

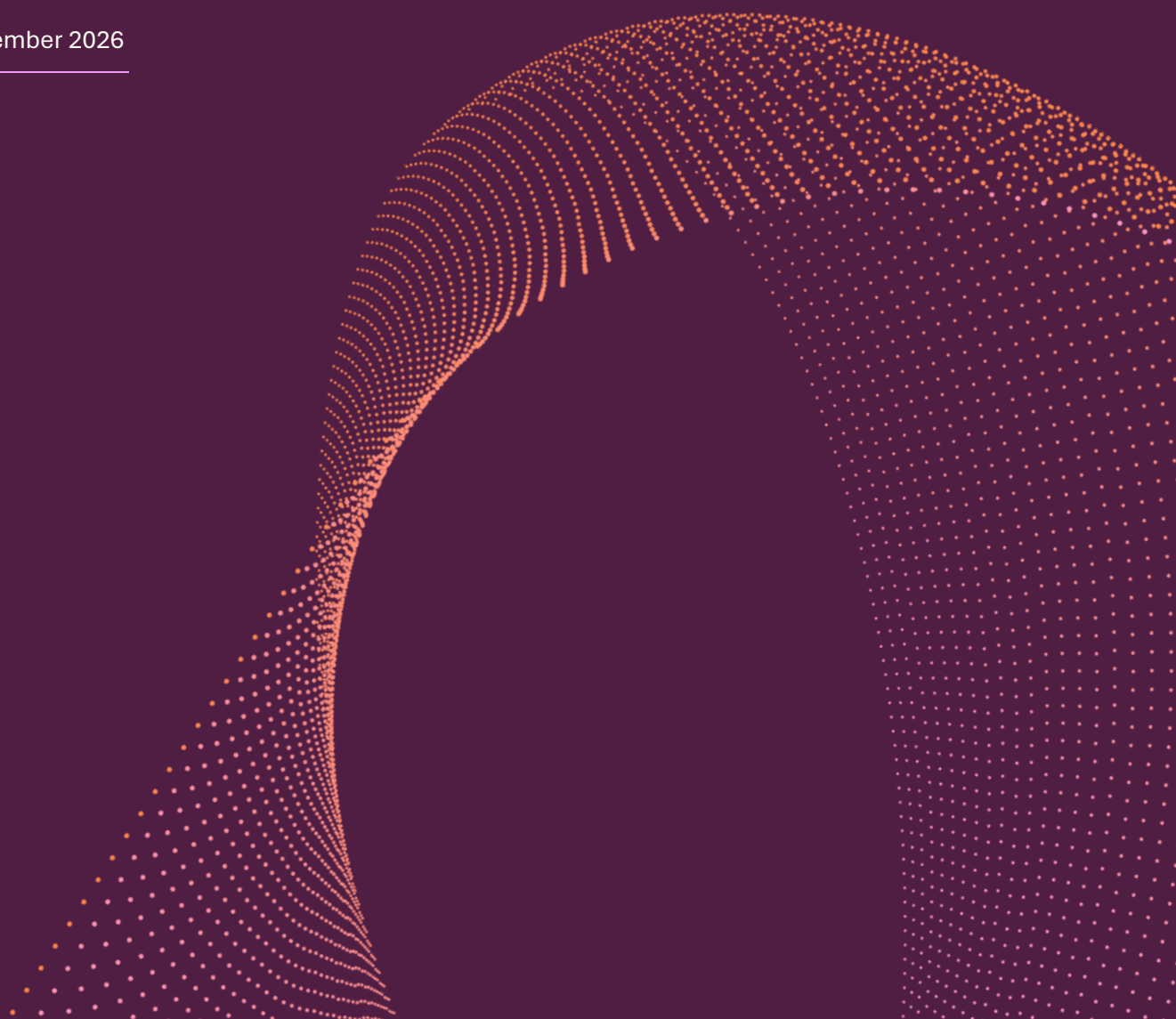
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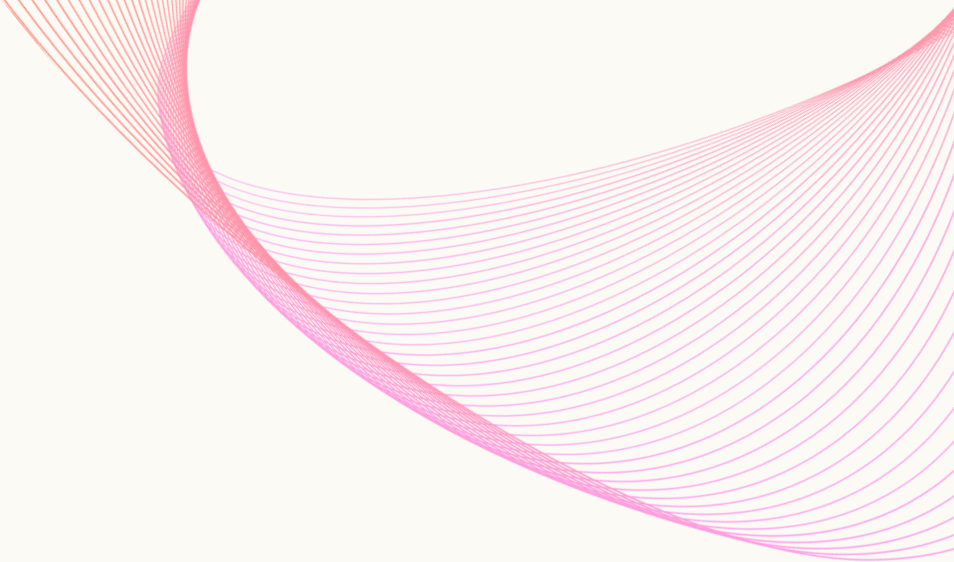
Insight paper

The Future of the Gas Grid

The challenge of maintaining and decommissioning the gas distribution network in Great Britain as gas demand falls

September 2026





About the MCS Foundation

The MCS Foundation's vision is that every UK home benefits from being carbon free. The MCS Foundation engages in grants, advocacy, research, and programmes to drive the widespread adoption of renewable energy technologies in UK homes. It was founded in 2018 to oversee the MCS (Microgeneration Certification Scheme), the UK's quality mark for small-scale renewables like solar panels and heat pumps. Since then, it has distributed more than £3 million to organisations across the UK, contributed to the development of ambitious government policies, and overseen record growth in certified renewable installations.

About Regen

Regen provides independent, evidence-led insight and advice in support of our mission to transform the UK's energy system for a net zero future. We focus on analysing the systemic challenges of decarbonising power, heat and transport. We know that a transformation of this scale will require engaging the whole of society in a just transition.

Acknowledgements

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Executive summary

The gas distribution network is a significant part of Britain's energy infrastructure, delivering methane through hundreds of thousands of kilometres of pipework to around 25 million domestic, commercial, industrial and electricity generation customers across Great Britain.

However, gas demand is in decline. Since 2004, overall demand has fallen almost 40%. Government policy is to continue to reduce fossil gas demand to meet our country's statutory climate and energy security goals. In particular, it aims to reduce household exposure to volatile gas prices by electrifying home heating.

“We know installing technologies like solar, batteries, heat pumps and insulation can save families hundreds of pounds a year on their bills, while protecting them from fossil fuel shocks.”

– UK government, Warm Homes Plan¹

The declining use of fossil gas will have significant implications for how the networks are used and paid for. The number of customers on the gas distribution network will start to decline from 2027, when the Future Homes Standard stops new homes connecting to the gas grid. The pace at which households and commercial buildings stop using gas is uncertain, but the direction is clear. Eventually the gas distribution network will withdraw from large areas.

Hydrogen and biomethane are unlikely to alter the downward trajectory of gas demand for heat in buildings. High-pressure networks may continue to serve industrial users and power stations with low-carbon gases, but not customers on low-pressure networks.

Under the current cost recovery mechanisms, the costs of the network will be shared by the shrinking group of customers left on gas, leading to ever-increasing charges per household.

As demand falls and customers disconnect, the costs of the network will need to be recovered from the dwindling customer base. In the worst case, left unmanaged, we risk a ‘death spiral’ in which increasing network charges land on those least able to switch, such as renters and households in fuel poverty. DESNZ and Ofgem have acknowledged these challenges. Ofgem states that it expects RIIO-GD3 to be “the last steady-state price control” for the sector.² Broader awareness of the need to plan for a declining gas distribution network remains low.

¹ Warm Homes Plan, UK Government, January 2026

² RIIO-3 Final Determinations GD, Ofgem, December 2025

This report examines the nature and scale of the challenge presented by customers disconnecting from the gas distribution network. It argues that work on a well-planned decline must start now and sets out recommendations for the critical features of the policy and regulatory framework that will need to be developed.

Three main costs will need to be recovered from the declining customer base:

- **Existing regulatory asset value (RAV):** £26bn of historic investments already made by network companies.
- **Ongoing maintenance:** £1.5bn per year is currently spent on pipe maintenance and replacement to reduce leakage, for public safety and to reduce the significant contribution to global warming.
- **Disconnection and eventual decommissioning:** an uncertain future cost to safely disconnect customers and eventually decommission sections of the network. Current disconnection costs imply a total of over £36bn to disconnect all customers, and there is little evidence on the cost of decommissioning.

Ofgem's own analysis, which included only the recovery of the existing RAV, projected escalating network charges from the mid-2030s reaching 30-40p/kWh, with £3bn of RAV still outstanding in 2050.³ Independent analysis from Citizens Advice painted a similar picture, with gas-only household bills reaching levels of more than £9,000 per year.⁴

Three key policies need to be developed to ensure the decline of the gas distribution network is well planned and managed:

1. Costs should be recovered while the customer base is large.

The large customer base the gas networks currently have should contribute to costs that will otherwise fall on a much smaller group in the future. Ofgem has acknowledged this in the current price control period (GD3 2026-2031) with its decision to accelerate depreciation of new investments, costing around £10 per year on the average dual fuel bill.

Recommended actions:

- Ofgem should set out a pathway in the next price control (RIIO-GD4) to depreciate the whole RAV by 2050
- The government should explore the creation of a decommissioning fund in its review of network investment and affordability.

³ RIIO-3 Sector Specific Methodology Consultation – Finance Annex, Section 8, Figure 3

⁴ The Great Grid Switch Off, Citizens Advice, 2025

2. Prepare now for planned decommissioning rather than ad hoc disconnection.

It will be expensive to disconnect each customer one-by-one and continue maintaining an expansive network for a small number of customers. The limited evidence available today suggests a strategic, area-based approach has the potential to reduce disconnection costs by around 65 per cent. Across all customers, that would bring the total cost of disconnection down from around £36.4bn to £12.5bn, a saving of £24bn. Area-based decommissioning remains some years off, and more evidence is needed to build an overall business case and a proven delivery model. Ofgem can use the GD3 period to identify pilot projects so that the evidence is in place before decisions are needed in GD4 and beyond.

Recommended actions:

- The government should commission a study of area-based decommissioning to understand the costs and impacts of different approaches to delivering customer disconnection and decommissioning at scale.
- Ofgem should fund decommissioning pilot programmes during this price control period (GD3 2026-2031), to provide evidence for wider decommissioning during GD4 and beyond.

3. Protect consumers that cannot switch away from gas.

Even after taking steps to minimise and fairly distribute future gas network costs, protections for vulnerable consumers will still be needed. Support to understand, fund and implement the switch to clean heat must reach renters who have no control over their heating systems, low-income households who cannot afford to upgrade, occupiers of buildings with technical barriers to electrification, and groups that engagement programmes have historically struggled to reach.

Recommended actions:

- The government and Ofgem should develop a plan for consumer protection in the delivery of gas network decommissioning, so that no household is left trapped on an increasingly expensive network or is unable to access clean heat.

Contents

Section 1: The changing role of gas distribution	7
1.1. Introduction to the gas distribution system	7
1.2. Demand on the gas network.....	13
Section 2: The challenges of a network in decline	20
2.1. What happens to costs as the customer numbers decline?	23
2.2. Customer impacts.....	30
Section 3: Towards a plan for managing gas decline fairly	32
3.1. Sharing the cost fairly	33
3.2. An efficient approach to disconnection and decommissioning	43
3.3. Consumer protections.....	48
Glossary.....	50

Section 1:

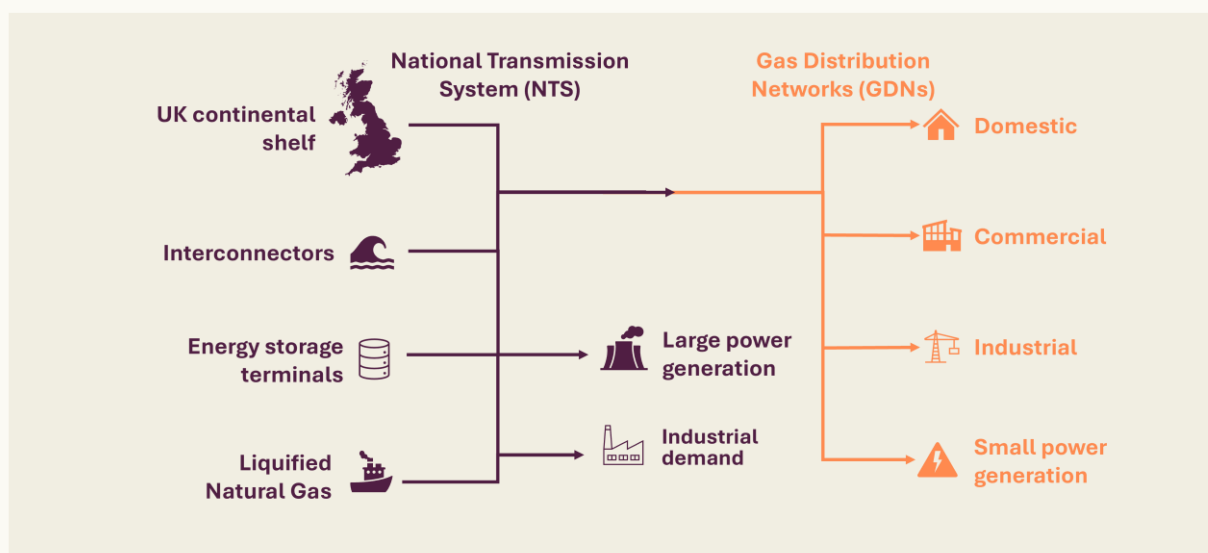
The changing role of gas distribution

An overview of how our gas distribution network operates and the challenges it faces.

1.1. Introduction to the gas distribution system

The focus of this report is the 280,000km of pipeline that make up the gas distribution network in Great Britain. The gas distribution networks (GDNs) take gas from the National Transmission System (NTS) and deliver it to almost 25m domestic, commercial and smaller industrial connections in local distribution zones (LDZs), as illustrated in Figure 1.

Figure 1: The UK gas system, highlighting the role of gas distribution networks



The GDNs are operated by four network companies: Cadent, SGN, Northern Gas Networks and Wales & West Utilities. Each runs a regional monopoly and recovers its costs through network charges paid by its customers, which include domestic households and all but the largest industrial customers. The areas served by these companies are shown in Figure 2.

Figure 2: Map showing the area covered by each gas distribution network in GB.

