imported LNG.

Carbon emission intensity is also being foregrounded by the offshore regulator, with action to phase out flaring and venting and a 2023 proposal (the OGA Plan) to couple emission intensity to cessation of production orders.[26] The latter is interesting for the way it seeks to make the timing of cessation a function of emissions intensity and suggests, for the first time, how the long-established objective to 'maximise the economy recovery' of hydrocarbons in the North Sea may be conditional on climate-related thresholds. Although consultation on the OGA Plan preserved the general nature of this coupling, it removed thresholds for action, highlighted trade-offs, and stressed a process of negotiation with the regulator.

In any case, the apparent advantages of (lower-emission) UKCS gas over LNG are negligible when calculated on a full life cycle basis, i.e., taking into account the much larger emissions attributable to gas combustion.[27] As the CCC argues, alongside policies to reduce the burning of gas, "*a tighter limit on production*" on the UKCS with "*a presumption against exploration*" is required.

The prospects for fossil gas production on the UKCS will be shaped by policy decisions around offshore licensing and onshore gas demand. Labour's policy proposals seem to recognise that locking in future fossil gas from the UKCS in the name of energy security will not materially arrest output decline or improve affordability, and makes more difficult the deep, rapid, and sustained decarbonisation now required to meet net zero and respond effectively to UK energy security challenges. Reforming offshore oil and gas regulation can support this transition, although the incoming government needs to look beyond the necessary but narrow question of new licensing. It should focus on ending the current obligation on the regulator to maximise the economic recovery of hydrocarbons and prioritise the reduction of economic, environmental, and social harm.

MIDSTREAM INFRASTRUCTURES

5. LNG

Marshall Hall, Oxford Institute for Energy Studies

The ongoing Russia–Ukraine crisis dramatically revealed both the strengths and weaknesses of UK energy markets and public policy towards the twin objectives of energy security and affordability of energy for UK consumers. The crisis confirmed the highly favourable supply position the UK enjoyed compared to its EU neighbours based on its own domestic gas production, pipeline supply from Norway and access to the global LNG market through its three regas terminals commissioned in 2005–2010.

But at the same time, it highlighted the unbalanced nature of UK gas supply, in particular the dearth of underground gas storage capacity after the closure of the facility Rough in 2017 and the absence of firm term LNG contracts, which together increased the UK's economic exposure to the exceptionally tight spot LNG market.

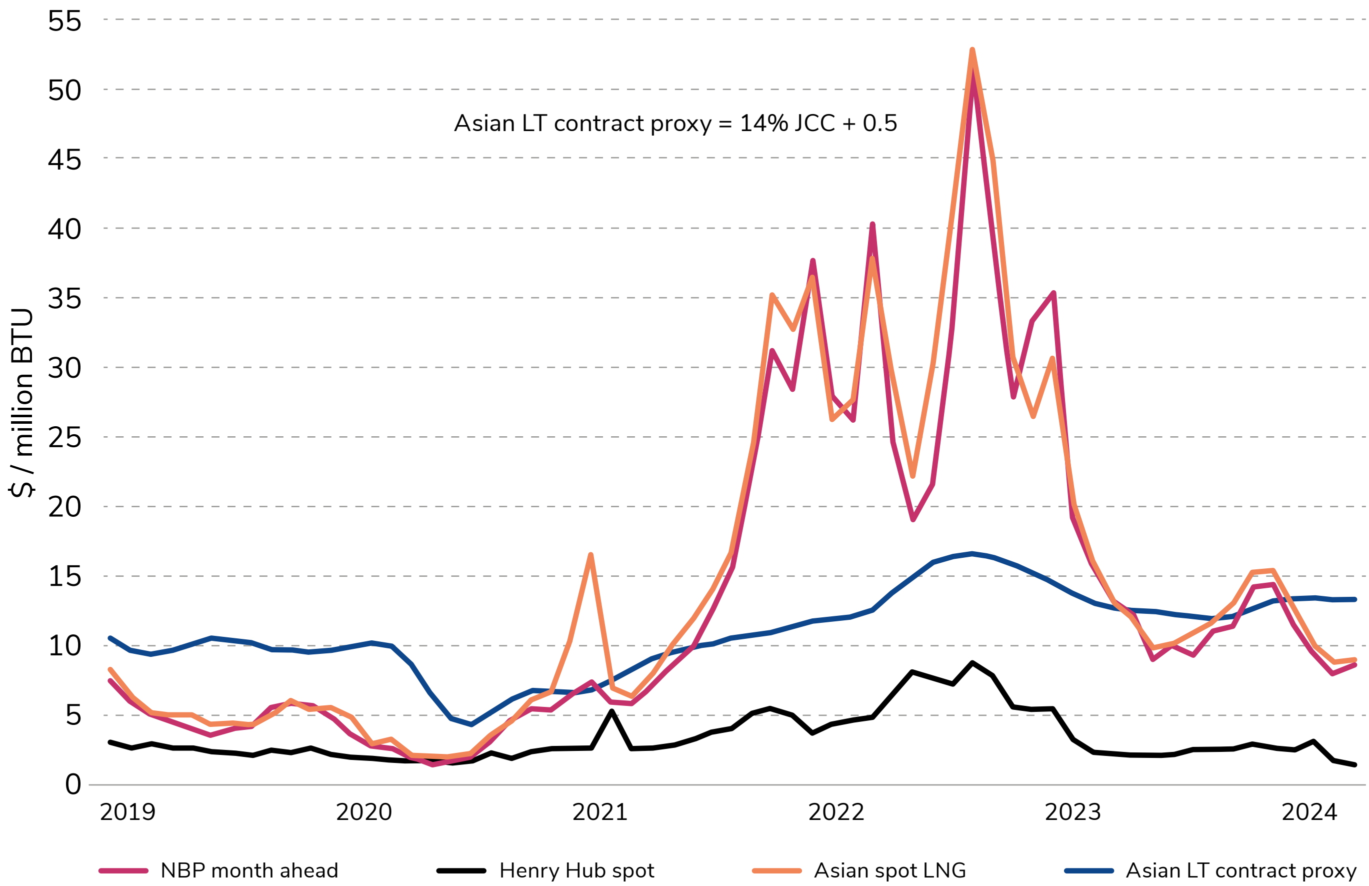
For too long assessments of UK energy security were restricted to physical supply; too little attention was given to wholesale price-formation and its link to consumer affordability. The only direct physical impact of the crisis on UK gas supply was the self-imposed ban on Russian LNG imports at the end of 2022. All the damage to the UK economy and the public finances came from the unprecedented and unimagined rise in wholesale gas prices, beginning in Q2 2021 when Russian pipeline deliveries to Europe were first restricted, and culminating in Q3 2022 as Europe scrambled for replacement supplies to build pre-winter gas stocks to legally mandated targets. Assessments of UK energy security and affordability are intimately linked and need to incorporate international LNG markets, the GB wholesale power market and the setting of retail gas and electricity prices. It is to be hoped that the enormous cost to the public finances of direct energy price support to residential and commercial consumers, estimated by the OBR at £41.6bn in 2022-23, will prompt a future policy approach which unifies security and affordability, seeks to address revealed policy weaknesses and develops new policy tools.[28]

The UK's favourable access to LNG ensured that, in 2022, the average National Balancing Point (NBP) wholesale price was 20% lower than the average price in the EU's most actively traded market (TTF). Indeed, this price disparity allowed the UK to serve as a transit country for imported LNG,

delivered as gas to the EU via the two UK-EU interconnectors. The economic cost to UK consumers of exceptionally high spot LNG prices might have been mitigated still further if more gas storage capacity had been available to suppliers in the UK. After the price rise, the Rough facility was partially re-commissioned in October 2022, at much reduced capacity and deliverability, but even after an increase in its working capacity to 1.5 bcm in 2023, the UK still remains short of gas storage, unduly dependent on non-storage supply and therefore more vulnerable to international shocks. This lack of long-duration energy storage will become a more pressing policy issue as UKCS gas production declines and the energy transition proceeds.

In macroeconomic terms, the crisis provided a painful and costly reminder that UK wholesale gas prices are no longer anchored by oil-related European contract prices and are set principally by the cost of attracting uncontracted LNG from the global market. At times of intense competition between Europe and Asia for spot LNG, there is no natural ceiling to NBP wholesale prices. The linkage of NBP and TTF prices to spot LNG values in the largest market for LNG in north-east Asia is illustrated starkly in Figure 5. The UK's own gas production and pipeline imports from Norway provide an important element of physical supply security but the value of uncontracted spot LNG is the principal determinant of NBP wholesale market prices, and, indirectly, UK wholesale electricity prices and retail gas prices.

