Watt-Logic

Electrification - can the grid cope?

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Abstract

Britain's decarbonisation strategy assumes rapid electrification of heating, transport and industry, yet deployment trends and infrastructure constraints indicate these ambitions are unlikely to be met. Heat pumps, EVs and industrial fuel-switching are stalling, while ageing gas and nuclear assets are retiring faster than firm replacement capacity can be delivered. At the same time, AI-driven data-centre growth is adding material new load that the grid is increasingly unable to accommodate.

Without urgent action to secure dispatchable generation and stabilise the gas network, the UK faces escalating risks of supply shortfalls and widespread system failures well before 2030. It will be difficult to meet existing demand without rationing, let alone any additional demand from electrification.

The Government must urgently pivot to ensuring there is sufficient dispatchable power generation available to meet demand on low wind days, making realistic assumptions about what can be delivered by 2030. The UK would do well to follow the example of Germany, which despite its strong commitment to renewables, has identified a need for significant new gas-fired power generation capacity.

Without such a plan, electrification ambitions risk remaining theoretical while exposing the electricity system - and the public - to unacceptable levels of risk. Net zero promises should not be prioritised over public safety. To ensure the electricity system remains secure, new investment in gas generation is essential, even if it is unabated.

About Watt-Logic

Watt-Logic is an independent energy consultancy founded by Kathryn Porter. Watt-Logic was established in 2016, initially as a blog which grew into a consulting business that now works with clients around the world on projects across the energy supply chain. Projects include assisting clients on negotiating commercial contracts and gas and electricity trading arrangements; assisting businesses in evaluating new investments in solar generation, behind-the-meter storage and energy-from-waste; advising on various regulatory matters such as the impact of changing market price formation, and acting as an expert witness in energy-related disputes.

Watt-Logic's founder, Kathryn Porter, has extensive experience of physical and financial electricity, gas and oil markets, as well as significant experience in financial services across risk management/hedging and debt and equity financing in both public and private markets.

Watt-Logic is entirely self-funding and receives no external capital from any sources. It is therefore independent of any other business, individual or special interest group. The views contained within this report are solely those of the author.

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Executive Summary

In pursuit of its net zero targets, the UK Government has established ambitious decarbonisation targets for the entire country, and in particular the heating, transport and industrial sectors. Since 2022, previous climate ambitions have been bolstered by a desire to "get off gas", with gas price volatility being painted as responsible for driving end-user bills and making energy expensive.

Electrification could add around 7–10 GW of electricity demand by 2030, with AI data centres, adding a further 6 GW

Electrification has emerged as the primary strategy for decarbonising heating, transport and large parts of industry, and is increasingly treated as the default pathway for meeting near-term climate objectives – over the past year a consensus has emerged that the role of hydrogen will primarily be in industry. Although the National Energy System Operator ("NESO") still expects carbon capture and storage ("CCS" or "CCUS" if "utilisation" is added) to be significant, the Climate Change Committee ("CCC") believes the use of CCS will be more limited.

Overall up to 15 GW of new demand by 2030 is implied by Government targets

If delivered at scale, electrification could add around 7–10 GW of electricity demand by 2030, with AI data centres, now designated as critical infrastructure, potentially adding a further 6 GW. Whether this demand materialises in practice depends less on policy ambition than on economic viability, consumer behaviour and the ability of the electricity system to support additional load reliably.

In heating, the policy objective is a rapid transition away from gas boilers towards electric heat pumps, supported by mandates, subsidies and future restrictions on fossil heating systems. Delivery is constrained by high upfront costs, uncertain running costs relative to gas, limited consumer appetite, and a slow expansion of the installer base. As a result, large-scale electrification of domestic heating before 2030 appears unlikely without fundamental changes to electricity pricing, network capacity and consumer incentives.

In transport, electrification is being driven by vehicle sales mandates and the scheduled phase-out of internal combustion engines. Uptake is increasingly limited by charging-infrastructure availability and by local grid constraints, which are now a material barrier to both public and private charging deployment. Consumer concerns over charging access, vehicle costs and residual values suggest EV adoption is likely to lag policy targets during the remainder of this decade.

Deindustrialisation is likely to have a larger impact than electrification

In industry, electrification is often presented as a technically straightforward substitution of fossil-fuelled processes with electric alternatives. In practice, the binding constraint is economic rather than technical, with high electricity prices undermining competitiveness across energy-intensive sectors. Industrial electrification has therefore progressed slowly, while reductions in industrial electricity demand have been driven primarily by deindustrialisation rather than fuel switching.

This distinction is central to understanding recent demand trends. Falling industrial electricity demand is sometimes interpreted as evidence that electrification will not materially increase system load, but this masks the underlying cause: reduced output, plant closures and offshoring driven by persistently high power prices. Electrification has not offset these losses, and without a sustained improvement in industrial electricity affordability, it is unlikely to do so.

Net of new build, some 12 GW of firm generating capacity is at risk of closure by early 2030

At the same time, the electricity system required to support electrification is entering a period of growing vulnerability. Up to 17 GW of firm generating capacity, including ageing CCGTs and the entire AGR nuclear fleet, is at risk of retirement by 2030, with limited prospect of timely replacement. Global supply-chain constraints imply long lead times for both life-extension upgrades and new build, with major gas-turbine components taking around five years to deliver and grid connection times extending to a decade in some areas.

Although renewable capacity has expanded rapidly, wind and solar output cannot be relied upon during cold, still winter conditions, when demand peaks after sunset and generation can be minimal. Interconnectors offer limited protection in such circumstances, as neighbouring systems are exposed to similar weather patterns, while emerging constraints within the gas transmission network further increase the risk of supply stress during periods of peak demand.

An analysis of the system pressures, combined with experience to date of significantly low wind output leads to a conclusion that even without increases in demand, there is a 65-85% probability of regional electricity

rationing or blackouts by 2030 and a baseline risk of 5-10% of one of these cascading into a full grid failure. A certain level of complacency at NESO, and within the regulator, Ofgem, suggests that the response to the first such capacity crisis will be sluggish. This elevates the risk of a full system blackout by 2030 to 20-30%. The 2003 blackouts in Italy and Spain, and in the NE USA and Canada were both caused by failures of the system operators to take prompt action in response to system stress, so this elevated risk is not unprecedented.

There is a 65-85% probability of regional electricity rationing or blackouts by 2030 and a baseline risk of 5-10% of one of these cascading into a full grid failure

The inevitable conclusion is that the electricity system will struggle even to maintain today's demand reliably, let alone accommodate the 7–10 GW of new load implied by electrification agendas. AI data centres are therefore likely to adopt off-grid solutions, and large-scale electrification of heat and industry appears improbable before 2030 and likely not for several years after that.

Experience elsewhere in Europe illustrates these risks. Norway, despite a highly electrified economy, faces increasing challenges in meeting expected demand with existing resources, while the Dutch system operator, Tennet, has issued unusually explicit warnings regarding grid congestion and supply adequacy. Germany has gone further, concluding that significant new gas-fired generation will be required in the 2030s to maintain security of supply, despite its continued expansion of renewable capacity.

Electrification targets are unlikely to be met, and AI data centres may well be powered on-site, meaning that electricity grid demand is not likely to increase materially by 2030

These conclusions highlight the policy disconnect between decarbonisation ambitions and other elements of the "energy trilemma" – affordability and security. Net zero and other environmental policies have created insurmountable headwinds to investment in firm generating capacity with intermittent renewables attracting almost all of the new capital in recent years. The Government clings to a narrative of expensive gas driving prices, but ignores more than two decades of low and stable gas prices before 2021 and industry consensus that 2026 could see a return to long-term gas price norms. Indeed, energy executives recently told the British Parliament in clear terms that policy costs rather than gas prices are driving bills and making electricity unaffordable. The Government responded by moving the recovery of some legacy renewables subsidies from bills to taxation in the 2025 Budget.

Investing in life extensions for large gas generators is by far the safest strategy...

The central policy challenge is not whether electrification is desirable, but whether it can be delivered without undermining security of supply. A credible strategy requires keeping grid strength and dispatchable capacity ahead of demand growth, based on realistic delivery timelines rather than aspirational targets. The Government needs to urgently pivot to creating strong incentives to ensure there is sufficient dispatchable power generation available to meet demand on low wind winter days, making realistic assumptions about what can be delivered by 2030. The UK would do well to follow the example of Germany, which despite its strong commitment to renewables, has identified a need for significant new gas-fired power generation capacity.

...but to ensure the electricity system remains secure, new investment in gas generation is essential

Without such a plan, electrification ambitions risk remaining theoretical while exposing the electricity system - and the public - to unacceptable levels of risk and cost. While this will mean compromising on net zero ambitions, there is abundant evidence that blackouts cause fatalities. There were 11 direct deaths reported[1,2] during the 2025 Iberian blackout and recent research[3] suggests as many as 160 additional excess deaths over the two days in question, implying a material fatality rate. Net zero promises should not be prioritised over public safety.

1 https://gaceta.es/espana/asciende-a-diez-el-numero-de-muertos-causado-por-el-apagon-masivo-que-afecto-a-toda-espana-20250430-1126/

2 https://cadenaser.com/nacional/2025/05/02/el-ministerio-de-sanidad-de-portugal-investiga-la-muerte-de-una-mujer-como-la-primera-victima-del-apagon-masivo-de-espana-cadena-ser/

3 https://www.medrxiv.org/content/10.1101/2025.06.03.25328877v1

What are Britain's electrification targets?

Heating

The UK Government's home heating electrification target is to achieve 600,000 heat pump installations per year by 2028, as set out in the 2021 Heat and Buildings Strategy[4], which also set out an ambition to phase out the use of gas boilers by 2035 (this second part is not expected to be retained in the new Future Homes Standard which is due to be published this autumn). The 600,000 target includes both retrofit installations and heat pumps fitted in new-build homes, with financial support being provided through the Boiler Upgrade Scheme[5], which offers grants of up to £7,500 for air and ground source heat pumps until December 2027.

The Heat and Buildings Strategy also envisaged a significant role for hydrogen in heating, with village trials expected in 2025. These trials have been cancelled following local opposition and industry concerns, and government policy has pivoted firmly towards electrification of heat as the primary pathway, with hydrogen expected to play a much smaller role[6]. The National Energy System Operator ("NESO") in its 2025 Future Energy Scenarios ("FES")[7] now sees "industry, power generation and aviation fuels become the main hydrogen users" with little role for hydrogen in heating. The 2025 FES also say "heat pumps, whether residential or district heating, are the solution for most buildings by 2050 across the pathways".

The FES goes on to say: "The Ten Year Forecast (10YF) has a shortfall of almost 4 million heat pump installations relative to the pathways in 2035 if progress is not accelerated. Heat is a challenging, but essential, area and a variety of measures are required to close this gap. Implementing strong policy to further incentivise heat pump uptake, such as the full phase out of new gas boiler installations in 2035, maintaining the Boiler Upgrade Scheme grant until this point, enacting the Future Homes Standard with no further delay, improving consumer and installer awareness around heat pumps, innovating with new financial and technical solutions to enable distress purchases, and reducing the gap between electricity and gas prices."

The Climate Change Committee ("CCC") also believes hydrogen will have no role in heating, and sees electrification as the sole route to decarbonising this sector, saying in its Seventh Carbon Budget[8]: "Electrification of heating is central to eliminating emissions from homes. Heat pumps will be the dominant low-carbon heating technology, with a limited role for other electric heating options. There is no role for hydrogen heating in residential buildings."

> "Hydrogen is not a viable fuel for widespread decarbonisation of home heating, and hydrogen boilers and hydrogen heat pump hybrids are not included in the Balanced Pathway,"
>
> - Climate Change Committee, Seventh Carbon Budget

The CCC's Balanced Pathway indicates that "the share of existing homes with low-carbon heating increases from 8% in 2023 to 68% by 2040. The majority of these homes are heated by a heat pump (either an individual heat pump or a communal system). This share grows from around 1% in 2023 to 52% by 2040." It also believes direct electric heating will be deployed

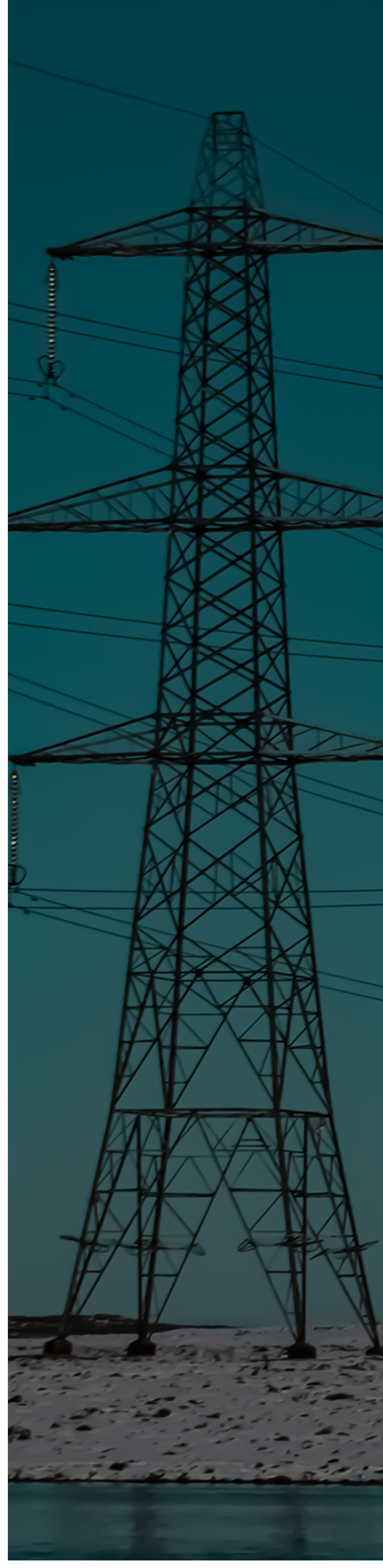
4 https://www.gov.uk/government/publications/heat-and-buildings-strategy

5 https://www.find-government-grants.service.gov.uk/grants/boiler-upgrade-scheme-1

6 https://www.gov.uk/government/publications/hydrogen-heating-town-pilot-open-letter-to-gas-distribution-networks

7 https://www.neso.energy/publications/future-energy-scenarios-fes/fes-documents

8 https://www.theccc.org.uk/publication/the-seventh-carbon-budget/



in homes with lower heat demand, particularly where heat pumps may not be an appropriate solution. Approximately 8% of homes already use direct electric heating, and it expects this to grow to 13% of low carbon heating by 2040.

NESO forecasts a shortfall of almost 4 million heat pump installations relative to the pathways in 2035 if progress is not accelerated

According to official Government data[9], there were only 42,645 heat pump installations under the Boiler Upgrade Scheme in 2024, far short of the target. The Heat Pump Association[10] says that 98,469 heat pumps were sold in 2024 – a figure which includes units not yet installed at the year end, as well as units sold outside the subsidy scheme. This is still well short of the target. A 2024 report by the National Audit Office found that the Government is relying on optimistic assumptions about consumer demand and manufacturer supply of heat pumps increasing substantially to achieve 600,000 installations per year by 2028.

The CCC expects annual heat pump installations in existing homes to increase rapidly. It says 60,000 heat pumps were installed in 2023 (these are actually heat pump sales rather than installations), and that this will increase to almost 450,000 in 2030, reaching around 1.5 million by 2035. In its model, installation rates do not exceed natural replacement cycles - the replacement of a heating system at the end of its life. Growth in consumer demand and installer capacity, rather than manufacturing capacity, are the primary constraints on deployment.

Transport

Light-duty (cars/vans)

EV mandates are not working - take-up is low and carmakers expect fines

Road transport is the largest component of transport electrification policy. There have been multiple laws and regulations[11] around vehicle emissions since 2019, all broadly referred to as "ZEV Mandates" ("zero-emission vehicle" mandates). The current situation is set out in the Emissions Trading Schemes Order 2023[12] ("VETS Order"), secondary legislation that creates four vehicle emissions trading schemes and applies to new cars and vans registered in Great Britain (England, Scotland, and Wales) from 3 January 2024.

Limited access to off-street charging, high purchase costs, and uneven public charging coverage continue to restrict adoption beyond early adopters

This policy framework replaced the UK's New Car and Van CO_2 Emissions Regulation, which ceased in GB with the commencement of the VETS Order, but has been preserved in Northern Ireland for the time being, with an expected move to VETS from 1 January 2026. Meeting this target will require not only the rapid growth of electric vehicle ("EV") sales but also the installation of an estimated 300,000 public chargepoints by 2030[13], supported by £1.6 billion of funding from the UK Electric Vehicle Infrastructure Strategy[14].

The VETS Order sets out the percentage of new zero emission cars and vans manufacturers will be required to produce each year up to 2030. The mandate was introduced in 2024, with car manufacturers required to ensure that at least 22% of their new car sales that year were ZEVs[15]. 80% of new cars and 70% of new vans sold in Great Britain will now be zero emission by 2030, increasing to 100% by 2035[16].

Mandating electric vans does not make them operationally viable….

In addition to the ZEV mandate, the VETS Order also includes carbon emissions trading for vehicles. The UK has regulated CO_2 emissions since the Motor Vehicles (Construction and Use) Regulations 1973. More recently the UK has regulated emissions through European Union regulations known as the New Car and Van CO_2 Emissions Regulations. VETS introduced a new approach to emissions regulation that is specifically designed to complement the vehicle targets.

The VETS Order places per-vehicle average CO_2 targets on new non-zero emission cars and vans to ensure that while the transition to ZEVs takes place, emissions from the remaining vehicles do not get worse on average compared to 2021. Emissions are measured as fleetwide averages calculated for each manufacturer. The Order describes the Non-Zero-Emission Car Registration Trading Scheme ("CRTS") and a van equivalent ("VRTS")[17]. The non-ZEV target is the percentage of a manufacturer's new vehicle registrations that may be non-zero emission – as the manufacturer sells zero-emission vehicles, it "earns" an ability to sell non-zero-emissions vehicles, expressed through allowances. If the ZEV target in a year is for 80% of cars to be zero-emission, then 20% can be non-zero emissions. Once the manufacturer has sold four zero-emission cars it earns an allowance to sell one non-zero-emission car.

…electric van mandates are misaligned with commercial reality: payload limits, charging downtime, and infrastructure constraints remain decisive barriers

These allowances can be traded between manufacturers, so if one car company sells eight zero-emission cars and one non-zero-emission car it can sell its unused non-zero-emission car allowance to another manufacturer. Car-makers can also borrow against their own expected future allowances. If, after the trading window for allowances ends, a manufacturer has an allowance deficit, it will have to make a payment per allowance they

9 https://assets.publishing.service.gov.uk/media/67c7428516dc9038974dbe91/Heat_pump_deployment_quarterly_statistics_United_Kingdom_2024_Q4.ods

10 https://www.heatpumps.org.uk/record-year-for-uk-heat-pump-sales-and-training/

11 https://www.vehicle-certification-agency.gov.uk/download-publication/3899/BD-065%20New-Car-and-Van-CO2-Regulations-Guidance-2022%20v.3/#:~:text=3.2%20The%20latest%20Regulation%2C%20(EU)%202019/631%2C%20established,Harmonised%20Light%20Vehicle%20Test%20Procedure%20(WLTP)%20baseline.

12 https://www.legislation.gov.uk/uksi/2023/1394/article/2

13 https://www.gov.uk/government/news/tenfold-expansion-in-charge-points-by-2030-as-government-drives-ev-revolution#:~:text=Tenfold%20expansion%20in%20chargepoints%20by%202030%20as,announcing%20%C2%A31%20billion%20investment%20in%20ultra%2Dfast%20charging.

14 https://www.gov.uk/government/publications/uk-electric-vehicle-infrastructure-strategy

15 https://sustain-fuels.com/education/what-is-the-zero-emission-vehicle-mandate/

16 https://www.gov.uk/government/news/pathway-for-zero-emission-vehicle-transition-by-2035-becomes-law#:~:text=The%20zero%20emission%20vehicle%20(%20ZEV,increasing%20to%20100%25%20by%202035.

17 https://www.gov.uk/government/publications/vehicle-emissions-trading-schemes-how-to-comply

are missing. For cars this payment is £15,000 per allowance, and for vans it is £9,000 per allowance in 2024, and £18,000 per allowance from 2025 onwards. It is also possible to convert between car and van allowances.

In April 2025 the Government announced it would modify the VETS Order following intensive lobbying from carmakers. The changes confirmed the 2030 phase-out date for new petrol and diesel cars, while allowing hybrids to continue until 2035. Exemptions were introduced for small-volume manufacturers[18]. For vans, internal combustion engine ("ICE") models will be permitted until 2035, alongside full hybrids and plug-in hybrid vans. The 2030 car phase-out date has shifted back and forth several times in recent years, creating uncertainty for manufacturers and consumers. Alongside these changes, the Government also announced extended borrowing / credit flexibility allowing manufacturers to borrow credits out to 2030, and trading / conversion between car and van credits, as well as an extension of the credit trading window to 2029.

In addition, fines for manufacturers who fail to meet annual ZEV production targets were reduced from £15,000 to £12,000 per car and £18,000 to £15,000 per van. While hybrids and ICE vans are still able to be produced between 2030-2035, manufacturers will be held to stringent carbon emission targets for these vehicles. They must ensure that total carbon emissions for these non-ZEV vehicles remain at least 10% below the emissions of their total sales from 2021[19].

In order to incentivise the uptake of EVs, the Government has a number of schemes to lower their upfront and running costs which can be higher than for ICE vehicles, particularly where users rely on more expensive public charging infrastructure. This support[20] includes grants of up to £3,750 for electric cars (provided as a discount by the seller rather than as a grant applied for by the buyer, unlike the heat pump grants), although most cars are only eligible for the lower grant of £1,500. There are grants of £2,500 for small zero-emission vans, and £5,000 for larger vans. There are limits on the total number of grants available to each business, organisation or individual through the plug-in van and truck grant scheme each financial year.

Home charging points are supported by a grant of up to 75% grant (capped at £350) but only if they are installed in flats, rented accommodation or properties without off-street parking. Workplace charging points are eligible for similar grants of up to 75% capped at £350, on a per-socket basis. Applicants can claim for up to 40 sockets in multiple rounds, and units that can charge two cars qualify for two grants[21]. Zero-emission cars and vans also qualify for reduced Vehicle Excise Duty (commonly known as car tax) and there is corporation tax relief where these vehicles are purchased for business purposes. There are also income tax benefits for employees who have zero-emission company cars, or who purchase such cars using salary sacrifice schemes, with similar reliefs for workplace charging.

NESO, in its FES 2025 says that "all new car sales in 2030 in our pathways are EVs, requiring a current acceleration rate greater than current policy. Electrification is the main solution for road transport in our pathways, although hydrogen could play a role in larger HGVs in the 2040s." The CCC agrees, saying in the 7th Carbon Budget: "electric vehicles will be the main source of decarbonisation. By the middle of the Seventh Carbon Budget period, over three-quarters of cars and vans on the road, along with a fast-growing number of heavy goods vehicles, will be EVs. There will be no hydrogen cars or vans, and very little or potentially even no role for hydrogen in heavier vehicles."

18 https://www.gov.uk/government/news/backing-british-business-prime-minister-unveils-plan-to-support-carmakers

19 https://www.soppandsopp.co.uk/news/2025-zev-mandate-updates-what-fleets-need-to-know

20 https://www.gov.uk/plug-in-vehicle-grants

21 https://www.ayvens.com/en-gb/support-and-insights/insights-hub/electric-vehicles/incentives-for-low-co2-vehicles/

The CCC expects that by 2040, three-quarters of cars and vans on the road will be electric, up from only 2.8% of cars and 1.4% of vans in 2023. The share of new car and van sales that are electric will grow quickly, ahead of the zero-emission vehicle mandate, reaching around 95% by 2030 and 100% by 2035.

Electrification of the car fleet will increase electricity demand with significant scope for smart charging. NESO's FES 2025 suggests that by 2030 EV charging could contribute 8–10% of total annual electricity demand, equivalent to 30–40 TWh, with a potential peak load of 5–8 GW. However, if smart charging and vehicle-to-grid technologies are adopted at scale, around 83% of this peak load could be shifted away from system stress periods, materially reducing the challenge for system operators. NESO expects that vehicle-to-grid will reach the same capacity as a power station by 2030 at 1.2 GW, growing to as much as 41 GW in 2050. However, NESO also said that 2024 EV sales figures were marginally lower than required in its FES 2024 net zero pathways.

Buses & coaches

The Government has proposed to end the sale of new non-zero emission buses (non-ZEBs) between 2025 and 2032, subject to consultation. Currently there is no mandate for buses or coaches to be zero emission by any specific date, and in 2024 only 2% of England's buses were zero emission. The Bus Services (No. 2) Bill[22], which has completed its passage through Parliament and is now awaiting Royal Assent, includes provisions to give the government the power to set a date, no earlier than 2030, for the prohibition of new non-zero-emission buses being registered.

The recent consultation[23] returned varied responses on the timing of such a mandate, with respondents pointing out the challenges that would arise in rural areas. Most supported a date between 2025 to 2030 - the preferred year for the end of sale was 2030 for the majority of bus industry stakeholders, with the second being 2025. On average, bus operators preferred a later phase out date compared to bus manufacturers.

Most operators and manufacturers expressed a preference for end dates between 2030 and 2032, highlighting technical barriers to overcome before a transition could be considered feasible. Some identified issues with the availability of technology and warned that an end date earlier than 2030 would overwhelm zero emission infrastructure providers and create increased pressures on the electricity grid. Trade and passenger organisations' generally preferred dates between 2025 to 2030, with the majority preferring an end date of 2030. However, two respondents from these groups suggested there should be no end date, due to the perceived challenges of transitioning to a zero emission bus fleet.