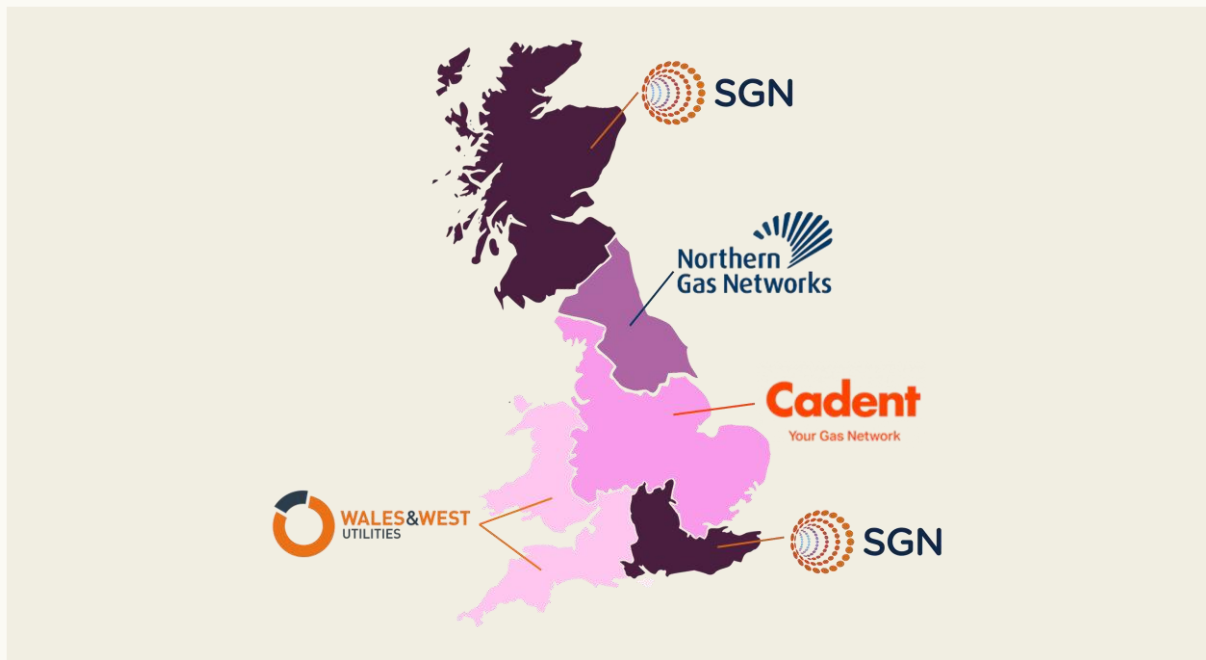


Figure 3: Gas distribution network hierarchy



The network is made up of pipes that move gas from the point of injection to customers for consumption. Gas is transported at high pressure over longer distances to maximise energy throughput and minimise frictional losses, then stepped down through successive pressure tiers as it nears the point of consumption, as illustrated in Figure 3. The lower-pressure tiers of the network are made up of hundreds of thousands of kilometres of underground pipework.

Figure 4: Distribution network pressure and length

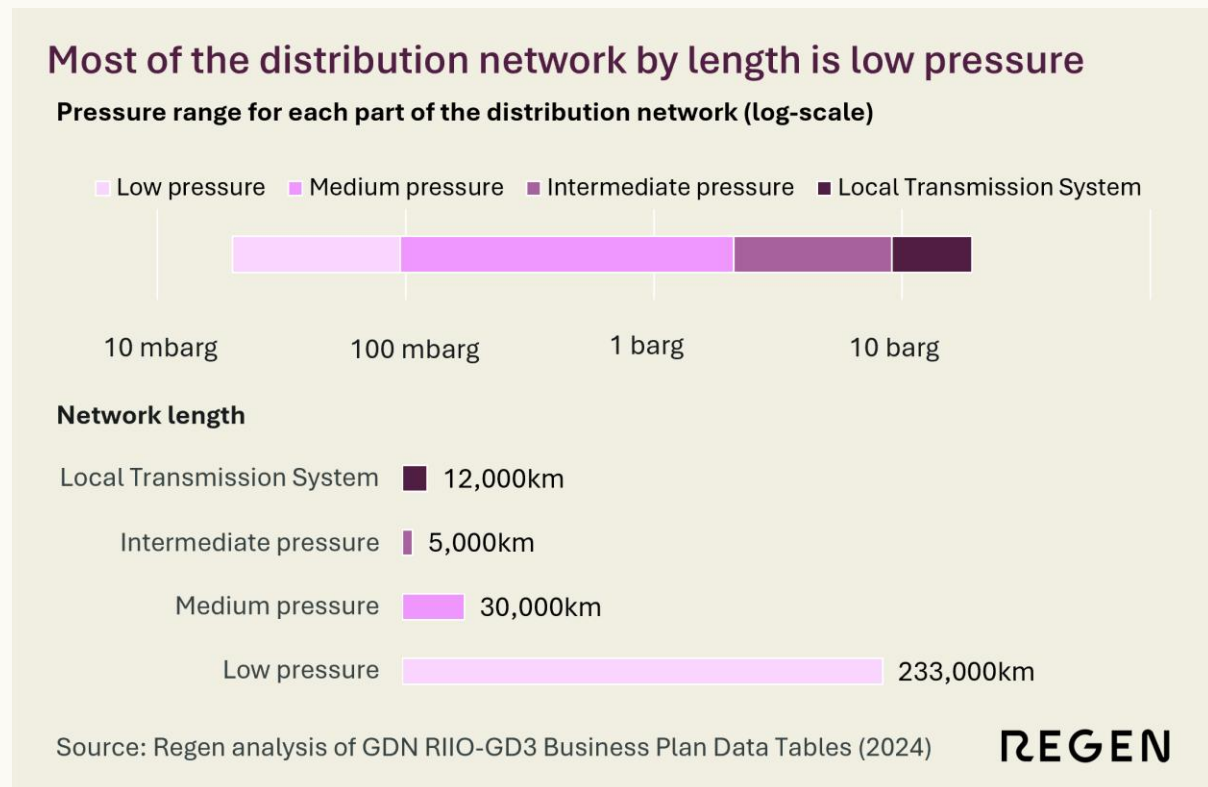
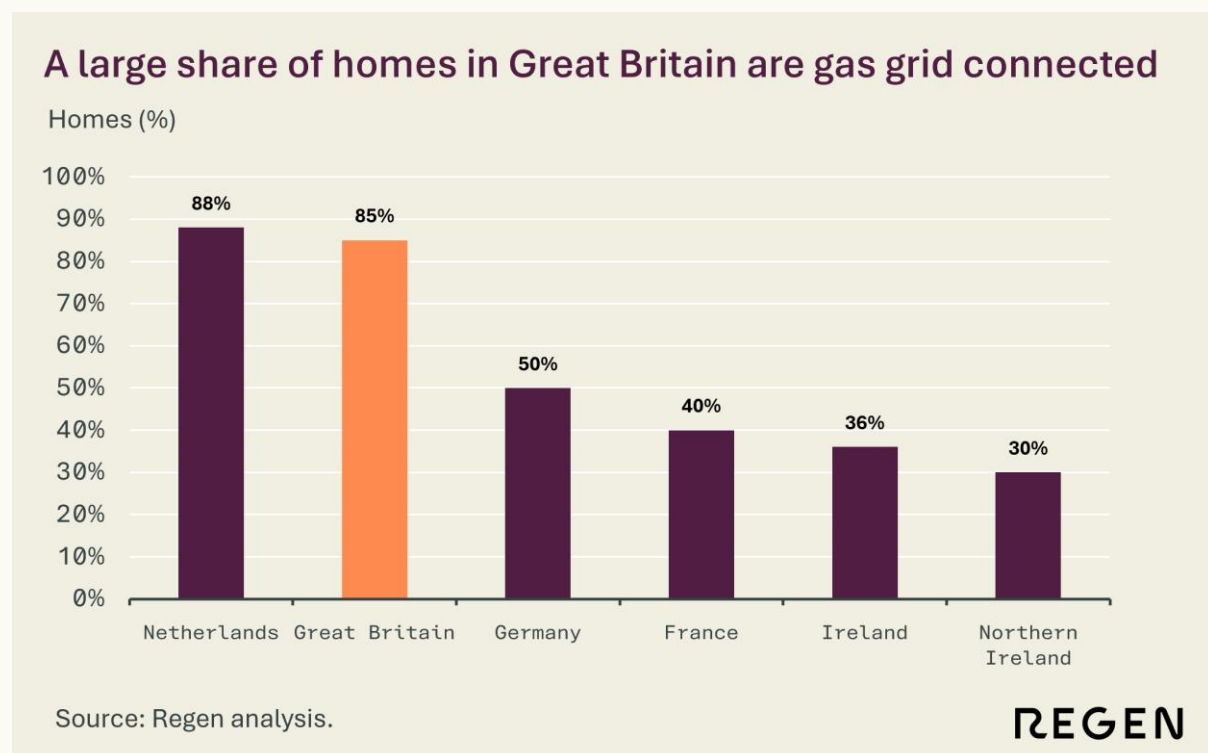
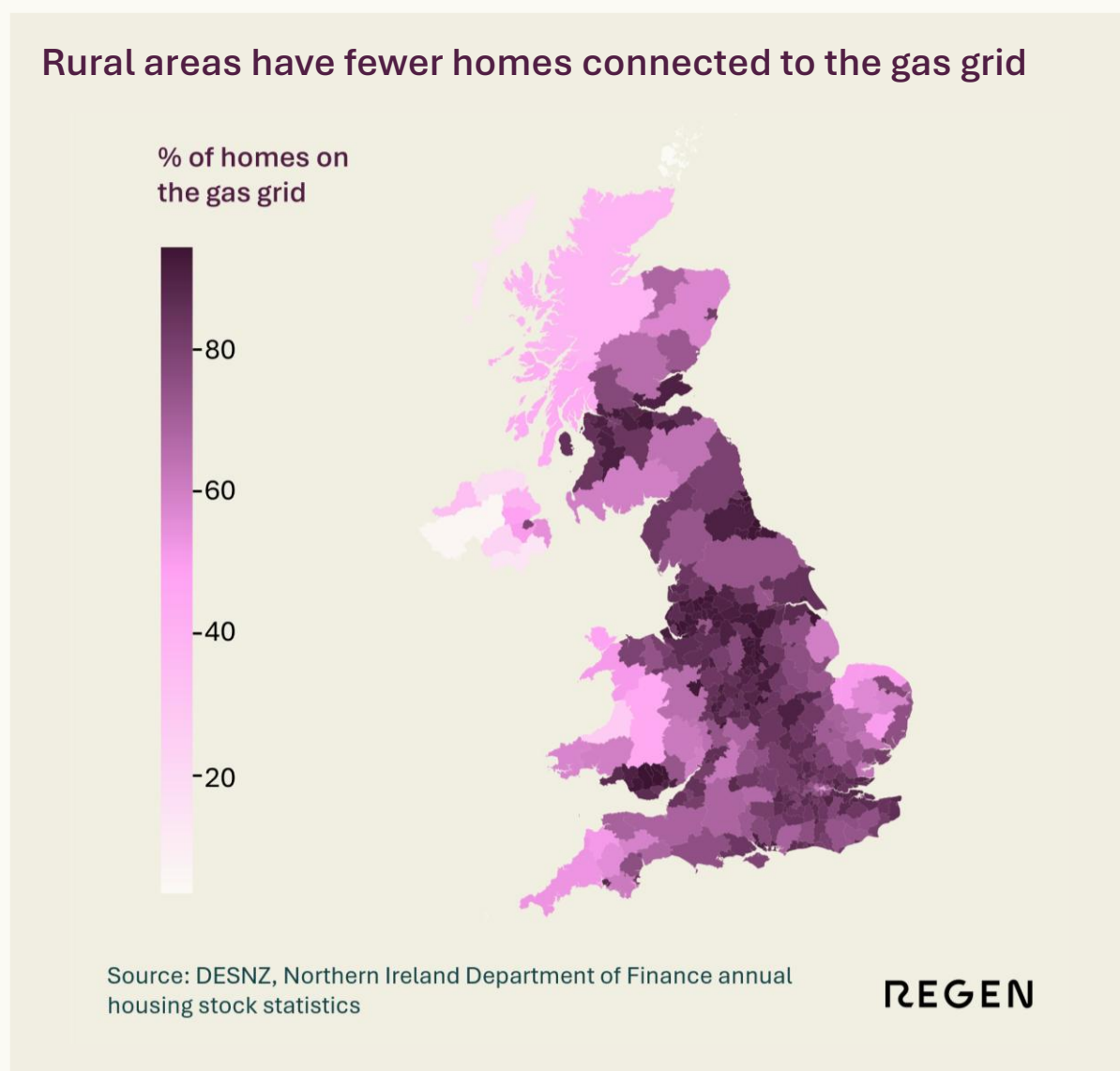


Figure 5: Share of gas customers in Great Britain compared to its neighbours



In GB, 85% of homes are connected to the gas network – much higher than most of our European neighbours, as shown in Figure 5. This has been driven by both economic and infrastructure factors. Gas discoveries in the North Sea from the 1970s and 1980s provided households with a strong economic incentive to switch to natural gas. At the same time, the state-owned monopoly (British Gas) ran a coordinated national conversion from town gas, which had been manufactured from coal at municipal gasworks, and a near-universal natural gas connection programme during the ‘dash for gas’ in the 1980s and 1990s.

Figure 6: Spatial coverage of the gas distribution network



An additional factor that has enabled widespread domestic gas connection is Britain’s high urban density. As Figure 6 shows, only in rural parts of south-west and north-east England, East Anglia, Wales and Scotland are homes mostly off the gas grid. For several reasons, Northern Ireland missed out on the initial dash for gas and still has a relatively low level of gas connection.

Evolution of the gas network

Britain's gas distribution networks trace back to hundreds of local municipal and private 'town gas' companies founded in the 19th century, which were nationalised into Area Gas Boards in 1949, consolidated as British Gas, privatised in 1986, and then split apart again in 2005 when the regional networks were sold off to the companies that run them today.

Figure 7: Gas distribution history and timeline

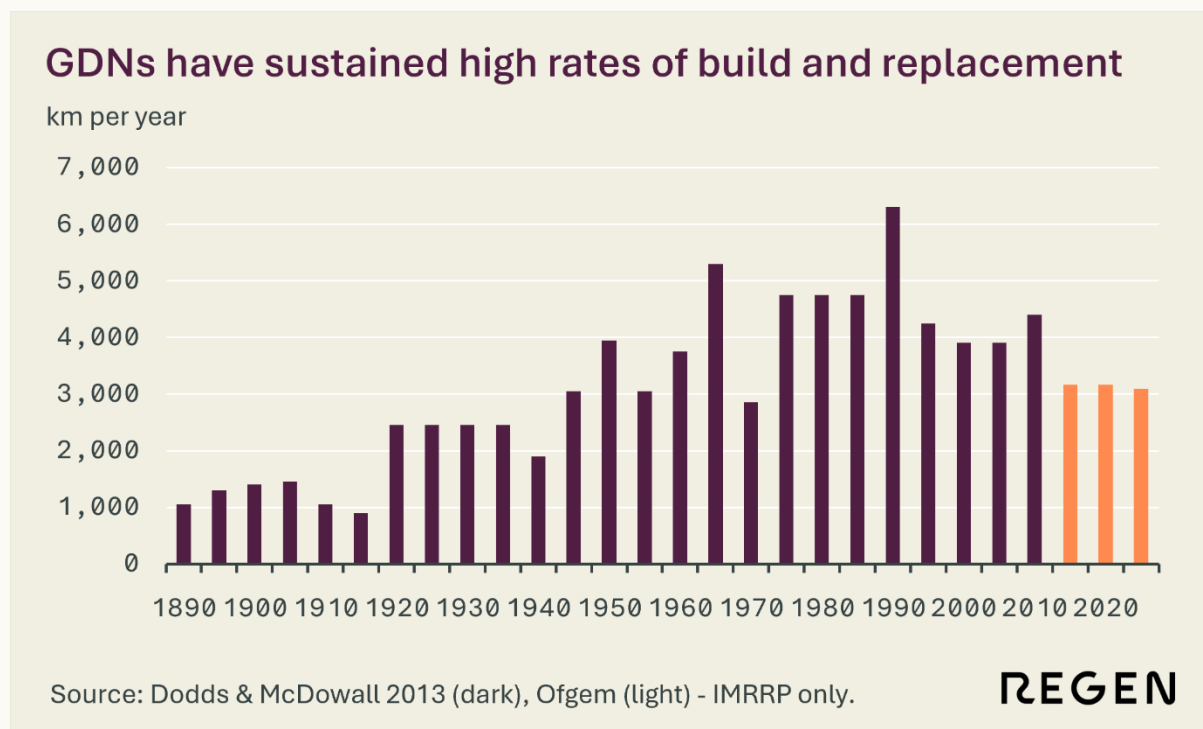


The state gas monopoly was privatised in 1986 with the aim of introducing competition and improving efficiency, overseen by an independent economic regulator, Ofgas. From that point, gas distribution was regulated through incentive-based price controls, which capped price increases at inflation (measured by the retail price index) minus an efficiency factor to push companies to cut costs, referred to as ‘RPI-X’.