Figure 5: Monthly Wholesale NBP Gas and LNG Prices Jan 2019 – Mar 2024

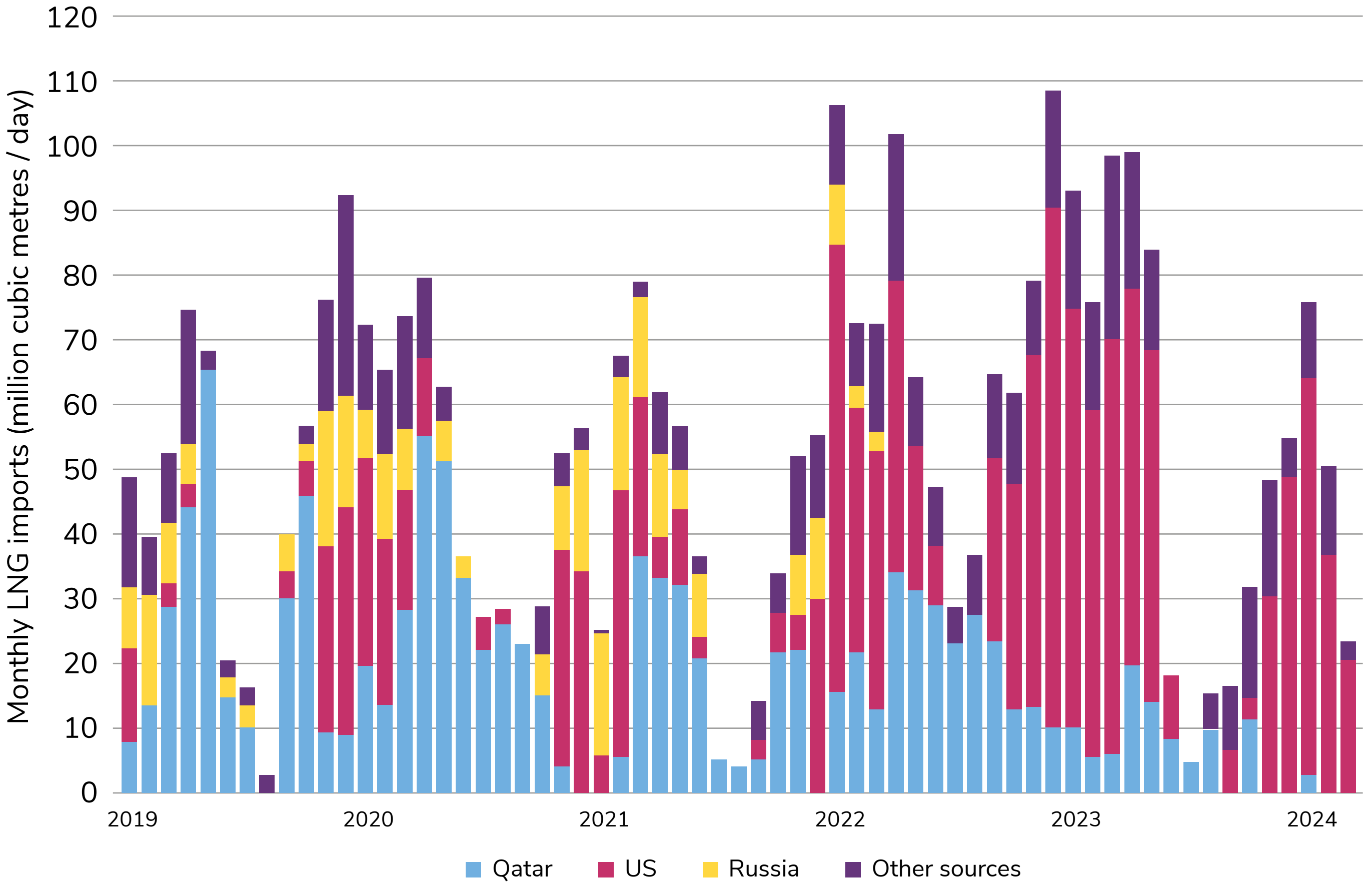


Source: Argus Media

The UK's three existing LNG import terminals confirmed their place in the UK's critical energy infrastructure in the recent crisis. Yet they remain outside the scope of formal regulation by Ofgem; all current regas capacity enjoys an exemption from third-party access. The central pillar of UK physical gas supply security remains domestic UKCS production, but it cannot respond to changes in UK demand or to short-term NBP prices. The only sources of flexible, uncontracted supply are Norwegian pipeline supply, underground storage and LNG regas send-out. Once Norwegian supply to the EU was maximised early in the crisis, it ceased to be able to offer the same flexibility to the UK. In such circumstances, LNG send-out from the three regas terminals provided both the main source of both peak winter supply and short-term flexibility in the daily-balanced NBP market. In the extended cold spell in December 2022, regas sendout was sustained at 130 mcm/d for two weeks, meeting about one-third of total demand on the National Transmission System (NTS) in this period. The unusually mild following winter (2023-24) was accompanied by much lower LNG imports, lower regas sendout and lower demand for flexibility, as Figure 6 shows. Given the central role that LNG regas send-out now plays in flexible NTS supply, it is essential that LNG market participants have fair and transparent commercial access to UK regas capacity and to entry capacity on the NTS if the UK is to remain a competitive destination for uncontracted spot LNG.

LNG supply to the UK has changed remarkably in the last five years as the liquidity of the spot LNG market has been transformed by the rapid expansion of US LNG liquefaction capacity and exports (see Section 3). Until 2021, Qatar was the largest supplier of LNG to the UK, largely through the South Hook terminal where primary capacity is owned by a Qatar Energy/ ExxonMobil joint venture, South Hook Gas.

Figure 6: Monthly UK LNG Imports by Origin Jan 2019 – March 2024



Source: DESNZ, Argus Media

Qatar Energy has invested also in additional regas capacity and storage due on stream at the end of 2025 at the Isle of Grain terminal and will hold almost half the UK's regas capacity by 2026. In 2022, the rise in European prices attracted mainly US cargoes into all the UK terminals, including South Hook, as capacity holders bought spot cargoes, or unused regas capacity was sold in the secondary market to holders of US cargoes. This highlights the importance of a well-functioning secondary capacity market to attract uncontracted LNG and of ensuring that regas capacity is made available for third-party use in all market circumstances, especially at times of market stress. Qatari volumes delivered to the UK have continued to fall since the 2021-22 crisis as Qatar Energy has supplied more of its production to higher-value Asian markets under term contracts.

The corollary of this is that the US is now firmly established as the largest LNG supplier to the UK. Current investment in new liquefaction capacity, concentrated in the US and Qatar, is expected to lead to a new wave of uncontracted LNG supply beginning in 2025-26, which will help to alleviate temporarily the post-crisis market tightness in Europe. But whatever the course of wholesale gas prices in the coming years, it behoves the UK government and regulator to seek to improve UK energy security and to mitigate the domestic economic consequences of price volatility on international gas markets to which the UK will continue to be exposed as decarbonisation proceeds.

6. Pipelines

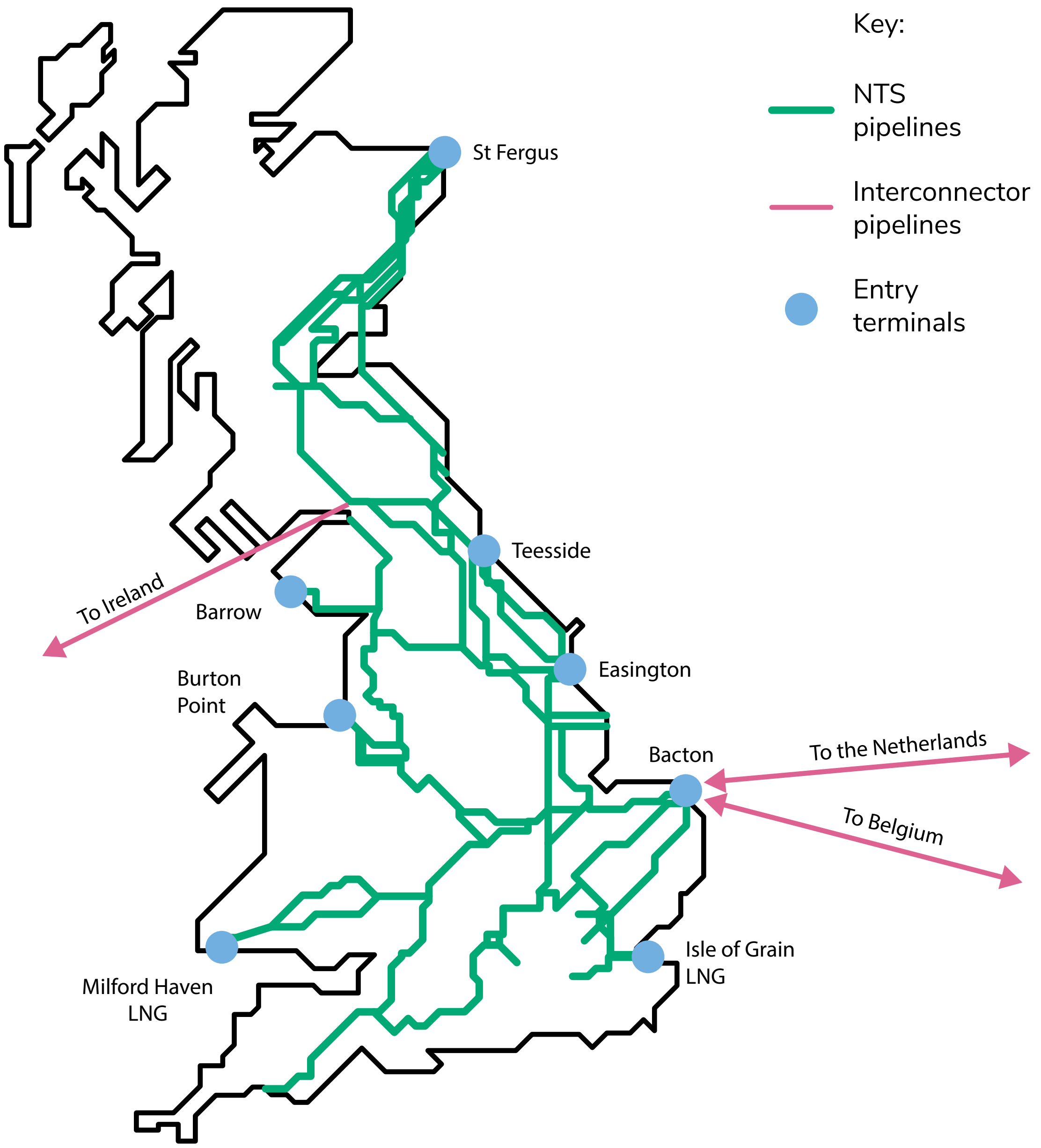
Louis Fletcher, Warwick Business School

The backbone of Britain's gas pipelines is the 'National Transmission System' (NTS), owned and operated by National Gas Transmission (NGT). Comprising 7,600km of high-pressure pipelines, and powered by a fleet of 60 compressor stations, it has three functions.

First, it accepts gas from eight entry points – gas extracted offshore and processed at several dedicated facilities, LNG import terminals at Milford Haven and Isle of Grain, and bilateral interconnectors capable of receiving imports from Belgium and the Netherlands at Bacton (see Figure 7). Second, it transmits gas to power stations and major industrial users, as well as to the Gas Distribution Network.