> "There was a consensus among respondents that there are still key infrastructure challenges that may make it hard to invest in and transition to ZEBs,"
>
> - ZEB consultation responses, Department for Transport

Many respondents, particularly energy industry groups and operators, expressed concerns about the pressures on the electricity grid and its capacity, saying that significant upgrades to the grid would be essential to accommodate the transition to a fully electric fleet. Some respondents said electric infrastructure on rural routes would have difficulties in providing suitable charging facilities since there are inadequate ranges on longer-dis-

22 https://commonslibrary.parliament.uk/research-briefings/cbp-10266

23 https://www.gov.uk/government/consultations/ending-the-sale-of-new-non-zero-emission-buses-coaches-and-minibuses/public-feedback/ending-the-sale-of-new-non-zero-emission-buses-consultation-and-coach-and-minibus-decarbonisation-summary-of-responses

tance services. The importance of early engagement between government, local authorities, bus operators and distribution network operators to commit to a strategic approach and help prevent long timescales for building the infrastructure was highlighted.

Bus electrification faces operational constraints that vary sharply by geography...

Issues were also identified with a lack of space in some depots for electric buses and charging facilities. Many commented that maintaining enough space for charging equipment and additional technologies like batteries would represent a considerable challenge for operators and should be a critical consideration. Lack of standardisation in charging and refuelling infrastructure was also raised. Local authorities said infrastructure interoperability will be important to allow operators the flexibility to move their buses between depots when required.

...urban routes can be electrified at depots, but rural and inter-urban services face range limits, charging downtime, and grid constraints that undermine timetable reliability...

The consultation responses highlighted that coaches have significantly different operating cycles from buses in service, for example, they may not return to home depots as often as service buses do. Coaches may need to find charging /fuelling locations wherever they operate and the vehicles themselves may need ranges in the order of hundreds of miles. There are likely to be difficulties in enabling charging /fuelling infrastructure to be installed in existing coach parking sites and at motorway service areas, primarily due to grid constraints, cost, and uncertainty in technology (battery electric or hydrogen fuel cell).

Charging was less of a concern for minibuses, but issues around driver licencing were identified since the weight of batteries or fuel cells would likely push zero emission vehicles above the weight restrictions for category B licenses. This would mean drivers with category B licenses may not be able to drive zero emission minibuses, unless the additional weight is offset (for example, by reducing passenger capacity). Upskilling drivers for zero emission minibuses would require additional training and expenditure, potentially an issue given many minibuses are operated by schools and sports clubs.

... rural and small-town depots often sit on constrained networks, increasing reinforcement costs and delivery risk

Although the electricity demand impact is modest compared with cars and vans it is still material at the distribution network level, with local depots requiring significant reinforcement to support overnight charging of large fleets.

The Climate Change Committee expects "the share of buses that are zero-emission grows from 1% in 2023 to 18% by 2030 and 60% by 2040. Local routes will be largely served by battery-electric vehicles. Long-distance routes and coaches face similar challenges to HGVs, so decarbonise more slowly." In its FES 2025, NESO says that "buses are decarbonising faster than other transport sectors. Although the number of registered hydrogen buses and coaches on the road is decreasing, as access and cost of hydrogen remain a challenge for transport, electrification of this sector is progressing well as the technology develops."

Heavy goods vehicles

Electric HGVs face similar challenges with charging infrastrutre

For heavy goods vehicles ("HGVs"), the UK Government has pledged that all new HGVs will be zero-emission by 2040, and that new non-zero-emission models under 26 tonnes should cease by 2035. However, unlike cars and vans, there is currently no binding ZEV-mandate for HGVs with annual sales-targets, penalties or compliance mechanisms. An infrastructure strategy for zero-emission HGVs and coaches was due to be published in 2024, but as yet it has not and the pathway remains uncertain.

The eFreight 2030[24] initiative is a collaboration of HGV fleet operators, vehicle manufacturers, data analytics companies, battery manufacturers, energy suppliers, service station operators, finance companies, research and technology organisations and trade associations. The consortium aims to drive a widescale switch from diesel to electric power across the industry by 2030, with full electrification of the HGV sector by 2035. The eFREIGHT 2030 project was tasked with installing 34 MW HGV charging sites across the country, however, it has encountered challenges[25] with securing grid connections, with disparate processes and timescales across different network operators.

Battery weight materially reduces payload capacity, while the space required for charging infrastructure is incompatible with many existing depot layouts

For example in one region, interim load offers enabled early deployment, while in another, there was a five-year wait for reinforcement. The exercise has shown how "network, land, and business decisions are deeply intertwined. Interim leases, planning delays and uncertain fleet transitions can all influence when and where connections actually happen".

HGVs are the only part of the road transport sector in which NESO sees

24 https://efreight2030.com/about/

25 https://www.linkedin.com/pulse/whats-slowing-hgv-electrification-energy-systems-catapult-bba6e/

any potential role for hydrogen, saying "electrification is the main solution for road transport in our pathways, although hydrogen could play a role in larger HGVs in the 2040s". The CCC expects nearly two-thirds of heavy goods vehicles on the road to be electric by 2040, and assumes electrification over hydrogen for all HGVs. It expects that from zero electric HGVs in 2025, 6% will be electric in 2030, rising to 31% in 2035, in 63% 2040 and 93% in 2050.

Rail

Rail is already one of the most electrified transport modes...

Rail policy is framed by the Transport Decarbonisation Plan[26], which commits to the removal of all diesel-only trains by 2040 and a net-zero railway by 2050. Scotland has set a more ambitious target of full passenger rail decarbonisation by 2035, largely through electrification. In addition to electrifying track, battery and hydrogen trains are also being considered. By 2050, 97% of railway emissions could be removed given the assumed levels of electrification, hydrogen and battery technologies in Network Rail's Traction Decarbonisation Network Strategy.

> "We will deliver a net zero rail network by 2050, with sustained carbon reductions in rail along the way. Our ambition is to remove all diesel-only trains (passenger and freight) from the network by 2040,"
>
> \- Decarbonising Transport, Department for Transport

...remianing lines may be hard to electrify...

In 2024 38% of track was already electrified. The CCC expects this to increase to 44% in 2030, 49% in 2035, 55% in 2040 and 66% in 2050. The CCC's modelling does not assume that road freight will move to rail. This could aid decarbonisation of the freight sector in the short term and reduce congestion, however zero-emission HGVs are expected to become available across the road haulage sector sooner than it will be possible to completely remove diesel from rail freight. This is due to the limitations of other rail technologies and the likely need for diesel-electric hybrids to service certain routes.

...rural lines, freight corridors, and lightly used branches face high costs, long disruption, and limited operational upside

The CCC sees a small role for hydrogen powered and battery-electric trains in the medium term, which together will enable all fully diesel trains to be removed from both passenger and freight operations by 2040. Diesel-electric hybrids will continue to operate on non-electrified freight routes until 2050. It also expects some residual coal use in heritage railways due to the lack of viable alternatives.

26 https://share.google/nyYRD1IX8rQ5bSkFu

Industry

Cluster-based electrification depends on coordination the UK system struggles to deliver

The UK Government's Industrial Decarbonisation Strategy ("IDS"), published in March 2021 by DESNZ (then BEIS), sets out a plan to align heavy industry with the Net Zero 2050 target while retaining competitiveness in global markets[27]. The strategy identifies a pathway to reduce industrial emissions by roughly two-thirds by 2035 compared with 2018 levels and by at least 90% by 2050. It says that 2020s will be "crucial" for laying the "bedrock" for industrial decarbonisation, starting the switch away from fossil fuels to low carbon alternatives such as hydrogen and electrification, and deploying key technologies such as carbon capture, usage and storage, and supporting industrial sites to maximise their energy and resource efficiency to reduce costs for businesses.

Aligning network investment, planning consent, and private capital across multiple firms has proven slow and complex in practice

According to the Energy System Catapult[28], the UK's six industrial clusters are responsible for over half of the country's industrial emissions, with many ideally situated for use of carbon capture, usage and storage ("CCUS") as well as low carbon hydrogen production and use. For this reason, Government policy has largely focused on clusters, mainly through direct funding, as well as developing support mechanisms (supplemented by additional funding), for CCUS and hydrogen. Deployment of CCUS in the first two of these clusters is called 'Track-1'. The first 2 clusters were chosen via a process called Phase 1 launched in 2021, and are HyNet in the North West of England and North Wales, and the East Coast Cluster ("ECC") in Teesside. In March 2023, the Government announced the eight emitter projects in ECC and HyNet which would be taken forward to commercial negotiations to secure long-term financial support[29].

Industrial electrification is constrained by site-specific complexity...

In July 2023, the Government outlined the next two clusters it felt were best placed to take forward carbon capture. These were Acorn, in the North East of Scotland, and Viking in the Humber. In October 2024, £21.7 billion in funding for the first CCUS projects in the UK was announced by the Government. Following this, in December 2024 the Transport and Storage Network for ECC, and the project Net Zero Teesside reached financial close, with HyNet following in April 2025.

...many processes require bespoke electrical upgrades, additional space for equipment, and major grid connections that are difficult to deliver on existing sites

In addition to supporting CCUS, fuel switching is another key part of the UK's industrial decarbonisation strategy, through the Industrial Fuel Switching ("IFS") and Low Carbon Hydrogen Supply ("HS") innovation programmes[30]. The £21 million IFS competition was designed to stimu-

27 https://www.gov.uk/government/publications/industrial-decarbonisation-strategy

28 https://es.catapult.org.uk/report/towards-industrial-decarbonisation-the-strategic-role-of-industrial-clusters/

29 https://www.gov.uk/government/collections/uk-carbon-capture-usage-and-storage-ccus

30 https://share.google/CUWkKHgiKHDGhLEeU

late early investment in and development of fuel switching processes and technologies, so that a range of technologies would be available by 2030. The competition was split into three phases: a market engagement study during 2018 (Phase 1, £200k); feasibility studies during 2019 (Phase 2, £2 million); and four demonstration studies during 2020-22 (Phase 3, £18.4 million). The Phase 3 projects demonstrated the use of hydrogen, biomass and electrical heating across a range of industry sectors.

The £33 million Low Carbon Hydrogen Supply programme sought to develop, demonstrate and reduce the cost of low carbon bulk hydrogen solutions (production, storage and supply), and was aimed at innovations involving pre-commercial technologies with a medium level of maturity. Phase 1 of the HS programme funded 13 feasibility studies during 2019 across four lots (Low Carbon hydrogen, 'Zero' Carbon hydrogen, hydrogen imports and hydrogen storage). Phase 2 funded five demonstration projects from 2020-2022, including three 'zero' carbon and two 'low carbon' hydrogen technologies.

A 2025 evaluation of the two schemes found that the IFS had limited influence on innovation and investment due to two factors: the small number and scale of projects (although the programme was not designed to have large-scale influence), and external factors such as inadequate electricity grid connections, lack of hydrogen infrastructure, fuel price volatility, supply chain expertise deficits, and long investment timescales in industrial sites. Despite evidence of the HS programme influencing innovation investment, interview evidence suggested investors remained hesitant to invest in hydrogen technology deployment, due to the need for ongoing government support, challenges such as commercial and technical issues, water access, supply chain limitations, and insufficient CCUS infrastructure. Despite this, the UK Government is now running successor versions of both programmes.

The Industrial Energy Transformation Fund[31] ("IETF") is another UK Government initiative, that supports the development and deployment of technologies that enable industrial decarbonisation. The IETF was designed to help energy intensive businesses to cut their energy bills and carbon emissions by investing in energy efficiency and low carbon technologies. It launched in 2020, with £500 million of funding available over three phases, up until 2028. The IETF closed in July 2025, following the Spending Review, with the planned second competition window of IETF Phase 3 being cancelled. No successor fund is planned.

The IDS sits within the broader Net Zero Strategy[32], published in October 2021, which provided the UK's first economy-wide roadmap to net-zero by 2050. It established sectoral pathways consistent with the Sixth Carbon Budget, including 100% clean electricity by 2035, 40 GW of offshore wind, and 5 GW of low-carbon hydrogen by 2030. For industry, the NZS linked the IDS to wider energy-system measures such as CCUS and reform of the UK Emissions Trading Scheme.

The Net Zero Growth Plan[33], published in March 2023, reframed decarbonisation as an industrial growth and competitiveness strategy. It re-packaged existing policies reaffirming cluster funding with plans to deliver four CCUS clusters by 2030, increasing the hydrogen target to 10 GW, and introducing the UK's first consultation on a Carbon Border Adjustment Mechanism to protect domestic producers.

In its FES 2025, NESO accepts that: "at the current pace, industry is unlikely to switch from natural gas to low carbon alternatives at a sufficient rate. Rebalancing electricity and gas prices and speeding up grid connections will support this, alongside strategic consideration of where to target and enable the use of hydrogen and CCS for other users. Some industry may

31 https://www.gov.uk/government/collections/industrial-energy-transformation-fund

32 https://www.gov.uk/government/publications/net-zero-strategy

33 https://www.gov.uk/government/publications/powering-up-britain/powering-up-britain-net-zero-growth-plan

face high upfront costs to transition to low carbon fuels and further support may be required. The industrial energy transition needs to be guided by clear long-term carbon accounting policy for industrial imports of materials and products which, in turn, makes electricity, hydrogen and abated gas more economical than unabated gas, while ensuring Great Britain remains an attractive economy for industry."

The CCC believes that electricity will meet 61% of industrial energy demand in 2040, up from around 26% today. The major sources of heat in industry will be replaced with electric options including electric boilers, electric ovens, electric furnaces in the glass sector, and, most significantly, electric heat pumps. Electrifying industry allows UK manufacturers to benefit from global demand for low-carbon goods. Hydrogen is expected to play a small role, particularly in industrial sectors such as ceramics and chemical production which may find it hard to electrify. It expects CCS to be used in industrial subsectors with process emissions for which alternatives are unlikely to be available. This results in CCS being deployed in the chemicals and cement and lime industries. Achieving the CCS trajectory will rely on the establishment of CO_2 storage and rapid construction of pipelines to connect sites.

Overall, the CCC expects a smaller role for both hydrogen and CCS/CCUS than envisaged by the Government when the various industrial decarbonisation plans were written however it notes that it "cannot see a route to Net Zero that does not include CCS".

How realistic are Britain's electrification targets?

UK electrification targets are politically and economically fragile. Overall, the UK is off track for its net-zero pathway in buildings and industry, with transport somewhere in the middle - electrification of rail was on track even before net zero targets were developed, and while there has been some progress in the electrification of car and small van transit, there is still a long way to go to meet targets for electric buses and HGVs. Recent reviews by Parliament[34], the International Energy Agency[35] and the Climate Change Committee[36] all highlight that policy delivery is lagging behind ambition, particularly for heat and industrial electrification.

Heating

According to the DESNZ Public Awareness Tracker[37], following an increase in knowledge levels at the start of the tracking series between Autumn 2021 and Winter 2021, levels of awareness and knowledge of the need to change the way homes and buildings are heated in order to reach the Net Zero target have remained broadly stable. Older people are more likely than younger people to report both awareness and knowledge of heat pumps, while people living in owner-occupied households were more likely than those in rented households to say they were aware. However, levels of self-reported knowledge were much lower than levels of awareness. For example people in owner occupied homes reported awareness levels of 86% but knowledge levels of just 33%.

Only a very small proportion of owner occupiers in Spring 2025 said that they had already installed a heat pump (2% and 1% for air source and ground source heat pumps respectively). A substantial minority of people in owner-occupied households reported not knowing enough about heat pumps to make a decision to install one, but this has decreased steadily from Winter 2021 to Spring 2025: from 39% to 21%, and from 39% to 22% for air source and ground source heat pumps, respectively.

34 https://commonslibrary.parliament.uk/research-briefings/cbp-9888/

35 https://www.iea.org/reports/united-kingdom-2024/executive-summary

36 https://www.theccc.org.uk/publication/progress-in-reducing-emissions-2025-report-to-parliament/

37 https://share.google/cNBEGKwsXXihDwtp2

There has been a steady increase in the likelihood (very or fairly likely) of installing either type of heat pump and in those who said they already have one: rising from 19% to 26% for air source heat pumps and from 13% to 18% for ground source heat pumps.

Public acceptance of heat pumps remains low...

However, between Winter 2024 and Spring 2025, there was no further increase in the likelihood of installing heat pumps of either type, while there was an increase in the proportion of people saying they were either not very or not at all likely to install a heat pump. Between Winter 2024 and Spring 2025 this increased from 38% to 45% for air source heat pumps and from 43% to 52% for ground source heat pumps. These data indicate a significant number more people intend not to install a heat pump than plan to acquire one.

The Government is targeting 600,000 heat pump installations per year by 2028 – an eleven-fold increase on 55,000 heat pump sales in 2022[38]. By 2035, Government wants to see up to 1.6 million heat pumps installed annually. However, according to the National Audit Office ("NAO")[39] the number of heat pump installations by December 2023 was less than half of planned projections; and uncertainty around the role of hydrogen in home heating is hampering investment and effective planning.

...but a lack of qualified installers limits the ability to increase installation rates

> "Whilst this level of growth is welcomed, substantial efforts are still needed to ensure heat pump deployment and workforce growth reach the levels required to reduce UK carbon emissions in line with legally binding targets.
>
> The previous Government's target of 600,000 heat pump installations per year by 2028, and the Climate Change Committee's recommendation of heat pumps in 10% of UK households by 2030, remain a challenging goal.
>
> Meeting such will require swift, decisive government action, and the heat pump industry remains committed to working collaboratively with government, consumers and stakeholders to deliver the scale needed,"
>
> - Heat Pump Association

According to the National Audit Office, the Government is "relying on optimistic assumptions about consumer demand and manufacturer supply of heat pumps increasing substantially to achieve 600,000 installations per year by 2028". Heat Pump Association data indicate that a record 98,469 hydronic heat pumps were sold in the UK in 2024[40], meaning the 600,000 target will require an sixfold increase 2024 to 2028, using sales as a proxy for installations.

38 https://www.heatpumps.org.uk/wp-content/uploads/2023/12/HPA-Unlocking-Widescale-Heat-Pump-Deployment-in-the-UK.pdf

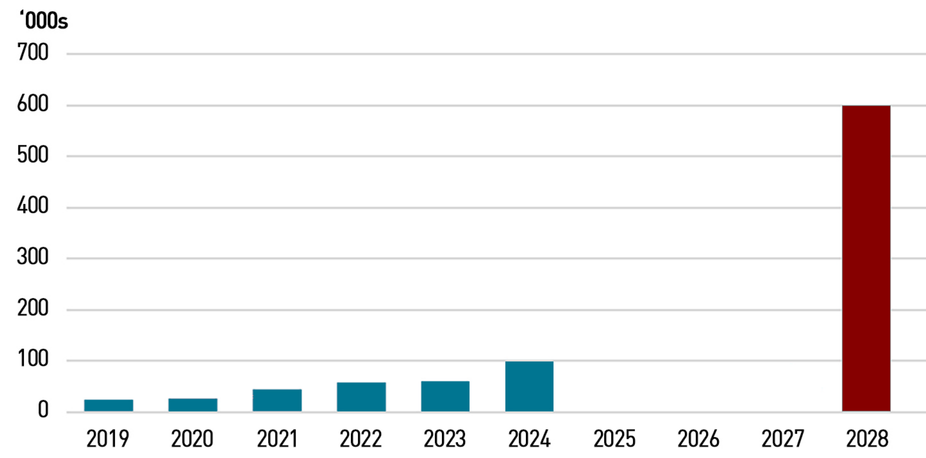
39 https://www.nao.org.uk/press-releases/low-heat-pump-uptake-slowing-progress-on-decarbonising-home-heating/

40 https://www.heatpumps.org.uk/record-year-for-uk-heat-pump-sales-and-training/

Installation rates must rise by a large margin to meet targets...

...meeting the 2028 installation target would require annual deployment rates far above historic sales growth

Heat pump sales and installation target



The data from 2018 to 2022 show annual heat pump sales since the Government does not track installations data. The 2028 figure represents target installations and illustrates the size of increase required over the coming years

Source: Watt-Logic, based on Heat Pump Association and UK Government data

The NAO believes the Government's assumptions about levels of consumer demand and manufacturer supply are optimistic, after a third of respondents to the 2023 consultation on the Clean Heat Market Mechanism reported that Government's targets would be unachievable (although this pre-dated the increased grant available through the Boiler Upgrade Scheme). The flagship Boiler Upgrade Scheme has also underperformed, installing just 18,900 heat pumps between May 2022 and December 2023 compared with Government expectations of 50,000 installations by this point.

Full installation costs including home adaptations remain a major barrier

The NAO says that a key issue behind lower-than-expected heat pump uptake is their cost to use and install. The Government has delayed its planned work to reduce running costs, by rebalancing gas and electricity prices, for example by moving some levies and charges from electricity to gas bills, although it has said that price rebalancing remains an essential policy but is challenging to implement.

Currently it is illegal for gas and electricity costs to be cross-subsidised, so gas costs cannot be recovered through electricity bills and vice versa. However, there is nothing to prevent these levies from being recovered through general taxation rather than through energy bills, and many in the energy industry believe that this would be more equitable since the current approach is seen as regressive.

Heat pump installation costs also fell more slowly than the Government hoped.

Low levels of public awareness

The NAO also found that the Government has no overarching long-term plan to address the low levels of awareness among households about the steps necessary to decarbonise their heating systems. Decarbonising home heating will require almost every household to make a decision that will have a significant impact on their homes, but public awareness around this is low: around 30% of respondents to a 2023 Government survey had never heard of, or hardly knew anything about the need to change the way homes are heated in order to reach net zero.

The Government has promoted heat pumps as part of its *Welcome Home to Energy Efficiency*[41] communications campaign, and provides information online. However, research by the Energy Saving Trust[42] indicated that homeowners are unsure where they can get independent, impartial advice on making improvements to reduce the carbon dioxide emissions of their homes.

Possibly at least in part due to lack of awareness, uptake of the Boiler Upgrade Scheme[43], a Government grant for people in England and Wales for the installation of a heat pump or a biomass boiler, has been lower than the Government expected. As a result the size of the available grants was increased to £7,500 for air or ground source heat pumps (and £5,000 for biomass boilers), with the intention that the residual cost paid by the homeowner would be similar to that for installing a gas boiler. Between May 2022 and December 2023, just under 19,000 heat pumps were installed in England and Wales as a result of the Boiler Upgrade Scheme, against an initial target of 50,000. As a result around £100 million less was spent on the grants than had been budgeted.

The grant is expected to cover almost 60% of the average cost of installing a heat pump, based on the average cost in 2023, following the increase in its size. The number of grant applications under the scheme increased by almost 50% in December 2023 compared with December 2022, and applications in January 2024 increased by nearly 40% compared with January 2023. However, the NAO found that the Government does not track the reasons that some grant applications do not progress to heat pump installation.

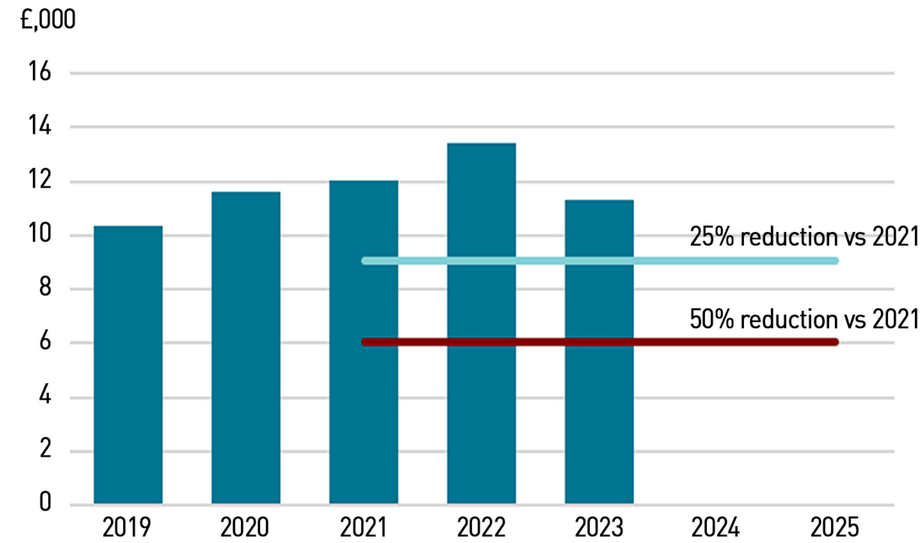
High capital and operating costs

Cost is clearly a key driver behind the uptake or otherwise of heat pumps, and while there are now larger grants available and average installation costs have fallen, these reductions have been slower than the Government had hoped, and there has been no progress on reducing running costs. A survey[44] of heat pump installers by Nesta found that 45% of survey participants believe that home owners do not progress with a heat pump installation after receiving a quotation as the costs are too high.

According to the NAO, at the end of 2023, the average cost to replace a gas boiler with a heat pump was around four times higher than replacing it with another gas boiler. In 2021, the Government set a target for a 25–50% reduction in installation costs by 2025 and to ensure heat pumps are no more expensive to buy and run than gas boilers by 2030. However between 2021 and 2023, installation costs only reduced by 6% in real terms, meaning that costs would need to fall three times faster over the next two years if even the lower end of the target is to be met. The Government told the NAO that global supply chain pressures were responsible for the slow pace of cost reductions, including, shortages of semiconductors that are a key component in heat pumps, manufacturers being unable to keep up with increased global demand; and high energy prices increasing the cost of manufacturing processes.

41 https://energy-efficient-home.campaign.gov.uk/
42 https://energysavingtrust.org.uk/report/national-or-local-retrofit-advice/
43 https://www.find-government-grants.service.gov.uk/grants/boiler-upgrade-scheme-1
44 https://www.nesta.org.uk/report/how-to-install-more-heat-pumps-insights-from-a-survey-of-heating-engineers/

Heat pump installation costs in 2021 prices



This figure presents the average (mean) cost of MCS-certified installations of air, ground and water source heat pumps in UK homes, based on MCS data. The costs are self-reported by MCS-certified installers and should cover "the full cost of the installation that is charged to the consumer" which includes materials and labour.

MCS does not monitor whether grants are deducted from the cost values entered onto MCS certificates, so some cost entries may include the grant value and others may not. However, Ofgem provides guidance to Boiler Upgrade Scheme installers on what to include so the Government expects the vast majority of Boiler Upgrade Scheme installers to report costs inclusive of the grant.