From 2013 this evolved into RIIO (Revenue = Incentives + Innovation + Outputs), which links allowed revenues to defined outputs, rewards innovation in how they deliver an efficient service and uses a total expenditure (Totex) approach rather than favouring capital spending.

While electricity network build rates have reduced to a fraction of historic levels under privatisation, gas networks have continued to expand their networks and replace assets – mainly driven by the Health and Safety Executive’s requirement to replace iron pipes within 30m of a building in the Iron Mains Risk Reduction Programme (IMRRP).

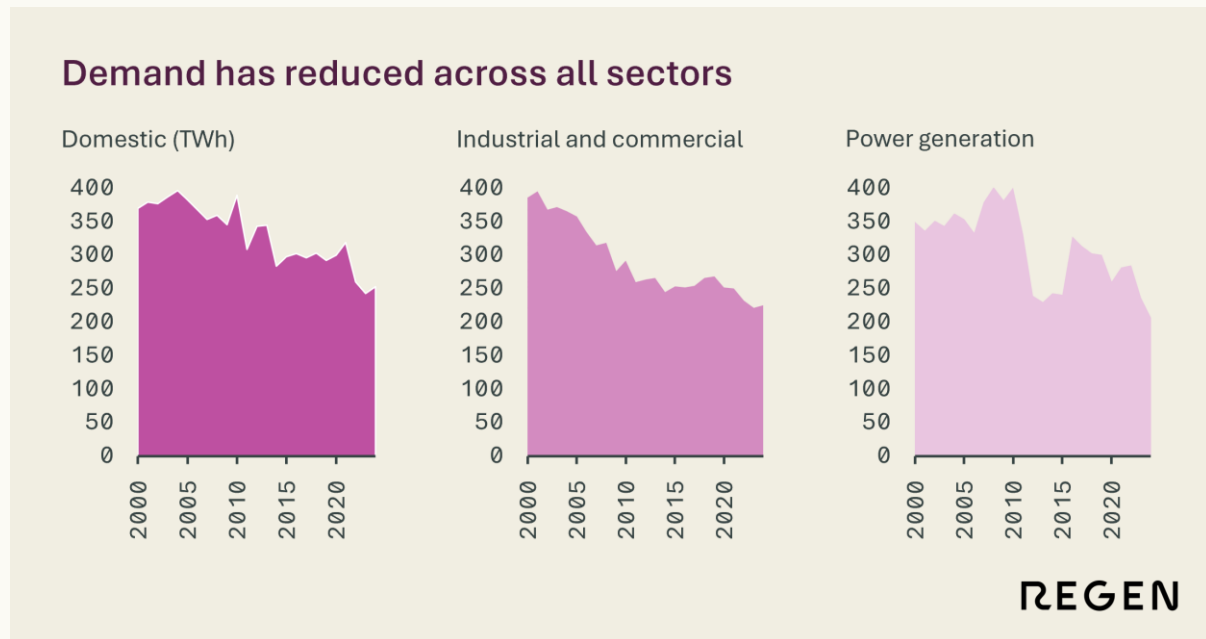
Figure 8: Gas distribution construction and replacement rates



1.2. Demand on the gas network

Central to the future of the gas network is the outlook for the numbers of customers connected and the volume of gas that will flow through it.

Figure 9: Historic UK gas demand by sector



As shown in Figure 9, overall gas demand has fallen by 39% since 2004.⁵ The key drivers of this vary by sector:

- **Domestic:** Improving efficiency (notably the switch to condensing boilers mandated from 2005), milder winters and price spikes (in 2008 and 2021) have all contributed to demand reductions in people's homes. Domestic connections to the gas network are still increasing each year, but the rate of growth has declined over the last decade.⁶ Heat pump deployment is yet to significantly impact domestic demand.
- **Industrial and commercial:** Reductions reflect the long structural decline of the UK's energy-intensive industry (closures, offshoring, the 2008 economic crisis and the 2021 gas price spike). All commercial and some industrial demand is supplied by the distribution networks. The largest declines have been in manufacturing, steel and chemical production, while commercial buildings have been the exception, where demand has remained largely flat. There are signs of new gas demand from data centres, with around three times as many connection enquiries in 2025 than 2024.⁷

⁵ Digest of UK Energy Statistics (DUKES) 2025, DESNZ, Table 4.1.

⁶ Subnational estimates of properties not connected to the gas network, DESNZ, December 2025.

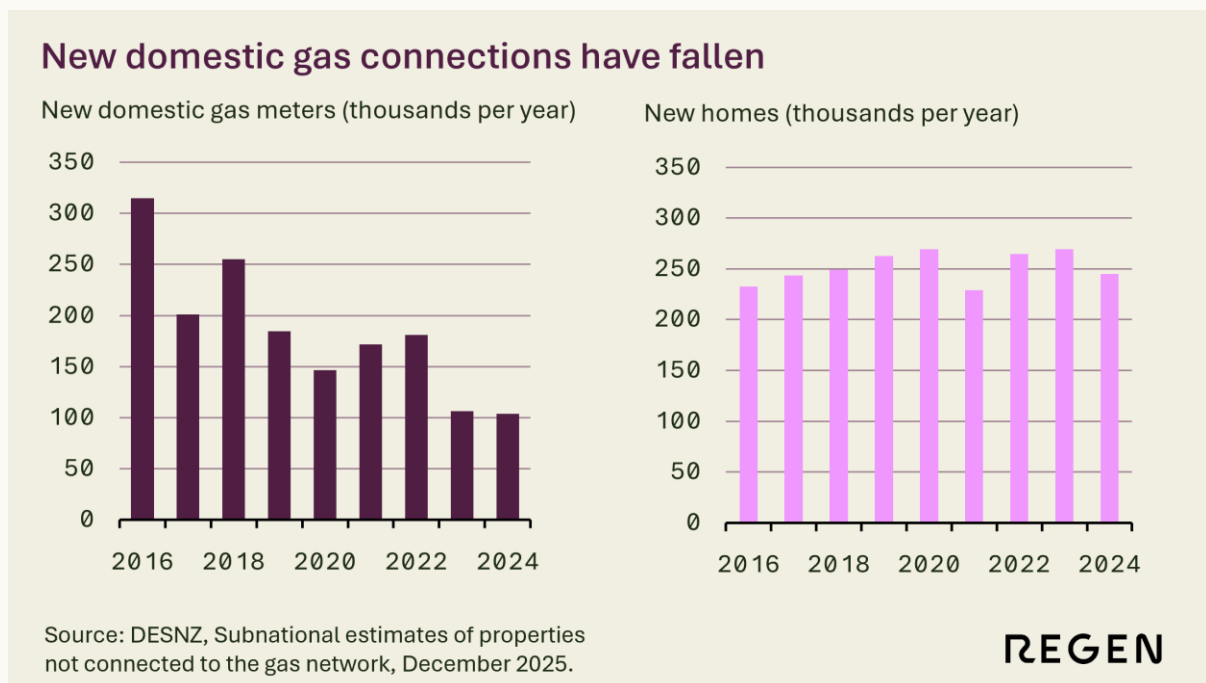
⁷ Data centre gas connections enquiries surge amid electricity grid queues, IGEM and FEN, April 2026.

- **Electricity generation:** Gas use in power generation has changed over time, rising to fill the gap as nuclear capacity retired through the 2000s and coal was phased out in the 2010s. Since 2016 the trend has been downward, as growing renewable output and falling electricity demand have pushed it into a flexible balancing role at lower load factors. Gas for power generation is almost entirely supplied by the transmission network and so has less impact on the future of the distribution networks.

Domestic gas connections are on the cusp of decline

While gas demand has fallen significantly over the last 20 years, new domestic connections have continued, as shown in Figure 10. This reflects that homes are still being built with gas boilers, and that disconnections of existing homes remain slow.

Figure 10: Estimated growth of domestic gas connections.



The rate of new gas grid connections has been reducing in the last decade. From March 2027 new buildings will be unable to connect to the gas network, due to the Future Homes Standard coming into force.⁸ From that point, the number of homes connected to the gas network will begin to decline as existing gas customers electrify their heating.

⁸ Future Homes and Buildings Standards, DESNZ, 24th March 2026. [Approved Document L \(2026\)](#), Welsh government, 7 April 2026. [New Build Heat Standard](#), Scottish government, 1 January 2025

Gas demand on the distribution network is set to reduce significantly, though the timing is uncertain

Government policy is to virtually eliminate gas demand to meet our country's climate and energy security goals. The legislated 2050 net zero target, the Climate Change Committee's Seventh Carbon Budget and the Warm Homes Plan are aligned to the need to rapidly decarbonise heating through electrification, principally using heat pumps.

The government, Ofgem and NESO are all aligned to declining gas demand:

“We expect typical daily gas demand to decline over the coming decades, as more residential and commercial buildings transition to alternative sources of heating, gas becomes a back-up source of power generation (rather than a baseload source), and industry decarbonises.”

– UK government⁹

“Across the Future Energy Scenarios 2025 pathways and the 2026 Ten Year Outlook, overall gas demand declines, although the pace and scale of this reduction vary.”

– NESO¹⁰

“In all future scenarios we expect a decline in natural gas demand.”

– Ofgem¹¹

In existing buildings, the rate at which electricity is replacing gas for heating is still slow. The deployment of domestic heat pumps in existing buildings last year was 53,265 units, around 12% of the 2030 annual target of 450,000.¹² Rates dropped in the first quarter of 2026 against a backdrop of high installation costs, a high electricity price relative to gas and insufficient awareness and consumer demand.¹³ Accelerating the adoption of clean heat requires clear communication of the need and policy that provides the means for widespread electrification. As certain European countries have demonstrated, when the incentives are right, heat pump deployment can grow rapidly. One aspect of this is illustrated in Figure 11, which shows how countries with a lower electricity-to-gas price ratio tend to have higher levels of heat pump adoption. That ratio has narrowed from over 4 in 2024 to 3.3 under the latest price cap (October-December 2026), as gas prices have risen faster than electricity prices.¹⁴

⁹ [Gas System in Transition: Security of Supply](#), DESNZ, Feb 2026

¹⁰ [Gas Market Roadmap](#), NESO, July 2026.

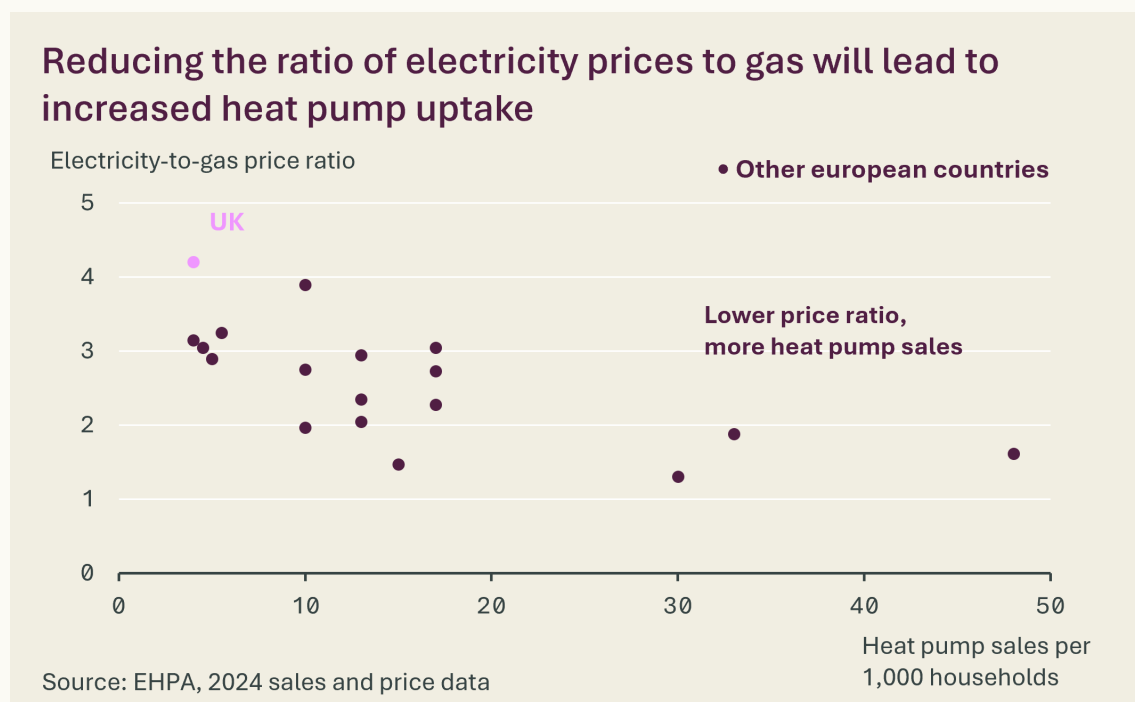
¹¹ [RIIO-3 Final Determinations Overview Document](#), Ofgem, 4th December 2025. Chapter 7

¹² [Heat pump deployment statistics March 2026](#), DESNZ.

¹³ [Electrified Heat Transition Tracker \(EHTT\)](#), Regen, accessed August 2026.

¹⁴ [Energy price cap unit rates and standing charges](#), Ofgem, 2026

Figure 11: Comparison of electricity-to-gas price ratio with heat pump sales in European countries



Around 40% of demand on the distribution networks is non-domestic. Commercial buildings are following a similar trajectory as domestic buildings, with a tightening of minimum energy efficiency standards.¹⁵ The Climate Change Committee is clear that this sector must decarbonise through “rapid electrification”, yet government ambition is uncertain with few mentions of commercial buildings in their flagship Warm Homes Plan.¹⁶

For power generation, annual demand is likely to continue to fall quickly with an accelerated pipeline of renewable and clean flexibility technologies. Disconnection may occur more slowly if revenues can justify low running hours. As noted previously, gas demand in the power sector has less impact on distribution networks, as most plants are transmission-connected.

One area of uncertainty is the future of Combined-Heat and Power (CHP). There is around 3 GWe of Combined-Heat and Power (CHP) across the distribution networks.¹⁷ Electrification of CHP plants is challenging as there is a loss of generation capacity alongside a new demand source, as well as technical and cost challenges for plants that produce high-temperature heat. A government review of the CHP Quality Assurance programme indicated that CHP “can still play a useful role in the future energy system”, though principally as a “transition” to net zero.¹⁸

¹⁵ [MEES in the non-domestic Private Rented Sector: interim response](#), DESNZ, 18 June 2026.

¹⁶ [The Seventh Carbon budget](#), CCC, February 2025. Section 7.9.

¹⁷ [CHP installations, capacity total fuel use and outputs, by sector and fuel type \(DUKES 7.4\)](#), 2026.

¹⁸ [Review of the Combined Heat and Power Quality Assurance Programme](#), DESNZ, 2026

Industrial use of gas varies widely across industries. Most use cases can be electrified, but there are some very high-energy processes that face technological barriers.¹⁹ Industrial electrification is also held back due to long waits for accessing larger electricity network connections and the difficulty in building a business case. The latter issue is extremely sensitive to the gap between gas and electricity prices and requires long-term certainty that electrification offers savings.

Are there alternatives to heat electrification?

Other options for decarbonising heat and reducing the UK's reliance on imported gas have been proposed, but have significant problems or limitations.

Hydrogen can effectively be discounted as a feasible alternative to heat pumps. Trials have been cancelled or shelved, the National Infrastructure Commission (now the National Infrastructure and Service Transformation Authority) advised against it, and while the government has not yet formally ruled it out, it has indicated that any role will be limited to applications that cannot be electrified, which does not include domestic heating.²⁰ Though green hydrogen produced via electrolysis can be near-zero carbon, the cheaper and more widely used steam methane reforming method causes high emissions.²¹ There is also a significant gap between ambition and implementation when it comes to green hydrogen supply, with only 7% of global capacity announcements finished on schedule in 2023.²²

Biomethane could play a part in displacing fossil gas and is already blended in small volumes into the gas supply. Regen's 2025 paper 'Making the Most of Biomethane' found that in all credible studies, biomethane production is projected to be limited to between 2% (13 TWh) and 17% (120 TWh) of current demand for fossil gas. A recent report by NESO aligned with this, stating that producing "30 TWh by 2050 could be achievable before material dependencies, trade-offs and risks arise", principally related to feedstock production.²³ Biomethane is also expensive, costing around 10p/kWh to produce (more than twice the wholesale price of fossil methane) according to analysis for the Green Gas Taskforce.²⁴ The limited biomethane resource will need to be prioritised for displacing fossil methane in applications where electrification is particularly expensive or unfeasible, such as high-temperature processes or for low-utilisation

¹⁹ [The Seventh Carbon budget](#), CCC, February 2025. Section 7.3.