Third, it supports the outflow of gas, back along the two European interconnectors, and via the unilateral interconnector to Ireland. In turn, the Gas Distribution Network (GDN) is made up of 276,000km of low-pressure pipelines, branching out from the NTS to deliver gas to homes and businesses. The GDN is split into 12 'local distribution zones', owned and operated by four different private companies.

Figure 7: The UK National Transmission System (NTS)



Source: National Gas Transmission, Ten Year Statement, 2023

The gas system faces various operational challenges. It is midway through the 30-year 'Iron Mains Replacement Programme', replacing at-risk pipes with safer polyethylene alternatives. The pattern of system use is changing as domestic production from the UKCS declines (see Section 4) and imports increasingly make up a proportionally larger share of gas consumption. There is a greater need for compression to accommodate flexible gas imports at Bacton, the Isle of Grain, and Milford Haven, while intervention may be necessary to support falling compression at St Fergus as inflows from the North Sea continue to dwindle. NGT will also have to upgrade part of its compressor fleet to meet emissions directives by 2030.

But the defining energy security challenge facing the gas network is terminally falling demand (gas demand has already fallen 30 per cent since 2004).[29] At the moment

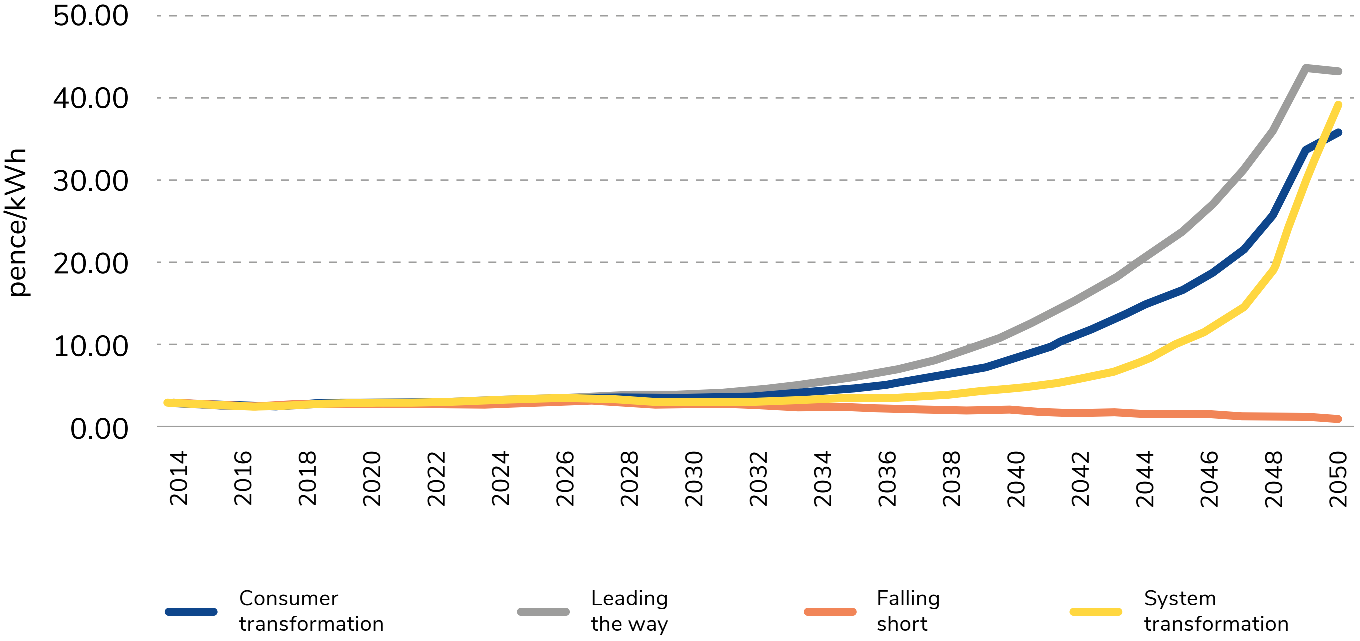
there are two costs that are unaccounted for.[30] First, there is a mismatch between the existing schedule for paying off the investment costs of the gas network, and net zero. Second, there will be large, additional costs involved in physically decommissioning the network.

Both costs will be partly offset if elements of the gas network are repurposed for hydrogen. What scale might this take? NGT's 'Project Union' would involve the repurposing of 25% of the gas transmission system.[31] Given that the regulatory asset value of the GDN is almost four times as much as the NTS, this represents around 5% of the value of the entire gas network.[32] This fact ultimately means that the share of the asset value of the current gas grid that can partly be recovered through future hydrogen use is heavily dependent on the use of the distribution network to service home hydrogen heating (see Section 9). Yet expert opinion remains strongly in favour of electrification via heat pumps and heat networks.[33] The Government will need to make a decision on the role of hydrogen in domestic heating in 2026. In sum, hydrogen repurposing will not solve the problem of gas network decline, which will have to be faced head on.

Under the existing regulatory regime administered by Ofgem, the capital expenditure of private network companies is amortised over a default asset lifetime of 45-years and gradually recouped from bill-payers over that period (gas network costs are charged via unit rates, rather than standing charges). This makes up the 'regulatory asset value' (RAV) of the network. The good news is that Ofgem uses a 'sum of digits' depreciation rate which means that the recovery of RAV is front-loaded. The bad news is that, according to Ofgem's own calculations, the total RAV will be £26bn in 2026, and under present asset lifetimes and depreciation rates, there will still be £3bn of RAV outstanding in 2050.[34] This is a problem because in 2050, there should be no gas customers left to pay the RAV off. Further capital expenditure from 2026 will only add to the problem (and at an increasing rate, given that more years of depreciation of new CAPEX will be scheduled for post-2050).

An intersecting problem is that as gas demand falls, the RAV will have to be recovered from a shrinking customer base. If bills rise sharply enough, this could precipitate a negative feedback loop where more customers leave the network, hiking prices for those remaining, resulting in a 'death spiral' for the gas network. It is precisely those who are least able to meet these rising costs who will be most likely to remain on the network longest: low-income households unable to afford heat pumps, or renters who cannot unilaterally refit their homes, but will have to pay bills, nonetheless.

Figure 8: Ofgem's Modelling of Gas Distribution Charges Under the Status Quo Regime



Source: Ofgem, RIIO-3 Sector Specific Methodology Consultation – Financial Annex, 2023

Yet these sums are dwarfed by the cost of physically decommissioning the network. In modelling commissioned by the National Infrastructure Commission and Ofgem last year, Arup estimated that the cost of phasing-out the gas system could be as much as £70bn.[35] In this scenario, 20% of the transmission system is folded into a hydrogen backbone, and a further 20% is used to store hydrogen, accounting for £13bn of the total cost. Disconnecting customers from the network would cost an estimated £29bn, while safely retiring physical pipelines would require a further £25bn. Who will pay for any of this? Charging households to disconnect from the gas network will simply add a further cost to heat electrification – offsetting the government's own subsidies. Pre-adjusting customers' bills to cover these future costs over the remaining lifetime of the gas network is regressive, and surely politically untenable, given the sums involved. Decommissioning also raises difficult coordination problems – pipelines are integrated physical systems and cannot be retired ad hoc.

The challenge that terminally declining demand poses to the gas network has only just begun to attract the attention of UK regulators and experts, but two contrasting options have already emerged. One, 'business-as-usual' option is to accommodate these costs within the existing regulatory framework. Unsurprisingly, Ofgem has sounded support for this idea.[36] It has suggested adjusting the asset lifetimes and depreciation rates of the RAV to make sure costs are brought to zero by 2050 on a curve which is equitable on a per capita basis. In other words, it would bump up bills while there is still a large customer base, a move that would be exacerbated were social and environmental levies to be shifted from electricity to gas.[37] In March 2024, Germany's utility regulator (the Bundesnetzagentur) proffered a similar proposal, explaining: "*we expect user numbers to drop more quickly than costs. That would mean that the remaining users would have to pay higher and higher tariffs. We're now planning to enable network operators to spread their costs over time so that as many customers as possible can bear them.*"[38]

Ofgem has, further to this, even raised the prospect of creating a mechanism to "*pre-fund future decommissioning liabilities and spread the burden of this expected future expense over current and future generations of consumers*".[39]

The other, more ambitious solution is nationalisation. Richard Lowes and, more allusively, the National Infrastructure Commission, have raised this option.[40] Network companies enjoy information asymmetries over Ofgem, have reaped multi-billion-pound excess profits and engaged in damaging financial engineering in the past, and in this context cannot be expected to wind-down their own profit-generating assets in good faith.[41] The prominent role of Macquarie-led private equity groups in the gas network – it owns the largest distribution company (Cadent) and 80% of the transmission system (NTS), with an option to buy the residual 20% – gives new salience to these concerns, in light of its role in the recent collapse of Thames Water.[42] Whatever the motives of its fragmented private owners, it will be difficult to coordinate the phase-out of the gas network, across geographies, across distribution and transmission, and in sync with the transition to net zero, without nationalisation. Still, this would pose political and financial risks to any government.

Whatever the solution, decisions will need to be made soon. This is especially true in Scotland, where a ban on the installation of new gas boilers is scheduled to take effect in 2028, and falling demand will bite first. If customer bills are to be increased and brought forward to pay back investment costs, the longer this is left, the higher the squeeze will be. Clarity on the coordination and cost of disconnecting from the gas network, and how this will be managed area-by-area, will be key for consumer decisions – starting now.

7. Storage & Interconnectors

Louis Fletcher, Warwick Business School

Europe's gas storage capacity is equal to more than 20% of annual demand. Britain's is equal to only around 4%. Its eight geological gas storage sites combine to provide 3.1 bcm of capacity, and a maximum daily output of 127 million cubic metres (mcm).[43] By comparison, averaged over the last five years, winter demand has peaked over January at 315 mcm/day, reaching 24 bcm for Q1.[44] [45] [46]

The economics of long-term gas storage depend on arbitraging between low prices in summer and high prices in winter. But the rise of continental and Nordic supplies, and latterly LNG imports, have progressively closed the spread between summer and winter prices over the last fifteen years. The government made the decision that it would not intervene to prop up the market in 2013.[47] When the Rough storage facility reached the end of its scheduled life in 2017 the government therefore let it close freely, despite the fact that it made up some 70% of the UK's entire gas storage capacity. It was, the government deemed, "not economically viable", given that inter-seasonal price spread had fallen from 17p/therm in 2010, to 6p/therm in 2017/18.[48] Rough lost £329m in 2015 alone. This left Britain with medium-range storage facilities increasingly geared to shorter balancing cycles, over days and weeks, rather than seasons.