Installations that cost below £1,000 and above £100,000 plus the remaining top and bottom 5% of the data have been excluded. These average costs do not factor in cost per kilowatt capacity, so changes in average cost could also be due to changes in the distribution of heat pump capacities being installed.

Source: National Audit Office, based on MCS (Microgeneration Certification Scheme) data

Heat-pump unit costs remain materially higher than gas boilers

Despite policy support, installed costs are typically several times those of a replacement boiler, limiting mass-market appeal

Heat-pump costs are unlikely to fall dramatically

An October 2024 study by the University of Edinburgh and Imperial College London[45] found that there had been little to no reduction in the average installation cost of heat pumps in the UK over the past decade. Forecasts suggest only a modest 20-25% reduction in total installed costs by 2030, which falls short of government targets for cost parity with gas boilers.

> "While there is a growing policy consensus that heat pumps will pay a key role in decarbonising home heating, there are some stubborn economic challenges. Our research suggests the need for realistic expectations about heat pump installed cost reductions, and also, introducing targeted support measures to reflect their competitive running costs and wider benefit,"
>
> - Dr Mark Winskel, School of Social and Political Science,University of Edinburgh

The core technology is mature, manufacturing is established, and most future cost reductions are expected to be incremental rather than transformational

DESNZ and Octopus Energy have consistently claimed that heat pump costs will fall as the market matures. Significant cost reductions are unlikely since the global market for heat pumps is already mature and there is nothing unique about the UK market that would lead to experience curve benefits. Octopus Energy[46] claims that its current heat pump costs are £3,818 compared with the national average of £5,295, after the £7,500 subsidy – in other words £11,318 versus £12,795, which is not lower than

45 https://www.ed.ac.uk/news/2024/high-costs-slow-widespread-use-of-heat-pumps-study
46 https://octopus.energy/blog/heat-pump-cost-explanation/

the 2023 cost data in the NAO report. In 2023 the Government re-stated[47] its ambition set out in the 2021 Heat and Buildings Strategy to "work with industry to achieve 25-50% reductions in the upfront cost of installing a heat pump by 2025 and for cost parity between owning and running a gas boiler and a heat pump by 2030". Clearly the former ambition has not been met, and the research cited above suggests these are the maximum costs achievable by 2030. The maturity of the global market gives little room for unit costs to fall, although there could be some reductions in fitting costs.

Heat-pump costs extend well beyond the unit itself

However, for many households, the installation of a heat pump goes beyond the heat pump equipment itself. Since heat pumps deliver low grade heat compared with the high grade heat delivered by gas boilers, it is more important for buildings to be well insulated, and larger emitters (eg radiators) may be required. These involve both additional costs and significant upheaval and disruption to homeowners.

It is not just the installation cost that inhibits heat pump update, running costs are also higher than for gas boilers since electricity is more expensive per unit than gas. The government has committed to "rebalance" energy prices over the course of the 2020s, including potentially shifting energy levies and obligations from electricity to gas bills, but plans to do this have been delayed by nearly two years. The Government has said that price rebalancing remains essential but is "politically challenging".

Many installations require upgraded emitters, larger pipework, and fabric improvements, materially increasing total system costs

The Government believes that a combination of the Boiler Upgrade Scheme, the Clean Heat Market Mechanism and other energy "efficiency" and low-carbon heating retrofit schemes such as the Social Housing Decarbonisation Fund and the Energy Company Obligation will be sufficient to deliver its installation targets. However, a third of respondents to the 2023 consultation on the Clean Heat Market Mechanism reported that these targets would be unachievable (although this pre-dated the increase in the Boiler Upgrade grant). In addition, both the Boiler Upgrade Scheme and Clean Heat Market Mechanism are set to expire, in 2027 and 2029 respectively.

Supply chain constraints

A major barrier to meeting heat pump installation targets is a lack of capacity in the supply chain. Two thirds of heat pumps installed in the UK

47 https://www.gov.uk/government/publications/energy-security-bill-factsheets/energy-security-bill-factsheet-low-carbon-heat-scheme

are manufactured abroad, compared with under half of gas boilers. The majority of heat pumps sold in the UK are imported from Asia (China, South Korea and Japan) and Europe[48].

UK heat-pump deployment depends on a thin specialist supply chain

As of 2020, there were at least 33 manufacturers supplying ASHPs in the UK, three of which manufacture in the UK (Mitsubishi, Global Energy Systems and Big Magic Thermodynamic Box, accounting for total market share of 32%). The market is dominated by Mitsubishi, Daikin, and Samsung which together accounted for almost two-thirds of annual sales in the UK in 2019. The rest of the market is distributed amongst around 30 firms. Leading UK-based boiler manufacturers are also beginning to produce heat pumps but so far their market share is limited.

Reliance on imported components and a limited domestic installer base reduces resilience and slows expansion

In a 2020 survey, carried out by Eunomia Research & Consulting Ltd on behalf of the Department for Business, Energy and Industrial Strategy, manufacturers reported being very confident that they could increase heat pump supply into the UK market, through a combination of imports and domestic manufacture, by a minimum of 25-30% year on year for the next 15 years. Such increases have been achieved before, but not consistently for many years, or decades as is now required. Also, the extent to which demand could be met from UK-based manufacturing is unclear.

Manufacturers said they would consider opening manufacturing facilities in the UK if there was a "significant increase" in demand that would give greater certainty of an attractive return on investment. What constituted a "significant increase" varied between manufacturers, and they also indicated that demand increases alone would not necessarily be enough to justify developing UK-based production capacity. They cited the following additional requirements:

- A clear long-term strategy and commitment from the Government providing clarity on the need for heat pumps;
- A stable regulatory system;
- Additional standards and quality requirements on heat pumps installed in the UK, although care would be needed to avoid making heat pumps uncompetitive;

48 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/943712/heat-pump-manufacturing-supply-chain-research-project-report.pdf

- Lower-cost space for manufacturing through tax-breaks, start-up grants or interest-free loans, to make the UK more competitive compared with other European countries, and support for up-skilling and re-skilling; and

- Innovation funding to focus on areas identified with added value to the UK, such as smart control systems to facilitate demand-side response and management, efficient use of hybrid heat pumps, improved performance monitoring, increasing heat pump output temperature and/or greater integration with other low-carbon technologies.

The majority of heat pump components are sourced from outside the UK, with the exception of compressors where one UK manufacturer – Emerson Copeland of Northern Ireland, serves a large proportion of the UK heat pump market. Several factors drive the location of manufacture beyond the UK. Currently, there is not enough heat pump manufacturing demand in the UK to support local components manufacture, and producers of these components also serve several other markets such as cooling, ventilation, and air conditioning, so growth in heat pump manufacturing may not be enough to stimulate re-location.

European and Asian manufacturers have the volumes necessary to justify investment in automation and other efficiency technologies. Survey respondents suggested that this divergence has become so entrenched that it would be effectively impossible to establish large-scale manufacturing in the UK for specialised components as these markets are all international, and have been developing in the absence of the UK for so long, the barrier to entry would now be prohibitive. This was not seen as a determining factor in the growth of UK heat pump manufacturing. In the boiler market many of the components are imported for assembly in the UK.

The Government believes the development of UK-based heat pump manufacturing will have a positive impact on the UK economy. In addition, an increase in domestic heat pump production would mitigate the risk of job losses in boiler manufacturing.

To support this growth, the Government has introduced the Heat Pump Investment Accelerator Competition[49] which offered £30 million to support domestic heat pump manufacturing. UK registered businesses could apply for grant funding of up to £15 million per project, for major investments in the manufacture of heat pumps and strategically important components. Applications closed in October 2023 and two schemes were awarded just under £10 million between them..

The Government also intends to impose obligations on boiler manufacturers through the Clean Heat Market Mechanism to sell a certain number of heat pumps, however there is limited evidence from other countries as to the success of such schemes, and as the obligation can be met through imported heat pumps, it may not have the desired impact on UK manufacturing capacity. The most likely outcome is manufacturers being fines and recovering the costs by increasing the prices of gas boilers.

Lack of skilled installers is hampering installations

There is no currently formal definition of who is and who isn't recognised as a heat pump installer, and no data on the number of people currently carrying out such installations. It is agreed, however, that the sector is small. According to the Heat Pump Association[50], the number of people who completed a short training course to become qualified heat pump installers increased by 166% between 2022 to 2023, from just under 3,000 in 2022 to close to 8,000 in 2023. MCS[51] reports there are 1,500 businesses with MCS accreditation currently installing heat pumps.

According to the Nesta survey cited earlier, only 16% of sole traders they surveyed and 42% of companies with one to five employees were MCS certified, compared to 87% of companies with six or more employees. MCS certification is not a requirement for heat pump installation. In contrast there are around 150,000 gas boiler engineers[52] on the Gas Safe Register (which replaced the CORGI scheme) in the UK. Since the installation of gas boilers does require certification, there is more certainty around the numbers.

The Heat Pump Association estimates that the equivalent of 33,700 full time employed heat pump installers will be needed to support the Government's installation ambitions, however MCS expects 50,000 installers will be needed.

The Government has put in place the £5 million Heat Training Grant[53] for heating installers, which supports trainees in England taking short training courses relevant to heat pumps. Training providers offering the grant are able to provide trainees with a discount or rebate of up to £500. Since the courses typically cost £500-600, the grant will cover the bulk of the cost. The Government has also launched the Low Carbon Heating Technician apprenticeship[54], which will be available across England and has been designed by industry experts. This apprenticeship will allow new entrants into the heating sector to learn how to install low carbon heating technologies including heat pumps, and will "offer sustainable long term career opportunities".

A survey by Nesta of 345 heat pump installers found smaller businesses do not generally focus solely on heat pump installation - only 16% of sole traders and 43% of companies with one to five employees reported that they mostly or only install heat pump systems. Respondents reported that their largest challenge with increasing heat pump installations was either: a lack of customer demand (41%), an inability to find additional suitable staff (30%), and the time spent on unnecessary tasks or administration (19%). The survey found that administrative tasks may be a bigger barrier to increasing installations than elements of the job relating to physically installing the heat pump, and that finding ways to make these tasks less time intensive, could allow engineers to increase the number of installations they complete.

The survey also found a strong preference among employers to hire experienced staff, and that employers expect a much higher level of practical heat pump installation experience than apprenticeship graduates currently have. Fewer than 10% of company owners said they were confident or very confident that recent graduates from apprenticeship schemes are trained to an appropriate level, with 61% having no or very little confidence in their training. Almost half of company owners believe the training on general plumbing and heat pump installation skills are most in need of improvement. The smallest companies reported reluctance to take on apprentices as they are unable to find appropriate candidates and the costs of doing so are too high. This may undermine the success of Government apprenticeship initiatives, and financial support for companies that take on apprentices may increase their attractiveness to employers and be more effective in increasing the numbers of junior installers in the sector.

Practical skills are so important to employers that 34% reported that they would not recruit candidates whose qualifications did not include work-based learning even with other incentives or support schemes. 29% of respondents said they would be encouraged to take on such people if their salary was initially supported, with salary support being the most popular incentive amongst respondents. This suggests a need for non-apprenticeship courses to include a greater element of work-based learning, or for the creation of pathways to support those who obtain such qualifications with securing on-the-job training after graduating.

It is clear that there is currently a lack of skilled heat pump installers, and that existing Government schemes to grow their number are likely to prove insufficient.

49 https://www.gov.uk/government/publications/heat-pump-investment-accelerator-competition

50 https://www.heatpumps.org.uk/166-increase-in-qualified-heat-pump-installers/

51 https://mcscertified.com/uk-on-track-for-best-year-ever-for-renewable-energy-and-heat-installations/

52 https://www.gassaferegister.co.uk/about-us/what-is-gas-safe-register/

53 https://www.gov.uk/government/publications/training-providers-how-to-offer-the-heat-training-grant-for-heat-pumps

54 https://www.gov.uk/government/news/thousands-of-low-cost-training-spaces-available-in-boost-to-green-jobs-sector

Transport

There are multiple challenges to the delivery of the electrification mandates for vehicles. As with the underperforming smart meter roll-out, the Government has chosen to impose mandates on car and van sellers rather than buyers. Manufacturers must ensure a certain percentage of the vehicles they sell are zero emission, but there is no corresponding obligation on consumers who are free to choose conventional cars and vans. Despite the financial incentives, zero-emission vehicles remain more expensive than their conventional counterparts both to buy, and to run in the case of public charging, so people who do not (or cannot) have a home charger face higher running costs than for conventional cars and vans.

Transport electrification is constrained by cost and charging reliability

Other challenges include customer acceptance around range anxiety and the reliability and ease of use of chargers, infrastructure challenges around both charging infrastructure and the ability of electricity grids to cope, and policy instability which threatens investability.

The EV mandate is acting as a stick on the supply side, forcing manufacturers to sell a minimum proportion of electric vehicles. However, there is no corresponding carrot driving demand – in fact the opposite is true with many headwinds to EV ownership, including a new pay per mile scheme announced in the recent Budget. Consequently consumer adoption rates will undershoot and some organisations will miss sales targets, potentially resulting in significant costs (or a movement of credits from other manufacturers). In addition, Chinese and US EV manufacturers are ahead in some areas of manufacturing, which could make it harder for European brands to compete.

Economic and supply-side challenges

The choice to go electric in the small vehicle space is almost always more expensive than to own and operate a conventional internal combustion engine vehicle. The same applies for larger vehicles where diesel is almost always the cheaper alternative. This represents a significant challenge, particularly where mandates are applied to sellers rather than owners – the mandate risks becoming a sales tax rather than a genuine driver of adoption. The exemptions for smaller companies mean that new ICE cars will continue to be available after the target dates for full electrification of new car sales. Constraints in global battery supply chains will further strain the targets. Residual value uncertainty means fleet and leasing companies remain cautious about second-hand values, further hampering EV adoption.

EVs remain more expensive than equivalent ICE vehicles, while unreliable public charging undermines confidence for drivers without home charging

Apart from new home-charged EVs, ICE cars are cheaper to buy and run

New EVs are still more expensive to buy than comparable ICE models although the gap is narrowing. Auto Trader's Retail Price Index[55] shows the average list price of a new EV in 2024 was still £11,000 – 14,000 higher than an equivalent ICE car. The CCC assumes cost parity between new EVs and ICE cars in 2030[56]. However, electric cars benefit from lower first year vehicle excise duty[57] payments of just £10 compared with £390 for a typical petrol car (typical new cars had emissions of 102 g /km in 2024[58]).

Home charging is the cheapest way to fuel a car, but public charging for electric cars costs about the same as petrol and diesel. His Majesty's Revenue and Customs ("HMRC") publishes tables of fuel costs per mile[59] for tax purposes, which sets out a policy-neutral position on these costs which is useful for comparison purposes. These indicate that the charging costs for electric cars are 8 pence per mile for home charging and 14 p /mile for

55 https://plc.autotrader.co.uk/news-views/retail-price-index/

56 https://www.theccc.org.uk/wp-content/uploads/2025/02/Understanding-the-tail-of-the-electric-vehicle-transition-ERM.pdf

57 https://www.gov.uk/vehicle-tax-rate-tables

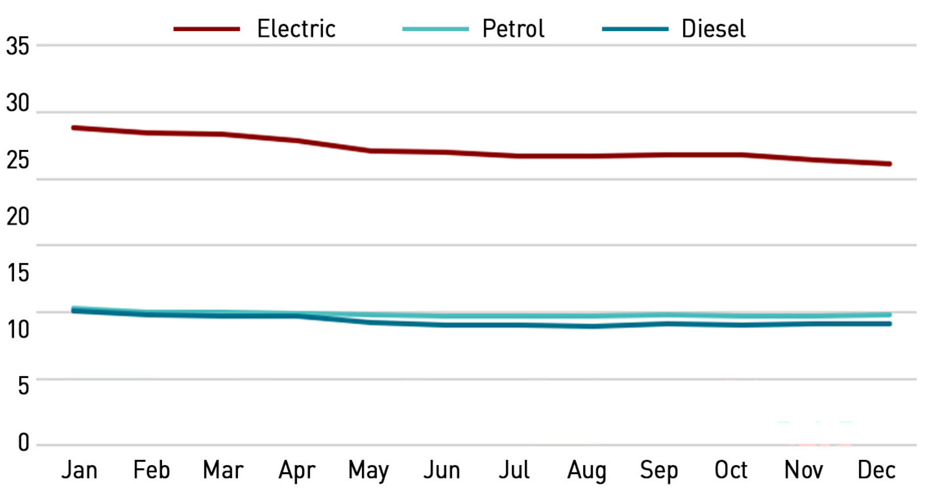
58 https://www.nimblefins.co.uk/average-co2-emissions-car-uk#nogo

59 https://www.gov.uk/guidance/advisory-fuel-rates

public charging. The fuel cost for a petrol car ranges from 12-22 p /mile depending on engine size with a mid-sized engine costing 14 p /mile. The equivalents for diesel are 12-18 p/mile with 13 p /mile for a mid-sized engine. Households without home chargers face significantly higher running costs, undermining the EV advantage over conventional cars.

Electric cars cost considerably more to buy than conventional cars...

Prices of electric versus conventional cars in 2024 (£000)



Source: Auto Trader

Fuel is not the only cost of owning a car – insurance is another major element. A 2023 study by Solera[60] (a vehicle life-cycle management company) based on 92,000 data points collected over 18 months to August 2023 from 20 countries showed:

...and they have higher repair costs, hiygher inurance costs and parts are nore expensive

- Overall, EV repair costs are 29% higher than ICE repair costs, globally, on average;
- EV parts costs are 48% higher, on average, per estimate. Parts included high-voltage battery; battery-control unit, cabling, battery box, and system battery charger. Battery repair is the highest cost;
- Driver airbag systems were replaced 8% more frequently on EVs;
- Rear bumper absorbers were replaced 1,390% more frequently on EVs;
- Rear bumper reinforcements were replaced 14% more frequently on EVs.

These higher repair costs feed into insurance premia. Evidence suggests

60 https://www.businesswire.com/news/home/20231115820568/en/Groundbreaking-Global-EV-Repair-Cost-Research-Unveils-29-Higher-Overall-EV-vs.-ICE-Repair-Costs-in-Side-by-side-Model-Comparison

Except for home-charged EVs, both the initial purchase costs and annual running costs remain lower for conventional cars

EVs are being written off after relatively minor accidents over concerns relating to repair of battery packs, when an equivalent accident would not require an ICE car to be written off[61]. As a result, the cost of insuring EVs can be twice as high as that for a conventional car[62]. According to UK insurance broker Howden Group, the average insurance premium for an EV rose to £1,344 at the end of 2023, approximately twice the cost of insuring a petrol car. Insurance costs fell across the board in 2024, with an EV costing between £641 and £910 per year and petrol cars costing £467 – 670 per year.[63]

With average annual car mileage of 7,400 miles[64], the running cost (insurance plus charging plus vehicle excise duty) of an EV charged at home would be £1,563 compared with £2,007 for a car charged using public chargers, assuming the new standard rate of car tax of £195 after the first year[65]. However, a petrol car would cost £1,800 (insurance, plus petrol, plus vehicle excise duty) with car tax also being £195 per year.

New home-charged EVs have lower running costs, but this advantage is contingent on access to home charging and may be eroded over time by higher repair and insurance costs

Overall, except for home-charged EVs, both the initial purchase costs and annual running costs remain lower for conventional cars. New home-charged EVs have lower running costs, but this advantage is contingent on access to home charging and may be eroded over time by higher repair and insurance costs. And from 2028, owners of electric cars can expect to pay an additional pay-per-mile tax that is likely to be set at 3p /mile[66].

Diesel buses, coaches and HGVs are all cheaper than electric equivalents

For heavy road transport, diesel vehicles are all cheaper than electric equivalents

Electric and hydrogen buses remain substantially more expensive to purchase than diesel models, though costs are falling to a certain extent as production scales and government grant support continues. According to the Department for Transport's Zero Emission Bus Regional Areas[67] ("ZEBRA") programme, the average purchase price of a new electric bus in the UK in 2024 was between £350,000 and £450,000, compared with £200,000 to £250,000 for a typical diesel equivalent - roughly 1.5 to 2 times higher. Hydrogen fuel-cell buses were even more expensive, typically £500,000–£600,000, or around 2.5 times the cost of a diesel vehicle. Although government grants under ZEBRA 1 and 2 can bridge part of this gap, operators still face significantly higher upfront investment requirements.

61 https://www.autoexpress.co.uk/news/359993/electric-car-write-offs-could-be-more-likely-due-high-cost-battery-repairs

62 https://www.independent.co.uk/news/uk/home-news/electric-cars-insurance-premiums-howden-b2484605.html

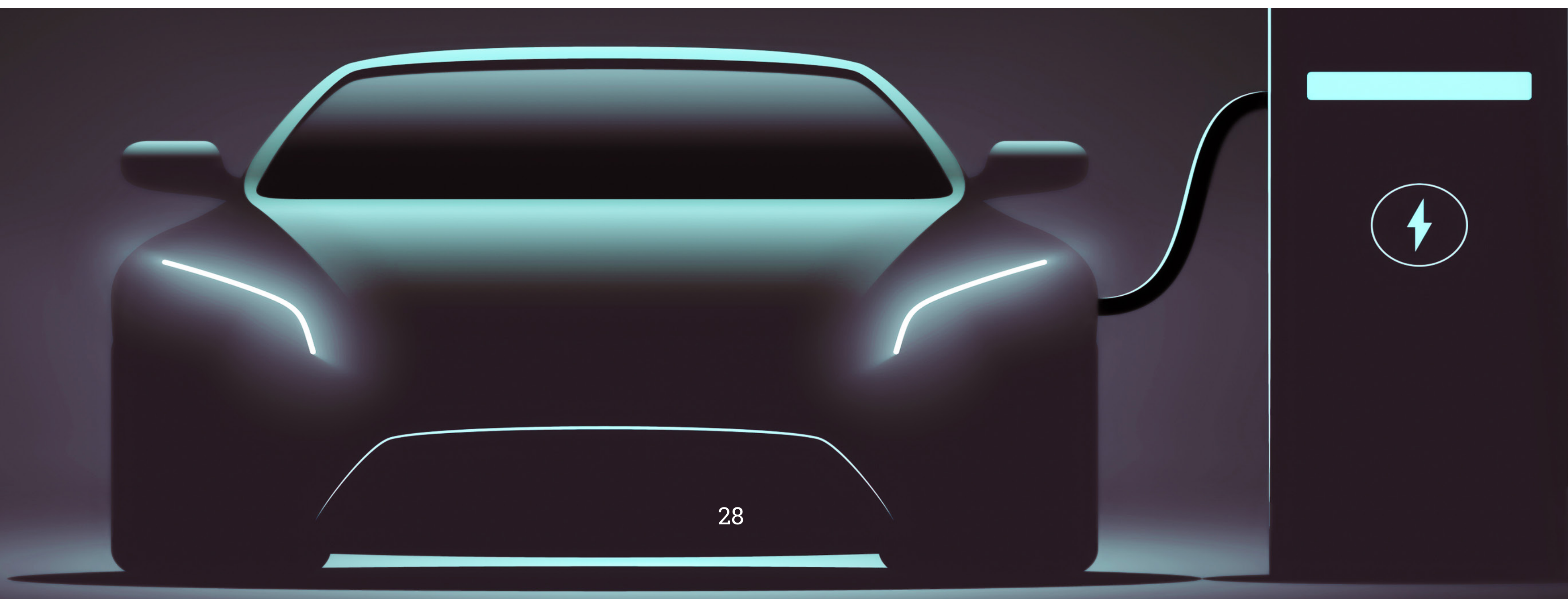
63 https://www.autocar.co.uk/car-news/consumer/electric-car-insurance-cost

64 https://www.britanniacarleasing.co.uk/news/annual-uk-car-mileage/#:~:text=Average%20Annual%20Mileage%20in%20the,to%20understand%20the%20bigger%20picture.

65 https://www.gov.uk/guidance/vehicle-tax-for-electric-and-low-emissions-vehicles

66 https://www.drive-electric.co.uk/news/what-2025-budget-means-for-ev-drivers/

67 https://www.gov.uk/government/publications/apply-for-zero-emission-bus-funding-zebra-2/apply-for-zero-emission-bus-funding-zebra-2



There are almost no public chargers for elecric heavy road transport vehicles

Once in service, battery-electric buses benefit from lower energy costs per kilometre than diesel, provided they are charged at depots during off-peak hours. This is not always possible based on bus schedules, particularly in rural areas – so it may be necessary to charge during peak hours instead. There is no public charging infrastructure for buses since chargers used by cars are unsuitable (bays are too small, lack of turning circles, inadequate power levels etc). At electricity prices of around £0.25–£0.30/kWh, energy costs per mile are typically 20–30% lower than for diesel buses.

Chargers must be installed in depots, but they often require grid reinforcement which can take years to deliver

However, many operators report that connection and demand charges can erode these savings, especially in depots requiring grid reinforcement. Maintenance savings are mixed: while electric drivetrains have fewer moving parts, additional costs associated with battery thermal management, software support and component replacement offset much of the advantage. As a result, lifetime total cost of ownership ("TCO") analyses by Transport Scotland[68] indicates that, without grant funding, electric buses still cost around 10–20% more than diesel equivalents over a 12-year operating life.