²⁰ [Hydrogen Village Trial](#), DESNZ, December 2023. [Second National Infrastructure Assessment](#), NIA, October 2023. [Hydrogen heating: overview](#), DESNZ, 2026.

²¹ [Comprehensive review of hydrogen production technologies](#), Mohammadi et al, October 2025.

²² [The green hydrogen ambition and implementation gap](#), Odenweller & Ueckerdt, *Nature Energy*, January 2025.

²³ [Biomethane](#), NESO, July 2026.

²⁴ [Reducing the cost of Net Zero with biomethane](#), Baringa, October 2025, Page 17. Regen analysis of ONS gas price, January to July 2026

power generation, rather than in applications that can be more easily electrified, such as low-temperature heating in buildings.

Hybrid heat pumps retain dependence on the gas network but reduce demand. They are not supported by the Boiler Upgrade Scheme, they received no mention in the Warm Homes Plan and ministers have indicated they would not want to use government funding for technologies that might be a “stepping stone”.²⁵ The rationale for this decision is supported by evidence that the economic cost of maintaining two energy systems is greater than one.²⁶ Decarbonising the hybrid element with biomethane is unrealistic due to its high production cost.²⁷ Installing hybrid systems that will eventually need replacing with full heat pump systems stores up additional cost and disruption for consumers.²⁸

What if we stick with gas?

The health, wellbeing and security implications of climate change have become very clear this summer. A secure future relies on cutting global emissions, which requires an end to the widespread burning of fossil fuels. The UK has made a legally binding commitment to this global effort through the Climate Change Act.²⁹

Alongside the imperative to address emissions, there is also a compelling economic and security case to be made for heat electrification.³⁰ The government’s Digest of UK Energy Statistics (DUKES) data shows that the UK has been a net importer of gas since 2004, as the UK Continental Shelf is a mature gas basin with depleted reserves.³¹ Recent international events, such as the invasion of Ukraine and the US war in Iran, show how global events can lead to rapid increases in wholesale gas prices.³² Our gas infrastructure is also vulnerable to attack as supply is concentrated in just four clusters, as compared to a much more distributed electricity generation system.³³

²⁵ [In conversation with Martin McCluskey MP, Minister for Energy Consumers](#), Nesta, 19 March 2026. From 50m 20s.

²⁶ [Heat GB: Calculating the network costs for low carbon heating](#), Citizens Advice, October 2023.

²⁷ [Making the most of biomethane](#), Regen, 29 September 2025.

²⁸ [Hybrid heat pumps](#), Nesta, accessed July 2026.

²⁹ [The Climate Change Act](#), legislation.gov.uk, 2008.

³⁰ [Back to gas isn’t the answer](#), Regen, September 2026.

³¹ [DUKES](#), DESNZ, 2026, Chapter 4.

³² [UK firms pull fixed energy deals as Iran war pushes up prices](#), BBC news, March 2026.

³³ [The Home Front](#), E3G and the Department of War Studies Kings College London, June 2026.

Regen view

Gas demand has already fallen 40% since 2004, and there is no plausible future scenario where gas continues flowing to homes, businesses, industry and power plants at the levels of today. The Seventh Carbon Budget and the Warm Homes Plan assume that most homes will be heated by electricity by the middle of the century. Reducing gas demand is not only essential to meet climate targets, but also represents an economic and security imperative.

Despite this consensus, electrification of heat in buildings and industry remains slow. However, evidence from our European neighbours shows that when barriers to electrification are addressed, and there is a strong economic incentive, heat electrification can become widespread.

Hydrogen and biomethane are unlikely to alter the downward trajectory of gas demand for heat in buildings. High-pressure networks may continue to serve industrial users and power stations with low-carbon gases, but not customers on low-pressure networks.



Section 2:

The challenges of a network in decline

How a declining customer base and gas demand will impact consumers.

The costs of the gas network are paid for by domestic, commercial and industrial customers via network charges. When network companies make investments, for example replacing or upgrading pipes, these capital investments are added to the Regulatory Asset Value (RAV) of the network. Network charges paid by consumers are set such that they recover in-year operational costs, allow network companies to make a return on the RAV and recover annual RAV depreciation.

As the gas network grew, network charges could be levied against a growing customer base and increasing demand for gas. This model of future customers paying for investment in and maintenance of the network will begin to break down as gas demand and customer numbers reduce. Ultimately, the cost of paying for the network, including the value of network assets, will be borne by an ever-decreasing customer pool.

How are gas network revenues calculated?

Network owners make investments in the gas networks which are paid for by customer network charges to cover depreciation and a return on investment over the long term. Their yearly revenue draws on three sources.

Network expenditure is sorted into two groups. The first, known as **fast money**, covers day-to-day operating costs and is paid each year. The second, **slow money or depreciation charge**, covers capital investment. Rather than being repaid straight away, it is added onto the RAV and returned gradually over the life of the asset via depreciation.

And lastly, since networks fund their capital projects before they recover the cost, they are allowed a **return on the outstanding RAV**. This compensates them for their cost of capital and provides a regulated return on their investment.

Figure 12: Illustration of network revenue breakdown

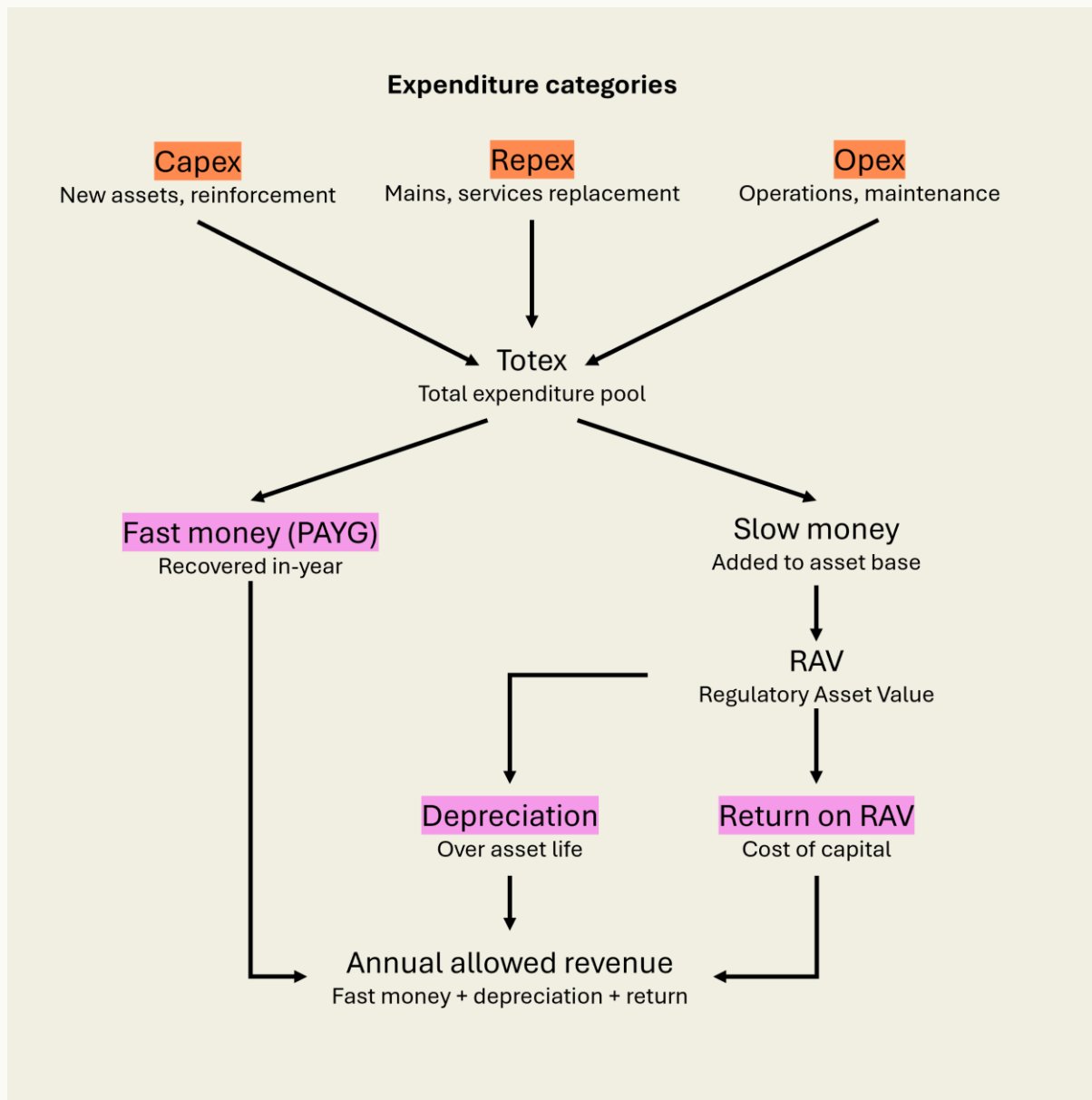
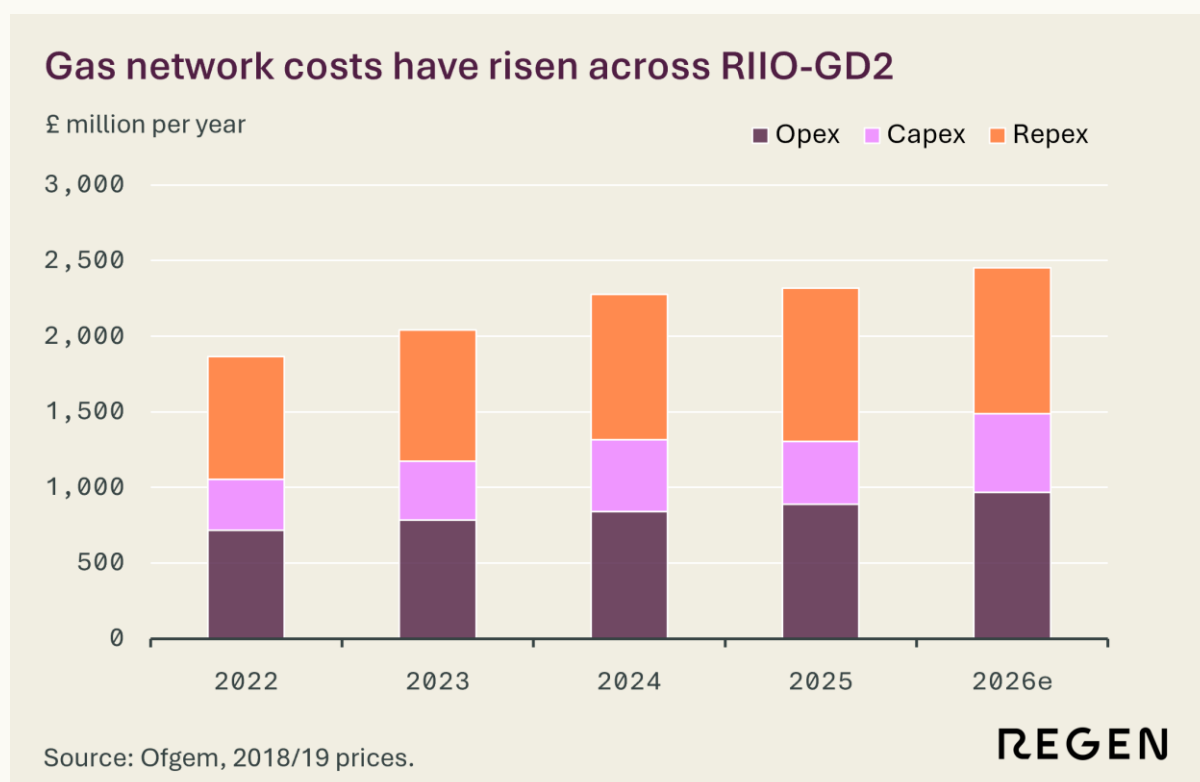


Figure 13: Breakdown of gas network expenditure by Opex, Capex and Repex



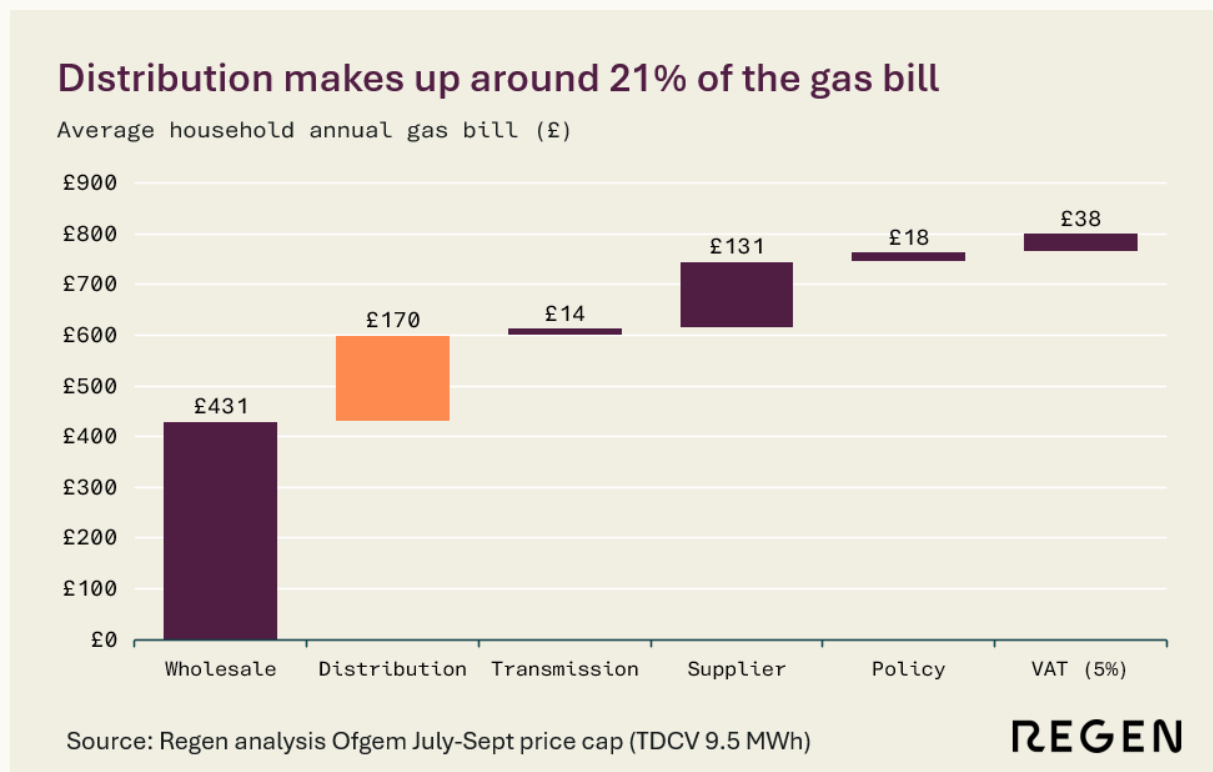
Gas distribution network costs have risen steadily across the RIIO-GD2 period (which spans 2021 to 2026), from around £1.9bn in 2022 to a forecast £2.5bn in 2026.³⁴ The composition of that spending has also changed. Capital expenditure (Capex) was the largest element of network costs in RIIO-GD1, but during GD2 it has been overtaken by replacement expenditure (Repex), now the single largest component and the main driver of the overall increase.

Repex costs are mainly attributed to the Iron Mains Risk Reduction Programme. Mandated by the Health and Safety Executive, this requires network companies to replace ageing iron gas mains within 30m of buildings to reduce the risk of fires and explosions caused by leaks.

Expenditure across all categories is ultimately paid for by consumers. As Figure 14 shows, gas distribution network charges make up around 21% of the average annual household gas bill.

³⁴ RIIO-GD1 Annual Report 2020-21, Ofgem. Note: Ofgem uses 2028/19 prices for GD2 reporting.