The problem is that these seasonal economics never reflected the full value of gas storage as a security backstop. Markets, in general, will struggle to capture this 'insurance value'.[49] Declining revenues were therefore a misleading proxy of declining value. This came to a dramatic head after Russia's invasion of Ukraine left Britain stuck paying over-the-top prices for spot LNG cargoes while spending tens of billions subsidising consumer bills. Centrica did re-open Rough in response to the gas crisis in 2022, at a fifth of its original capacity, 850 mcm. It then expanded capacity to 1.5 bcm in 2023 – half of the UK's total gas storage capacity today.

Centrica has demanded government support from the outset, and in 2023 it impaired Rough's value by £83mn "*as a result of both the fall in forecast gas prices and the flattening of summer/winter gas spreads*".[50] Support is likely forthcoming, on three possible counts. First, the government has left the door open to providing "*incentives*" to gas storage facilities, which "*could be regulatory, financial or both*", but "*any natural gas business model would need to align with the hydrogen storage business model which the Government has committed to designing by 2025*".[51] Second, in line with this position on gas storage, the government has adopted a "*minded position*" to support a revenue floor for hydrogen storage providers, while allowing the government to recover some fraction of revenue from the upside.[52] It will launch an allocation round for two hydrogen storage facilities in autumn 2024, with approvals scheduled for the end of 2025. The House of Lords Science and Technology Committee recommended, in March 2024, that the government "*work with Centrica to understand its proposed project to repurpose the Rough storage facility for hydrogen*".[53] Third, and least definitely, there are ongoing discussions as to whether the government ought to mandate the creation of a strategic reserve of natural gas or hydrogen to insulate the country against future supply shocks. This would require its own regulatory incentives. But the government has equivocated, noting that strategic reserves "*are complex logistical and technical exercises that can carry significant costs*", while raising the possibility of using the storage capacity at LNG terminals for this purpose, instead of geological gas storage sites.[54]

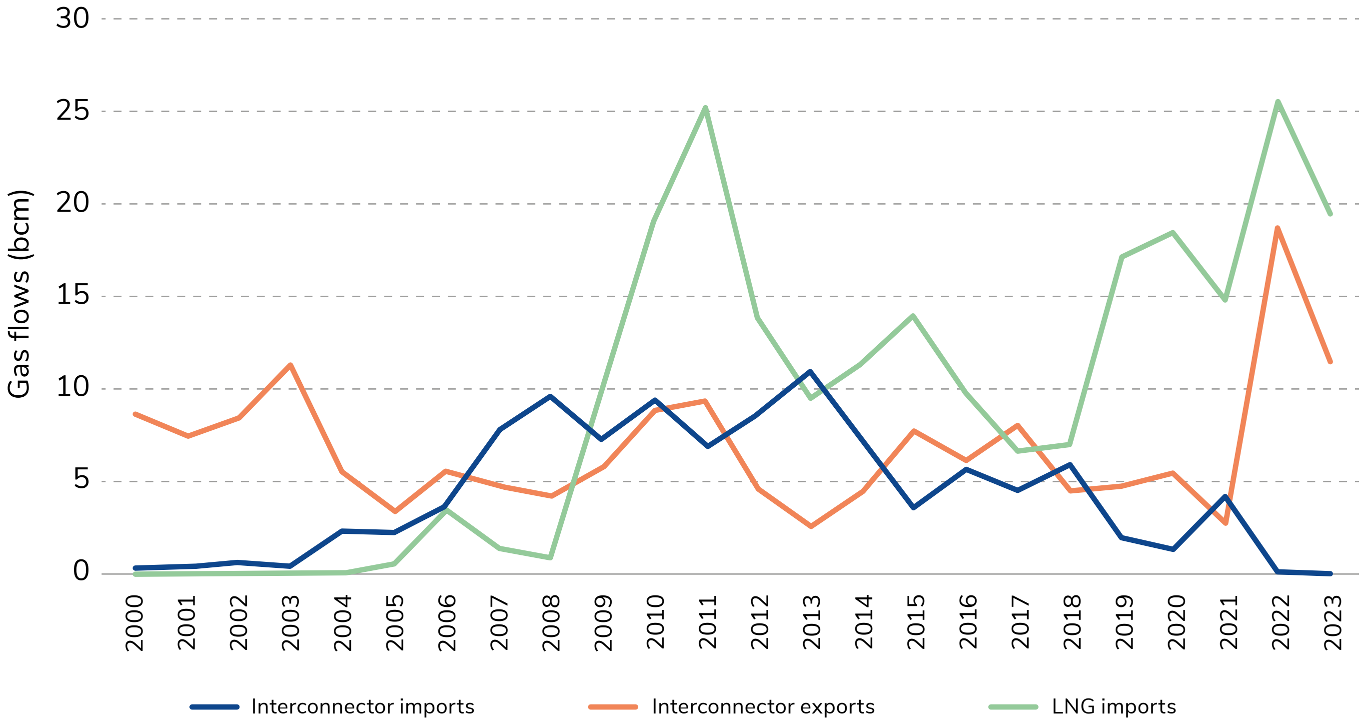
Centrica has plans for a 'hydrogen-ready' expansion of Rough to 3.5 bcm by 2027/28.[55] Close to both offshore wind infrastructure and the Langeled pipeline delivering Norwegian gas to Britain, it is well-positioned to support the future of nearby Easington terminal as a 'green' or 'blue' hydrogen hub servicing Humberside and Teesside.[56] Centrica says that these plans are conditional on government support given that, at present, there is "pretty *much zero insurance value for long-duration energy storage*".[57]

Given that it will almost certainly receive it, the UK's gas capacity is likely to expand in anticipation of a public-private hydrogen storage market.

Interconnectors

Two bilateral interconnectors reach out across the North Sea from the Bacton terminal on the Norfolk Coast. One of them, 'BBL', connects to Balgzand in the Netherlands. It is majority owned by the Dutch state and is able to import 15 bcm/year to the UK, and export 5 bcm/year. The other, 'IUK', runs to Zeebrugge in Belgium, and is majority owned by Belgian municipalities. It can import 25.5 bcm/year to the UK, and export 20 bcm/year back to the Continent. Flows are driven by the gas price spread between the UK and Europe and are highly seasonal. Exports from the UK help to fill European storage in summer, which can then be flowed in reverse over winter when market conditions permit.

Figure 9: UK-EU Interconnector Flows and LNG Imports 2000-2023



Source: DESNZ, March 2024, DUKES: Natural gas imports and exports (author's analysis)

Figure 9 tells the recent history of the interconnectors. In the early 2000s when North Sea production was close to its peak, the interconnectors supported large net outflows. By the end of the decade the situation had changed. Britain's gas production had halved since 2000, increasing European imports. But the completion of LNG terminals at the Isle of Grain (2005) and Milford Haven (2009) also introduced a new source of flexible imports. Low temperatures and industrial action in Norway saw a huge spike in LNG imports in 2010, subsiding after a surge in LNG prices on the back of Japanese demand post-Fukushima.[58] The interconnectors originally flowed gas to the UK on the basis of stable long-term contracts, but BBL's contract expired in 2016, followed by IUK's in 2018.[59] Alongside falling gas demand, and ongoing competition from LNG, this saw interconnector imports fall significantly from their 2007-2013 highs. It was in this context that BBL enabled reverse flows from the UK to the Netherlands in late 2017, with the first exports delivered in 2019. Finally, since Russia's invasion of Ukraine in 2022, surging LNG imports have allowed the UK to act as a 'land bridge' re-exporting cargoes to the Continent along the interconnectors.

Europe's build-out of LNG import terminals since 2022 will soon undercut Britain's role as an LNG transit route, and the future of the interconnectors will change once more, perhaps rebalancing from exports to imports.[60] Ultimately this will depend on the gas price spread between the UK and EU. Even as UK gas demand falls, it may be that demand for flexible supplies rises over the medium-term.[61] This depends on the portfolio of flexibility options that emerge to smooth out intermittent renewable electricity generation and, in particular, the extent of the UK's reliance on gas-fired power plants and 'blue' hydrogen, both of which would require flexible gas imports. It is notable that in National Grid's 2023 Future Energy Scenarios, the net zero scenario heavily dependent upon blue hydrogen production, 'System Transformation', involves the import of 4 bcm of gas a year from the Continent as late as the 2040s.[62] At the other end of the spectrum, as discussed in Section 8, some modelling exercises have shown that it is possible for green hydrogen and long-term storage to provide adequate system flexibility, allowing for the almost total elimination of natural gas from the electricity system in the 2030s.[63]

The other lifeline for the interconnectors is their transformation to support hydrogen or CO_2. These are definite, if uncertain, possibilities. Arup, in research commissioned by the UK government, found that UK hydrogen exports to northwest Europe are a potentially viable prospect, given estimated UK hydrogen production costs, its proximity relative to competing suppliers, and the EU's already-existing hydrogen import targets.[64] It is cheaper to move hydrogen via pipeline than to ship it. Bacton is a leading candidate as a hydrogen export terminal, given its distance to import terminals in the Netherlands and Belgium, and the fact that it is included in existing plans for Project Union, National Gas Transmission's vision for a national 'hydrogen backbone'.

Yet Arup judges that while it would be 'technically feasible' to repurpose the two existing gas interconnectors at Bacton to transit hydrogen, several reasons weigh in favour of the construction of new pipelines: they can be tailor-built for hydrogen, are not locked into existing routes and so can sync up with emerging hydrogen infrastructure, and do not have to compete with gas for the pipelines. It should be added that EU's hydrogen import target is for electrolytic (green) hydrogen.[65] Yet it is far from clear that the UK will be in a position to produce enough electrolytic (green) hydrogen to meet even its own needs in the medium-term given the pace of its renewable buildout.[66]

Importing CO_2 from Europe to store in the North Sea's depleted gas fields is another tangible possibility but given that carbon capture and storage (CCS) has yet to be even proven at scale, it is a distant one. For the foreseeable future, then, the viability of the interconnectors will remain dependent on the gas trade.