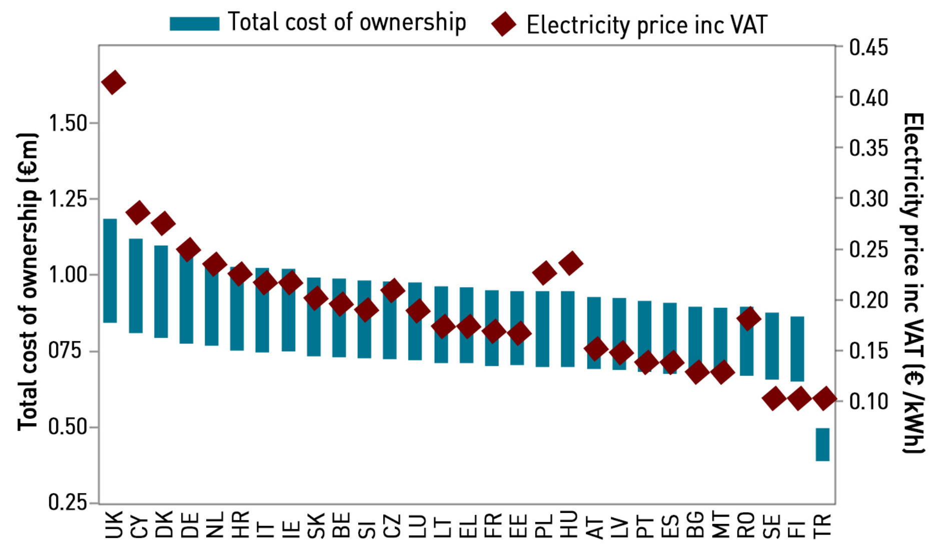
Range limitations are also an issue, particularly in cold weather, requiring more frequent returns to the depot for charging

A further constraint is range and operational flexibility. Electric buses typically achieve under 200 km in winter conditions, requiring either larger fleets or opportunity charging to maintain daily schedules. This raises depot and infrastructure costs. The European Battery-Electric Bus TCO study[69] similarly finds that fleet-wide parity depends heavily on utilisation rates and depot electricity tariffs, with the UK having the highest electric bus ownership costs in Europe.

68 https://www.transport.gov.scot/media/30mikj34/total-costs-of-ownership.pdf

69 https://www.mdpi.com/2032-6653/16/8/464

Net Present Value of the total cost of ownership of a single 12 m electric bus including 50 kW charging infrastructure



Source: Ghotge R, van Rooij D, van Breukelen S. Total Cost of Ownership of Electric Buses in Europe. World Electric Vehicle Journal. 2025

By contrast, the electrification of long-distance coaches remains at an early stage. Fully electric coaches are two to three times the cost of a comparable diesel coach, with limited models commercially available in the UK. Element Energy's analysis for the Climate Change Committee[70] found that even under optimistic assumptions, the higher capital cost and limited utilisation of long-haul coaches make payback periods unattractive. Hydrogen coaches trialled under Innovate UK's pilot saw costs of £600,000–£700,000

70 https://www.theccc.org.uk/wp-content/uploads/2020/12/Element-Energy-Analysis-to-provide-costs-efficiencies-and-roll-out-trajectories-for-zero-emission-HGVs-buses-and-coaches.pdf

per vehicle compared with £250,000–£300,000 for a diesel equivalent. Although electricity is cheaper per kilometre, the infrastructure required - such as megawatt-scale en-route charging or hydrogen refuelling stations - is prohibitively expensive, particularly for intercity routes. For these reasons, diesel remains dominant in the UK coach market, with electric and hydrogen options currently viable only in niche or demonstration fleets.

The cost challenge is even greater for heavy goods vehicles, where both capital and infrastructure costs remain high. According to the International Council on Clean Transportation[71] and the DfT's Zero-Emission HGV Trials, a 44-tonne battery-electric truck typically costs £300,000–£400,000, compared with £120,000–£180,000 for a diesel equivalent - around 1.8 to 2.5 times more. Hydrogen fuel-cell trucks are more expensive still, at 2.5 to 3 times diesel cost. While electricity is generally cheaper per kilometre than diesel, these savings depend on depot charging tariffs and utilisation. Depot grid-connection upgrades can cost over £1 million per site, while the extra battery weight (up to one tonne) reduces payload and hence revenue. Maintenance savings of 20–30% partly offset these effects, but overall TCO parity with diesel is not expected before 2030–2032 for regional-haul vehicles, and later for long-haul operations[72].

For all three vehicle categories, the total cost picture is strongly dependent on usage intensity, access to low-cost electricity, and available grant support. In urban bus fleets with high daily mileage and depot charging, battery-electric models are already close to economic parity when ZEBRA grants are applied. By contrast, coaches and long-haul trucks, which operate at lower average daily utilisation and require high-power charging infrastructure, remain far from parity and face significant operational limitations.

Under the electric vehicle infrastructure strategy, local authorities are expected to drive the development of charging infrastructure in their areas, funding and project managing the process and co-ordinating with the Distribution Network Operators ("DNOs") who carry out the physical electrical work to connect these facilities to the power grids. The DNOs are also responsible for carrying out any reinforcement work that might be required to accommodate the increased demand resulting from this infrastructure.

Alternating current ("ac") chargers (for example, public on-street chargepoints) require relatively low amounts of power, whereas direct current ("dc") rapid and ultra-rapid chargers, such as those found at EV charging hubs and motorway service areas, require significantly more power. Typically, larger generation and demand projects (above around 100 MW) connect to the transmission network while smaller projects connect to the lower voltage distribution networks. Most low voltage networks are owned and managed by DNOs which operate on a regional basis, however there are also IDNOs – Independent Distribution Network Operators, which tend to operate newer equipment, and, unlike DNOs, are not confined to a specific geographic region.

Network capacity limitations, including the need for DNO reinforcement work, are a significant factor in delaying local authority EV charging schemes, particularly for high-powered rapid and ultra-rapid chargers. The different processes and timescales for connections to the transmission and distribution network add complexity, particularly when a connection to the distribution network also impacts on the transmission network, requiring additional reinforcement to the high voltage grid. In recent years, connections to electricity grids have become a growing barrier to the deployment of EV charging infrastructure.

The Local Electric Vehicle Infrastructure ("LEVI") Fund, while providing crucial support, focuses on smaller-scale, mostly ac charging, whereas larger dc projects require substantial grid reinforcement, which can slow down deployment. The Government is working to improve coordination

71 https://theicct.org/publication/total-cost-ownership-trucks-europe-nov23/
72 https://assets.bbhub.io/professional/sites/24/Commercial_ZEV_Factbook.pdf

with DNOs[73], but challenges remain in strategic network planning to ensure it can support the rapid rollout of the necessary charging infrastructure.

Fleet-level data on insurance cost differentials between electric and diesel heavy vehicles (buses, coaches, HGVs) is limited. Some studies assume insurance at around 1.5% of purchase cost for modelling purposes. As such, while insurance costs are higher for electric and hydrogen heavy vehicles than for diesel equivalents, it is likely a secondary factor compared to capital, energy and infrastructure costs.

Non-cost challenges with customer acceptance
While the financial cost of EVs remains a barrier for many consumers, non-cost challenges are also significant and continue to slow uptake. Chief among these is range anxiety – the concern that a vehicle will run out of charge before reaching its destination. Although the average daily mileage in the UK is well within the range of most EVs, the perception of limited range persists, exacerbated by variability in real-world performance due to weather, driving style, and battery degradation over time[74].

Motoring organisations stress that a change in perception is needed – few people consider the range of a tank of petrol or diesel when buying a conventional car, but this is to miss the point. There are many petrol stations and filling a tank takes mere minutes. To add a personal anecdote, I recently had to drive from rural Hampshire to Wells to give a speech in the evening, and then drive home, leaving after 11pm for the return journey. Having an almost full tank when I left home, I did not think twice about the journey, which was on largely unlit rural roads. I thought nothing of using my heated seat, stereo and air conditioning, all of which would reduce the range of an EV. The round trip consumed roughly a third of a tank of diesel, but had I needed to fill up, it would have been easy and safe to do so. I'm not sure how safe I would have felt having to find and use a public charging facility, late at night, particularly given the amount of time charging can take.

Concerns over unreliable public charging infrastructure, where out-of-service or incompatible chargers create uncertainty about journey planning, are not uncommon. These anxieties are reinforced by the slower refuelling process relative to petrol or diesel cars, particularly for drivers without access to off-street parking who must rely on public charge points. And reduced availability of chargers outside major urban centres[75].

A further barrier lies in the complexity and confusion surrounding the UK's regulatory environment and the wider EV transition narrative. The Government's Zero Emission Vehicle mandate has been poorly understood by the public, with many drivers mistakenly believing it represents an outright ban on internal combustion engine sales in the near term rather than a gradual shift in manufacturer supply. This has created uncertainty about future resale values, leasing terms, and the long-term availability of servicing for conventional vehicles.

Additional non-cost obstacles include anxiety over battery lifespan and recycling, limited consumer understanding of charging tariffs and home installation requirements, and concerns about the adequacy of the electricity grid to meet rising demand. Collectively, these factors contribute to widespread hesitation, meaning that even as costs fall, behavioural and informational barriers may delay full electrification of the vehicle fleet.

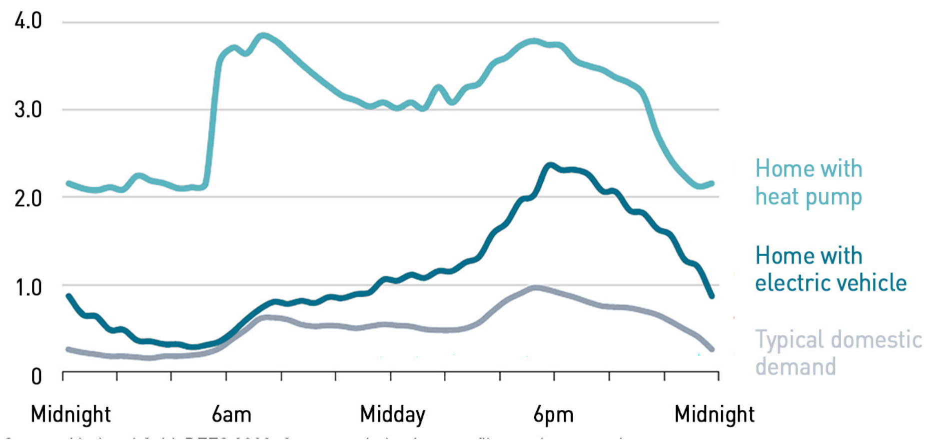
73 https://www.gov.uk/government/publications/improving-the-grid-connection-process-for-electric-vehicle-charging-infrastructure/improving-the-grid-connection-process-for-electric-vehicle-charging-infrastructure
74 https://www.rac.co.uk/drive/electric-cars/choosing/electric-vehicle-range-how-far-can-i-drive-in-an-ev/
75 https://electriccarsreport.com/2025/01/zapmap-releases-2024-ev-charging-statistics-revealing-record-rate-of-charge-point-installation/

Infrastructure challenges

The transition to electric vehicles presents significant infrastructure challenges that go well beyond the installation of chargers. The UK's electricity distribution networks were not designed for the high, simultaneous loads that widespread home and public EV charging could create. Local substations and low-voltage feeders, particularly in older residential areas, risk overloading if large numbers of households charge vehicles overnight – according to a 2024 paper by Regen and the MCS Foundation, for electrification of heating and transport at the rate required to meet carbon budgets, 45% of primary substations will run out of capacity by 2035 without intervention[76].

Winter peak day demand (kW)

Daily load profiles for households with and without low-carbon technologies



Source: National Grid, DFES 2023, Customer behaviour profiles and assumptions report[77]

Peak power loads will be higher following the electrification of heating and transport, however significant uncertainties remain in how customers will behave and, therefore, how much peak load will increase and how the load profile might change. As more people use dynamic tariffs, where electricity is cheaper or even free at times of high renewable generation, consumers are more likely to charge EVs and run heat pumps at the same time, reducing diversity and creating new localised peak loads.

Local distribution networks were designed to cater for peak loads after considering the diversity of demand ("ADMD" – After Diversity Maximum Demand). Low-voltage networks consist of hundreds of thousands of assets, each servicing relatively small numbers of customers. Secondary substations typically feed between 1 and 500 customers - with smaller groups, there is a higher chance that all customers' peak loads will coincide.

Capacity on distribution networks is limited. While capacity on the 11 kV network is well understood with monitoring at all primary substations, there has historically been very little monitoring of the low voltage networks. Monitoring equipment is now being installed, and aggregated with smart meter data to build a better picture of low voltage network utilisation. Data suggests networks are 30-40% utilised.

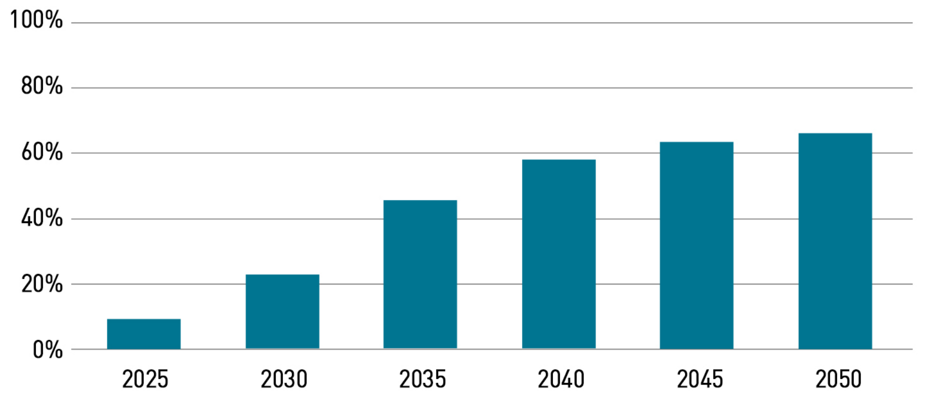
There are three main technical limits to distribution networks: thermal, voltage and phase imbalance. A thermal constraint limits the maximum load the equipment can carry before reaching its rated thermal capacity - further load would risk overheating. A voltage constraint is the maximum load a length of cable can carry whilst staying within statutory voltage limits of 216 V and 253 V. Demand causes voltage drop and generation causes voltage rise. Voltage changes increase with cable distances. The electricity grid carries three-phase alternating current, with each phase being carried

76 https://mcsfoundation.org.uk/wp-content/uploads/2024/05/Electrification-The-local-grid-challenge-Regen-FINAL.pdf

77 https://dso.nationalgrid.co.uk/planning-our-future-network/forecasting-for-future-need

on a separate cable. Power is delivered on just one of the three phases to domestic properties. Demand and generation must be roughly equal across phases.

Primary substations requiring upgrades across GB



The proportion of primary substations across GB with no remaining thermal capacity for demand under the Consumer Transformation DFES scenario. This decarbonisation scenario aligns closest to the CCC's Balanced Pathway scenario and the NIC's Second Assessment

Source: DNO data provided with the support of DNO open data platforms. Net Zero High demand used for SP Energy Networks licence areas

As electrification progresses, the likelihood of these constraints being breached will rise. Analysis for the CCC found that voltage constraints will drive around half of low-voltage network upgrades, with breaches of the statutory voltage limits are more likely on rural low-voltage networks with longer lengths of line. Reinforcement of high-voltage 11 kV grids will be almost entirely due to thermal constraints. Some technical limits can be exceeded temporarily, although this would affect asset lifetimes and fault rates, however, significant or prolonged breaches of thermal constraints would likely lead to network outages. Upgrades to primary stations are already required in some areas, and by 2035, electrification at the rate needed to hit net zero targets will require 45% of primary substations across the country to be upgraded. While most low voltage substations currently have significant spare capacity, about 7% of assets are already overloaded by estimated maximum demand conditions.

As well as upgrades to electricity networks, the equipment that connects directly to consumer properties may also need replacing. The low voltage network is connected to households by service cables and cut-outs which contain a fuse to avoid overloads. DNOs do not know exactly which properties need replacement service cables and upgraded cut-outs to enable the installation of heat pumps and EV chargers. While fuse replacements are straightforward, replacing service cables will require more planning as it can involve excavating cable trenches across roads and gardens. Grid connections for rapid charging hubs face even longer lead times than for homes, competing with other sectors such as data centres and renewable generation for limited connection capacity. These bottlenecks have already delayed several motorway service area projects, undermining confidence in the reliability of future charging provision[78].

The roll-out of public charging points has been uneven and poorly coordinated. Urban areas, where car ownership is lower but charge-point density is higher, contrast sharply with rural regions and motorways where charging provision lags. The coexistence of multiple networks with different payment systems and pricing structures adds further complexity, deterring drivers who might otherwise switch. Many existing chargers rely on grid connections that are insufficient for future ultra-rapid charging technologies, meaning that a large portion of current infrastructure could become obsolete within a decade. The challenge is therefore not only one

78 https://transportandenergy.com/2025/03/12/government-must-overcome-delays-to-charging-network-rollout/

of scale but of strategic planning, ensuring that grid reinforcement, connection approvals, and public charging networks expand in a coordinated, future-proof manner to support the pace of electrification the government envisages.

Industry

Cost considerations will impede electrification
An obvious barrier to the electrification of industry is cost. The UK already suffers the burden of the highest industrial electricity prices in the developed world, which presents a major competitive challenge to industry, despite some policy support. Creating additional costs is simply out of reach for many industries that are struggling to stay afloat. Energy-intensive industries are closing at an accelerating rate, with output in key sectors such as basic metals, paper, chemicals and glass down by over a third since 2021, reaching their lowest levels since official records began in 1990[79].

Industrial electrification is constrained first and foremost by cost....

This collapse in production has been accompanied by significant job losses, particularly in steelmaking and petrochemicals, where plants are being mothballed or closed outright. Recent announcements - including the closure of Tata Steel's blast furnaces at Port Talbot, the planned end of oil refining at Grangemouth, and large reductions in production across the chemicals and fertiliser sectors - illustrate a broader pattern of industrial contraction that threatens to hollow out the UK's manufacturing base. These developments highlight the risk that, without substantial reform of electricity pricing and grid-cost recovery mechanisms, further electrification could accelerate de-industrialisation rather than support it.

...with Britain already facing the highest industrial electricity prices in the developed world...

Industrial electrification may require extensive site reconfiguration
Some of the site-specific challenges were highlighted recently by Megan Turner, environment and sustainability manager at the Port of Dover, who spoke at LogisticsUK's 'Delivering Decarbonisation' meeting[80], providing an interesting case study into the challenges of industrial electrification. The Port currently has a peak use of 7 MW across its estate, which it expects to need a 160 MW grid connection if it is to serve electric vessels using its cruise, cargo and ferry terminals and other electric vehicles at the site – thousands of HGVs, as well as vehicles used by contractors and logistics operators. However there is limited space on the port estate and there is no room for on-site batteries to optimise supply. The port currently has back-

....leaving many firms unable to absorb further increases amid rising deindustrialisation

79 https://www.ons.gov.uk/economy/economicoutputandproductivity/output/articles/theimpactofhigherenergycostsonukbusinesses/2021to2024

80 https://www.newpower.info/2025/11/the-complexities-of-electrification-experience-from-port-of-dover/

up diesel generators (using bio-fuel) that cover its entire load, which are used regularly, as there are already interruptions to supply.

Case studies show that electrification can require grid connections to increase by an order of magnitude

The electricity grid in the entire Dover area is at maximum use so even installing 7 kW domestic vehicle chargers is impossible in the area, according to Turner. Grid reinforcements that would allow the Port to increase its grid connection from 7 MW to 160 MW would require network upgrades across the southeast as far as London, at significant cost, requiring Government support.

There are currently two hybrid vehicles at the port, but their batteries are charged by diesel engines since there is no opportunity to charge from the grid at either Dover or Calais. Eventually battery improvements may allow vessels to only need to charge at one port for a round trip, and Calais is likely to be chosen since it is currently upgrading its electricity connection, while upgrades for Dover are years away. Furthermore, the cost of charging vessels in France does not include taxes, so is cheaper than charging in the UK.

In parts of the UK, distribution networks are already at maximum capacity...

Infrastructure challenges provide further electrification headwinds
Beyond cost, the electrification of industry faces major technical and system-level challenges. The most immediate is the limited capacity of the existing electricity grid, particularly at the distribution level where many industrial sites are connected. Grid connection queues now stretch for years, and even where connections are available, local networks may lack the headroom to support large new electrical loads such as furnaces, electrolytic processes or heat pumps. Reinforcing substations and transmission lines requires lengthy planning and consenting procedures, meaning industrial electrification projects risk stalling long before construction begins[81].

...implying major reinforcements are needed before large industrial electrification can proceed

Renewable generation responds to the weather rather than to patterns of electricity use. When strong winds coincide with low overnight demand, fewer conventional generators tend to be online, which reduces the system's ability to keep voltages within normal limits. At the same time, the rapid growth of smaller, embedded generation connected to local networks has steadily increased the amount of electricity being pushed up into the transmission system from low voltage networks, further contributing to high-voltage conditions[82]. During the summer minimum period faults on the system could lead to issues with high voltage step change and potentially risk breaching the high voltage limits.

81 http://web.archive.org/web/20240604231020/https://nic.org.uk/app/uploads/Final-NIA-2-Full-Document.pdf

82 https://www.neso.energy/document/262316/download

Conversely to minimum demand, should annual peak electricity demand increase, as would be expected under an electrification scenario, there would be additional challenges in ensuring that the voltage remains within limits during significant networks faults. During a fault on the network, the number of circuits that transfer power from one area to another can reduce, which increases the power flow on remaining circuits potentially causing voltage depression requiring voltage support.

Large industrial loads introduce voltage instability, harmonics and flicker that can disrupt both site operations and the wider network…

The transmission system sees various loading patterns and system characteristics at different times during the day and throughout the year. This creates particular operational challenges during yearly extremes eg minimum demand during overnight or sometimes in the middle of the day in summer as a result of the high penetration of solar generation, or during winter cold snaps. While there has always been a requirement for sources of voltage control, in low demand periods there is not always enough conventional generation running due to lack of demand, and this reduces the most reliable sources of voltage control.

Large industrial loads can cause local voltage dips and harmonic distortion, while their rapid ramping can destabilise nearby networks. In some regions, these concerns have already led network operators to limit new high-demand connections or impose restrictions on operating hours, directly undermining the reliability and competitiveness of industrial processes. Industrial electrification often requires significant on-site investment in voltage-control and power-quality equipment to protect sensitive processes and ensure compliance with grid-connection standards.

…requiring costly on-site compensation equipment and tighter operating constraints

Large electrical loads such as motors, arc furnaces, compressors, and variable-speed drives can cause voltage fluctuations (flicker), harmonics, and voltage imbalances that disrupt both the facility's own operations and the wider network. Flicker is a visible manifestation of rapid voltage changes on an electrical supply, often perceived as the unsteady or fluctuating brightness of lighting. It arises when large or variable loads, such as arc furnaces, welding equipment, or large motors starting and stopping, cause momentary dips or rises in voltage that propagate through the local network. Although flicker rarely damages equipment directly, it is a serious power-quality problem because it creates discomfort for workers, disrupts visual tasks, and can trigger nuisance trips or malfunction in sensitive control systems. It can also create problems externally on the power grid[83].

Persistent flicker also indicates instability in the local voltage profile, which can affect neighbouring consumers and lead to regulatory breaches of network voltage-quality standards. For these reasons, industrial sites with rapidly varying electrical loads are often required to install dynamic compensation systems to stabilise voltage and eliminate flicker at source. Industries and network operators typically install a range of equipment including automatic voltage regulators, harmonic filters, static VAR compensators ("SVCs"), static synchronous compensators ("STATCOMs"), capacitor

83 https://www.epri.com/research/products/1020280

banks, and dedicated transformers designed to stabilise supply under dynamic load conditions[84]. These systems are essential not only to meet voltage-fluctuation limits but also to prevent damage to sensitive equipment and avoid breaching distribution-network operating agreements.

As electricity supply becomes more weather-dependent, electrified industrial demand becomes increasingly exposed to periods of low renewable output…

…exacerbating voltage-control challenges and peak-period stress

A further constraint lies in the limited availability of generation capacity, particularly during periods of low renewable output. As industries electrify, their demand becomes directly exposed to the intermittency of wind and solar generation. Without a significant expansion of firm, synchronous generation or storage, large-scale industrial electrification would increase strain on the system during peak periods and could necessitate rationing or curtailment, which is likely to drive the need for reliable onsite backup generation that will tie up capital. The current market framework is designed around variable generation and short-term balancing, offering little incentive to provide long-term, high-reliability power at industrial scale – this is evidenced by the poor performance of large new generators in the capacity market versus smaller units. Unless these structural issues are addressed, the promise of low-carbon electrified industry risks colliding with the practical limits of grid capacity and system stability.

Without stronger policy interventions, electrification targets will be missed

Persistently high electricity prices will continue to undermine electrification goals. While the Government continues to assert that gas is expensive and volatile, and that it is necessary for both energy security and affordability to "get off gas", the inconvenient truth is that gas was only expensive briefly and it is almost always cheaper to generate electricity with gas than wind and solar, once the full costs to consumers are included.

The inconvenient truth is that gas as only expensive briefly…

…it is almost always cheaper to generate electricity with gas than wind and solar, once the full costs to consumers are included

The most recent completed round of the Contracts for Difference subsidy for renewables, Allocation Round 6 ("AR6"), saw onshore wind and solar price just a little below the gas-based wholesale price of electricity (in £2024), while offshore wind was 13% higher. Despite this premium, Ørsted cancelled[85] Hornsea 4, the flagship project of the auction, on the basis that it was uneconomic. Once the costs of backup, grid connection and reinforcement, and real time balancing are factored in, gas was cheaper than any of the renewable generation technologies awarded contracts in the auction. AR7 is currently underway with an expectation of even higher prices[86].

Contracts for Difference strike prices (£2024)

84 https://www.hitachienergy.com/content/dam/pg/countries/indonesia/docs/2-1-edw-id20241030-power-quality-for-industries_dhannywijaya.pdf

85 https://orsted.com/en/company-announcement-list/2025/05/orsted-to-discontinue-the-hornsea-4-offshore-wind--143901911

86 https://watt-logic.com/2025/07/27/asps-for-ar7-prove-renewables-are-not-cheap/

£2024	Auction Year	Offshore Wind	Onshore Wind	Solar PV
AR1	2015	163.10	114.27	91.69
AR2	2017	86.59	n/a	n/a
AR3	2019	56.68	n/a	n/a
AR4	2022	52.05	59.18	64.09
AR5	2023	n/a	72.87	65.49
AR6	2024	82.04	70.93	69.77

Source: UK Government, CFD auction results

Intermittent renewables are more expensive than generating electricity with gas

Only briefly in 2022 was it more expensive to generate electricity using gas, and there were net payments from renewable developers to consumers under the Contracts for Difference Scheme. However, more than two decades of cheap gas before this, meant that even after the costs of the gas crisis stimulated by covid and the Ukraine war, British consumers spent almost £220 billion more in today's money by transitioning to renewables, than if they had continued to use fossil fuels for electricity generation[87].