Figure 14: Breakdown of average gas bill



2.1. What happens to costs as the customer numbers decline?

With fewer gas connections and lower gas demand, the costs of the network – which are more closely related to the extent of the network than to the amount of gas delivered or the number of customers – will be spread across lower volumes and fewer customers. This could lead to a situation where network charges spiral upwards as customers leave the network and demand declines further.

There are three cost areas that will need to be recovered from the dwindling customer base:

1. Historic investments in the RAV
2. Ongoing repair and replacement
3. Disconnection and decommissioning.

If investors judge that recovering the RAV from customers is at risk then they are likely to demand a higher return on their investments, which would further push up costs.

Cost recovery of historic investments

Ofgem's analysis in preparation for the RIIO-GD3 price control illustrates the challenge of recovering the cost of historic investments under the current regulatory regime. Ofgem estimated the gas distribution RAV to be in the region of £20bn. We estimate the total RAV across the GDNs at £25.8bn as of 31 March 2024.³⁵

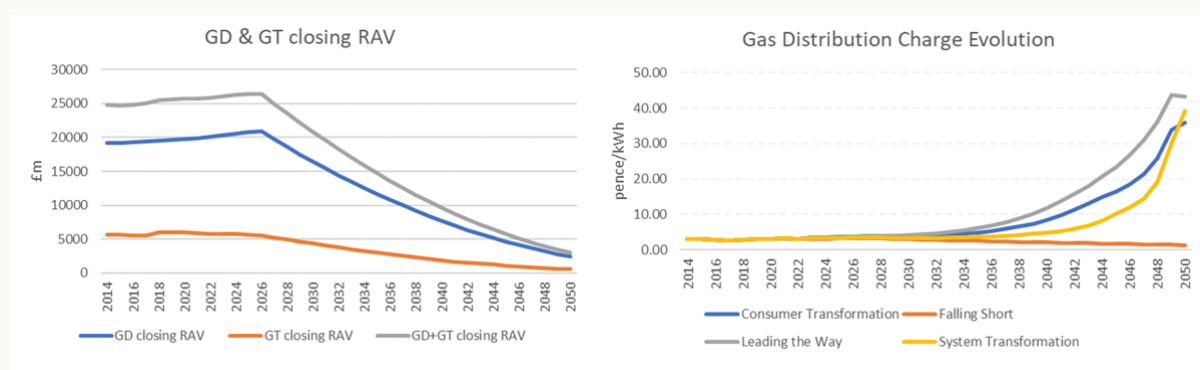
As Figure 15 shows, in scenarios with high levels of heat electrification, network charges (measured using a proxy of pence per kWh) rise to levels that would be unaffordable for most consumers. The assumed depreciation profile also leaves around £3bn of residual RAV in 2050, raising questions around how to manage this gap (see section 3).

***“The current level of depreciation charge per consumer...
is forecast to fall significantly short of the remaining RAV.”***

– Ofgem³⁶

This is despite the analysis only modelling RAV recovery (i.e. the costs of historic investments pre-GD3) and not including any ongoing capital investment, disconnection or decommissioning costs. Any additional costs will increase the outstanding asset value and future network costs.

Figure 15: Ofgem analysis of RAV and distribution network charge³⁷



The risk of under-recovery of network costs could increase the cost of capital. Where investors doubt that network charge revenues will be sufficient to cover the RAV before customers leave, they may treat the shortfall as a risk they could end up bearing through a write-down and demand a higher return. That would itself then be recovered through network charges.

³⁵ Total across NGT and GDNs was £32.9B. [CMA response](#), FEN, 22 April 2025.

NGT was £5.7bn at the same point in 2018/19 prices, we estimate this as £7.1bn in 2024 prices. [Gas transmission price control financial model: RIIO-2](#), Ofgem, 30 January 2024.

³⁶ [RIIO-3 SSMC](#), Para 1.7, Ofgem, October 2023.

³⁷ [RIIO-3 Sector Specific Methodology Consultation – Finance Annex](#), Section 8, Figure 3.

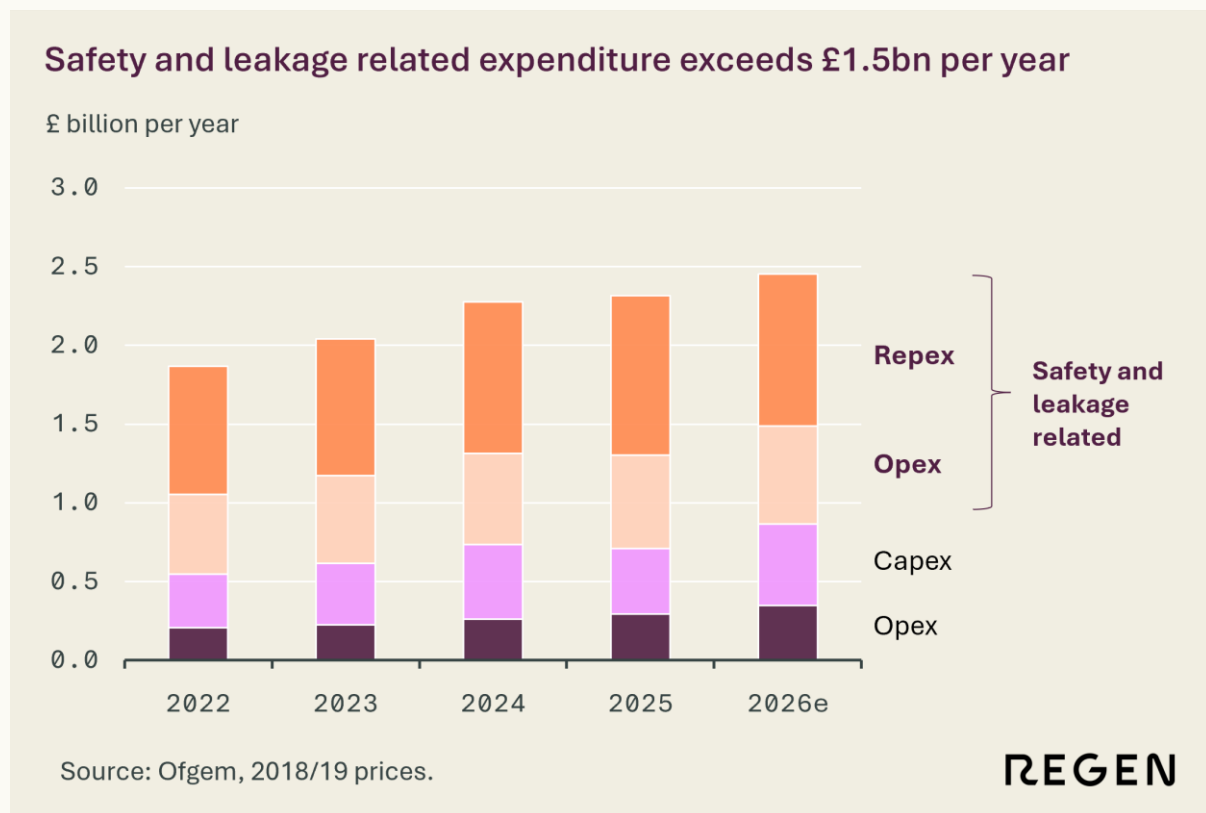
“Stakeholders have raised concerns about the pace of regulatory depreciation and the potential risk to the recovery of previous investment (asset stranding risk).”

– Ofgem³⁸

Ongoing maintenance for safety and leakage

Some 70% of the total £11bn gas network expenditure across RIIO-GD2 has been spent on safety and leakage-related asset maintenance. Around 40% (£4.6bn) of the total was on replacement of assets, with a further 26% (£2.8bn) on safety-related Opex.

Figure 16: Network expenditure



³⁸ RIIO-3 SSMD, Para 1.7, Ofgem, October 2023.

While maintenance costs may reduce, they are highly unlikely to stop entirely, for two reasons:

1. The Iron Mains Risk Reduction Programme only replaces pipes within 30 metres of buildings, so more work may be needed beyond the planned 2032 completion date.

The programme requires all ‘at risk’ Tier 1 iron mains – those up to and including eight inches in diameter and within 30m of a building – to be decommissioned by the end of 2032. This means other ageing iron assets (larger pipes and those beyond 30m from a building) remain in the ground in the rest of the network. GDNs have an ongoing duty under regulation 13 of the Pipeline Safety Regulations 1996 to maintain the network, which for ageing assets implies repair and replacement.

“While replacement volumes will remain broadly stable, we are seeing an increase in Repex costs.

“Repex costs will increase by 35% relative to RIIO-GD2. This increase is driven by changes in the mix and complexity of Repex workload we must now undertake.”

– Northern Gas Networks³⁹

- 2. The case for continued work to eliminate leakage is strong.** While the focus of the IMRRP is on the safety risk from leaking pipes, methane leakage also has an enormous global warming impact. The GDNs’ model estimates around 0.5% (2.2 TWh) of gas that enters their networks is lost as shrinkage, almost all of it leaked to the atmosphere.⁴⁰ An additional 2.5% (11.7 TWh) is unaccounted for.⁴¹ Reducing leakage avoids consumers paying for wasted gas and drastically reduces emissions directly because methane causes around 80 times the warming of CO₂ per molecule over 20 years.⁴² Addressing leaks through both repair and replacement is one of the most effective ways to cut the network’s global warming impact while lowering bills, so this work is likely to continue well beyond 2032.

Taken together, it seems highly unlikely that the gas networks will be able to reduce their expenditure on repair and replacement entirely – and under the current regulatory regime these costs will add further upwards pressure to network charges.

³⁹ Cost Assessment and Benchmarking Approach (Appendix A21), RIIO-GD3, NGN

⁴⁰ Shrinkage and Leakage Model Modification, Post-Consultation Report on the proposed revision to the Own Use Gas percentage factor, Joint Office of Gas Transporters, December 2025

⁴¹ Final Allocation of Unidentified Gas Statement for Gas Year 2024-2025, Engage Consulting, (31 March 2024, section 5)

⁴² Methane and climate change, IEA, 2021

Additional costs: disconnection and decommissioning

There will be further costs as customers switch away from gas. These may arise from the process of disconnecting customers' service pipes and potentially from decommissioning shared network assets.

What's the difference between disconnection and decommissioning?

Disconnection refers to removing an individual customer from a live gas network. The service pipe to the property is capped, the meter removed and the customer stops drawing gas, but the gas main remains in order to serve everyone else connected to it.

Decommissioning refers to taking an entire section of the network out of service. Once every property on a main has been disconnected, it can be isolated, purged and abandoned, ending the cost and safety obligations attached to it.

Disconnection

Currently, there are two routes to domestic disconnections:

- **'Safety disconnections'** where the customer notifies their supplier, who removes the meter and caps the supply at the emergency control valve. The GDN is notified via Xoserve and is required to make the service pipe safe under its safety obligations after 12 months of no supply. This is usually done by disconnecting the service pipe to the gas main. The cost is then socialised across all gas customers.
- **'Voluntary disconnections'** where the customer contacts their GDN and must self-fund the works, with an average cost of around £2,000 – significantly higher than for safety disconnections.⁴³

Most customers contact their supplier and do not pay, but this dual process creates confusion for consumers and a disparity in who pays for disconnection between otherwise identical processes, as has been pointed out by Citizens Advice and Sustainability First.⁴⁴

⁴³ [Summary of Responses: Gas Disconnections Framework Review](#), Ofgem, 19 September 2025. p. 5

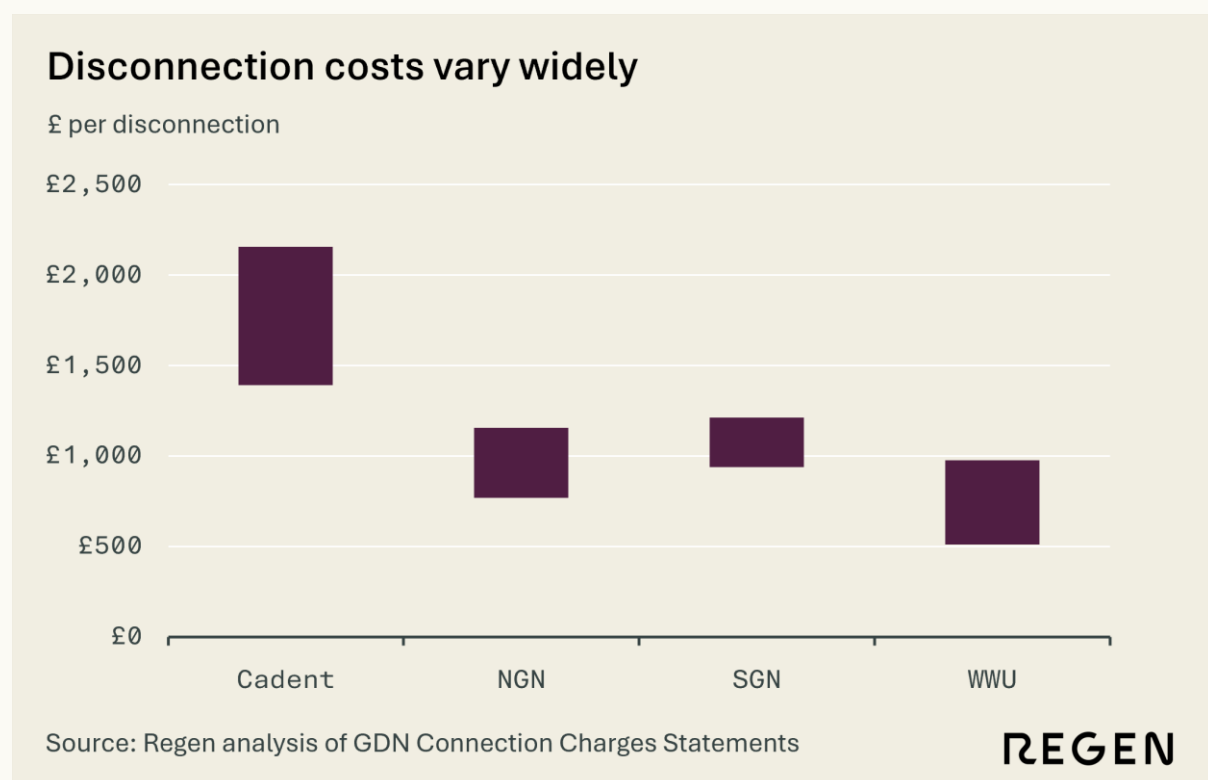
⁴⁴ [How to improve the consumer journey when installing low carbon technology](#), Citizens Advice, 2026. [Commentary on the Gas Disconnections Journey](#), Sustainability First, 2025.

With tens of thousands of disconnections carried out annually, there is sufficient historic data to understand the likely scale of costs under the current one-by-one customer-led approach. There is a significant spread of reported costs:

- £712 per disconnection from Ofgem’s gas disconnections framework review⁴⁵
- £510 to £2,157 from GDN connection charges statements (see chart below)
- £1,450 according to Arup’s study for the National Infrastructure Commission.⁴⁶

This spread has been highlighted by others, including Sustainability First in its Strawman on disconnections.⁴⁷

Figure 17: The range of reported disconnection costs for each GDN.



NESO has identified the uncertainty around disconnection costs and proposed exploratory analysis to identify potential efficiencies and process requirements to help manage rising costs.⁴⁸

⁴⁵ [Summary of Responses: Gas Disconnections Framework Review](#), Ofgem, 2025

⁴⁶ [Future of Great Britain’s Gas Networks](#), Arup, October 2023

⁴⁷ [Gas Disconnections: early steps to improve the customer journey](#), Sustainability First, March 2026

⁴⁸ [Gas Market Roadmap](#), NESO, July 2026.

Decommissioning

The costs of decommissioning are less well understood than for disconnection. Even the definition of decommissioning, and whether it necessarily requires full asset removal, is a point of debate.

Arup's study into the future of gas networks for the National Infrastructure Commission stated that "limited work has been done to investigate the best way to decommission large portions of the gas network and hence the costs associated with disconnecting customers, removing the natural gas from the system, making the network safe and permanently decommissioning".⁴⁹

The costs involved will clearly depend on the nature and locations of the work being carried out. In some situations, pipes may need to be removed entirely, but it may be possible for much of the low-pressure pipework to be isolated, purged and abandoned in the ground at much lower cost.