8. Gas Demand Futures

James Prices, Steve Pye & Oliver Broad, University College London

The war in Ukraine has seen concerns about energy security in Europe, which the International Energy Agency (IEA) defines as the uninterrupted availability of energy sources at an affordable price, catapulted back to the top of the political agenda. This stems from the impact the conflict has had on the supply of fossil fuels to Europe, particularly for natural gas due to the continent's dependence on Russian pipeline imports.

This turmoil in Europe's gas market sent prices rising, even for those countries with little direct reliance on Russian gas, like the UK.

As with many developed countries, the UK has a high dependence on gas right across its economy, and so the gas price crisis had ramifications for all sectors, from power generation to the gas used to heat more than 80% of the country's homes. Estimates as of January 2024 suggest that the number of UK households in fuel poverty have risen to 6.5 million. With energy prices also feeding inflation, the increased costs of a wider set of products have also impacted households.[67]

In light of this exposure to volatile global fossil fuel markets, the previous UK government set out a strategic response in the British Energy Security Strategy[68] and, more recently, in Powering Up Britain.[69] Its basic objective was to move the UK towards energy independence, cutting imports and increasing domestic energy production, including gas from the North Sea. It remains to be seen what the new government will do in the energy security space, but its approach is likely to be somewhat different given its view on new licenses in the UKCS (see Section 4).

Whatever the future direction of travel, the fact remains that gas produced in the UK is owned by private fossil fuel companies and therefore will not be sold to the UK at a discount. This is a fundamental feature of fossil fuel markets; they are global or regional and, as such, the price of these fuels is subject to factors beyond the UK's control. These policy documents also continued a long-running trend of focusing on the supply side of energy security, to the neglect of energy demand reduction. After all, as the adage goes, the most secure energy is that which is not required in the first instance.

A genuinely energy independent future for the UK is one where the gas dependence of the whole energy system is reduced and, where possible, eliminated. It is also a future where energy security holistically considers both energy supply and demand.

Pathways of Natural Gas Phase Out

In whole energy system modelling conducted for our report on UK energy independence[70], we explored how a range of policy levers across the energy system could be pulled on, with varying degrees of strength, to reduce gas consumption and support greater energy security, while still achieving net zero GHG emissions. The levers, shown in Table 2, spanned the provision of low carbon electricity to the uptake of low carbon end-use technologies and a reduction in demand for useful energy itself, critically engaging with the challenge from both demand and supply sides. Our approach drew on highly innovative research into the potential role of energy demand reduction under the CREDS Positive Low Energy Futures project[71]. This research explored how a range of measures, including behavioural aspects like modal shifts in transport, as well as more technical factors, like insulation in residential buildings, could support a transition to a net zero energy system.

Table 2: Policy Levers for Reducing Oil and Gas Demand Across the UK Energy System

		Scenario		
Sector	**Lever**	**Emerging**	**Developing**	**Secure**
Residential	Heat pump rollout in 2028	600,000 per year	900,000 per year	1.1m per year
	Peak heat pump rollout	1m per year	1.5m per year	2m per year
	Year peak heat pump rollout achieved	2037	2035	2033
	Residential energy demand	LED Steer[72]	LED Shift	LED Transform[a]
Transport	All new cars, vans, two wheelers and buses are zero emission	2035	2030	2025
	All new heavy goods vehicles are zero emission	2040	2035	2030
	Share of sustainable aviation fuels in 2050	10%	50%	95%
	Share of low carbon fuels in shipping in 2050	25%	50%	95%
	Transport energy demand across all modes	LED Steer	LED Shift	LED Transform
Electricity	Net zero emission electricity	2035	2032	2030
Non-domestic buildings	Share of low carbon fuels	60%	70%	80%
	Energy demand from non-domestic buildings	LED Steer	LED Shift	LED Transform
Industry	Share of low carbon fuels	60%	70%	80%
	Industrial energy demand	LED Steer	LED Shift	LED Transform
Carbon capture and storage	Year from which CCS is available	2030	2035	2040
Hydrogen production	Share of low carbon hydrogen production 2030 to 2050	50% (2030) 50% (2050)	50% (2030) 90% (2050)	80% (2030) 100% (2050)

Figure 10 shows a progressively faster reduction in gas demand to 2050 across our scenarios. The developing and secure scenarios show essentially zero consumption in the energy system by mid-century, i.e. a complete phase out of the UK energy system's dependence on gas. Both of these cases represent a more ambitious transition away from gas than that suggested by the Climate Change Committee's Balanced Pathway[73], as shown in our report. Indeed, if the levers set out in *Secure* were fully implemented, the UK could achieve a position with no net import dependence for gas from 2040. This means i.e., domestic demand could be met by projected North Sea production without further licensing rounds and essentially total phase out by 2045. This highlights the importance of both strong demand side measures and supply focused interventions in moving towards minimal dependency on gas.

In Figure 11, we highlight the difference between the contribution that each sector makes to the phaseout of gas in our *emerging* and secure ambitious scenarios. Where are these additional cuts in gas demand made? In the near-term, achieving net zero emission electricity generation five years earlier does much of the heavy lifting in cutting gas use, supported by reductions in industry. Beyond 2030, falls in gas consumption are driven by action in buildings, principally enabled both by a more rapid uptake of heat pumps and lower energy service demands as a result of greater insulation. In the 2040s, increased low carbon hydrogen production from renewable electricity further reduces the need for gas.

Figure 10: Natural Gas Demand from the UK Energy System Across our Scenarios Compared with North Sea Transition Authority Production Projections from February 2023

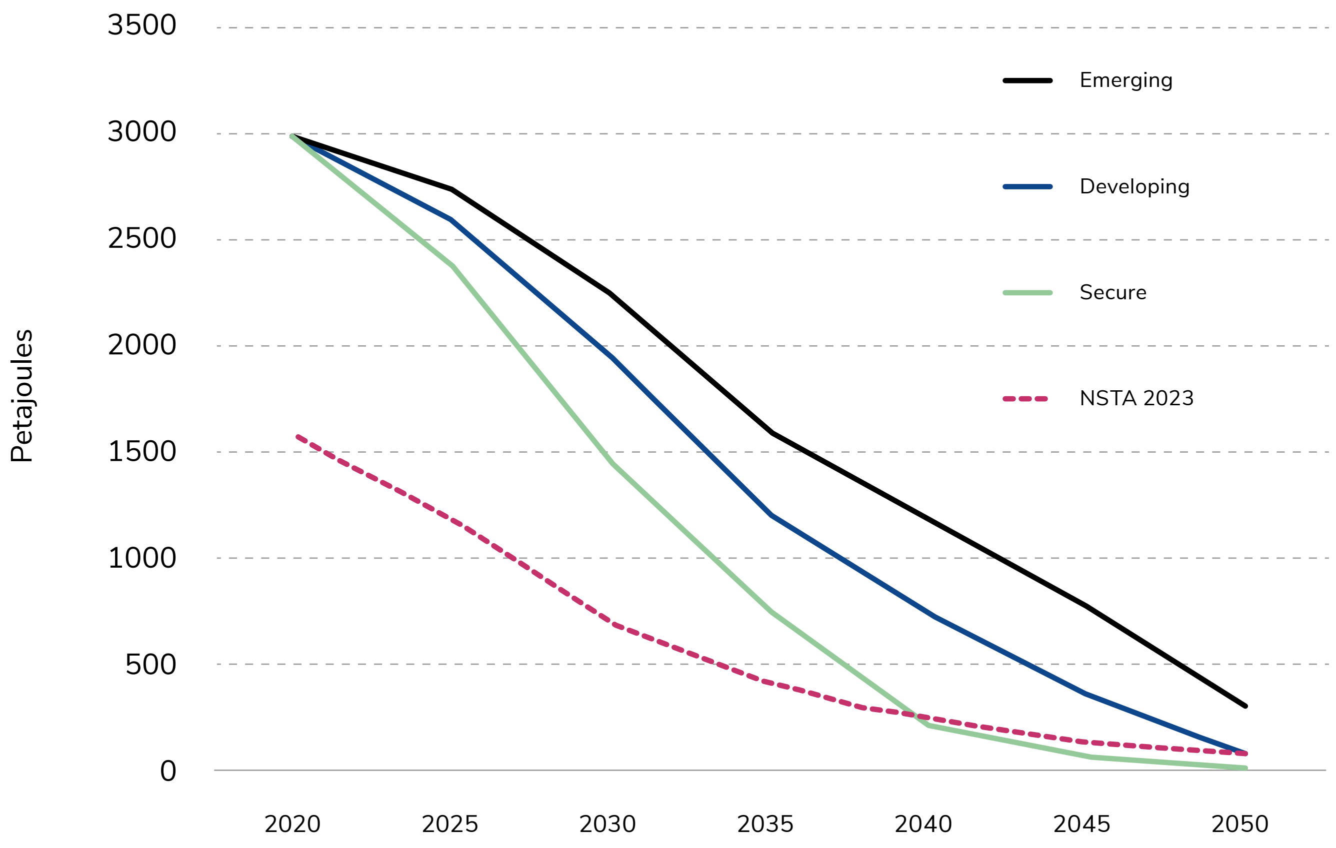
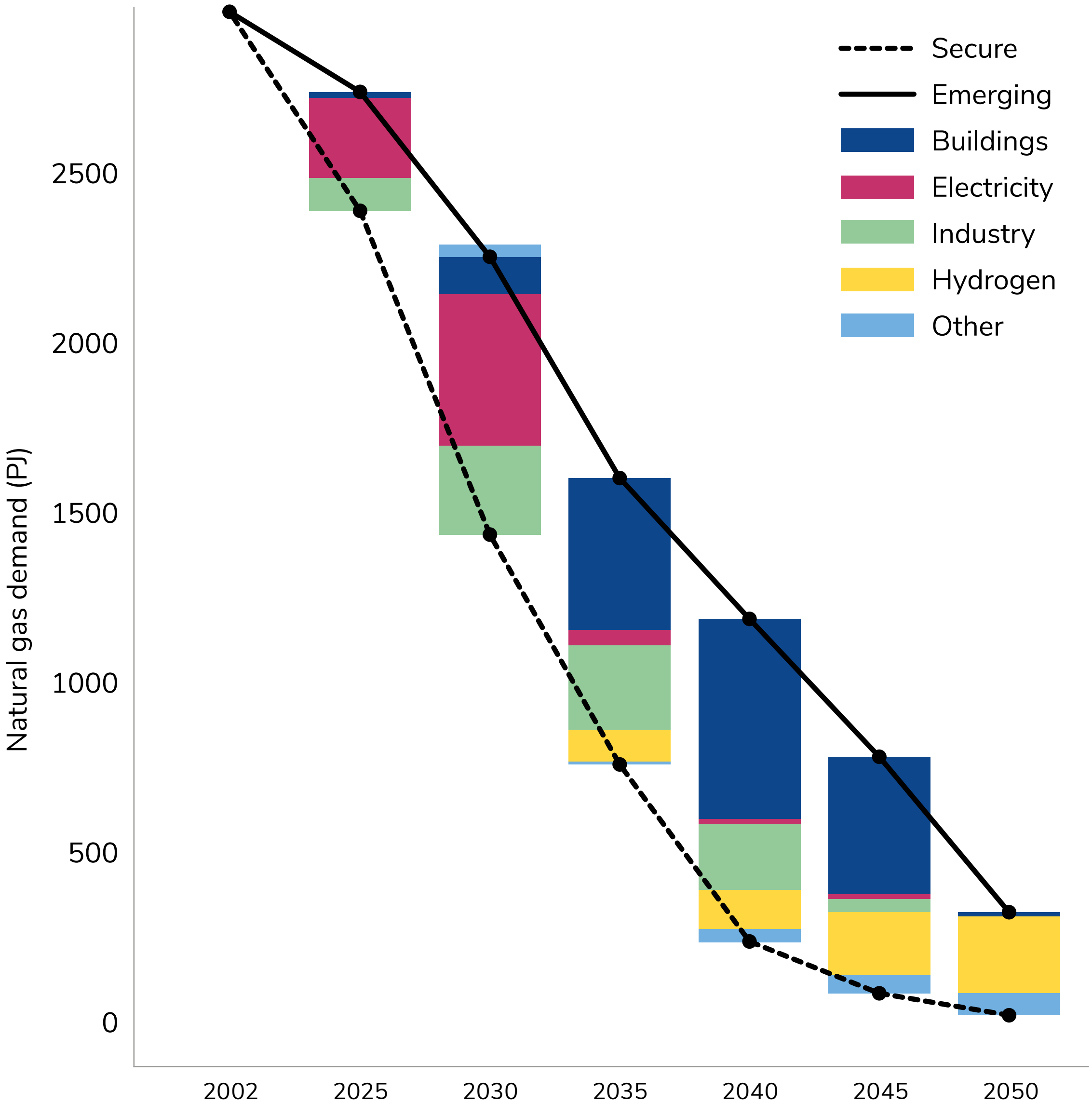