Wind subsidies began in 1990, yet 35 years later, subsidy levels are rising with contracts now being extended to 20 years

It is now expected that 2026 will see a return to the low and stable gas prices of the years before the gas crisis as new LNG projects see the global gas market return to length[88].

Ordinarily, these lower gas prices would translate into significantly lower wholesale electricity prices for Great Britain, given that the marginal generator on the system is still almost always a gas-fired generator. Yet the UK will be unable to fully benefit from this relief because policy continues to force an aggressive build-out of subsidised renewables while simultaneously squeezing the economics of the thermal fleet, and inflating the cost of carbon dioxide emissions which now account for almost a quarter of the wholesale power price.

Not only do capital costs of renewables need subsidy, so do their network connections

As more wind and solar enter the system without corresponding investment in firm generation, dispatchable gas units are running fewer hours and recovering a smaller share of their fixed costs, even though they remain essential for keeping the lights on during periods of low wind.

This raises the effective cost of renewables, because it becomes more expensive to secure the gas power stations needed to provide backup – they run for fewer hours in the normal market, so are less able to cover their fixed costs, meaning the cost they must be paid to remain in the open via the Capacity Market increases.

A North Sea oil or gas field must pay for its own connection (pipelines) to the shore - but for windfarms these connections are paid for directly by consumers

87 https://watt-logic.com/2025/05/19/new-report-the-true-affordability-of-net-zero/
88 https://www.energymarketprice.com/home/en/news/1176394

Power grid implications: competing pressures from electrification and deindustrialisation

Despite very different narratives, NESO's scenarios show remarkably little divergence in electricity demand...

Impact of electrification on electricity demand

In the past year or so, a consensus has emerged that electrification will be the main route to decarbonisation, with hydrogen and carbon capture playing much more limited roles than was previously believed (and that is anticipated in the various decarbonisation strategies which largely predate this new consensus). This new expectation is reflected in NESO's Future Energy Scenarios, 2025.

...raising questions about how uncertainty is being treated

What is striking from the data used in the FES is how little variation in electricity demand from heating, transport, industry and data centres there is. Given the high levels of uncertainties, the first decade of forecasts show remarkably little variation across the scenarios, even for Falling Behind which most closely resembles the counterfactual which made a brief appearance in FES 2024 there is little difference against the other trajectories.

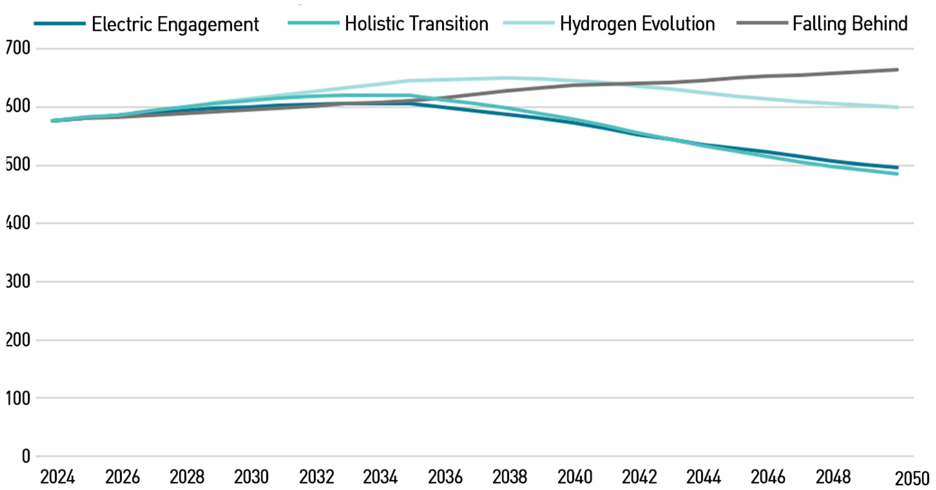
It's also interesting that in the early years of the forecasts, electrification drives higher electricity demand, but in the later years there is an assumption that increased efficiency will lower demand.

In all scenarios, electrification initially increases electricity demand...

...but later years assume large efficiency gains reverse this effect...

...these assumed efficiency improvements are not clearly tied to identifiable policy or technology drivers

Electricity demand for heating, transport, industry and data centres (TWh)



Source: NESO Future Energy Scenarios, 2025

Heating

NESO projects declining energy demand for heating even as heat pump deployment rises sharply...

NESO assumes demand from heating falls across all scenarios. Holistic Transition, Electric Engagement and Hydrogen Evolution all show large declines in heating energy demand, falling by 50–65% by 2050. Falling Behind shows only a modest decline (~15%), despite having essentially the same: population, weather, floor area, comfort assumptions (not differentiated in FES), and underlying heat-service need. The report does not identify any scenario-specific behavioural or demographic driver that would justify these differences.

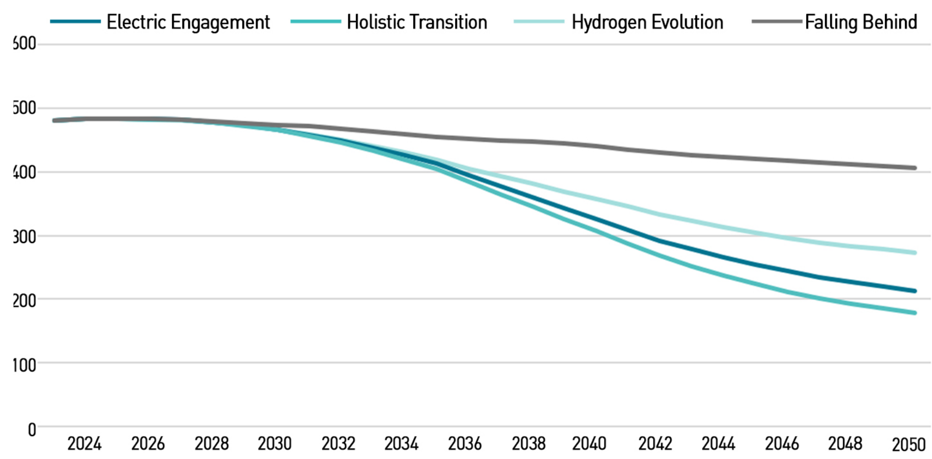
...in net zero–compliant scenarios heating energy falls by 50–65% by 2050...

NESO does not expect any significant increase in air conditioning demand even in the later years in most scenarios except Falling Behind where air conditioning penetration reaches 40% in 2050. This is somewhat curious – while Faling Behind is not intended to be a counterfactual, it does most closely resemble a "do nothing" scenario, so it is debatable whether high air conditioning uptake would really be consistent.

...far more than can be explained by insulation or behaviour alone

It is unfortunate that NESO only adopted a true counterfactual scenario in 2024. Good arguments can be made that air conditioning uptake will be high across all scenarios, and people will not be willing to sacrifice comfort levels. The Energy Demand Research Centre, expects a major increase in home air conditioning from 1 million units today to 18 million by 2050[89].

Electricity demand for heating (TWh)



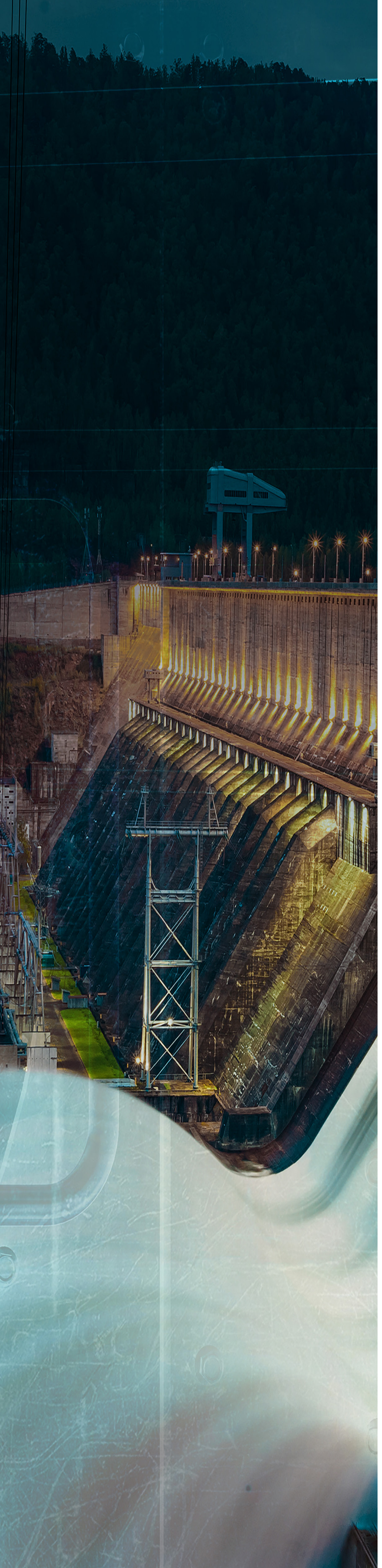
Source: NESO Future Energy Scenarios, 2025

Scenarios with similar heating technology stocks show very different total energy consumption...

...this implies materially different comfort levels or building performance assumptions that are not documented in the FES

Reductions in demand from insulation do not explain variation in demand across the scenarios. NESO attributes the pre-2030 dip in household heating demand to lower thermostats during the 2022 price shock, but this behavioural effect is assumed to unwind completely by 2030. The continued and widening divergence in heating demand after 2030 therefore cannot

89 https://www.edrc.ac.uk/research/projects/residential-air-conditioning-demand-futures-radfutures/

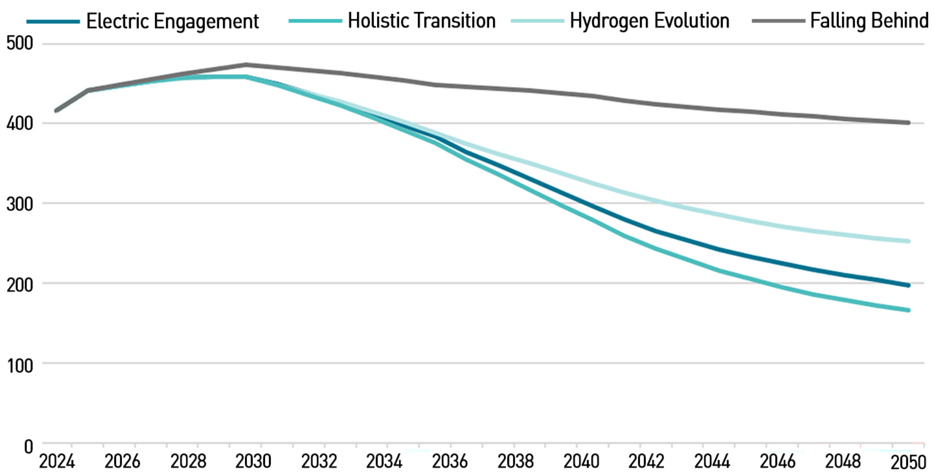


be explained by thermostat behaviour and instead indicates inconsistent or hidden modelling assumptions across the FES scenarios.

Heat pump stock rises sharply in all net zero compliant scenarios, although heat pump efficiency varies. NESO models heat-pump efficiency as if the UK determines global technology progress, installer competence, and system design practices, when in reality the UK is a tiny market with almost no influence on global heat-pump development.

This adds noise into the resulting demand expectations for heating, creating spurious differences across scenarios. Gas boiler stock falls while district heating grows in some scenarios but not others. These stock profiles are internally similar across scenarios for long periods. Across the scenarios, total delivered heating energy diverges significantly after 2030. The net zero compliant pathways show large drops in energy consumed, while Falling Behind shows only a mild decline.

Heating demand net of insulation and behavioural change savings (TWh)

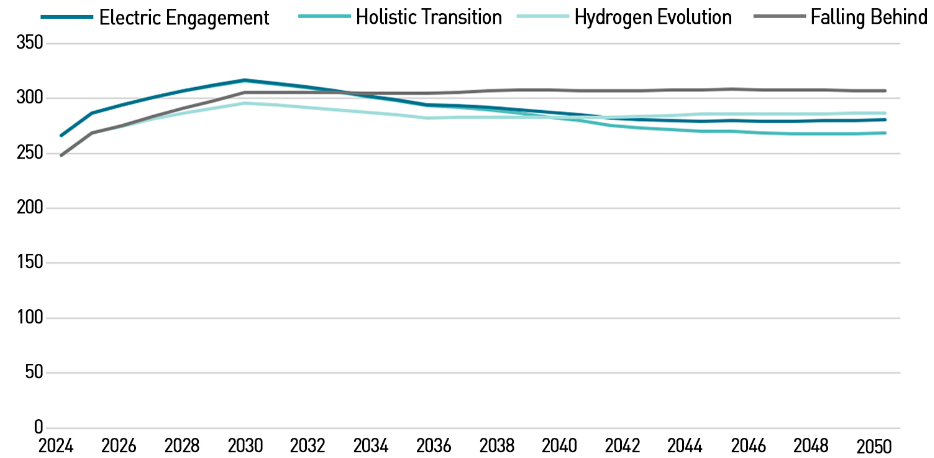


Source: NESO Future Energy Scenarios, 2025

If heating stocks are similar but the energy consumed is very different, then the delivered heat per household is different and comfort levels are different. The FES scenarios do not start from a common 2023 heat baseline - two scenarios Holistic Transition and Electric Engagement assume around 266 TWh useful heat, while the other two Hydrogen Evolution and Falling Behind, assume around 248 TWh, about a 7% difference in the very first year.

Since appliance efficiencies in 2023 are identical across scenarios, this implies different comfort/building assumptions baked into the FES data even before the scenario narratives diverge. This implies different heating levels or building fabric across the scenarios that is not set out or justified in the assumptions. These differences dominate total heat demand by 2040–2050, yet are not documented anywhere.

Delivered heat (TWh)



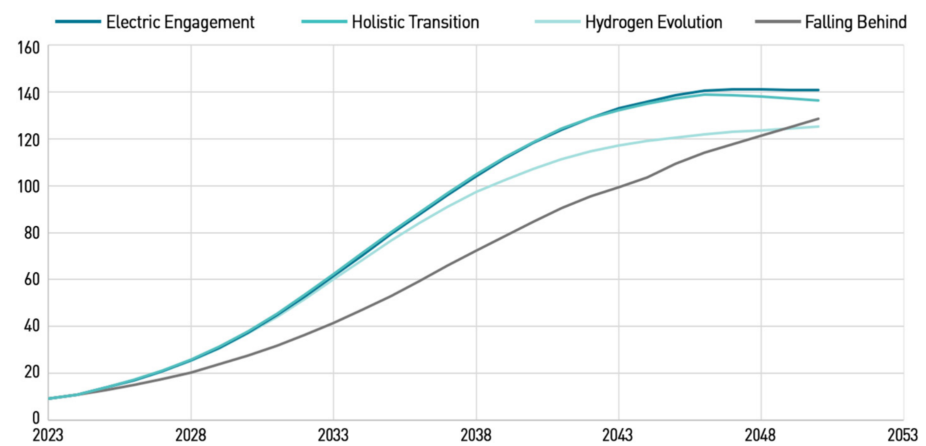
The efficiency levels used are set out in Appendix 1

Source: NESO Future Energy Scenarios, 2025, Watt-Logic

Transport

NESO expects electricity demand for transport to increase significantly across all scenarios to 2050.

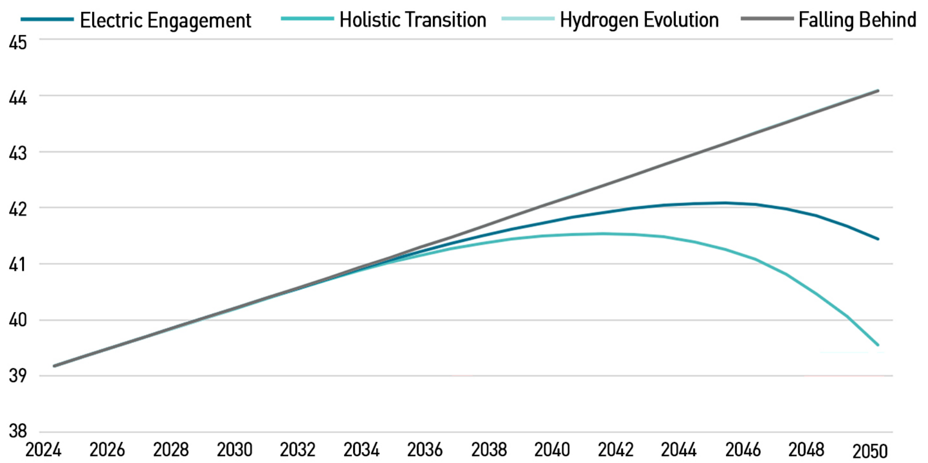
Electricity demand for road and rail transport (TWh)



Source: NESO Future Energy Scenarios, 2025

However, there are some questionable things within the data. For example when the number of vehicles and energy consumption for vehicles are analysed, they suggest some interesting trends in travel habits. Vehicle numbers across all scenarios grow until the mid-2030s, but then decline in the Electric Engagement and Holistic Transition scenarios (the Hydrogen Evolution and Falling Behind scenarios are almost identical in vehicle number projections).

Number of vehicles (millions)



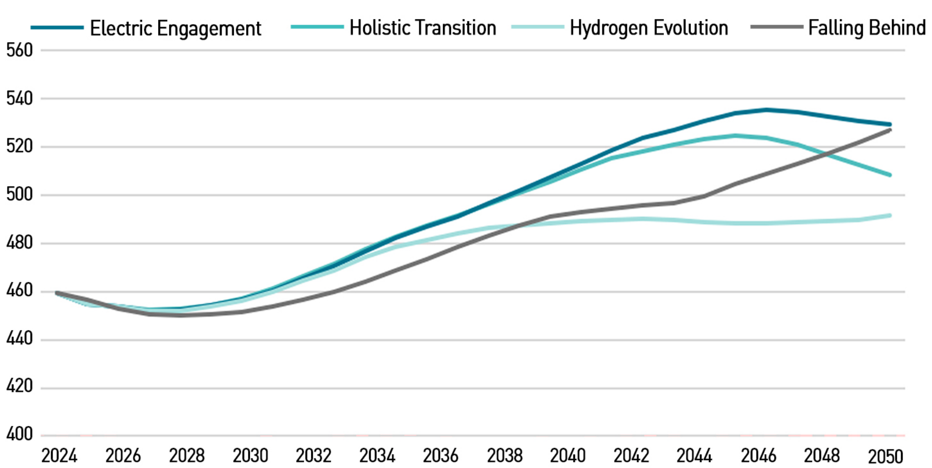
Vehicles include electric, hydrogen, natural gas and internal combustion engine vehicles

Source: NESO Future Energy Scenarios, 2025

The vehicle numbers and energy consumption data can be used to imply the distance travelled under each scenario in each year. This shows that NESO assumes a reduction in mobility in the next few years, and then increases across all modes of transport. What's interesting is that the scenarios have varying assumptions about the amount of mobility even though no explicit behavioural or policy drivers justify these differences.

This occurs because miles travelled are an implicit balancing variable in the transport-energy-carbon framework, rather than a clearly defined or independently modelled demand input. This type of anomaly undermines the value of the resulting electricity demand forecasts since they indicate a lack of coherent underlying demand logic across the scenarios. There is no mention of any differences in mobility across the scenarios in NESO's modelling assumptions.

Distance travelled (billions of miles)



Using the FES energy consumed per vehicle type and the following conversions:
EV: 0.25 kWh/mile, Hydrogen FCEV: 1.5 kWh/mile, Natural Gas: 1.0 kWh/mile, ICE petrol/diesel: 0.9 kWh/mile

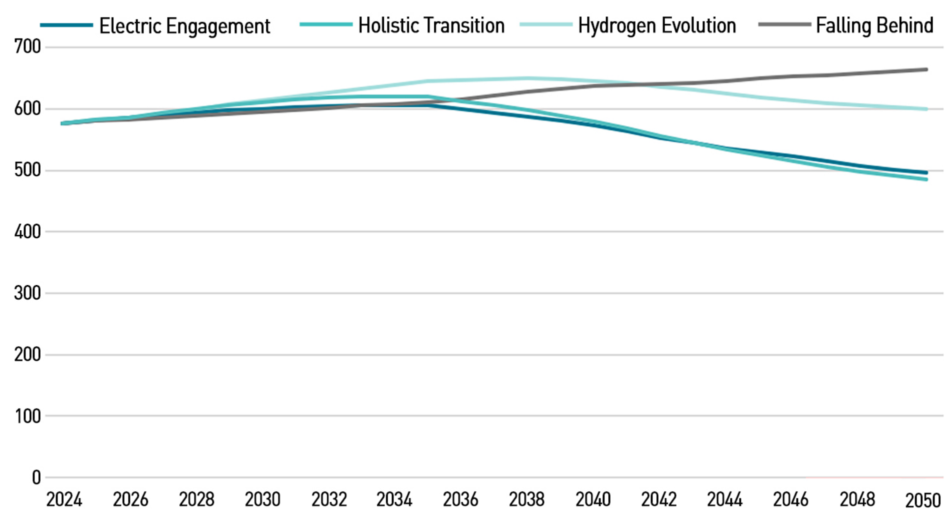
Source: NESO Future Energy Scenarios, 2025, Watt-Logic

Industry

Underlying industrial activity in the FES is consistent across the three decarbonisation scenarios (Electric Engagement, Hydrogen Evolution, Holistic Transition). All scenarios have the same 2023 baseline and by 2030 their total industrial final energy sits within a couple of percent of one another and of today. Falling Behind appears to have broadly similar industrial output, but with weaker efficiency and slower fuel-switching, so industrial energy barely falls (only about 3% down on 2023 by 2050). The higher 2050 energy use in Falling Behind is much more likely to be a result of less energy efficiency rather than higher industrial output.

Unlike in heating and transport, scenario differentiation is almost entirely about the relevant decarbonisation route. In Electric Engagement there is strong electrification of industrial demand (especially heat), with moderate industrial hydrogen, and a steep gas exit. Hydrogen Evolution shows the largest industrial hydrogen uptake, a smaller rise in industrial electricity, and steep methane exit. Holistic Transition has a balanced mix of hydrogen and electrification. Falling Behind has slower efficiency improvements and decarbonisation, retaining much more industrial gas and lower overall fuel-switching.

Electricity demand for industry (TWh)

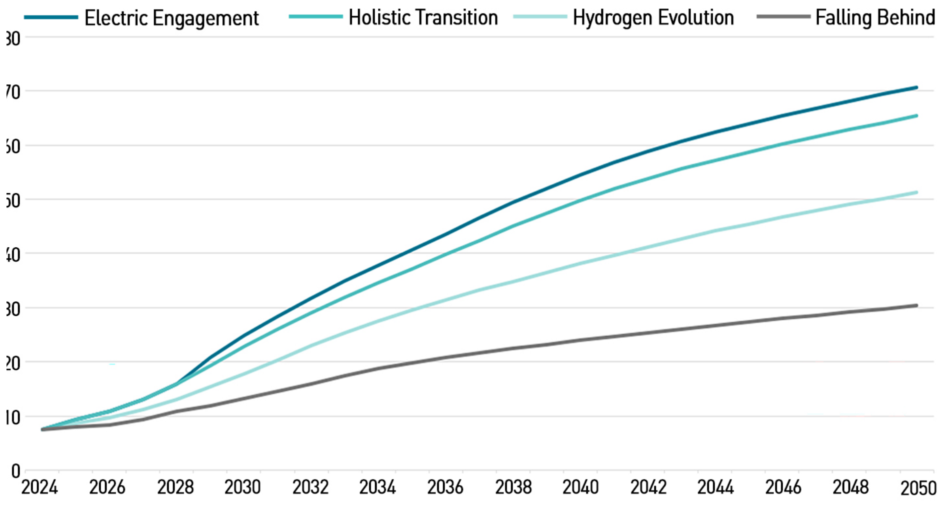


Source: NESO Future Energy Scenarios, 2025

Across all four FES 2025 pathways, data centre electricity demand rises extremely rapidly and becomes a system-scale load by the 2030s. Demand grows from 7.4 TWh in 2023 to between 30 TWh (Falling Behind) and more than 70 TWh (Electric Engagement) by 2050, a four- to nine-fold increase. Even by 2030, demand reaches 18–25 TWh in the electrification-led scenarios, equivalent to around 2–3 GW of continuous load.

This represents a shift in data centres from a marginal to a material share of national electricity use: from roughly 2–3 % of total demand today to 7–10 % by the mid-2030s in the higher-growth pathways. The FES therefore treat data-centre expansion as a structural, sustained driver of electricity demand growth, with significant implications for network sizing, location of new transmission investment, and the overall adequacy and flexibility requirements of the GB power system.

Electricity demand for data centres (TWh)



Source: NESO Future Energy Scenarios, 2025

Impact of electrification on distribution grids

The greatest strain from electrification will fall on low-voltage distribution networks because heat pumps, EV chargers and rooftop solar connect locally

The transition to widespread electrification of heat and transport places the greatest strain not on the national transmission system, but on the low-voltage distribution networks where most new load connects. Several recent independent studies show that today's distribution networks which were originally designed for after-diversity domestic loads of 1-2 kW per property, are structurally incapable of accommodating mass uptake of heat pumps, EV chargers and rooftop generation without major reinforcement.

UK distribution networks were built for domestic loads of just 1–2 kW per property...

Critically, these constraints are highly localised - electrification stresses occur at the level of individual feeders, substations and street circuits, meaning national averages obscure the true scale bottlenecks. A 2022 BEIS study on low voltage network capacity concluded that peak electricity demand is "very likely to increase rapidly over the next thirty years", even after assuming widespread smart charging and appliance response[90].