Stonehaven analysis of decommissioning Belfast's gas network in the 1980s found it cost £150m overall, or £55,432/km (inflation-adjusted £649m or £240,000/km).⁵⁰ Multiplying this with the length of the low-pressure networks (~233,000 km) produces a figure of more than £50bn. However, this estimate looks pessimistic when compared with unit rates achieved by GDNs in the Iron Mains Risk Reduction Programme. During GD2, both Wales & West Utilities and Northern Gas Networks achieved unit costs below £120,000/km (2017/18 prices) for work that involved full asset replacement (rather than just removal). The two activities are not directly comparable, but the gap suggests the Belfast benchmark could overstate the likely cost of decommissioning at scale.

This uncertainty points to the need for a detailed study into these different pathways to develop a robust estimate of overall costs. In Section 3 we explore the case for a more strategic decommissioning approach and what this would look like in practice.

⁴⁹ Future of Great Britain's Gas Networks, Arup, October 2023

⁵⁰ [Decommissioning the gas network](#), Stonehaven

2.2. Customer impacts

If network charges are set at a level to recover every necessary cost (RAV, depreciation, ongoing maintenance, disconnection and decommissioning costs), customers that remain on the network would face an escalation of network charges, leaving them with unaffordable bills and potentially increased supplier debt.

Many will be able to respond by electrifying their heating, but some will be less able to switch. These groups include:

1. **Renters**, who do not have autonomy over their heating system despite paying the energy bill directly in most cases. Over a third of homes in GB are rented, making this the largest impacted group.⁵¹ Fuel poverty is also more common in the rented sector, making the social impact of high bills more severe.⁵²
2. **Hard-to-reach households**, who are difficult to communicate with or support through change. As a recent example, one in four eligible households with pre-payment meters did not claim Energy Support Vouchers issued during the 2022 energy crisis.⁵³
3. **Technically blocked households**, who are prevented from installing electrified heating in their home due to limits of the energy network, the home or the supply chain. These are significant barriers that will need to be solved prior to large-scale gas disconnections and special care must be taken to ensure space-constrained and heritage buildings have viable options to decarbonise.⁵⁴
4. **Low-income households**, who may be prevented from switching heating systems due to prohibitive capital costs.

In extremis, the last customers on the gas network would end up footing an astronomical bill for the remaining network. This is clearly untenable. The obvious challenge, however, is how to manage network decline fairly and to determine how the costs should be shared between current and future customers or taxpayers. We explore this topic in the following section.

⁵¹ [Housing England and Wales: Census 2021](#), ONS, January 2023. 37.3% rented.

[Housing statistics stock by tenure](#), Scottish government, May 2025. 36% rented in 2023.
[MS-E15 Tenure. Census 2021](#), NISRA, 2021. 32.3%

⁵² [Annual fuel poverty statistics report 2025](#), DESNZ, March 2025

⁵³ [One in four vouchers for prepayment meters unredeemed in Britain](#), The Guardian, February 2023.

⁵⁴ [Mind the Gap: Ensuring heat policy reaches space-constrained homes](#), Regen, October 2025.

Regen view

Network costs are driven by the extent of the network, not by how much gas flows through it. As customers leave, a Regulatory Asset Value of around £26bn will need to be recovered from fewer and fewer billpayers. Ofgem's own GD3 analysis shows charges rising to levels most consumers could not afford, with roughly £3bn of RAV still outstanding in 2050.

In addition to the costs of historic investments in the RAV, there will be ongoing costs from repair and replacement work. Disconnection and decommissioning will further add to the burden.

The households least able to leave the network are the ones most likely to be left paying for it. Renters, low-income and hard-to-reach households, and homes that cannot yet electrify, all face rising charges with little ability to respond. Leaving the last customers to carry the cost of the whole network is not a tenable outcome.



Section 3:

Towards a plan for managing gas decline fairly

Approaches for a fairer distribution of costs and ways to minimise them.

Navigating the decline of gas as we electrify heat in our homes and businesses will require a plan to manage and fairly share the costs of maintaining and decommissioning the network. Ofgem and DESNZ have acknowledged these challenges, with Ofgem stating that it expects RII0-GD3 to be “the last steady-state price control” for the sector. This recognition is welcome, but we do not yet have the policy and regulation framework for managing a network in decline. This section of the report looks at the options.

The government has identified two transitional challenges for the distribution network:

“Balancing infrastructure investment and affordability – by maintaining investor confidence to support ongoing maintenance and investment needed in the gas system to ensure safety, resilience and capacity, while managing the fair and distributed recovery of those costs with a gradually decreasing gas consumer base.

“Managing a planned and orderly operational transition – by repurposing infrastructure assets where possible, and decommissioning other assets where no longer needed, in a systematic and planned way that recognises the scale and complexity of the gas network nationwide and its integration into our daily lives.”

– UK government¹

3.1. Sharing the cost fairly

A key principle that will need to shape a plan is how the costs of recovering the value of the gas network and the cost of decommissioning and disconnections, set out in Section 2, are distributed between billpayers and taxpayers and between current and future generations. In its policy development for RIIO-GD3, Ofgem set out the options it saw for addressing the gap in RAV recovery (not including additional costs). In its own words:

- **Government/taxpayers**, which is clearly dependent on future government policy
- **Investors**, although we recognise this would create asset stranding risk, could undermine regulatory stability and predictability and is likely not in the consumer interest
- **A smaller number of consumers who remain on the network in future**, more of whom may fall into vulnerable categories
- **Current consumers while the user base remains at its peak**, albeit this would require a considerable increase in charges from RIIO-3 onwards
- **Third-party entities who purchase assets for repurposing** into hydrogen or Carbon Capture, Utilisation and Storage (CCUS) applications.⁵⁵

Consumer contributions

Gas networks today are funded based on ‘beneficiary pays’. This principle, which was broadly implemented even under the nationalised industries pre-privatisation, is embedded via the current regulatory framework. Without a significant change to government policy, Ofgem will continue operating under the assumption that all costs must be recovered from current and future gas consumers. There is no provision to recover costs from past consumers who have left the gas network.

“In all future scenarios we expect a decline in natural gas demand. This introduces the risk where a shrinking base of gas consumers may be left to bear the largely fixed costs of past and ongoing network investments.”
– Ofgem⁵⁶

The question for Ofgem is how to spread network costs between the current, large consumer base and the future one, which will decline, though there is uncertainty around the timing and rate of that decline.

⁵⁵ RIIO-3 Sector Specific Methodology Consultation – Finance Annex, Ofgem, 6th march 2024. 1.7

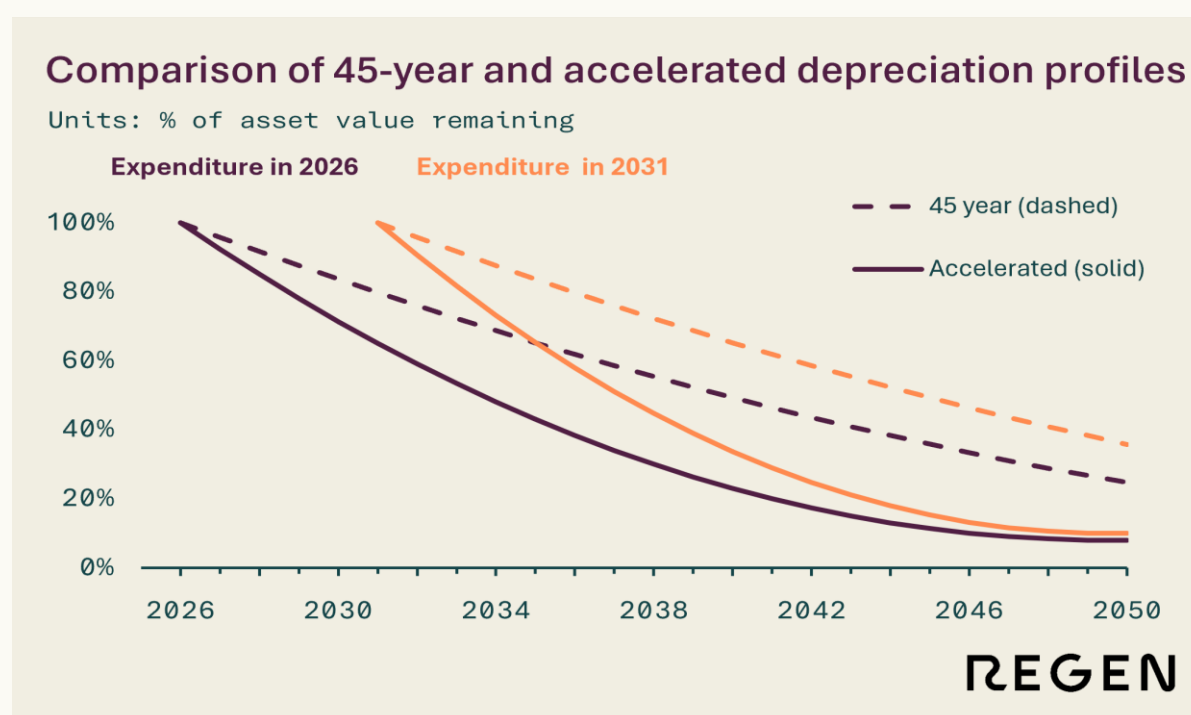
⁵⁶ RIIO-3 Final Determinations Overview Document, Ofgem, 4th December 2025. Chapter 7

Accelerated depreciation within GD3

Within the current regulatory paradigm, the main tool in Ofgem’s toolbox is adjusting the rate at which the RAV is depreciated. This would reduce the burden of outstanding asset value that may be passed to future consumers or left unrecovered at a time when the network is decommissioned.

In its policy development for GD3, Ofgem acknowledged the need to address declining gas demand. In its final determinations for the RIIO-GD3 period (1 April 2026 to 31 March 2031) it has adopted accelerated depreciation for new investments made over the period. This shortens the payback period for new investments during RIIO-GD3, such that they are fully depreciated by 2050 to align with the net zero statutory target date.⁵⁷ The existing RAV continues to use the previous depreciation profile (known as sum-of-digits) and 45-year asset life assumptions, as used for all additions to the RAV in GD2. Figure 18 compares these profiles for notional investments made at the beginning and end of the price control period.

Figure 18: Comparison of depreciation profiles for the GD3 price control period.



Ofgem’s analysis indicates that the additional cost of its accelerated depreciation decision would be £10 per year to the average dual fuel user in 2030/2031.⁵⁸ This reduces the RAV for future billpayers though without further changes it will leave a portion of the RAV remaining in 2050, as Ofgem acknowledged.

⁵⁷ RIIO-3 Final Determinations Overview Document, Ofgem, 4th December 2025. Chapter 7

⁵⁸ RIIO-3 Final Determinations Impact Assessment, Ofgem, 4th December 2025. Table 2

“We expect RIIO-GD3 [1 April 2026 – 31 March 2031] to be the last steady-state price control for the gas distribution sector.”

– Ofgem⁵⁹

Ofgem considered this decision an appropriate balance of risk in RIIO-3, within the context of “the uncertain future use of the gas distribution network and our ongoing work with government to explore alternative long-term solutions to recover network investment”.⁶⁰ Given that this excludes any costs from disconnection, decommissioning or further Repex beyond IMRRP, the current policy path leaves the prospect of a serious shortfall by 2050.

Sustainability First has also made the argument that some level of residual RAV is acceptable on the basis of demand uncertainty and to create an incentive for asset repurposing.⁶¹ The potential for recovering value through repurposing is limited and concentrated in a few locations in our view, as we explain in the subsequent section (Repurposing assets).

⁵⁹ [RIIO-3 Final determinations GD](#), Ofgem, 4 December 2025. Paragraph 2.5

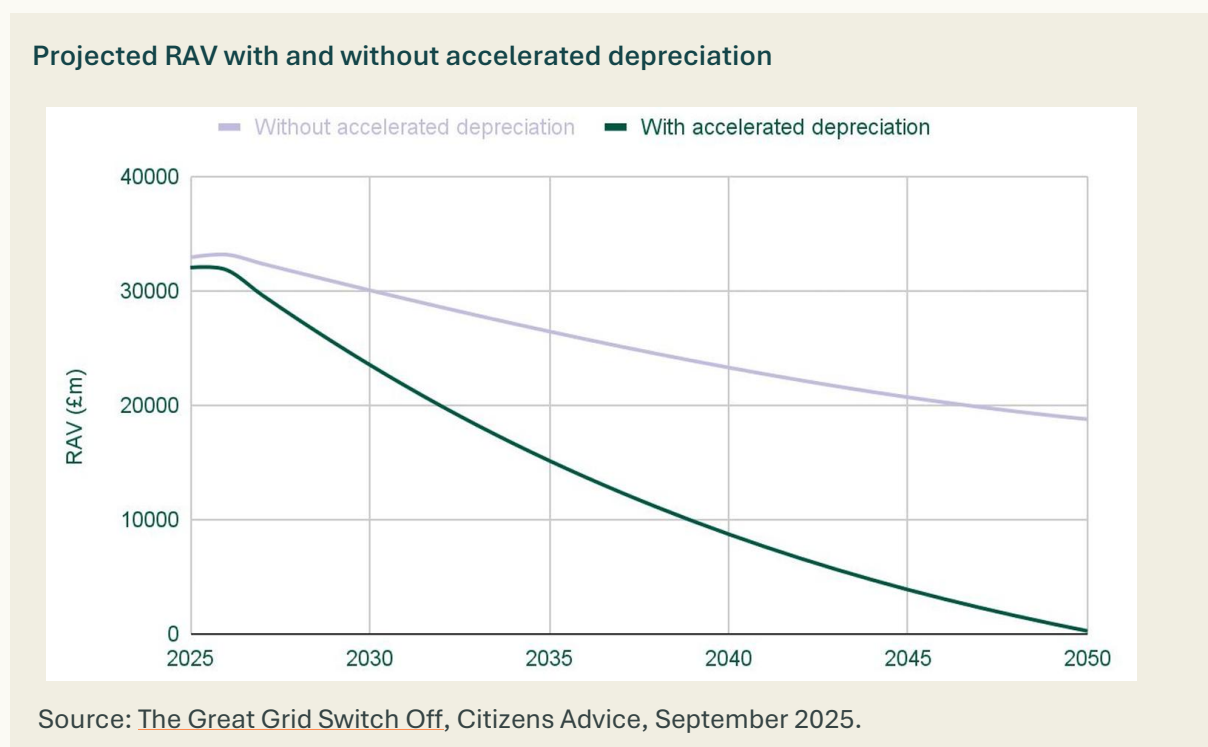
⁶⁰ [RIIO-3 Final Determinations Finance Annex](#), Ofgem, 4 December 2025. Paragraph 8.18

⁶¹ [Response to Ofgem’s Consultation on GD3 Plans](#), Sustainability First, February 2025

Depreciating the RAV completely by 2050

Analysis by Citizens Advice looked at a faster approach to depreciation, whereby the entire RAV was depreciated to 2050, rather than just new investment.⁶² By definition, this approach reduces the RAV to £0 by 2050, as shown in Figure 19, while Figure 20 shows the projected impact on bills. This shows that even complete depreciation of the RAV by 2050 has a small impact on bills with a slight increase until the late 2030s and then a decrease. This indicates that there is scope for faster depreciation beyond what has been set out in GD3 to reduce the potential liability of unrecovered RAV, without imposing undue impacts on bills.