Figure 11: Change in Natural Gas Demand from the UK Energy Sytems Between the Emerging and Secure Scenarios



Policy Priorities to Deliver Real Energy Security

It is clear that a future UK low carbon energy system that offers reliable energy at an affordable price will require bold policy interventions that target both the supply and demand side of the whole system. A singular focus on the former at the expense of the latter, as has historically been the case, will act to hamstring efforts to achieve these objectives as it ignores the wider benefits of fully engaging with the demand side of energy security.[74]

It is also evident that ratcheting up policy ambition to phase out gas demand, thereby limiting the country's exposure to volatile global fossil fuel markets, offers a direct route to delivering enhanced energy security (though as Section 7 explains, it will also bring forward risks to the ongoing viability of the UK's critical gas infrastructure). Expanding production from the North Sea will essentially have no effect on gas prices and, in this context, is a distraction from policy responses that can genuinely meet the energy security challenge.

Instead, if policymakers are really serious about fuelling Britain with cheap and reliable energy, they should be looking to a managed decline for the fossil fuel industry, from gas extraction to those that depend on the gas network, so as to wean the country off its dependence as quickly as possible. Contemporaneously, they should be pushing ahead with an acceleration in the uptake of low carbon solutions and efforts to reduce energy demand across the energy system.

Early hints are that the new Government intends to better align its energy policy with the delivery of real energy security by pushing for net zero carbon power by 2030 and looking to ban new North Sea oil and gas exploration licenses. However, as our modelling makes clear, it is essential that bold interventions are made right across the whole energy system, from supply to demand, including more challenging areas like buildings and industry. Such a holistic approach represents an unprecedented opportunity to reverse the conventional narrative that energy security, affordability and sustainability must be traded off against one another, and to recognise that they are in fact synergistic in the transition away from natural gas.

9. Domestic Heat

Modassar Chaudry & Jianzhong Wu, University of Cardiff

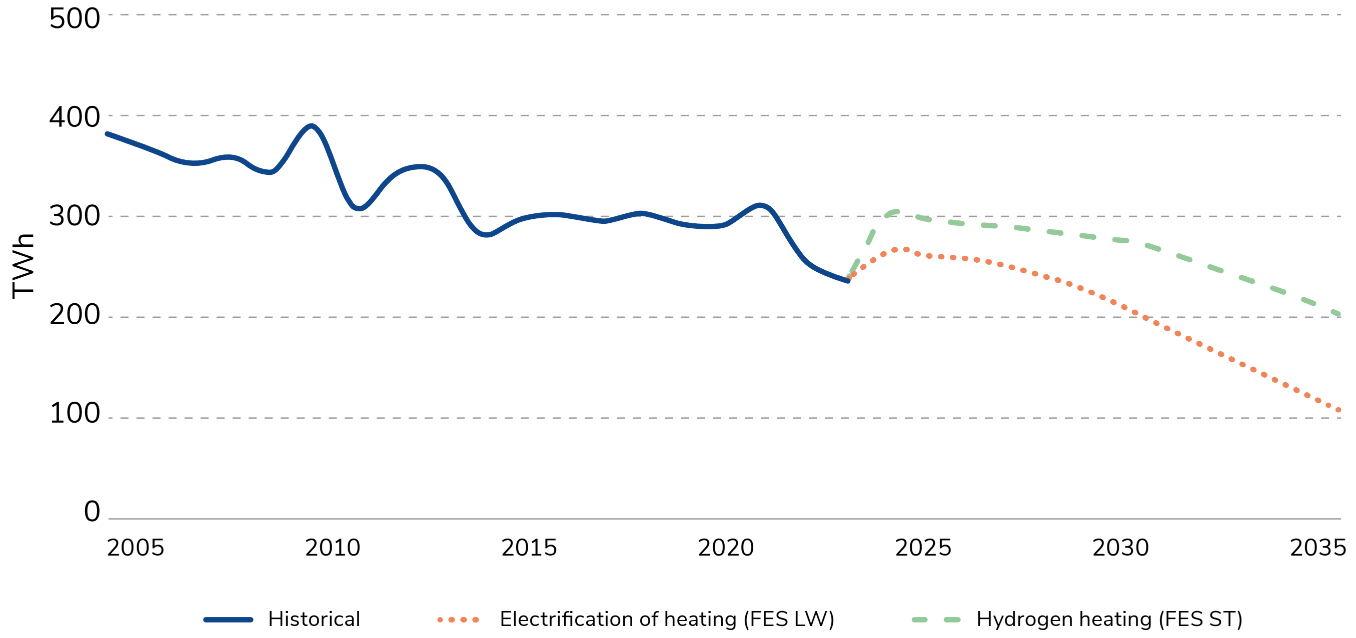
Heating the UK's 28 million homes accounted for 27% of total energy demand and approximately 18% of all greenhouse gas emissions in 2023. The largest source of natural gas demand in the UK is domestic heating, accounting for approximately 34% of total gas demand in 2023.[75] Domestic gas demand has steadily declined over the past two decades by more than a quarter (see Figure 12), driven mainly by energy efficiency improvements in gas boiler technologies and the increased insulation of homes.[76]

Over the past couple of years, due to a combination of Covid-19 and the invasion of Ukraine, gas prices have been very high, pushing down gas demand by approximately 8% between 2022 and 2023. But recently (2023-2024) gas wholesale prices have fallen back towards pre-invasion levels, though there is likely to be considerable time lag before these changes are reflected fully in consumer prices.[77] Despite high gas prices, in 2023, gas boilers accounted for nearly 80% of the total domestic heating market with annual sales hitting 1.75 million, which is a 14% increase compared with the previous year.[78]

The previous UK government introduced several policy initiatives, such as the Energy Bill, with the aim of meeting net zero, enhancing energy security, and reducing energy costs whilst promoting economic growth.[79] Key elements of this bill included exploring the role of hydrogen to heat homes and workplaces, accelerating home efficiency improvements, and scaling up heat pump installations whilst reducing the reliance on gas for domestic heating. In addition to this, the previous government banned the sale and installation of new gas boilers for new build homes from 2025, with unclear messaging on whether this will be extended to include all domestic homes in 2035, a position that is likely to be clarified by the new government.