...and are structurally incapable of supporting widespread electrification without major reinforcement

The report identifies a wide range of interventions that will be unavoidable under full electrification, including uprating local substations and pole-mounted transformers, replacing or reinforcing low voltage mains and service cables, unlooping properties, meshing formerly radial networks, and rolling out real-time LV monitoring and voltage control.

Distribution networks contain millions of assets, making them the most expensive section of the electricity system

It also notes that because the distribution grids are the largest part of the system, with millions of individual assets, many of them underground, it is already "the most expensive section of the network to maintain", and electrification will require upgrades at unprecedented scale.

Electrification pressures emerge at the level of individual feeders, substations and street circuits...

The most comprehensive recent modelling comes from the National Infrastructure Commission ("NIC") and its technical partners Regen and EA Technology, whose Electricity Distribution Networks – Creating Capacity for the Future analysis quantifies the scale of work required. They project that winter peak demand could rise from today's 57–58 GW to 108–119 GW by 2050, with "the majority of additional load-related expenditure required on the low-voltage network,"[91].

...national averages significantly understate the scale of bottlenecks

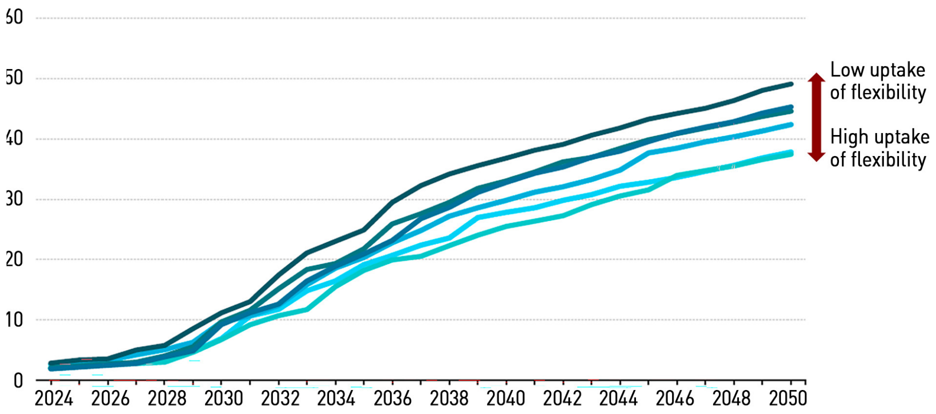
The NIC estimates that £37–50 billion of cumulative distribution-network investment will be needed between 2024 and 2050 to meet net-zero electrification, explicitly excluding the 132 kV system and therefore representing a conservative figure. Even under optimistic assumptions about consumer flexibility, DESNZ estimates that smart response can only reduce required distribution investment by around 15%, corresponding to savings of £6.7–7.9 billion, implying that the underlying need is structurally large[92].

90 https://share.google/TnoTsVuHKmr0lhJho
91 https://www.biee.org/nic-electricity-distribution-networks-creating-capacity-for-the-future/
92 https://share.google/KJzcCFrmE2EoINHtu

NIC modelling suggests winter peak demand could rise from around 58 GW today to over 110 GW by 2050...

...with most new expenditure on low-voltage networks

Cumulative load related expenditure from 2024 to 2050 (£billions in £2024)



Source: National Infrastructure Commission

Even under optimistic assumptions, smart charging and demand response reduce distribution investment needs by only around 15%, leaving the majority of reinforcement costs unavoidable

EA Technology found that "while flexibility can play a crucial role in managing peak demand, physical network upgrades will still be necessary to achieve net zero by 2050, especially in rural and suburban areas with high concentrations of heat pumps and EVs"[93]. It also found that network constraints vary significantly depending on location, customer distribution, and load types. Urban networks benefit from existing infrastructure for network reconfiguration, but rural networks are more likely to require significant transformer upgrades. The cost estimates may under-estimate the true need. They exclude climate-resilience upgrades, and may capture all "clustering" risks where several heat pumps or EV chargers connect on a single feeder, and assumes strong uptake of smart-flexibility behaviours that may not materialise.

The £37–50 billion distribution-network investment estimate should be seen as a lower bound: actual requirements are likely higher

Taken together, the evidence indicates that full electrification will require a substantial rebuild of parts of the distribution networks, on a scale and cost not yet fully reflected in current regulatory settlements. The "RIIO" price control for networks only covers five-year horizons and does not address the structural doubling of national peak demand or the long-term low voltage reinforcement needs associated with heat pumps and EVs. The NIC recommended that Ofgem should base future price controls on long-term distribution network needs. Given the uncertainties around consumer flexibility, the costs of civil works, and the rate of electrification uptake, the £37–50 billion range should be regarded as a lower bound, with actual investment requirements plausibly higher, and certainly higher than government or industry narratives often assume.

Deindustrialisation impacts industrial demand more than electrification

UK industrial electricity demand has been in long-term decline since the 1970s,...

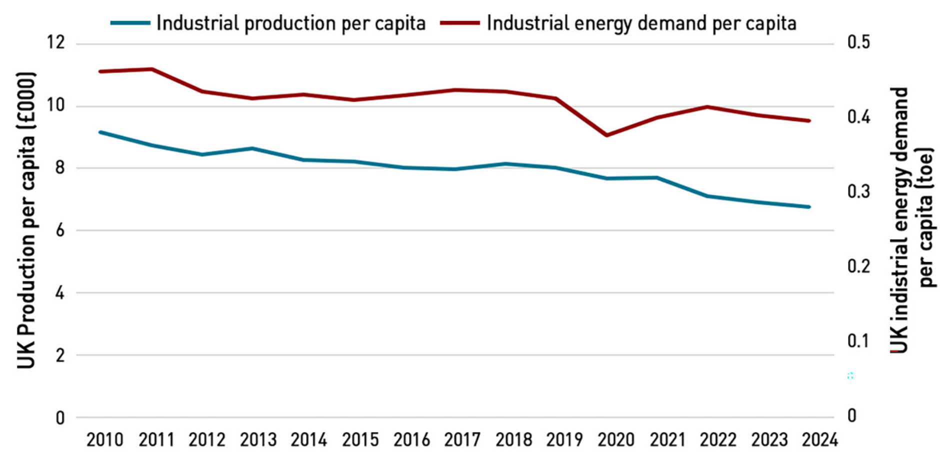
The impact of high electricity prices can be seen in UK industrial and domestic energy demand data. Despite long-term population growth, industrial demand has fallen consistently since 1970, and domestic demand grew until around 2005 but has since declined. Interestingly, demand grew faster than population during the 1980s and 1990 despite schemes to improve insulation to reduce heat losses in homes, but the more recent falls are more likely driven by concerns over the cost of living. The reasons for the reduction between 2014 and 2016 are not well understood[94].

...reflecting structural deindustrialisation rather than efficiency gains or recent electrification trends

The move to LED lighting is likely to have made some impact, as well as the improved efficiency of white goods and other household appliances. However, electricity demand for home electronics and computers was up 17% and 45% respectively between 2004 and 2012. More significant from an overall domestic energy consumption standpoint is likely to be the increasing switch to more efficient condensing boilers during this period.

93 https://eatechnology.com/news-blogs/blogs/2025/preparing-great-britain-s-distribution-networks-for-net-zero-the-local-challenge/
94 https://www.carbonbrief.org/a-detailed-look-at-why-uk-homes-are-using-less-energy/

Industrial and household energy demand vs population trends



Source: Government data[95], Office for National Statistics[96]

Industrial output in the UK has declined significantly in the past decade, falling 14% on a per capita basis. There has been a corresponding decline in industrial energy demand reflecting the impact of de-industrialisation. This trend has continued in 2025. The UK's manufacturing goods-producing sector is experiencing steep job and export losses: in April 2025, the S&P Global Manufacturing PMI for the UK stood at 45.4, with the survey noting the "steepest decline in manufacturing employment of all 31 economies surveyed"[97]. It went on to say that the UK is seeing "the steepest rate of job losses and the fastest rate of export order losses" while "UK factories are reporting the highest goods price inflation of all economies surveyed globally, and a supply chain that is suffering from delays to a greater extent than all other economies bar only war-torn Myanmar".

Among energy-intensive industries, including basic metals, petrochemicals, paper and inorganic non-metallics, output is now at its lowest level in 35 years. The Office for National Statistics reports around a 33% drop in EII production since 2021, citing the UK's high industrial electricity prices and reliance on gas-fired marginal pricing[98]. It said the production of paper, petrochemicals, basic metals and inorganic products such as cement and ceramics was in 2024 at its lowest level since 1990. High energy costs have been a significant factor in several large closures. A production report by Make UK flagged "eye-watering energy costs" as one of the top three obstacles for manufacturers, alongside tax and supply-chain issues[99].

As industrial electricity and gas costs become a structural competitive disadvantage, the industrial base is either retrenching or relocating, reducing large-scale power loads in the system. Fewer heavy-industry users means lower baseload demand, but also reduces the industrial anchor that justifies grid investment and capacity utilisation – this has knock-on implications for grid cost allocations and system resilience. From a supply-demand balance perspective, the disappearance of large industrial loads might superficially ease the supply side, but it raises structural risks as there are fewer flexible loads, less sector-coupling upside, and greater reliance on residential /heating loads which are often cold-weather-sensitive.

This matters – NESO, Ofgem and DESNZ all believe that flexibility will be an important tool in managing peak demand in future years, minimising the need to precure backup for intermittent renewables and reducing the need for grid expansion. However, in recent years the amount of flexibili-

95 https://www.gov.uk/government/statistics/energy-consumption-in-the-uk-2024
96 https://www.ons.gov.uk/peoplepopulationandcommunity/populationandmigration/populationestimates
97 https://www.spglobal.com/market-intelligence/en/news-insights/research/2025/05/uk-manufacturers-report-steepest-job-and-export-losses-of-all-economies-surveyed-may25
98 https://www.ft.com/content/a4301149-af90-4dc8-a4dc-250a98da509d
99 https://www.makeuk.org/insights/reports/manufacturing-outlook-2025-q2

ty procured has collapsed[100]. Under the now defunct “triad avoidance” approach to minimising network costs, National Grid ESO was able to procure on average 2 GW of flexibility from industrial and commercial consumers. These have almost entirely left the flexibility market under the new Demand Flexibility Service, which instead procures roughly 200 MW from primarily domestic consumers.

Energy-intensive sectors have seen production fall by around a third since 2021…

There are also ethical considerations: utilities exist to serve the needs of consumers. It’s dangerous to start thinking that consumers should serve utilities, and this type of thinking can lead to a range of harms to vulnerable consumers, for example pushing them into nocturnal living because that is when energy is cheaper, despite the health detriments, and exposing them to fire risk. Less affluent consumers are overwhelmingly more likely to own older, cheaper and less safe appliances. Encouraging people to, for example, do laundry at night, exposes such people to a choice between leaving their appliances unattended, with the associated fire risk, or adopting nocturnal living. There are other social considerations, since many multi-occupancy buildings forbid the use of such appliances overnight to avoid noise nuisance.

…high electricity prices are repeatedly cited as a decisive factor in closures and relocations

While long-term infrastructure and policy modelling often assume continued growth in industrial electricity demand (driven by electrification and decarbonisation), recent data and sector commentary indicate that the opposite trend - a net reduction in demand from industry - is a credible scenario. For example, the industrial sector’s final energy consumption fell by 1.2% in 2024 to 19.5 mtoe, pointing to contraction as well as efficiency gains[101].

The loss of large industrial loads lowers overall electricity demand but also removes flexible, high-load users that historically underpinned grid utilisation, cost recovery and system resilience…

The implication is that the expected large industrial loads which underpin electricity-system utilisation and cost recovery may not materialise, reducing demand pressure on supply-side planning, but also weakening the industrial anchor of the system - costs are spread over fewer users further discouraging electrification. Furthermore, modelling[102] suggests many industrial sites may actually require less electricity in future than they do today, which means second-order effects for grid investment, utilisation and cost allocation. Other sites may be constrained by substation capacity.

…as well as providing almost all of the demand-side flexibility

The interplay between industrial contraction and electrification means the electricity demand projection for the industrial sector is subject to bifurcation: a high-demand pathway if new industrial loads scale, or a lower-demand pathway if deindustrialisation dominates. With evidence of the latter gaining traction (via energy cost pressures and output declines in heavy industry), it is prudent for supply-demand modelling to incorporate a downward risk scenario for industrial electricity demand.

100 https://watt-logic.com/2024/12/29/falling-dsr-participation/

101 https://www.gov.uk/government/statistics/energy-consumption-in-the-uk-2025/energy-consumption-in-the-uk-ecuk-2025

102 https://ukerc.ac.uk/news/will-electricity-network-constraints-hamper-the-decarbonisation-of-uk-industry/

CCGT retirement risk

Name	Operator	Commissioning Date	Capacity	GT's	Comment	Retirement Range	
Peterborough	Whitetower Holdings	1994	245	2 x9E	Whitetower is owned by Rockland Capital. Converted to OCGT in 2018	2026	2029
Corby	EP UK Investments	1994	410	2x 9E	Website says: Currently the site is heading towards cessation of generation, however EP will be looking at options to repower.	2027	2028
Little Barford	RWE	1995	740	2x 9FA	In 2013 it had an upgrade to take plant life to 2025	2027	2031
Connahs Quay	Uniper	1996	1380	4x 9FA	No evidence of upgrade other than control software in 2011	2027	2034
Medway	SSE	1995	760	2x 9FA	During a major upgrade project in 2012 the power station benefitted from the GE DLN 2.6 install as well as an upgrade to the excitation and turbine control system.	2028	2032
Keadby 1	SSE	1996	740	2x 9FA	Mothballed 2013-2015. No record of upgrades	2028	2034
South Humber Unit 1	EP UK Investments	1997	750	3 x GT13E2	No evidence of upgrade	2028	2032
Rocksavage	Intergen	1998	810	2 x GT26A	No evidence of upgrade	2028	2032
Cottam	Uniper	1998	450	1 x V94.3A	No evidence of upgrade	2028	2032
Saltend	SSE	2000	1200	3 x 701F	CHP - power to the GB grid, and power and steam to the adjacent Saltend Chemicals Park. No evidence of upgrade other than control software in 2018	2028	2034
South Humber Unit 2	EP UK Investments	1999	510	2 x GT13E2	U2 secured a refurb contract in the T-4 auction for 2028-29, but so far, no evidence of FID. If the refurb goes ahead EOL will be 2041 - 2045	2029	2033
Sutton Bridge	Calon	1999	850	2 x 9FA	Mid 2000s upgrade but no turbine replacement	2030	3032
Seabank	SSE	2000	1230	3 x V94.3A	No evidence of upgrade	2030	2035
Damhead Creak	VPI	2000	810	2x 701F	No evidence of upgrade	2030	2035
VPI Immingham	VPI	2004	1250	2 x 9FA +1 x 9FB	No evidence of upgrade	2030	2038

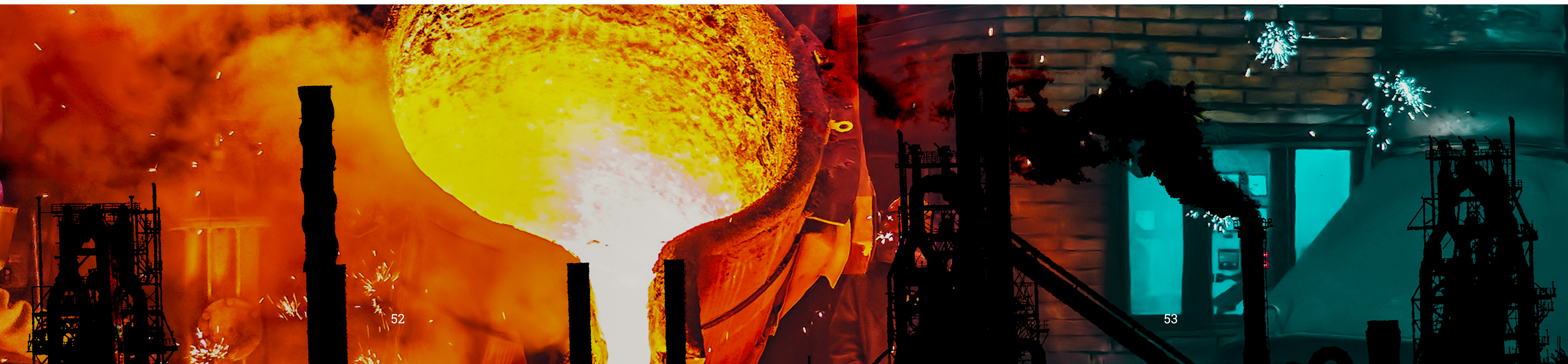
Retirement range assumes ~30-35 year mechanical life (200 000 EOH / 6 000 ES) under extended-peak duty, unless major upgrades documented

Source: Company information, Watt-Logic

Retirement of legacy assets likely to accelerate

Britain’s fleet of CCGTs is ageing with a third built in the 1990s

An under-reported risk to the power grid relates to the age of legacy assets both in generation and grid infrastructure. A third of the GB fleet of combined cycle gas turbines (“CCGTs”) was built in the 1990s, and while most received upgrades in the 2000s, in most cases this did not involve



Anticipated retirement dates are approaching with no replacement plans in place

Replacement timelines are dangerously long...

...new gas turbines face lead times of 7-8 years

replacing rotors, and so did not materially increase asset life. This means the **anticipated retirement dates are becoming imminent, and there is no replacement and minimal upgrade plans in place, putting just over 12 GW of capacity at risk**. This is a problem. Currently the lead time for a new gas turbine is between seven and eight years, with industry sources pointing to five year lead times for new rotors and up to 18 month for the components needed for major maintenance. With such long lead times, securing the equipment needed to upgrade or replace the aging CCGT fleet will be challenging. Even South Humber Bank and Langage which have capacity contracts may be unable to secure the necessary equipment in time, given there is no evidence the Final Investment Decisions have been taken, which would be required before equipment is ordered.

The closure of the remaining AGR nuclear reactors by 2030 removes a further 4.7 GW of firm generating capacity

In addition to the 12 GW of CCGTs close to retirement, the entire fleet of Advanced Gas Cooled nuclear reactors is due to close by 2030, representing a further 4.7 GW. This means around 17 GW of conventional, non-intermittent generating capacity could retire by the beginning of the next decade. Only one significant new generation project is on the horizon – Hinkley Point C, the new 3.2 GW nuclear plant, but this is unlikely to open before 2030. There could be another 2-3 GW of smaller open cycle gas plants opening. Taken together, the GB market is facing a net loss of around 11-12 GW, which will make meeting existing demand highly uncertain, raising the prospect of rationing, unless urgent action is taken to secure replacement capacity that is not weather dependent.

Net of new-build, 12 GW of firm capacity could leave the grid in the next 5-7 years...

...making it hard to meet demand on low wind days in winter

It is important to note that for security of supply, solar should be excluded since peak winter demand occurs after sunset so there is zero contribution by definition. Despite there being over 32 GW of wind capacity now installed, it is not uncommon for actual output to fall below 1 GW, so wind can also be close to zero. On this basis, wind and solar should be almost entirely discounted when considering the amount of secure capacity available to meet GB power demand. The short duration of batteries means they cannot be counted on to cover periods of low wind that can last for days rather than hours.

Without an urgent replacement plan, demand rationing is likely on days with low renewables output

In addition to these generating capacity risks, there are also asset life challenges on the power grid itself. There was an investment spike in the 1970s, with half of all power lines, a third of transformers and 30% of switchgear installed in that decade. While power lines have long lifetimes, transformers and switchgear can expect to be replaced after around 60 years. The replacement plans for this equipment is part of the network price controls, but regulator Ofgem routinely slashes what it calls "non-load" capex, that is expenditure that is not related to new "load" which is primarily the connection of new renewables.

A somewhat dysfunctional relationship has developed between Ofgem and the network companies – both electricity and gas - in relation to the price control, and issues concerning asset life. The North Hyde substation fire in March 2025 illustrated some of risks, with a fire in an aging and poorly maintained transformer, causing damage to an adjacent transformer, and loss of power to almost 70,000 local homes and businesses, including Heathrow Airport, with a cost of up to £150 million (£100 million of direct costs to airlines[103], plus other economic impacts).

Much of the power grid was built in the 1970...

...large volumes of transformers and switchgear are approaching replacement age just as system stresses are increasing

This incident highlights the hidden risks within the power grid[104,105]. There are others relating to the way in which some of these ageing assets are used – for example, the growth in distribution-connected solar generation means that some substations that were only designed for export from the transmission system, now flow in two directions, with rapid changes of direction during solar ramping. This places both mechanical and thermal stresses on the equipment. Little is known about how older transformers will behave under such conditions and how this may affect asset life (or indeed how it could affect newer transformers – some of the most robust grid equipment dates back to the 1950s and 1960s when equipment was routinely over-engineered).

Impact of firm power generator retirements

Power sysem risks are often modelled as being independent when in reality they are inherently linked...

The main risks of inadequate capacity arise on cold, still winter evenings, when wind output collapse and solar is absent (as it is after sunset). Cold weather also reduces both the reliability of older CCGTs, and their efficiency, reducing output when they are running, for several overlapping mechanical and operational reasons. These factors compound exactly when the system is tightest, meaning the probability of failure is not independent of stress. NESO's models often assume random, weather-independent outages, when in reality, outage likelihood rises sharply during cold snaps, particularly so-called "Beast from the East" events.

...weather systems bringing cold weather in winter often have little wind...

...so generation falls as demand risis

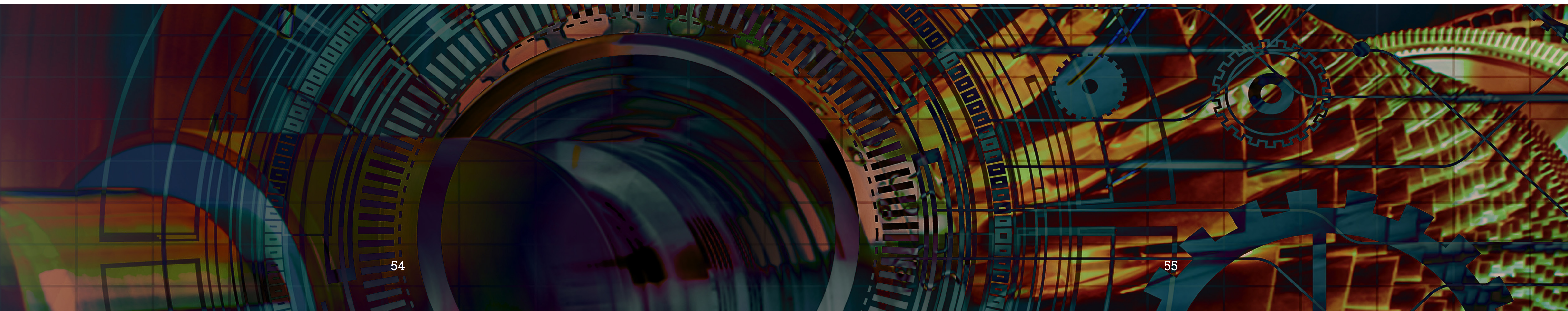
Blocking over Scandinavia and associated sudden stratospheric warming events are a recognised UK winter pattern that can deliver cold, dry, often low-wind conditions for days to a couple of weeks. The Met Office documents the 26 February to 8 March 2018 episode (an archetypal "Beast from the East"), and explains the mechanism: a Scandinavian high pressure system, easterly winds and suppressed Atlantic flow[106]. These weather events can generally be identified about a week ahead, even if the surface impacts vary, and they are not one-off curiosities - UK guidance now treats them as plausibly recurring within planning horizons to 2030, and recent government-sponsored scenario work suggests a greater propensity for cold, low-wind winters under certain circulation shifts.

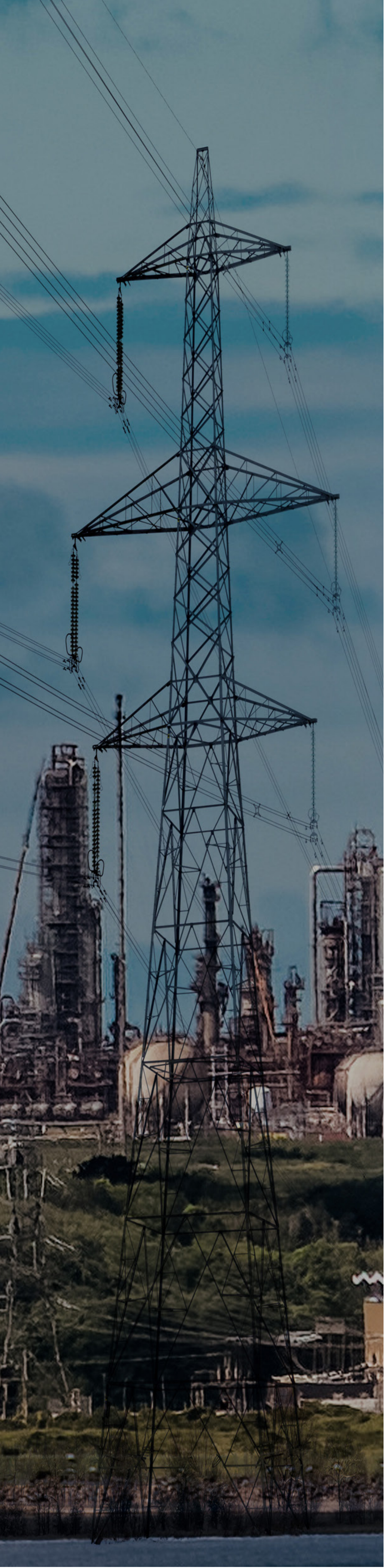
103 https://www.standard.co.uk/business/heathrow-outage-electricity-cut-power-transport-select-committee-b1220272.html

104 https://watt-logic.com/2025/03/24/heathrow-airport-blackout/

105 https://watt-logic.com/2025/07/04/north-hyde-transformer-fire-report/

106 https://weather.metoffice.gov.uk/learn-about/weather/types-of-weather/wind/sudden-stratospheric-warming



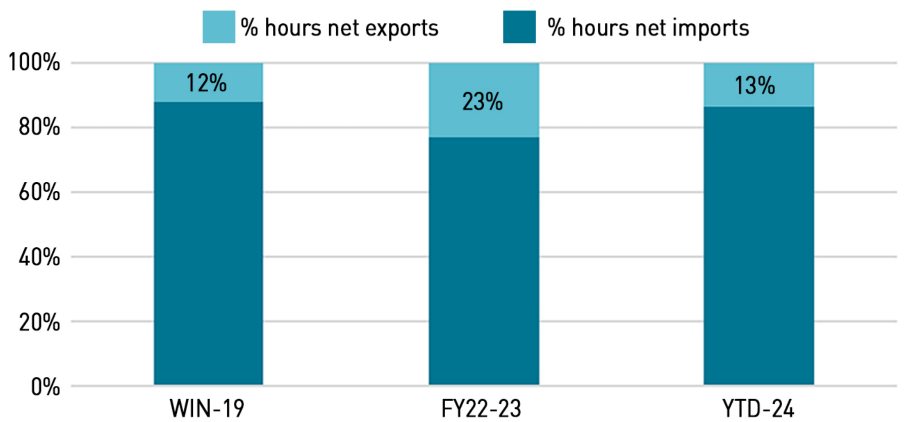


The coincidence of cold weather and still weather presents a particular risk, not just to the British power system, but those of neighbours which also follow a wind-led transition strategy, notably Denmark, the Netherlands and Germany. Prolonged periods of low wind power generation have become a significant challenge for decarbonising the electricity system. Research[107] by the University of Oxford on wind drought events in GB based on 72 years of data found that **sustained periods of low wind power generation with a duration of 14 days have an estimated return period of five years and the longest event on record of approximately 26 days is expected to occur once every 100 years**. The investigation of these wind droughts showed that they may not be particularly rare occurrences.