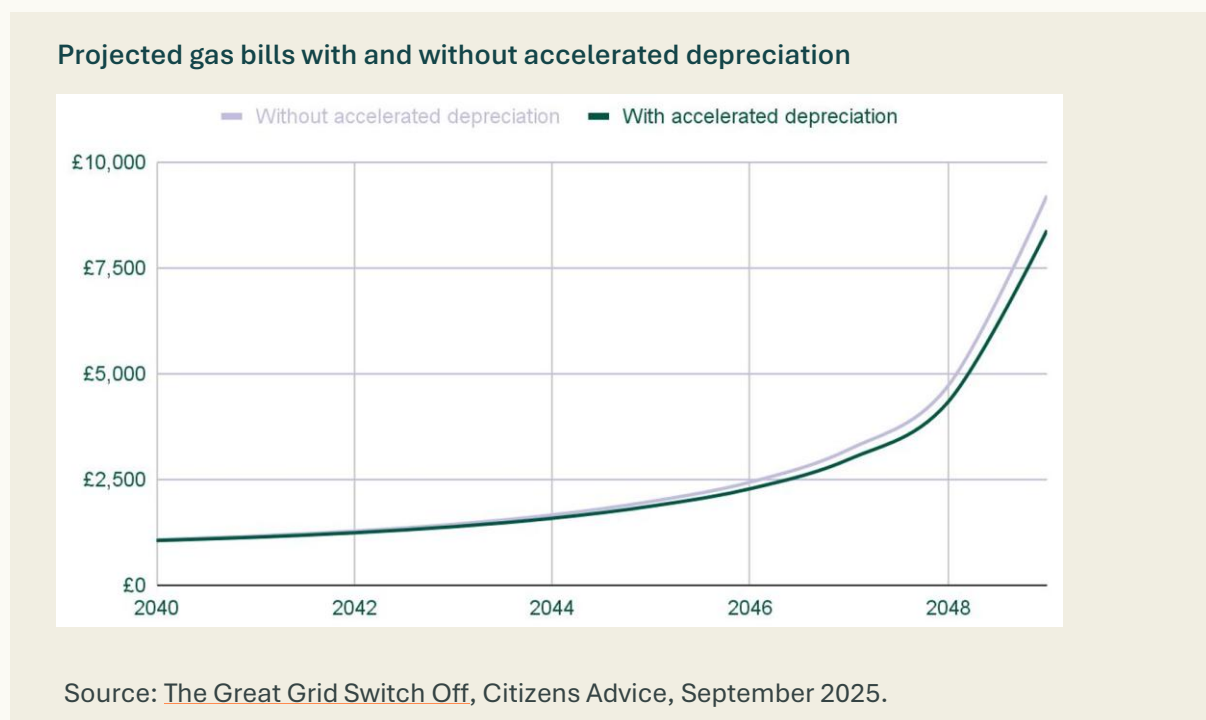
Figure 19: Projected impact on RAV of complete accelerated depreciation⁶³



⁶² [The Great Grid Switch Off](#), Citizens Advice, 7 October 2025.

⁶³ [The Great Grid Switch Off](#), Citizens Advice, 7 October 2025.

Figure 20: Projected impact of complete accelerated depreciation on gas bills⁶⁴



The same modelling found that gas bills per household remaining on the gas grid will rise inexorably in the 2040s with or without complete accelerated depreciation. While the costs to be recovered reduce as the RAV is depreciated, the last customers remaining on the gas network would still have huge network charges to cover. Their model uses a fixed assumption on how domestic gas customers disconnect, based on the 2024 Future Energy Scenarios, so if customers react to rising bills by disconnecting earlier, those costs for remaining customers could become even greater.

Accelerated depreciation changes the profile of cost recovery (bringing charges forward in time to reduce the risk of stranded assets) but does little to address the underlying affordability problem created by a shrinking customer base. Even ignoring additional costs, recovering network costs with accelerated depreciation will still lead to unaffordable bills driven by the falling number of customer connections and demand.

This evidence suggests two priorities for Ofgem:

1. Lay the groundwork for accelerating depreciation of the existing RAV by 2050, not just new investment
2. Explore ways it can broaden the toolkit such that depreciation can be set at a rate which holds network charges at a level that remaining gas customers will be able to afford, even as the number of customers declines.

⁶⁴ [The Great Grid Switch Off](#), Citizens Advice, 7 October 2025.

Both the analysis from Citizens Advice and that by Ofgem's GD3 framework leave important parts of the picture unaddressed:

- Neither fully explores a more realistic rate of near-term electrification, under which demand and connections fall more gradually than the carbon budget-compliant scenarios assume (Ofgem's analysis did include FES 2022 Falling Short, but this assumed very low long-term electrification, which is also unrealistic)
- The analyses also left unexplored the interdependencies between the different rates of decarbonisation of domestic, I&C and power generation demand segments.

Addressing these gaps in the analysis should be priorities for Ofgem and DESNZ to ensure a full picture of the challenge.

Decommissioning fund

A decommissioning fund offers an alternative approach for recovering the future costs of gas network decline through a levy on bills of the current, large customer base. This would protect future consumers, as well as future taxpayers, from meeting the full cost of decommissioning and means that current gas consumers are liable for some of the cost of decommissioning a network that they are benefiting from now. It would be important for ensuring value for money for billpayers that the fund did not increase the RAV or add to the returns for the GDNs' shareholders.

Decommissioning funds are established mechanisms in other industries. For example, the Nuclear Liabilities Fund is a ringfenced pot which exists to meet the costs of decommissioning eight nuclear power stations in Great Britain.⁶⁵ The fund was established in 1996 with an endowment from the government in preparation for the privatisation of British Energy and receives regular, pre-agreed payments from EDF as the operator of the nuclear power stations that the fund is liable for. In practice, this means that the cost of decommissioning these power stations is met throughout their operational life.

The biggest challenge in implementing a decommissioning fund is the additional cost to bill-payers. Particularly while energy bills are the biggest driver of concern around the cost of living and gas prices are set to rise due to higher wholesale prices.⁶⁶ Nevertheless, if gas consumers are the group that must pay for decommissioning, then failure to capture this cost now leaves the tab to a future, smaller group, placing a larger burden on each consumer.

⁶⁵ [Our purpose](#), Nuclear Liabilities Fund, accessed 12th June 2026.

⁶⁶ [Energy Bills Public Sentiment Tracker](#), More in Common, March 2026
[Energy price cap will rise by 13% from July](#), Ofgem, 27th May 2026

Taxpayer contributions

Another option is for some costs to be met by the state. This has the potential to be a much more progressive approach. Policy costs levied on bills have a higher burden for low-income households, as a proportion of their income, while the UK tax system imposes a lower relative burden on lower-income households.⁶⁷ The main argument against this approach is that it goes against the principle of ‘user pays’ – i.e. the cost of the gas network should be recovered only from those who use the infrastructure.

Nationalisation

The government could intervene by nationalising the gas distribution networks to deliver a centrally managed decline. This would be a strategic, time-bound process that would remove the tension between decline and the motive of the privatised regime to maximise investment and returns. In this sense it differs from typical debates about the merits of nationalised and privatised delivery.

We estimate the total RAV across the GDNs as £25.8bn as of 31 March 2024.⁶⁸ This gives a ballpark indication of the cost to taxpayers of nationalisation. There is continuing investment in the distribution networks, principally through the IMRR programme, which is likely to contribute to the RAV growing in the coming years. Nationalisation would also move financial risk from shareholders onto the taxpayer. Depending on how and when nationalisation was delivered, this risk could be mitigated by the fact that GDNs are currently highly profitable. If nationalised, this income could support the delivery of disconnection and decommissioning activities.⁶⁹

Government-funded delivery of decommissioning and nationalisation would potentially reduce the cost of borrowing to finance continuing investment, as well as the additional costs of disconnection and decommissioning. It is also possible that a nationalised gas distribution network is better able to reduce investment requirements, as it can be incentivised to do so, whereas privatised GDNs have the opposite incentive. Taken together, these could allow for a more efficient transition and potentially avoid investment that is not necessary in the context of winding down the gas network.⁷⁰

This would be a major undertaking for the government, and a major change for the industry. There would be many wider implications for how GDNs are currently operated and regulated.

⁶⁷ [Household energy bills include green levies. What are they and why do we need to pay them?](#), Nesta, accessed June 2026. Analysis based on October-December price cap data.

[Tax statistics: an overview](#), House of Commons Library, 10th June 2026.

⁶⁸ Total across NGT and GDNs was £32.9B. [CMA response](#), FEN, 22nd April 2025.

NGT was £5.7bn at the same point in 2018/19 prices, we estimate this as £7.1bn in 2024 prices.

[Gas transmission price control financial model: RIIO-2](#), Ofgem, 30th January 2024.

⁶⁹ [What the network companies should do with their windfall profits](#), Citizens Advice, February 2025.

⁷⁰ [Decompression: Policy and regulatory options to manage the gas grid](#), RAP, 1 August 2025

It would also come at a cost and arguably would be better implemented when the decline of gas demand is further advanced.

Options short of nationalisation

The government could still decide to contribute directly to some of the costs of this transition. Most obviously, this could be through funding a decommissioning programme delivered by a centralised body, or through the existing GDNs. This is a less radical route to sharing the costs between billpayers and taxpayers with less disruption to the status quo than nationalisation. However, it does not remove the tension between a declining network and the profit motive, which could potentially lead to a slower or less efficient transition.

It should also be noted that the duty of care that the government has for its citizens may require contributions from the taxpayer should the transition not be well managed. These could be in the form of bailouts for GDNs should there be significant stranded assets or bill subsidies in the case of very high network costs. These could both be triggered by a sharper-than-expected decline in gas usage.

Repurposing assets

Ofgem cited third-party purchase for repurposing as one route to bridging the RAV recovery gap in its GD3 policy development. In Regen's view (Demand on the gas network), large-scale repurposing for hydrogen is off the cards and while the share of biomethane in the networks is likely to increase, it will remain limited to a fraction of current throughput.

Setting gaseous uses aside, there is a valid question whether the low-pressure distribution network holds material residual value in any other application. Proposals have included:

- Fibre and telecoms cabling
- Electricity distribution
- Water and stormwater conveyance
- Heat networks.

Innovation projects have begun to look at these options, but there is little evidence of significant repurposing opportunities.⁷¹ Much of the evidence base to date has focused on the larger-scale assets. While technically feasible, the case for repurposing is weak for the majority of assets in the lower-pressure networks. Almost all homes are already connected to fibre, power and water, so there is little room for further expansion. There may be some scope for optimising costs of overall utilities works, for example by upgrading electricity service cables at

⁷¹ [Repurposing Decommissioned Network Assets](#), Innovation Basecamp, ENA 2024

the same time as removing a gas service pipe, rather than independently. However, while the GDNs have permanent easements, they are only granted for the purpose of gas conveyance.

Heat networks are one application where there is potential for repurposing. The government ambition is for 20% of heat to be delivered by heat networks by 2050.⁷² Where a gas main is abandoned inside a designated heat network zone, the existing trench and route could be reused to lay new pre-insulated heat pipe, avoiding fresh road opening. This is an avoided-cost benefit rather than reuse of the asset itself, since gas mains cannot carry pressurised hot water and new pipework is always laid. It would be an option only in dense urban areas, capturing a fraction of the overall network.

It is therefore our view that third-party repurposing cannot be relied upon as a significant contribution to bridging the RAV recovery gap. The realistic value is small, uncertain and concentrated in a few locations. Opportunities to optimise the cost of decommissioning (for example by digging the road up once) should of course be maximised, but this will not help with plugging a shortfall in RAV recovery. It is therefore prudent to plan on the basis that the majority of the distribution network will be decommissioned rather than repurposed, and to treat any repurposing value that does materialise as a welcome bonus.

⁷² [Warm Homes Plan](#), UK government

Regen view

The large customer base the gas networks currently have should contribute to costs that will otherwise fall on a much smaller group in the future. Ofgem's decision to accelerate depreciation of new GD3 investment so it is fully recovered by 2050 is a welcome first step (costing around £10 per year on the average dual fuel bill). Depreciating the entire Regulatory Asset Value by 2050 would have only a small impact on bills and would be a logical next step. Ofgem's Cost Recovery review and DESNZ's review of network investment and affordability provide the opportunity to explore further steps such as creation of a decommissioning fund.

Recommendations

Ofgem should set out a pathway in the next price control period (RIIO-GD4) to depreciate the whole RAV by 2050.

Government should explore the creation of a decommissioning fund in its review of network investment and affordability.



3.2. An efficient approach to disconnection and decommissioning

The government put consumer choice ‘at the heart’ of the Warm Homes Plan.⁷³ The current geographical distribution of heat pumps therefore does not follow a strategic geographic distribution. The implication for the gas network is that disconnections will occur across the network driven by consumer choice rather than network optimisation. This means that the overall footprint of the gas network will need to stay roughly constant even as demand, connections and, therefore, the consumer base for network charges shrinks. An alternative would be a strategic or area-based approach that delivers a co-ordinated decommissioning of the gas network across different areas over time. Table 1 summarises some approaches.

Table 1: Outline of the impacts of three approaches to disconnection and decommissioning.

Feature	Choice-led disconnection	Area-based disconnection	Strategic decommissioning
What it is	Individual households leave gas one at a time, on their own timetable	A defined area or cluster is targeted for disconnection together	Whole sections of network are taken out of service in a strategic programme
Effect on lower-pressure gas main	Network areas stay live until the last remaining customer disconnects	Decommissioning in targeted areas. Outside those is choice-led	Whole network isolated, purged and decommissioned in sequence
Ability to avoid network costs	Repex, maintenance and safety duties persist for the entire network even as the customer base declines	Whole-main decommissioning saves cost where coverage is complete	Avoids Repex and ends safety obligations on removed asset
Deliverability	Easiest from a consumer perspective, avoiding enforced conversion. Burdens GDNs to maintain underutilised networks	Targeted areas would require support and funding to ease the transition.	Significant consumer barriers likely. Makes most sense from a network and cost perspective.

⁷³ [Warm Homes Plan](#), DESNZ, 18 March 2026.

The case for strategic decommissioning

Strategic decommissioning has several potential advantages over an uncoordinated, consumer choice-led approach:

1. Delivering disconnections at lower cost
2. Coordination to minimise network costs across electricity and gas
3. Giving greater certainty.

Strategic decommissioning could also be part of a wider area-based heat transition model, which could accelerate delivery and generate economies of scale savings in electricity network upgrades and installation costs. Ofgem acknowledged the potential benefits of an area-based approach in its decision making for the ED3 price control, though it acknowledged that the current evidence base has been “exploratory”.⁷⁴

1. Deliver disconnections at lower cost

There are significant potential savings in delivering cost-effective disconnections. An average of disconnection costs across all GDNs, provided by Arup in its 2023 study on behalf of the NIC, gave a cost of £1,450 per customer.⁷⁵ If disconnections are coordinated and delivered by a specific service then there is scope for significant savings. The same study estimated a “well-coordinated national programme” could deliver significantly lower disconnection costs of £500 per customer.⁷⁶ The cumulative cost of this difference represents a significant additional cost if a purely ad hoc approach were taken, as shown in Figure 21.

2. Coordination to minimise network costs across electricity and gas

Research commissioned by Citizens Advice found that failing to define which heating technology will be delivered in an area more than doubles the cost, as it requires large-scale upgrades of both electricity and gas networks.⁷⁷ This is the current situation in GB, where we are investing heavily in both the electricity and gas networks.