Over the short-term, according to Future Energy Scenarios 2023 (FES) from National Grid, the energy required for heating is likely to fall, mainly due better home insulation.[80] In its electrification of heating scenario, FES 'Leading the Way' (LW in Figure 12), the reduction of domestic gas demand could be as high as 20% by 2030 compared with 2022 (2022-2023 saw a dip in domestic gas demand which is likely to recover by 2025). But this would still leave around 20 million gas boilers in operation. The pathway envisages a sharp drop in gas boiler installations by the mid-2030s, as a potential ban on new gas boilers starts to bite, and domestic gas demand is likely to be more than halved as heat pump installations increase.[81]

Figure 12: Domestic Gas Demand for Heating in the UK – Historical, Electrification and Hydrogen Heating Scenarios



Source: National Statistics, 2024; National Grid, 2023

To encourage growth in the heat pump market to 600,000 installations per year by 2028, the previous UK government established its flagship Boiler Upgrade Scheme (BUS), initially offering a £5,000 grant, which was increased to £7,500, to meet upfront and installation costs. Despite this, the heat pump market has not seen the desired growth. The National Audit Office (NAO) stated that the BUS has underperformed, installing just 18,900 heat pumps between mid-2022 and end of 2023. Several explanations have been cited, such as higher than expected costs, and uncertainty over the future role of hydrogen in home heating.[82] One major barrier to encouraging gas-to-electricity switching is the fact that, for consumers, the ratio of gas-to-electricity prices per unit of energy is currently 1:4.[83] The previous government reiterated that heat pumps are the primary low carbon technology for decarbonising home heating over the next decade, and that it will pursue measures to rebalance gas and electricity prices.[84] But on the current trajectory the government's heat pump installation target has little chance of being met.

One of the key decisions that the new UK government is expected to make in 2026 is on the role of hydrogen in domestic heating. As part of the evidence gathering process, two village trials were proposed to study the operational efficacy of hydrogen heating systems. Unfortunately, both were ultimately scrapped. Several independent advisory organisations, such as the National Infrastructure Commission and the CCC, have also highlighted the many technical difficulties facing hydrogen as a viable low carbon heating fuel.[85]

The previous UK government made the strategic policy decision to permit a 20% hydrogen blend into the gas distribution networks, subject to a final decision.[86] This is supported by the replacement of iron pipes in the gas distribution system with materials compatible with hydrogen flows. If hydrogen for heating is approved by the new government it will likely be phased, starting with a 20% blend, and new gas boiler installations from 2026 able to operate with this gas blend (hydrogen blend ready).

A scenario that envisages large domestic heat demand for hydrogen (the FES System Transformation scenario) whilst meeting the long-term net zero target illustrates minimal change in domestic gas demand in 2030 compared with 2022 (ST in Figure 12).[87] Natural gas steam methane reforming with carbon capture, utilisation, and storage (blue hydrogen) is seen as the most cost-effective low carbon solution to produce hydrogen out to mid-2030s despite various subsidies such as the Net Zero Hydrogen Fund and the Hydrogen Production Business Model targeting primarily electrolysis based (green hydrogen) schemes.[88] This pathway shows that by the mid-2030s domestic gas demand will drop by nearly a quarter compared with 2022, supplying mainly legacy gas boilers and the feedstock for blue hydrogen production.

In conclusion, domestic gas demand by the end of this decade is likely to be quite resilient. Beyond this point, given the government's aim to reduce carbon emissions, domestic demand for gas is most likely to decline in the mid-2030s. But the pace of this decline is subject to wide uncertainty, most particularly in relation to the future mix of hydrogen and heat pumps in home heating, and the policies in place to support their roll-out. A prompt strategic decision is required from the new government regarding the role of hydrogen in heating. If this is approved, given that natural gas remains the lowest-cost option for hydrogen production, domestic gas demand could remain quite resilient over the coming decades.

10. Industrial Decarbonisation

Imogen Rattle, Ahmed Gailani & Peter Taylor, University of Leeds

Industry is a significant consumer of natural gas, accounting for 13.1% of UK demand in 2022.[89] Around a quarter of industrial gas demand is from high temperature processes in sectors such as iron and steel, chemicals and non-metallic minerals.[90] However, gas demand from industry has almost halved since 2000, largely driven by a combination of changes in the structure of industry (including some offshoring of energy intensive sectors) and improved energy efficiency, although most of this decline occurred before 2010.[91]

Over the past five years, UK industrial gas prices have risen by 121% in real terms, while electricity prices have increased by 73%, and gas demand has been relatively constant.[92] Industrial consumers of gas still typically pay lower prices than their European counterparts, with the UK having the lowest average industrial gas prices of the EU14[93] in the first six months of 2023, alongside the highest average industrial electricity prices.[94]

Historically, the sector has been more concerned with electricity prices than gas prices due to the lack of parity with the lower prices that European competitors were paying.[95] Consequently, government policy efforts have mainly focused on tackling barriers to electrification. Initiatives include the British Industry Supercharger which aims to reduce electricity costs for energy intensive industries (EIIs) through increased subsidies under the exemption from UK Capacity Market charges, and the introduction of the EII Network Charging Cost Compensation scheme.[96] In addition, a consultation on Enabling Industrial Electrification identified further barriers to uptake including low technology readiness, high capital costs, constraints on grid access and regulatory/policy uncertainty.[97]

The short-term outlook for industrial gas demand is uncertain. Whether gas use will continue to decline is dependent on several factors including industrial activity and policy approaches to decarbonise the sector, not least whether gas and electricity prices can be rebalanced, and if other barriers to at-scale electrification can be addressed. Manufacturing industry is highly heterogeneous and the most appropriate approach to decarbonisation will be site and process dependent. The overarching UK plans for industrial decarbonisation are set out in the Industrial Decarbonisation Strategy.[98] In the short to mid-term, they are focussed upon adopting low-regret technologies and building infrastructure to enable alternative solutions, such as electrification, hydrogen and CCS.

As policies and infrastructures to enable fuel-switching are developed, so industrial gas demand is likely to decline. However, the timeframe for this shift remains uncertain. Alongside industrial decarbonisation, the Russian invasion of Ukraine has led to increased policy support for initiatives to enable demand reduction in industrial processes in order to improve energy security.[99] To this end, grant funding through initiatives such as the Industrial Energy Transformation Fund has been increased to support energy efficiency pilot projects. The impact of these initiatives on gas demand has yet to be quantified, but it is likely to add to the downward pressure.

A further factor complicating the gas demand outlook is the potential replacement of natural gas in industrial processes by green hydrogen or its utilisation as feedstock and fuel for blue hydrogen.

The Government expects hydrogen to play an important role in the industrial transition, serving as a fuel for hard-to-electrify industries and a low carbon feedstock. The UK aims to have 10GW of hydrogen production capacity by 2030 with 6GW from electrolytic (green) production and 4GW from CCS enabled (blue) production from natural gas.[100] However, since natural gas serves as both the feedstock and fuel for blue hydrogen, production costs are highly sensitive to gas prices. Recent spikes in gas prices have cast uncertainty on meeting the 4GW target and raised concerns that blue hydrogen projects could become stranded assets.[101]

One estimate for future industrial gas demand is provided by the CCC in its analysis that informed the sixth carbon budget.[102] The CCC's balanced pathway[103], shows industrial demand for natural gas falling by over 60% from 2020 to 2035. This reduction is mainly due to industrial sites deploying mitigation options, including resource and energy efficiency along with electrification, hydrogen and other technologies, and is driven by carbon prices increasing from 110 to 180 £/tCO_2 over the period. If, in reality, carbon prices or equivalent regulatory pressures are lower in the future than assumed under this pathway, then the decline in gas use could be slower than forecast.

As previously noted, the use of natural gas for blue hydrogen production is another driver of gas demand. Under the balanced pathway, blue hydrogen consumption by industry increases significantly from zero in 2025 to reach 25 TWh by 2035. However, the additional gas used to produce this blue hydrogen would not offset the predicted decrease in the direct use of natural gas by industry. Furthermore, in a scenario with higher gas prices (similar to those seen in the recent price crisis) the increase in blue hydrogen use by industry could be limited to 10 TWh by 2035.[104]

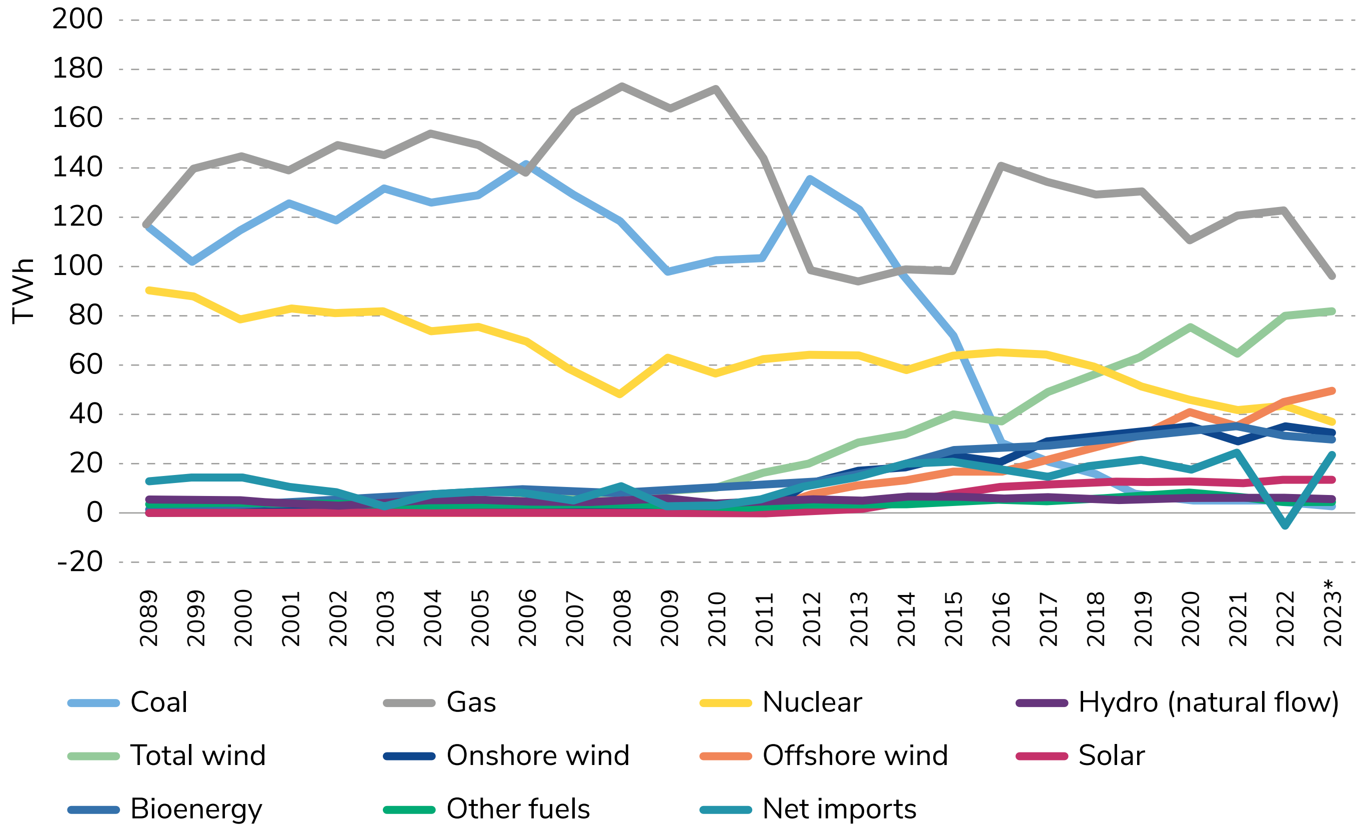
In conclusion, given the UK's commitment to greenhouse gas reductions, industrial demand for gas is most likely to continue its long-term reduction over the period to 2035 but the extent of this decline is subject to a range of uncertainties, including the future level of gas and electricity prices, the support for widespread electrification, and the role of different types of hydrogen.