Imports cannot be assumed as a safety valve in those spells. During past continental stress such as French nuclear outages and cold snaps, flows have reversed, with GB exporting at times, even in winter, illustrating the risk of interconnectors contributing near-zero just when UK demand is peaking[108].

Between now and 2030, it's reasonable to expect at least one "beast-like" episode (not necessarily identical to 2018) where wind stays very low for multiple evenings and temperatures drive up demand. On those evenings, the average annual metrics used by NESO to determine the winter capacity margin are misleading - the relevant stack is the tight-hour under low wind, zero solar and uncertain imports. The Panel of Technical Experts has also warned[109] that using P50 wind assumptions on winter peak days overstates wind's contribution during stress events.

Interconnector flows during periods of high GB electricity demand



The chart indicates the number of hours during the top 5% of GB electricity demand during which GB was importing or exporting. The higher net exports in 2022-23 reflect the extensive French nuclear outages which switched France from a net exporter to a net importer. So far in 2024 interconnector activity reverted to previous trends (2020-21 were excluded due to the effects of covid). 2024 data are in 5 min intervals rather than hours

Source: BMRS, Watt-Logic

These weather conditions create tight margins because demand is higher when the contribution from renewables is lowest. But they also reduce the availability and reliability of the gas-fired generation on which the system relies under such weather conditions. These risks are amplified when much of the gas fleet consists of aging plant.

Thermal cycling and brittle fatigue

Modern F-class turbines were designed for relatively steady baseload or 1-2 daily start-stop cycles. Today's two-shifting with its multiple starts per

107 https://www.sciencedirect.com/science/article/pii/S0960148123017627

108 https://watt-logic.com/2024/12/09/renewables-and-interconnectors/

109 https://assets.publishing.service.gov.uk/media/64b5d6100ea2cb001315e436/panel-of-technical-experts-2023-report.pdf?

week means thermal stress on turbine blades, rotors, and heat recovery steam generator tubes[110]. In cold weather the metal temperature delta is larger at start-up, producing higher thermal gradients and more risk of cracking or deformation.

- Cold, dense air raises compressor pressure ratio and thrust load on bearings and seals;
- Differential expansion between hot gas paths and casings increases rubbing and vibration risk;
- Any moisture ingress (frozen drains, condensate carryover) can cause flame instability or control trips during firing.

Auxiliary system vulnerability

Auxiliaries including instrument air, fuel-gas heaters, cooling-water lines, condensate drains, are all points of failure in freezing conditions. Fuel-gas heaters may struggle if grid gas pressure drops or heater controls freeze, leading to flame-out or poor combustion.

Condenser cooling water and closed-cycle cooling systems can suffer ice formation at low ambient temperatures, especially for air-cooled condensers[111]. Air cooled condensers are used for converting steam into condensate by using ambient air. They are prone to suffer damage when the condensate inside the tubes of the heat exchanger is frozen, in particular, tubes can break during cold weather.

As temperatures drop, lube oil naturally becomes thicker and flows more slowly. This high viscosity makes it difficult for the oil to circulate quickly and reach all critical components, especially during start-up. This leads to:

- Delayed lubrication, increased metal-to-metal contact, and accelerated wear on vital parts like bearings and gears;

- Increased load and strain on oil pumps and starter motors, potentially causing pump cavitation (formation of vapor bubbles that damage pump parts);

- Increased flow resistance through filters, which can cause filter bypass valves to open, allowing unfiltered oil (and contaminants) to circulate in the system, or potentially rupturing the filter element;

- Increased risk of start-up failures as the increased resistance from the thick oil makes it harder for the turbine to turn over during a cold start, putting extra strain on the starting system.

Low ambient temperatures can also lead to condensation within the lube oil system, resulting in water contamination. In freezing conditions water can turn into ice crystals, potentially causing blockages in pipes and oil passages, leading to a complete loss of flow or even burst pipes. Ice crystals can damage machinery components as they move through the system, and the presence of water impedes the lubricating oil's performance and can promote rust and corrosion.

The additives in the lube oil, which are crucial for enhancing performance (eg anti-wear, rust inhibitors, and pour point depressants) may become insoluble and separate from the base oil in very cold temperatures, forming sludge or settling in the sump. This reduces the oil's protective qualities.

Control and sensor issues

Automated start-up sequence controls can be less reliable during cold

110 https://www.powermag.com/reducing-cycling-damage-to-combined-cycle-steam-turbines/

111 https://inis.iaea.org/records/ajva3-gme56#:~:text=An%20air%20cooled%20condenser%20is%20a%20device,in%20particular%2C%20tubes%20can%20break%20during%20winter.

weather operations. Minor faults or unexpected data from frozen instrumentation can upset the complex control logic, causing significant delays or forcing the plant to operate outside of optimal parameters. Modern digital controls trip conservatively - if readings fall outside expected envelopes, the turbine control system execute an automatic shutdown. Where cold, dry weather creates low humidity, static charges can build up rapidly on non-conductive materials. These charges can then discharge to sensitive electronic components, causing operational disruptions or permanent damage.

Risks are amplified by reduced performance of thermal plant in cold weather...

Fuel supply risk

CCGTs require a specific, consistent gas inlet pressure to the combustion chamber for efficient and stable operation. Lower inlet pressure directly limits the mass flow rate of gas that can be supplied to the gas turbine's combustion chamber. Gas turbine power output is directly controlled by the fuel flow rate and the resulting turbine inlet temperature (within limits). A lower fuel flow results in less heat input and a corresponding reduction in electrical output.

...with ageing plant having worse perfrormance with higher trip risks

Gas turbines are designed to operate most efficiently at specific design conditions, including a particular pressure ratio. Operating at non-optimal, lower inlet pressures forces the plant to run at part-load conditions, which typically leads to a notable decrease in overall efficiency. In extreme cases of low gas pressure, CCGTs may have to significantly reduce generation or even shut down completely to protect equipment and ensure the integrity of the wider gas system.

During cold spells, gas system pressure is lowest because of heating demand as more gas is taken off the system than is added. For example, the 2018 "Beast from the East" weather event saw significant impacts on the GB gas grid's inlet pressure, causing reductions in power output and efficiency in the CCGT fleet.

In a 2030 stress case with only around 24 GW of CCGT capacity available, assuming at least 1 GW of coincident unplanned loss as the modal condition during cold weather, is reasonable - not an edge case. That means a 5-8 GW supply gap becomes 6-9 GW, and if multiple trips cluster, as they tend to in frost events, the system can move from Stage 1 to Stage 2 demand control within a single settlement period.

Risks to gas grid infrastructure may threaten power supplies

Gas infrastrucutre is also vulnerable

A further concern relates to the gas grid, and its impact on the availability of gas for power generation. The gas system in GB today depends on four main supply routes into the National Transmission System ("NTS"):

The GB gas system relies on four main supply routes: the UKCS, LNG, Norwegian pipelines and interconnectors, each with distinct physical and geopolitical vulnerabilities

- The UK Continental Shelf ("UKCS"): gas from North Sea and East Irish Sea fields enters the NTS via onshore terminals at St Fergus, Teesside, Bacton, Easington, and Barrow. UKCS production has fallen from around 100 bcm /year in 2000 to around 30 bcm more recently - roughly 35–40% of GB annual demand;
- LNG imports: Milford Haven (South Hook, Dragon) and Isle of Grain can deliver a combined 130–150 mcm /day, equivalent to around half of GB's theoretical peak-day demand, but only if tanks are full and send-out is not constrained by regasification capacity, shipping delays or NTS constraints;
- Norwegian pipelines: Langeled, Vesterled, and the Tampen Link bring Norwegian gas mainly to Easington and St Fergus. Combined they can supply roughly 80–100 mcm /day, though actual flows vary with continental nominations; and
- Interconnectors: the Bacton–Zeebrugge ("IUK") and Bacton–Balgzand ("BBL") pipelines connect GB to northwest Europe. In theory they allow imports of 60–70 mcm /day. They typically export gas to Europe in the summer and import in the winter (effectively using European gas storage facilities although there are no explicit contracts behind that).

Accelerating decline in North Sea gas production risks undermining the economic and operational viability of offshore pipeline systems...

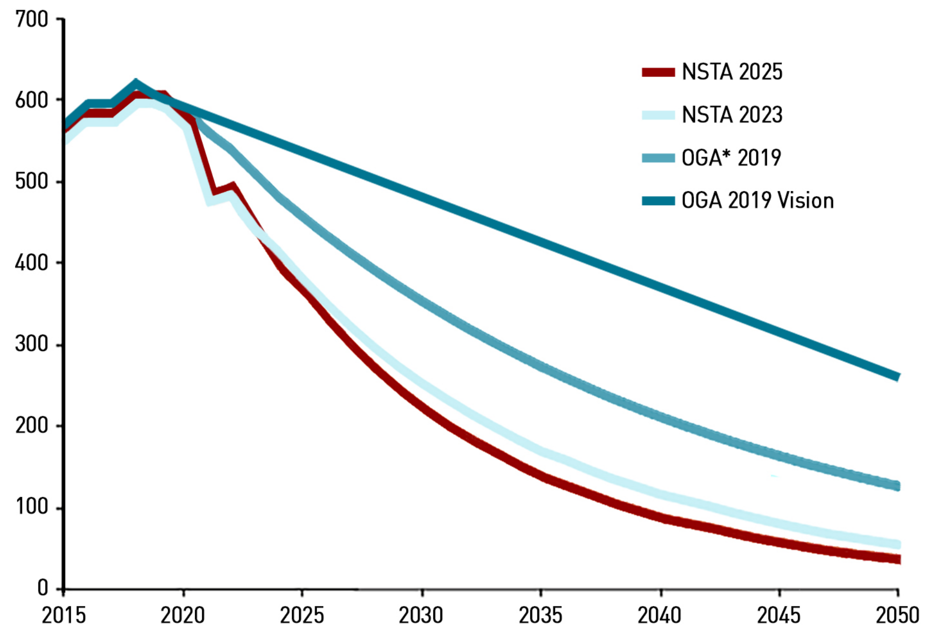
It is possible that issues with offshore gas pipeline viability could emerge as early as the winter of 2026/27. The North Sea Transition Authority's ("NSTA's") latest projections show accelerating UKCS decline through the 2020s[112].

...creating the potential for early, irreversible shutdowns

The UKCS is in a much sharper decline than had previously been expected, primarily as a result of a punitive fiscal regime and current Government policy against new exploration. This not only threatens energy security in terms of access to molecules, it also threatens the viability of offshore pipeline infrastructure. The key issue isn't simply that UKCS output is declining, but that the offshore gathering and transmission system has fixed costs and physical interdependencies - as throughput falls, it becomes progressively harder to maintain and justify these assets.

112 https://oeuk.org.uk/product/impact-of-fiscal-policy-on-the-uk-continental-shelf/

Forecast UKCS oil, gas production (millions of barrels of oil equivalent)



* the NSTA was previously known as the Oil and Gas Authority

Source: OEUK

Pipelines such as the Central Area Transmission System ("CATS"), the Scottish Area Gas Evacuation ("SAGE") system and the Far North Liquids and Associated Gas System ("FLAGS") were designed for high throughput and depend on tariffs from producers. As volumes decline, unit tariffs rise to recover fixed costs. At some point, remaining producers face uncompetitive transportation tariffs which accelerates field decommissioning, leading to a "death spiral" where loss of one anchor field undermines the economics of the whole system.

Offshore gas lines require a minimum flow to maintain stable pressure, gas velocity, and to prevent liquids (water, condensate) from pooling. If flows drop too low hydrates can form, liquids can accumulate, increasing corrosion risk, and compression and dehydration systems become inefficient. Below a certain threshold, the system cannot safely operate without costly reconfiguration. So, a sudden production fall can force early shutdowns of gathering systems, even if some reserves remain in place.

It is possible that issues with offshore gas pipeline viability could emerge as early as the winter of 2026/27. The North Sea Transition Authority's ("NSTA's") latest projections show accelerating UKCS decline through the 2020s[113].

According to Westwood Global Energy Group[114], the Reserves/Production (R/P) ratio, a measure of how long an asset could continue to produce at current rates, given remaining reserves and 2025 production estimates, for four pipeline systems is <6 years, two of these are critical for the UK with a high number of field entrants.

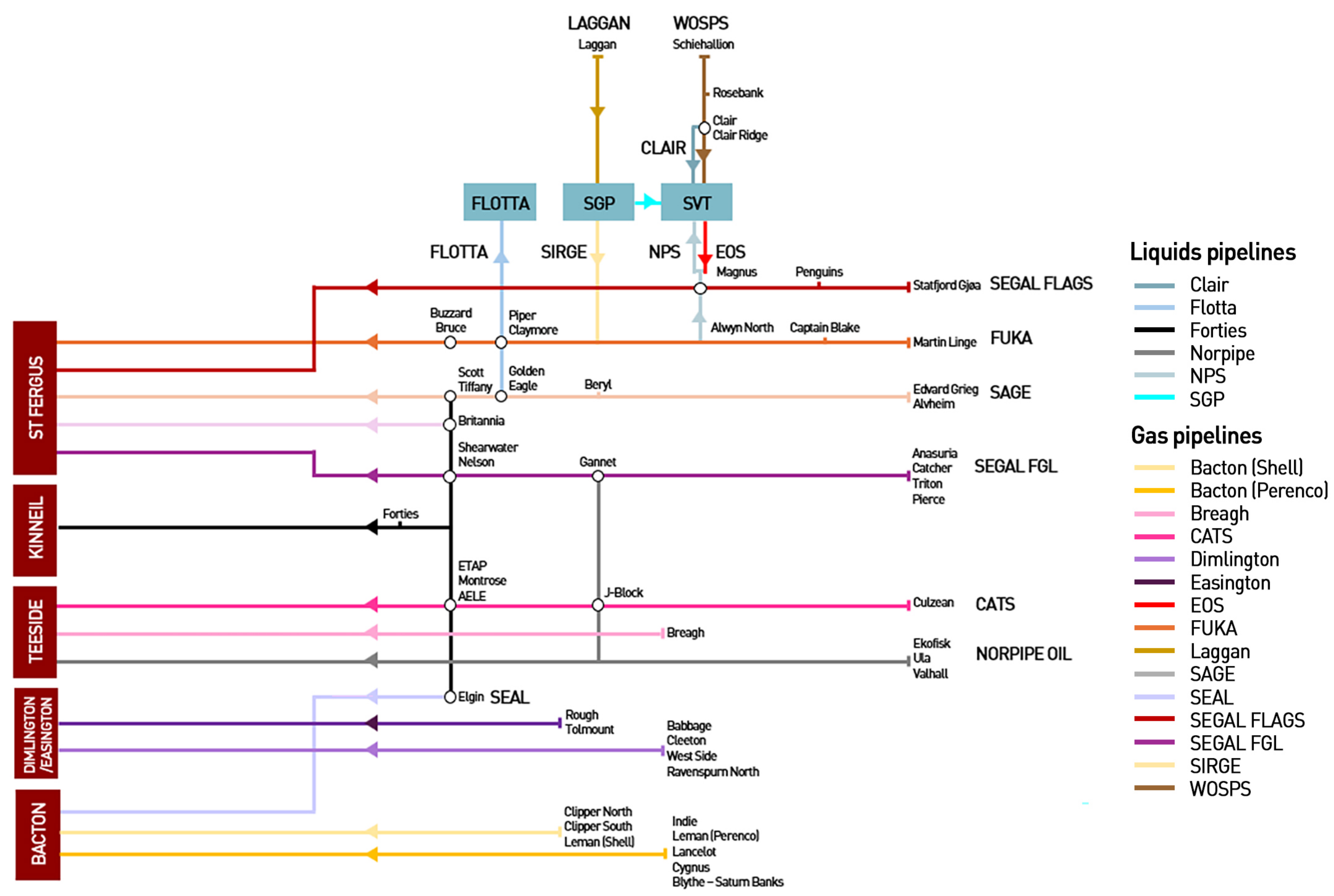
Flotta Pipeline System: relies on production throughput from three hubs (seven producing fields). Although infill drilling and workover activity is ongoing at the hubs, the R/P ratio is 5.5. The progression of the Marigold discovery as a tieback to the Piper hub would change the current outlook. Roughly 40% of the resource upside within 50 km is unlicensed.

Forties Pipeline System: a critical liquids pipeline system for the UK, with 71 field entrants via 17 hubs, accounting for around 23% of UK liquids throughput in 2025. Seven hubs could cease before 2030, including the

113 https://www.nstauthority.co.uk/data-and-insights/insights-and-analysis/production-and-expenditure-projections/

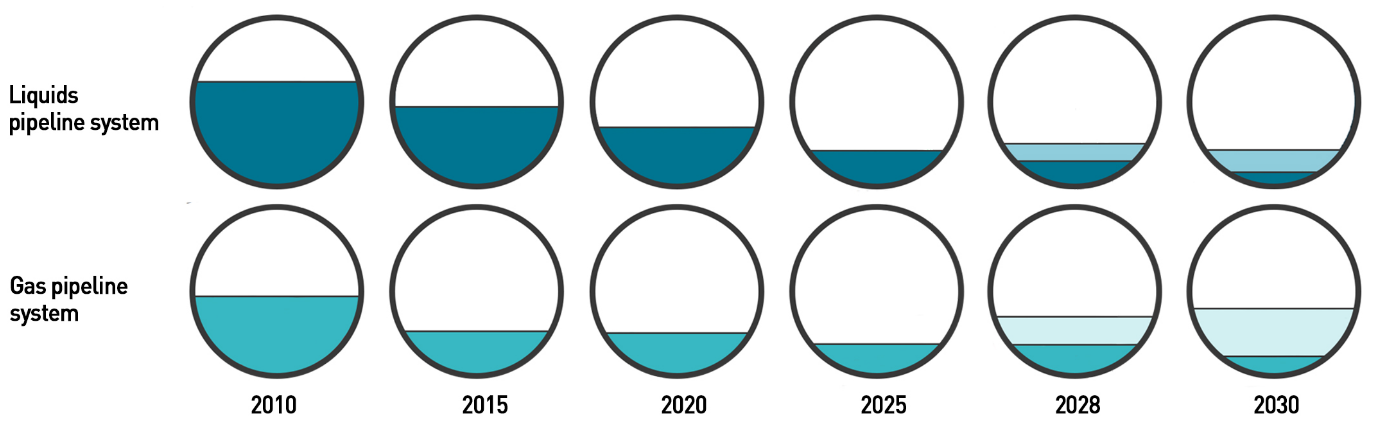
114 https://oeuk.org.uk/product/licensing-and-infrastructure-report-2025/

Figure 19. Infrastructure schematic (not geographically accurate, excludes hubs closing before 2028)



Source: Westwood Global Energy Group

Figure 20. North Sea gas pipeline infrastructure outlook



These circular diagrams represent throughput for selected pipeline systems. Historic years (2010 - 2020) show actual throughput levels. Forecast years (2025 - 2030) include two projections: Base case (dark fill) and Upside case (pale fill). Each circle is filled proportionally to indicate throughput relative to peak capacity, eg a half-filled circle represents 50% of peak throughput

Source: Westwood Global Energy Group

namesake Forties. There is one tieback under development and infill drilling at some hubs, but due to the relatively high current throughput rates versus the reserves replacement the R/P ratio is 5.5. Three hubs are expected to contribute 45% of 2025 throughput. Delivery of upside opportunities, such as an infill well at Elgin, additional drilling at ETAP and progression of new developments such as Birgitta, Fotla and Leverett, would improve the outlook for this system. Over half of the resource upside within 50 km is unlicensed.

Infrastructure failure could create cliff-edge supply losses...

CATS Pipeline System: a critical gas pipeline system for the UK, with around 42 field entrants via nine hubs, contributing roughly 25% of UK gas throughput in 2025 but due to the relatively high current throughput rates compared with the reserves replacement, the R/P ratio is 5.0. Two hub entrants account for 68% of 2025 forecast throughput. Strong performance from a development well being drilled at Culzean (largest entrant), the progression of ongoing drilling opportunities at J-Block and ETAP, and development of tieback opportunities at Birgitta will be important to the outlook. There is high upside potential within proximity of the hub entrants.

Ninian Pipeline System: the most northerly pipeline system in the UK feeds liquids production from three hubs via 12 fields. The Ninian hub has commenced decommissioning activities, with only one of the three original platforms still operating. The pipeline, however, feeds into the Sullom Voe terminal which also receives oil from Clair and Clair Ridge and therefore supports economics. Over 80% of the resource upside within 50 km of the Ninian Pipeline System is unlicensed.

...forced decommissioning of offshore trunklines would cause sudden, non-linear losses of gas entry capacity to the National Transmission System...

Liquids and gas export routes are intrinsically linked - changes to one export route can impact many other export routes. This interdependency means that if one system becomes uneconomic, it could lead to a cascading effect forcing the closure of other systems, stranding potentially viable fields and leaving some areas of the North Sea inaccessible for future development.

When an offshore trunkline is decommissioned, all connected satellites lose evacuation routes. For example, closure of the SAGE or FLAGS system would strand several smaller tiebacks. Once a trunk is gone, re-establishing offshore transport to shore would require new infrastructure which would be uneconomic for tail-end volumes. With each major offshore system that shuts down, the steady baseload flow into the NTS diminishes, which has several system-level implications:

...potentially removing tens of mcm/day overnight

(a) Reduced baseline inflow capacity: St Fergus, historically a high-pressure feed point, is already seeing declining flows. As these terminals wind down, the NTS loses one of its few north-to-south supply anchors, increasing reliance on southern entry points (Easington, Bacton, LNG). This complicates linepack management and reduces network flexibility under high demand.

(b) Greater dependence on LNG: LNG can physically fill the gap on paper, but it is price sensitive as cargoes may divert to Asia, and vulnerable to weather and shipping delays. They are also logistically constrained due to availability of shipping and regas throughput limitations, and they are not instantly dispatchable as tank inventories must be pre-positioned. This means that during cold snaps or high continental demand, the GB system may struggle to ramp LNG send-out quickly enough to cover both power station and heating loads (which are higher in cold weather).

(c) Interconnector reversal uncertainty: Continental gas systems are structurally net importers, especially after the closure of the Groningen field in the Netherlands. During European cold spells, they are unlikely to export to GB. Recent investments in IUK /BBL reversibility help, but molecule availability is the limiting factor.

LNG and interconnectors cannot fully substitute UKCS flows...

(d) Power-sector rationing: gas-fired power plants are classified as interruptible customers under the emergency supply hierarchy. If total inflows (UKCS + LNG + Norway + IUK/BBL) cannot meet domestic heating and firm industrial loads, supplies of gas to power generators may be curtailed to preserve household supply (although this is not necessarily rational since most heating systems require power to operate, so supplying gas but not electricity to households would be counterproductive.

In an orderly decline, UKCS production falls predictably, pipelines are rationalised, and alternative import capacity is scaled up. In fact, most production forecasts indicate a smooth decline profile over the coming years. This is unlikely in practice because forced decommissioning of offshore pipeline infrastructure would lead to a cliff-edge loss of capacity. This would reduce maximum NTS entry capacity by tens of mcm /day overnight, and shift pressure management southwards changing the utilisation of key compressor stations such as that at Peterborough.

...while LNG and interconnectors can fill part of the gap on paper, they are constrained by logistics, price competition, regas capacity and continental demand, particularly during winter cold snaps

It would also force higher LNG and interconnector reliance without time to build redundancy, or sufficient NTS capacity – there are currently constraints that limit the volumes of gas that can be transported from Dragon and South Hook eastwards to consumers in England. Because offshore decommissioning is irreversible, the risk is asymmetric - once a trunkline or compressor is removed, it cannot be reinstated in winter emergency conditions.

There are several mitigation strategies that could be employed. The best option would be to remove the fiscal headwinds that are making North Sea gas production uncompetitive, and to allow new drilling to optimise the gas resources owned by the UK. The Government should also consid-

Construction of floating regas capacity is likely to ne required to offset falling UKCS production…

er providing financial support to key pipelines that would support their economics even under lower throughput conditions, essentially removing the economic drivers for decommissioning. This would be analogous to the Capacity Market that ensures lower utilisation of gas power stations due to the use of wind and solar generation does not force their premature closure.