Making strategic decisions on network requirements on an area-by-area basis can allow some investments to be avoided for both the gas and electricity networks. Pipe replacement under the IMRRP for some of the most expensive areas could be avoided, if strategic decisions about the gas network were made to withdraw gas provision from these areas. Similarly, electricity network planning can be delivered more effectively if there is greater certainty around the timeline of gas grid decommissioning for different areas, as it helps to identify high-priority

⁷⁴ [ED3 Sector Specific Methodology Decision](#), Ofgem, 21st May 2026. Para. 3.285

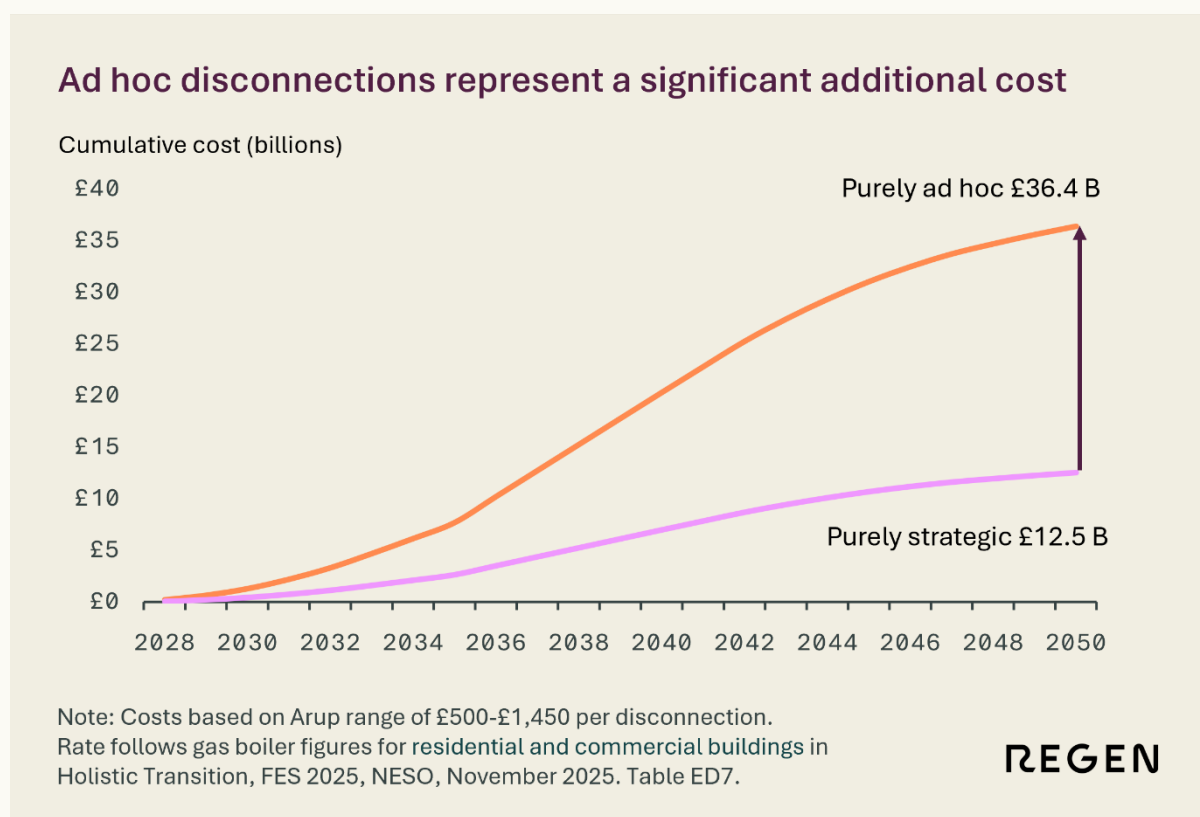
⁷⁵ [Future of Great Britain’s Gas Networks](#), Arup, October 2023. P. 59

⁷⁶ [Future of Great Britain’s Gas Networks](#), Arup, October 2023. P. 141

⁷⁷ [Heat GB: Calculating the network costs for low carbon heating](#), Citizens Advice, October 2023

areas. Maintaining and operating the network also has some costs that will scale to the extent of the network. If the gas network begins to reduce, as the customer base reduces then the overall network costs will reduce, which would mitigate some of the per-customer increases in network costs.

Figure 21: Cumulative disconnection costs assuming purely ad hoc and purely strategic cost profiles.



3. Giving greater certainty

Giving certainty that the gas network will be decommissioned in an area gives a clear direction of travel to consumers, investors and the supply chain. It would support demand for the electrification of heat by making it clear to consumers that this is the future-proof approach to heating. It would give the same certainty for the heating supply chain, which would encourage retraining and investment in delivering clean heat. This in turn would support a more effective and competitive service to consumers for installing and maintaining clean heat. The need for policy certainty has been highlighted as a key action for delivering low-carbon buildings by the Climate Change Committee, including reinstating the requirement for all new heating systems to be low-carbon by 2035.⁷⁸

⁷⁸ [The Seventh Carbon budget](#), CCC, February 2025. Section 7.2.4.

Prerequisites for a strategic approach

There is a compelling case for some degree of strategic decommissioning, but it cannot be announced or implemented prematurely. There are several prerequisites:

1. **A business case** – decommissioning part of the gas network must be supported with a clear business case where avoided maintenance and running costs are worthwhile
2. **A credible alternative** – the cost of installing and running clean heating systems must be lower, and the supply chain must be able to meet the growing demand
3. **Groundswell of public support** – clean heating must be more widespread with strong consumer awareness, trust and support
4. **A proven, tested approach** – clear evidence for how decommissioning will be implemented is required, so consumers understand the process
5. **A ‘protective wrapper’** – vulnerable consumers must be protected with support to understand, implement and fund the transition, balanced with the need to retain an economic signal to electrify, as discussed in section 3.3 below.
6. **A legislative change** – gas network companies must currently maintain supply where a customer wants it, preventing targeted decommissioning if a single customer refuses.

The first opportunities

The first opportunities to pilot strategic decommissioning will be small areas of the network where there is a clear business case. This would allow for savings to be made that can offset the costs of delivering the decommissioning. Implementing these now will support the evidence base for wider implementation.

These will be parts of the gas network where maintenance costs are high relative to gas demand and replacement costs can be avoided by decommissioning the network. Multiple-Occupancy Buildings (such as domestic high-rise blocks of apartments) are a good example that could be piloted today where interventions under the Iron Mains programme have very high costs due to costly riser replacement, and where the money could be spent instead upgrading for low carbon heating.

The degree of customer disconnection will be fairly modest over the RIIO GD3 period (until 31st March 2031), but the following price control period will see a significant reduction in both gas demand and connections if the Committee on Climate Change Balanced Pathway is achieved.⁷⁹ Building these prerequisites must happen now in preparation. In particular, pilot decommissioning programmes should be implemented in small areas where there is a clear business case for avoided investment.

⁷⁹ The Climate Change Committee’s ‘balanced pathway’ sets out 16% of homes having low carbon electrified heating in 2030, rising to 39% in 2035 and 68% in 2040.
[Seventh Carbon Budget](#), CCC, 26th February 2025. Table 7.2.1.

Regen view

Under current policy, disconnections happen wherever individual households choose to move away from gas. This means the network needs to stay the same size while its revenues shrink. A strategic, area-based approach has the potential to reduce disconnection costs significantly: by around 65 per cent per customer. Area-based decommissioning remains some years off, but developing a credible business case and a proven delivery model will take time, and that work can start now.

Recommendations

Government should commission a study of area-based decommissioning to understand the costs and impacts of different approaches to delivering customer disconnection and decommissioning at scale.

Ofgem should fund decommissioning pilot programmes during this price control period (GD3 2026-2031), to provide evidence for wider decommissioning during GD4 and beyond.



3.3. Consumer protections

It is vital that the transition away from gas heating is accessible and affordable to all so that vulnerable groups are not stuck with an increasingly costly heating system. The government must ensure policy is delivered in such a way and with appropriate protections to ensure these groups are enabled to transition away from fossil gas heating without undue harm.

We describe the groups most at risk from this on page 30. The form of consumer protection required will vary:

1. **Protecting renters** requires regulations to ensure landlords invest in their buildings. Increased minimum energy efficiency standards (MEES) go some way to encouraging electrification, but they do not require it.⁸⁰ What's more, compliance can be achieved up to 30 September 2039 using the current methodology, which incentivises gas boilers.⁸¹ These rules may need updating should we see a rise in gas network costs over this period.
2. **Protecting hard-to-reach households** requires well-resourced engagement to be put in place in advance of need. Efforts are required to identify these households early on and provide trusted, personalised engagement and support.
3. **Protecting technically blocked households** will need to be delivered to achieve the level of heat electrification required to stimulate gas network disconnections. The very hardest homes to treat will need specific attention to protect households. These will include ensuring that planning allows for suitable approaches for heritage buildings, that there are affordable solutions for space-constrained homes and that network connections and supply chain are available in all parts of the country.
4. **Protecting low-income households** requires adequate grant provision for those most in need. Loan schemes may also be able to fill this gap, as they could be paid for from a portion of the bill savings. A scheme in France takes this approach by paying off the installation cost with a total monthly cost for heating no more than the previous bill.⁸²

⁸⁰ [Improving the energy performance of privately rented homes: 2025 update](#), DESNZ, January 2026
[Improving the energy efficiency of socially rented homes in England](#), DESNZ, April 2026
[Draft Energy Efficiency \(Domestic Private Rented Property\) \(Scotland\) Regulations: consultation](#), Scottish government, 6 June 2025

⁸¹ [Improving the energy performance of privately rented homes: government response](#), DESNZ, 21 January 2026. P. 7-8. "private rented homes that are graded C or above against the Energy Efficiency Rating (EER) on EPCs before 1 October 2029 will be considered compliant with the higher standard until the EPC expires" The EPC validity period is 10 years.

⁸² [Offres intégrées pompes à chaleur](#), Agir pour la transition, accessed 10 July 2026

Regen view

Even after taking steps to minimise and fairly distribute future gas network costs, a protective wrapper for vulnerable consumers will still be needed. Support to understand, fund and implement the switch to clean heat must reach the groups that engagement programmes have historically struggled to reach.

Recommendation

Government and Ofgem should develop a plan for consumer protection in the delivery of gas network decommissioning, so that no household is left trapped on an increasingly expensive network or is unable to access clean heat.



Glossary

Accelerated depreciation – Shortening the period over which the value of a network asset is recovered from customers, so more of the cost is paid by today's larger customer base.

Biomethane – Methane produced from organic material.

Boiler Upgrade Scheme – The government grant scheme for households installing a heat pump or biomass boiler in England and Wales.

Capex – Capital expenditure.

CCC – Climate Change Committee. The independent statutory body advising government on carbon budgets.

CCUS – Carbon capture, utilisation and storage.

CHP – Combined heat and power. Plant that generates electricity and useful heat from the same fuel.

Decommissioning – Taking a section of the network out of service.

Depreciation – The annual charge that returns the value of an asset to the network company over its assumed life.

DESNZ – Department for Energy Security and Net Zero.

Disconnection – Disconnecting an individual customer from a live network. The service pipe is capped and the meter removed, but the main stays in service for everyone else.

DUKES – Digest of UK Energy Statistics. The DESNZ annual statistical publication, and the source for historic demand and import data in this report.

Easement – The legal right a network company holds to keep and access its pipes in land it does not own. Gas easements are granted only for conveying gas.

EER – Energy Efficiency Rating. The rating on an EPC used to judge compliance with minimum standards.

EPC – Energy Performance Certificate.

Fast money – The share of network expenditure recovered from customers in the year it is spent, covering day-to-day operating costs.

FES – Future Energy Scenarios. NESO's annual set of pathways for the energy system, now published alongside the Ten Year Outlook.

Future Homes Standard – Building standard that stops new homes connecting to the gas network in England from March 2027, with equivalents in Wales and Scotland.

GDN – Gas distribution network. The four regional companies — Cadent, SGN, Northern Gas Networks and Wales & West Utilities — and the pipes they operate.

HSE – Health and Safety Executive. Mandates the Iron Mains Risk Reduction Programme and sets the safety duties networks must meet.

Hybrid heat pump – A heat pump paired with a gas boiler, which reduces gas demand but keeps the property connected to the network.

I&C – Industrial and commercial.

IMRRP – the HSE-mandated Iron Mains Risk Reduction Programme.

LDZ – Local distribution zone. The area supplied by a section of the distribution network from its offtakes from the NTS.

MEES – Minimum energy efficiency standards. The rules setting the lowest energy rating at which a property can be let.

NESO – National Energy System Operator.

NIC/NISTA – National Infrastructure Commission, which became the National Infrastructure and Service Transformation Authority in 2025.

NTS – National Transmission System. The high-pressure network that moves gas around the country and feeds the distribution networks.

Ofgem – The Office of Gas and Electricity Markets, the independent energy regulator.

Opex – Operating expenditure. The day-to-day costs of running and maintaining the network.

Price control – The regulatory settlement that sets the revenue a network company can recover over a fixed period.

RAV – Regulatory asset value. The value of past investment on which network companies earn a return and which they recover through depreciation.

Repex – Replacement expenditure. Spending on replacing existing assets, now the largest component of gas distribution costs.

RIIO – Revenue = Incentives + Innovation + Outputs. The regulatory framework Ofgem has used since 2013, which links allowed revenue to defined outputs.

RPI-X – The price control approach used from privatisation until RIIO, capping price rises at inflation minus an efficiency factor.

Service pipe – The pipe connecting an individual property to the gas main.

Slow money – The share of network expenditure added to the RAV and recovered gradually, rather than in the year it is spent.

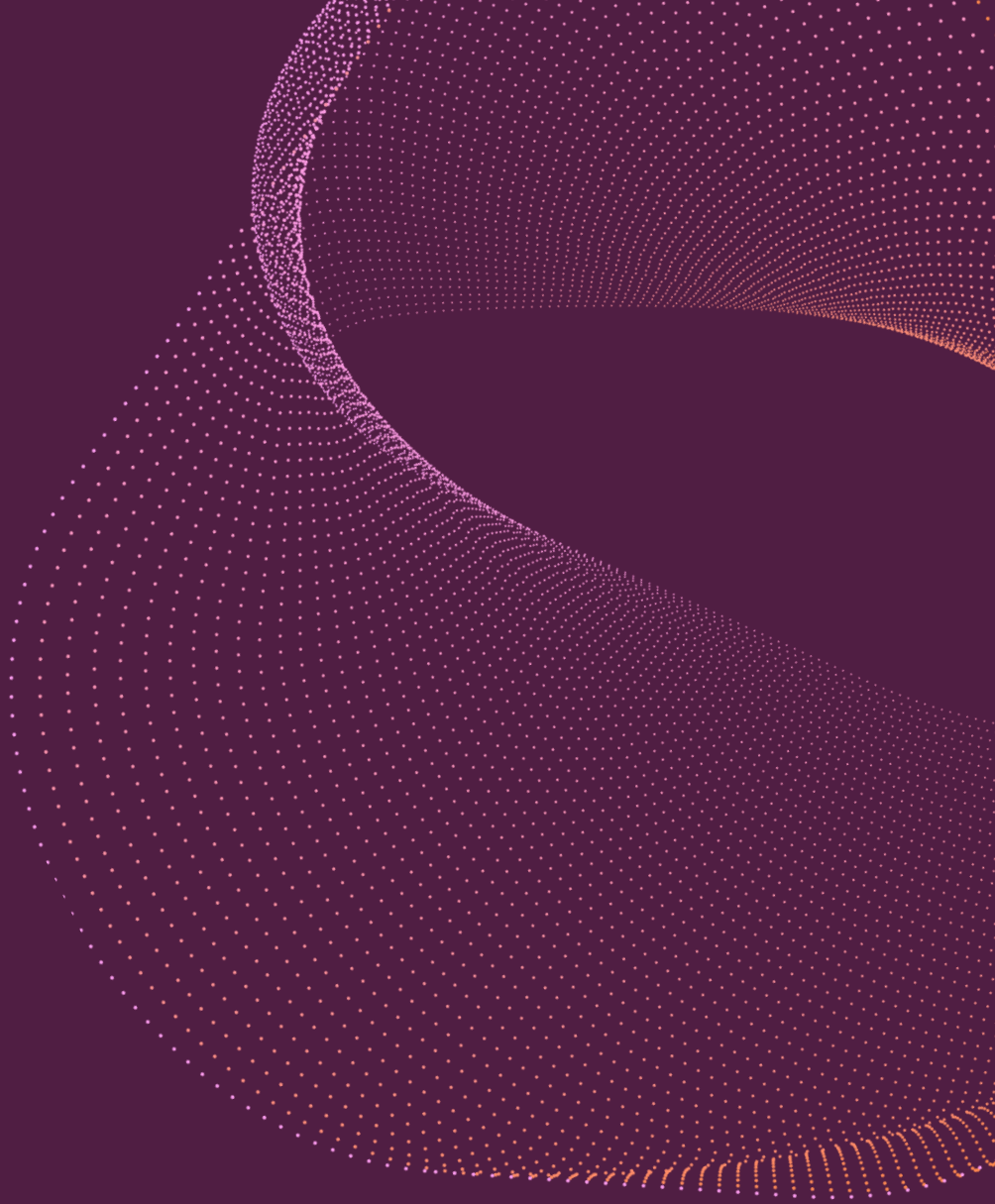
Stranded asset – An asset whose value cannot be recovered because it is no longer used, or because too few customers remain to pay for it.

Totex – Total expenditure. Treating operating and capital costs together, rather than favouring capital spending.

Town gas – Gas manufactured from coal at municipal gasworks, replaced by natural gas during the conversion programme of the 1960s and 1970s.

Warm Homes Plan – The government's plan for upgrading homes, published in March 2026.

Xoserve – The central data services provider for the gas market, which notifies networks of changes such as meter removals.



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