11. Low Carbon Power

Keith Bell, University of Strathclyde

Since the 'dash for gas' was initiated in the 1990s, the UK has been increasingly dependent on gas for the generation of electricity, reaching a peak of 173 TWh of electricity production (net of station demand) in 2008, 46% of all electricity supplied that year.[105] In recent years, however, the proportion of electricity demand met by gas-fired generation has fallen to 32%, less than that met by weather-related renewables: wind, solar and natural flow hydro (34%) (see Figure 13). The amount of gas used in electricity production has fallen from 377 TWh in 2008 to 203 TWh in 2023.[106]

Figure 13: Electrical Energy Supplied from Different Sources (Figures for 2023 are provisional).



Source: DESNZ, 2024, Energy Trends: UK Electricity

In October 2021, the UK Government announced plans for the electricity system to be fully decarbonised by 2035.[107] The British Energy Security Strategy published in April 2022 committed to an ambition of 50 GW of offshore wind capacity by 2030 and 70 GW of solar PV capacity by 2035.[108]

Against a background of five of Britain's six remaining nuclear power stations closing by 2030 (leaving just 1.2 GW of capacity at Sizewell B), the Strategy included a plan for up to 24 GW of nuclear capacity by 2050.[109]

For a report published in March 2023, the CCC commissioned the consultancy AFRY to assess the potential shape of a reliable, fully decarbonised electricity system in Britain in 2035.[110] It took as given that there would be 50 GW of offshore wind by 2030 and 70 GW of solar PV by 2035 and used best estimates of capital and operating costs of generation technologies, 'social values' of carbon defined by the Treasury, and costs of additional offshore wind and solar PV. It also used a fixed capacity of bioenergy with CCS and estimates of the costs of electrolytic hydrogen, 'blue' hydrogen production from natural gas with CCS, and the geological storage of large volumes hydrogen.

For an electricity system to operate in a stable manner, the rate of production of electricity must closely match the rate of use. System operators' ability to do that has depended, historically, on the ability to store fuels – which, in Britain, has primarily meant fossil fuels – until needed to meet demand for electricity.

The low carbon electricity system for Britain envisaged by the CCC has the majority of energy coming from wind and solar sources. However, it will also require low carbon sources of energy to meet demand when wind speeds and solar irradiation are low. When we have a very large total capacity of wind and solar generation, there will be times when the available power from renewables exceeds demand. If we are not to waste the available renewable energy through curtailment of production we need an ability to export it or store it.

The least-cost technology mix that AFRY's modelling came up with for the CCC for a 'typical' weather year, subject to a stress test of a 4-week wind drought, included 10 GW of nuclear capacity and between 17 and 22 GW of "dispatchable low carbon" – which could be plants burning low carbon hydrogen or natural gas with CCS.

While not intended to be a prescription for what the power system should look like in 2035, it does indicate that a very low carbon and reliable system is feasible, provided the necessary investment in new capacity – including in network capacity that allows the different resources to be accessed – proceeds at the necessary pace.

AFRY's central case for the CCC had 176 TWh of electricity supplied from generation using storable fuels as part of total production in 2035 of 572 TWh. This included 11 TWh from unabated gas and 39 TWh from "dispatchable low carbon" sources. Crucially, if the latter is to have minimal dependency on natural gas, there must be sufficient 'green' hydrogen production and storage capacity with AFRY's analysis suggesting a need for between 3 and 5 TWh of the latter by 2035.[111] The National Infrastructure Commission has recommended a strategic reserve of 25 TWh of electricity storage by 2040.[112] Production of 'green' hydrogen depends on enough 'spare' renewable electricity production after the main electricity demands are met.

The CCC's report observed that, "*it is unlikely that all UK hydrogen demand can be met from domestic 'green hydrogen' production by 2035, given likely limits on the rate at which renewable generation capacity can feasibly be built*".[113] This suggests a need for natural gas as a feedstock for 'blue' hydrogen.

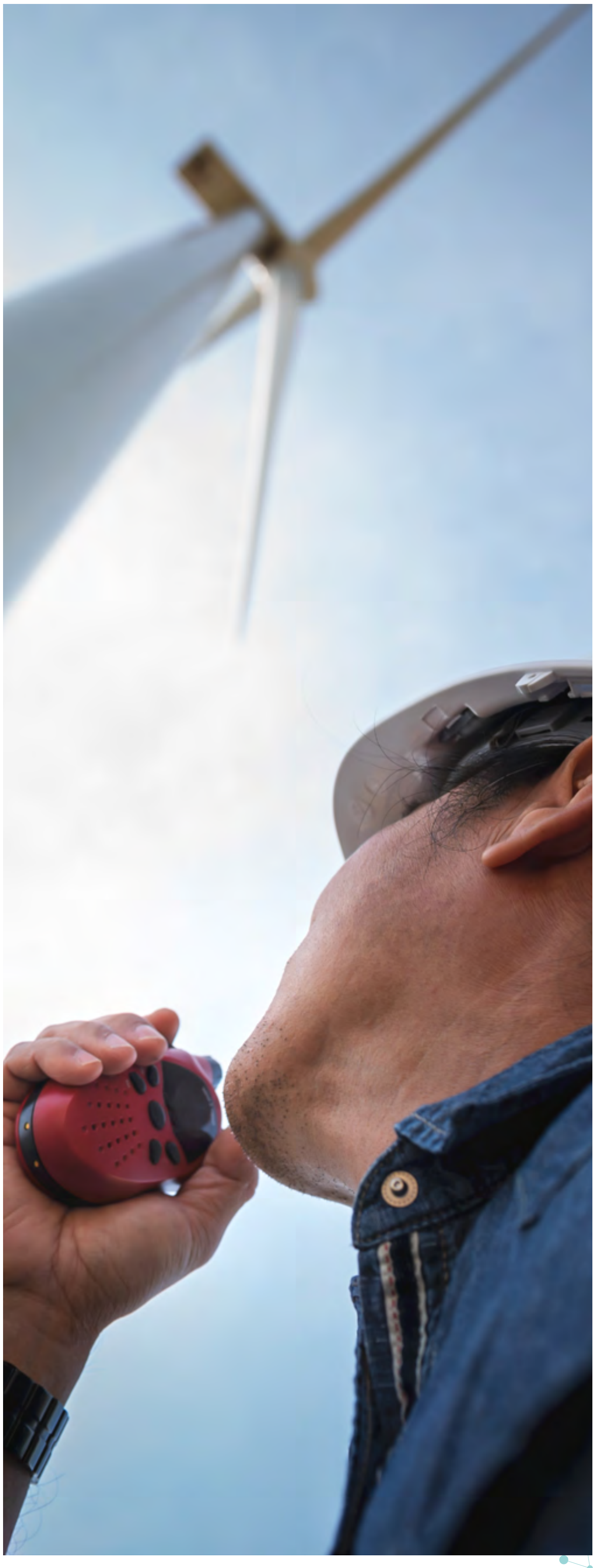
The challenge of building enough renewables capacity to meet the 2030 and 2035 targets – an average of over 9 GW per year for offshore wind from 2024 to 2030 and 5 GW per year from 2024 to 2035 for solar PV – should not be underestimated.[114] However, the development of network capacity and large-scale storage capacity to store energy for long periods of time and of business models to incentivise its development and appropriate use are now also on the critical path for a fully decarbonised electricity system by 2035.

The Electricity Networks Commissioner has stated that, in recent years, major transmission developments have typically taken between 7 and 14 years.[115]

The House of Lords Science and Technology Committee reported that it will take between 7 and 10 years to develop a salt cavern as a store of hydrogen.[116] In evidence given to that Committee, the Minister of State for Energy Security and Net Zero (ESNZ), equivocated about whether a strategic energy reserve was necessary. In separate evidence, the Chief Scientific Advisor to the Dept. for ESNZ, Prof. Paul Monks, said that options for strategic energy storage "*have to include unabated gas*".

As regards potential sources of 'schedulable' low carbon electricity that depend neither on natural gas nor hydrogen, the new Hinkley Point C nuclear power station is currently looking unlikely to be commissioned before 2029, with further delays possible, increasing the amount of energy required from other sources in the meantime.[117] Sizewell C has still not moved to a final investment decision and is therefore unlikely to be commissioned by 2035.

One of the key benefits of a decarbonised electricity system, and of the electrification of end use demand in buildings, transport and industry, is reduced dependency on fossil fuels. Natural gas can provide a back-up, in that it can offer physical security of electricity supply that can be drawn on when other energy sources and stores are unavailable, but it does not reduce sensitivity to global fossil fuel markets. The challenges in building low carbon generation, storage and network capacity quickly suggest that we might not succeed in reducing our dependency on natural gas as fast as we want, which will have knock-on impacts on the UK's ability to meet the 2030 Nationally Determined Contribution promised to COP26, and the legislated 6th Carbon Budget between 2033 and 2037.



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