A more expensive, and less viable option would be to develop a gas storage policy. The UK has very little gas storage capacity, and while the key facility, Rough, has re-opened, it is not very useful since deliverability rates are far lower than before it closed[115], and there are few other sites that could be developed for gas storage. Rough closed because its operator, Centrica, considered it was no longer safe to operate some of the wells as age had eroded their integrity.

…this will raise the UK's import dependece further

In order to continue operating the facility, new wells would need to be drilled, at a significant cost (about £1 billion was the estimated upgrade cost). Since the Government declined to provide a subsidy for this work, and the facility was not generating enough income for it to be economic for Centrica to make this investment, so it decided to close the site. Following the closure, Centrica removed the cushion gas and the produced a significant amount of the tail reserves, materially reducing the reservoir pressure.

This lower pressure is why the facility can operate safely following its re-opening, but, as there are no pumps on the production wells – the speed with which gas is extracted depends on the reservoir pressure – the rate of gas deliverability from Rough to the NTS is very low. To make Rough a meaningful source of gas during cold snaps, it would be necessary to either drill new wells and re-inject cushion gas to raise the reservoir pressure – which would require a significant investment – or to install pumps on the production wells. Either option would require new capital expenditure, but the result would not solve the problems caused by a decline in gas from the UKCS.

115 https://watt-logic.com/2022/08/08/re-opening-rough-gas-storage/

Gas infrastructure risks coincide with power generation risks

Finally, Britain could install floating regasification terminals which would increase the amount of LNG GB could accept. Spare NTS entry capacity at Easington and St Fergus would make these the most likely sites, but ship docking facilities as well as storage tanks would need to be built. Depending on the extent of works needed to accommodate large LNG tankers, this is likely to be part of the solution to the eventual decline of the UKCS.

At current decline rates, UKCS inflows to the NTS could fall from around 30 bcm in 2024 to 20 bcm by 2030, with much of the loss concentrated in the north and east coast terminals. This progressively reduces the steady baseload inflow that underpins pressure and linepack flexibility in winter.

This will lead to rising import dependence, as GB will rely more on LNG (up to half of peak-day supply) and Norwegian imports (Langeled, Vesterled). From 2028 risks of structural reduction in Norwegian deliveries will also begin to manifest - before then, Norwegian offshore pipeline operator, Gassco, projects stable or slightly higher export capability, although maintenance outages will present some short-term risk.

As UKCS production falls, even if overall gas availability remains adequate on paper, North Sea gas flows will reduce baseload pressure support, increase reliance on LNG logistics, and heighten the risk of generator curtailment on extreme-demand days, beginning as early as winter 2026/27, and increasing year-on-year into the 2030s unless policy change reverses the

accelerating decline in UKCS production.

> “We think Neso forecasts are too optimistic. We forecast gas production to decline by 70pc by 2030 due to the impact of the windfall tax. That suggests the UK will run out of LNG import capacity as early as 2031, as the current import terminals reach the maximum rate they can deliver gas into the UK grid during winter. The best way to ensure security of gas supply is to maximise domestic gas production,”
>
> - Chris Wheaton, analyst at Stifel

In November 2025, NESO warned[116] that by 2030, there could be insufficient gas entering the UK to meet demand on cold days, however, these forecasts are seen by industry insiders as optimistic and there is an expectation the risk will manifest earlier.

AI data centres may be powered off-grid

A recent development which could have a material impact on the GB power grid is the advent of AI data centres. Data centres are specialised facilities that house computer servers, storage systems, and networking equipment to process, store and distribute digital information. They support a wide range of digital services from banking, e-commerce and public-sector IT systems to video streaming, cloud computing and industrial automation. Data centres require high-capacity connectivity, stringent security, resilient power supplies and advanced cooling. Their electricity demand is largely driven by the servers themselves and the energy needed to cool them to maintain safe operating temperatures.

AI data centres differ from traditional or “general-purpose” data centres primarily in the type of computing loads they host. Traditional facilities are optimised for workloads such as cloud hosting, databases, and general IT services, while AI data centres incorporate large volumes of hardware designed for high-intensity computation, particularly for training and running artificial intelligence models. These systems consume significantly more power per rack, generate more heat, and require denser electrical and cooling infrastructure. In terms of power consumption, a rack used for AI training can require 30–60 kW, versus 5–10 kW per rack in a traditional data centre.

There are two distinct types of AI workloads:

- AI Training where models are developed and taught using very large datasets. These require extremely high power density, often at multi-megawatt scale, and operate in short, intense bursts. Training facilities therefore demand the highest-spec power, cooling and electrical redundancy, however service interruptions are less critical;

- AI Inference where trained models are deployed to run real-time services such as search queries, customer service chatbots, fraud detection and so on. Inference is less compute-intensive than training and can be run on lower-power accelerator hardware, although widespread adoption across services still increases aggregate demand, however, inference data centres require high levels of availability to avoid interruptions to consumer workloads (so-called “5 nines” availability ie available for 99.999% of the time).

116 https://www.neso.energy/news/mitigations-protect-future-security-gas-supply-identified

Data centres were designated Critical Infrastructure in GB in September 2024. NESO and the Government will need to consider both the scale and location of new electricity demand associated with data centres as part of their strategic network planning. In addition to meeting core requirements for telecom connectivity, access to reliable power supplies, access to skilled staff, and access to water, many data centres need to be located near areas of high economic activity and customer demand.

The type of data centre often defines where it will be located, for example, AI inference data centres will often need to be close to customers to minimise latency. Data centres using the cloud may need to be near other data centres to create resilience, although some cloud computing is done hundreds of kilometres away from customers.

A hyperscaler is a company that operates very large-scale cloud and data-centre infrastructure, providing on-demand computing, storage and AI services globally. The term typically refers to Amazon Web Services (AWS), Microsoft Azure, Google Cloud, and sometimes Meta, Apple and Alibaba. Hyperscalers operate multiple multi-hundred-megawatt campuses, build their own international fibre networks, and directly contract with energy suppliers and grid operators to secure capacity. Their growth plans, particularly for AI training clusters, are now a major driver of future electricity and grid-connection demand.

Data centres currently use 1-2% of electricity in GB, however the growth in AI and other digitisation means that they are forecast to account for 10% of GB electricity demand by 2050, the equivalent of more than 11 million homes[117]. In July this year, the Department for Science, Innovation & Technology and UK Research and Innovation published the UK Compute Roadmap[118], which suggests AI data centres could require 6 GW of new power capacity by 2030. Currently, it is unlikely that AI data centres could be powered by the power grid or indeed use the grid for backup should on-site generators fail. The power grid lacks the spare generating capacity and there are waits of up to ten years for datacentres to secure new power grid connections[119].

In some quarters there is a view that data centres will seek to co-locate with “cheap” wind resources. While this is happening in some markets such as ERCOT (Texas), it is happening on the basis that gas peaking plants are being used to provide backup for the wind[120]. It is very unlikely that data centres will want to locate in Scotland, because despite the abundant wind resources, there is limited ability to install backup generation, and indeed, telecoms connectivity in the north of the country where wind is most abundant, is inadequate.

Of 20 potential data centre sites identified in a report commissioned by Scottish Futures Trust /Host in Scotland, Crown Estate Scotland and Scottish Enterprise and published in June 2023, five sites were identified as having high connectivity (multiple fibre providers and tier 1 providers) and the remainder had moderate connectivity (just one fibre provider)[121]. In the meantime the trend elsewhere, particularly in the US, is for firm power Power Purchase Agreements to be signed for data centres, with nuclear, gas and hydro generators[122]. Wind and solar cannot provide firm power unless they partner with another technology such as batteries or gas generators.

117 https://www.energy-uk.org.uk/publications/powering-the-cloud-how-data-centres-can-deliver-sustainable-growth/

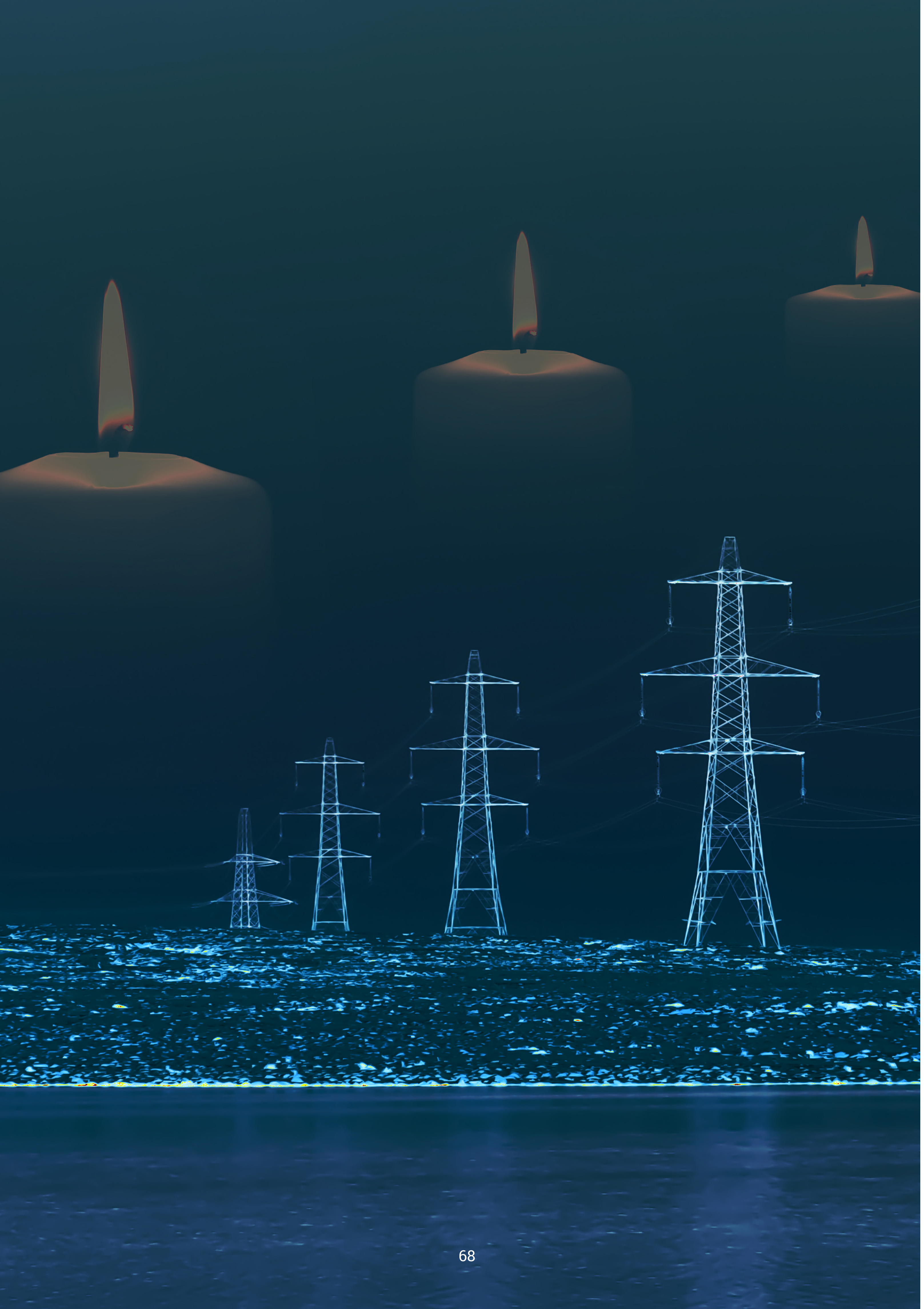
118 https://www.datacenterdynamics.com/en/news/new-uk-compute-roadmap-says-country-needs-6gw-of-ai-capable-data-center-capacity-by-2030/

119 https://www.datacenterdynamics.com/en/news/ofgem-approves-uk-interconnection-reforms-potentially-clearing-more-than-750gw-from-its-connection-queue/

120 https://www.investmentmonitor.ai/features/gas-versus-renewables-how-will-the-power-demand-of-data-centres-be-met/?cf-view&cf-closed

121 https://sobencc.com/white-papers/scottish-data-centres/

122 https://www.power-eng.com/renewables/brookfield-says-hydro-and-nuclear-are-back-in-demand-as-baseload-ppas-shift-to-firm-power/



Anecdotally, technology companies are approaching gas network operators for gas grid connections with a view to generating their own electricity on site. The most robust plan for the foreseeable future - subject to planning, emissions limits and gas network capacity - would be to build power generation facilities consisting of multiple smaller gas engines, with some diesel units for backup, calculating the extent of the over-build based on the degree of resilience required, the anticipated power unit failure rate, and the desired degree of spare margin. In terms of emissions, it seems likely that technology companies would be able to successfully lobby for some relaxation of the rules if the UK is to attract significant investment in AI.

Despite 32 GW of wind capacity on the GB grid, output below 1 GW is not unusual...

Electricity rationing is more likely than electrification

Official projections from NESO and DESNZ suggest that the GB electricity system can meet rising demand through a combination of renewables, interconnectors, storage and flexibility. However, these assessments are built on average conditions - comparing annualised generation with Average Cold Spell ("ACS") demand - and therefore underestimate the risk of capacity shortfalls during prolonged low-wind periods. The more relevant question is whether the grid can meet demand on a still, cold weekday evening when wind generation falls to 1 GW or less, solar contributes nothing, and demand peaks at roughly 48 GW today.

...the grid is already tight on low wind winter days

Imports are at risk during low wind conditions as many of our connected markets also rely on wind...

...even France and Norway which don't have reducing spare margins - the French nuclear fleet is ageing and electricity exports are becoming politically challenging in Norway

Electricity generation de-rating factors in GB

	Capacity (GW)	De-rating factor	De-rated Capacity (GW)
Gas	32.0	0.92	29.44
Nuclear	6.5	0.78	5.07
Biomass	4.5	0.88	3.96
Hydro	1.5	0.91	1.37
Pumped storage	3.5	0.67	2.35
Batteries	6.8	0.37	2.52
IFA1	2.0	0.62	1.24
IFA2	1.0	0.64	0.64
Eleclink	1.0	0.68	0.68
Nemo	1.0	0.68	0.68
Britned	1.0	0.67	0.67
NSL	1.4	0.7	0.98
Viking	1.4	0.63	0.88
TOTAL			**50.47**

Source: Watt-Logic

Under these conditions, the current system is already tight. After accounting for typical outage rates, the available CCGT fleet provides around 32 GW, with a further 11 GW from the remaining nuclear reactors and biomass, just under 5 GW of hydro and pumped storage, and just under 7 GW of batteries. Current interconnector capacity is 8.8 GW, but imports cannot be relied upon if continental systems face the same weather pattern, causing corresponding stress events. That leaves roughly 64 GW of dependable capacity against 48 GW of demand.

By 2030, the situation worsens considerably – the loss of around 12 GW of firm generation cuts de-rated firm capacity to 39 GW. Peak demand will rise substantially as electrification proceeds: **electrification of heating, transport and industry (net of deindustrialisation) could add 7-10 GW of winter peak demand.** At the same time, **AI data-centre expansion would add 6 GW of largely inflexible demand** likely concentrated around London and the M4 corridor, if Government plans materialise.

The potential for higher demand through electrifiation would add further stress to an already stressed grid...

In a repeat of today's low-wind scenario, the deliverable stack in 2030 could fall almost 25 GW short of peak, even before accounting for transmission constraints or voltage-stability margins. Even if electrification does not progress beyond today's levels and AI data centres are powered entirely by behind the meter generation, the potential retirements of even just 2.7 GW of CCGT retirements (8% of the current gas fleet) would eliminate the margin of firm generation, leaving the power grid entirely dependent on whatever wind may blow on low wind days. This is a very uncomfortable position to be in.

...electrification and AI data centres together could add 16 GW of demand by 2030...

Proponents of hydrogen and carbon capture often cite these as future balancing resources, but neither technology is likely to make a meaningful contribution before 2030. The CCC's latest Progress Report anticipates only a marginal role for CCS and limited low-carbon hydrogen production within the decade. In other words, firm low-carbon generation will not arrive in time, and the task of balancing the system will fall almost entirely on the residual gas fleet, storage, and imports. If even a handful of large gas stations retire without replacement, it is hard to see how the grid could maintain supply through a multi-day cold spell without load-shedding.

...just when 12 GW firm generating capacity could leave the grid, and gas inflows are threatened by UKCS decline

The distribution networks add further stress. Electrification will sharply increase local peak demand, but the pace of reinforcement remains slow. While government reforms may shorten connection queues, physical works—new substations, transformers, and circuits—take years. The assumption that flexible demand will smooth peaks is unproven: households with heat pumps and EVs are unlikely to curtail consumption during freezing weather, and industrial loads may have limited flexibility when operating under contractual or production constraints.

Even if national energy balance appears adequate on paper, location and timing will determine resilience. The north of Scotland and eastern England are becoming generation-rich but load-poor, while demand growth is concentrated in the south-east. Without major transmission upgrades, which face long consenting lead-times, large amounts of renewable output will remain stranded during low-demand periods, and southern load centres will depend on ageing, overstressed circuits.

The Scottish grid is particularly vulnerable with only 2 synchronous generators remaining both of which are at risk of closure...

The generation in question in these regions is also largely renewables, primarily wind. Scotland has only two large synchronous generators left – Torness nuclear power station which is due to close in 2030 but might stretch for another couple of years, and Peterhead, a CCGT which opened in 2000 and has been suffering reliability issues. It may very well close by 2030 itself. This will mean Scotland has no native grid forming generation, and while there are claims that power electronics will do this job, so far there are no such electronics actually forming the grid in any market and there are hard limits to what semiconductors can deliver which mean inverters are never likely to great equivalent stability to conventional generators[123]. And using electronics in this way will be expensive – services such as inertia and voltage control, which are provided for free by synchronous generators since they are an inherent part of their physical characteristics, can only be delivered by inverter-based generation by sacrificing current that would otherwise power loads, meaning a reduction in income that must be compensated.

...this is not just a capacity problem: without synchronous machines voltage control becomes much harder...

Taken together, these realities suggest that the GB power system is unlikely to "cope" with full electrification on the present trajectory. Meeting demand on cold, low-wind days will require keeping a larger share of the CCGT fleet in service well beyond 2030, contracting new fast-start engines for reserve, and enforcing flexibility obligations on large data centres and electrolysers. Otherwise, Britain faces an unavoidable increase in intervention such as emergency redispatch, voltage support actions, and load-shedding at the regional level, with a non-trivial risk of widespread disruption.

...a similar problem exists in southern Spain where the grid operator has sought emergency powers to prevent further blackouts

123 https://watt-logic.com/2025/10/24/location-location-location-managing-voltage-in-weak-grids/

The prevailing optimism that renewables and flexibility alone can maintain reliability through electrification is not borne out by the generation arithmetic.

The prevailing optimism that renewables and flexibility alone can maintain reliability through electrification is not borne out by the generation arithmetic

> "Aging E-and F-class generating turbines require owners and operators to develop long-term strategies, from minimal investment until retirement, to complete flange-to-flange replacements,"
>
> \- GE Vernova

Without an urgent plan to replace the 12 GW of net firm generating capacity at risk of closure in the next 5-7 years, system management options will narrow...

By the late 2020s, most of the UK's large gas-fired power stations will be between 25 and 35 years old. The original 9FA fleet (Severn, Sutton Bridge, South Humber, Langage, etc.) entered service in the early 2000s, and even with life-extension works, these machines face mechanical fatigue. Mothballing and reactivation cycles could also have degraded reliability. With long equipment lead times, even if policy were supportive, the fleet we have today is the fleet we'll have for the rest of the decade. Life-extension is viable for some units, but that means outages while the upgrades are carried out, and costs that may "run into eight figures"[124]. The assumption that all CCGTs are available at the same time is already unrealistic: in recent winters, unplanned gas-plant deratings averaged 15–20 % during cold spells.

If this ageing fleet starts to fail faster than expected - a reasonable assumption after 2030 - the options for maintaining a balanced power grid on low wind days in winter shrink to three:

...demand control (rationing) will become likely on low wind days...

- Demand reduction (curtailment, rota disconnections, or appeals),
- Emergency imports (if continental conditions allow), and
- Voltage and frequency load-shedding triggered automatically by falling system frequency.

NESO can still balance the grid most of the time, but small faults or plant losses in winter low wind conditions will push it into emergency mode faster, with limited redundancy.

...with elevated risks of emergency actions and blackouts

If the current trajectory continues, the symptoms will not initially look like a textbook "blackout". Instead they will appear as a series of escalating stress events during low wind cold weather conditions:

- Chronic redispatch and curtailment with frequent out-of-market instructions to keep system voltages stable, plus expensive balancing costs as gas plants are ordered on out of merit;

Demand control including regional blackouts become an escalating risk on low wind days as firm capacity declines...

- Constrained industrial electrification with DNOs delaying or denying large demand connections - electrification projects are shelved because local networks cannot accommodate them;
- Regional brownouts or controlled load-shedding: short rolling disconnections (1–2 hours) in specific grid zones when supply falls short, managed manually or by automatic under-frequency relays;
- Extended use of diesel or open-cycle backup not only for data centres and hospitals but also factories and other I&C consumers running local generation for grid security, undermining decarbonisation goals;

...however full system blackout risk is no longer negligible....

- Grid-forming instability events as firm generation retirements weaken the grid. Inverter-dominated sections of the network experience voltage oscillations or failed resynchronisation, similar to the Iberian incidents in 2025;
- Political and operational normalisation of emergency actions with NESO invoking deeper demand response and Emergency Procedures multiple times each winter.

...voltage instability such as that seen in Spain is a risk...

In the worst case of a multi-day wind lull coinciding with a gas-plant trip or interconnector failure, contingency actions could escalate to load disconnection over large regions, likely lasting hours rather than minutes. A full GB-wide collapse remains unlikely, but regional or cross-zonal blackouts (London, Midlands, North West) become credible, with the scale of expected outages depending on the extent to which demand is increased through electrification or new AI data centre loads. A significant risk factor for blackouts is complacency. Currently none of NESO, Ofgem nor DESNZ seem overly concerned by retirement risk. NESO has also persuaded itself that there is plenty of spare capacity. This, combined with a poor track record of forecasting wind output and both the size and timing of daily peak demand, result in poor decision-making. This was seen on 8 January 2025 when the GB grid became unusually tight and could have seen a blackout had a large power station or interconnector tripped.

...as is complacency which may mean demand control is not enacted fast enough, particularly the first time it is needed

The day was characterised by cold weather and low wind. NESO both over-estimated wind output and under-estimated demand. It also thought peak demand would be earlier than it was. The tight conditions led NESO to issue various system warnings and to request that Energinet, the Danish system operator, would return a bipole of the Viking interconnector (700 MW) from maintenance early. The Rye House CCGT was receiving £2,500 / MWh in the Balancing Mechanism, so in order to save costs on a day when

124 https://www.gevernova.com/power/transform/authors/search-results/articles.transform.articles.2017.sep.addressing-the-problem-of-agin#

balancing had already cost more than £20 million, NESO decided to turn Rye House off in favour of Dinorwig.

Complacency is a real risk...

Dinorwig is the largest pumped hydro plant in Europe and the only GW scale asset in Britain with a fast response – it can ramp from cold to full load in 16 seconds. At 5:15pm Rye House reached zero output and Dinorwig was at maximum capacity (with half of its turbines unavailable for maintenance, the other three were running at their Maximum Export Limit). The peak of demand came at 5:21pm. Rye House would need about 25 minutes to ramp to full load from zero even on a hot start, so had Viking or any of the other interconnectors or power stations tripped at around that time, it would have been impossible to ramp up Rye House in time, and with Dinorwig already at full capacity, only a few hundred MWs of batteries would have been able to offer immediate response. Some of these were charging in the peak and some were taking advantage of high prices to discharge. A significant number of reserve units ignored their reserve contracts and ran anyway because the market prices were higher than any fines for failing to remain in reserve[125].

...on 8 January 2025 the grid was very tight...

...wind was lower than expected and demand higher than forecast...

Running Rye House for an additional hour instead of Dinorwig may have cost another £1.0 – 1.5 million that evening, but having already spent £20 million balancing the day, this would not be unreasonable when set against the cost a blackout would incur. Effectively NESO decided to do without proper insurance that evening – yes it superficially saves money, but there is a risk of significant losses if things don't go as planned. In a fact, NESO had another option which was to bring Sutton Bridge and Connagh's Quay CCGTs up to full load from their Stable Export Limits. Both were earning £2,000 /MWh in the Balancing Mechanism, so were cheaper than Rye House. This would have been preferable to running Dinorwig on a day that was known to be tight, and in the context that NESO was placing reliance on the early return of an interconnector maintenance, in the knowledge that any return from maintenance carries higher than normal start-up trip risk.

...but NESO chose to run pumped hydro for cost reasons rather than keeping it in reserve in case of a large trip....

Shortly after 8 January, NESO did announce an audit of its demand forecasting, but in a sign of its complacent approach to system margins, the engineer who announced the move in the Operational Transparency Forum said the methodology for demand forecasting had not been reviewed in "10-20 years"!

...had such a trip occurred, the market could have been left unable to respond

Reliance on the demand side to balance the market on low wind winter days also carries risks. Deindustrialisation may help by reducing demand but it hinders by reducing loads that can provide large demand response. Despite optimistic expectations by NESO, DESNZ and others, few new sources of flexible demand such as electrolysers and grid-connected AI training data centres will have been commissioned by 2030, meaning there will be reduced scope for GW-scale I&C demand response. Existing demand-control mechanisms are regional, not load-specific: NESO cannot dispatch industrial users individually except through Balancing Mechanism bids or Capacity Market demand response contracts, which are limited and non-instantaneous. The Demand Flexibility Service is almost exclusively provided by households, and its volumes are limited (200-300 MW). Consequently, when system margins collapse, the key practical tools are still rotational disconnections by grid-supply point, not targeted curtailment.

125 https://watt-logic.com/2025/01/17/nesos-approach-to-transparency/

Technology and demand response are unlikely to provide a get-out-of-jail-free card...

...expecting new storage technologies to emerge by 2030 is overly optimistic...

This means demand control will almost certainly be required several times each winter unless additional firm capacity is retained. And without a radical improvement in forecasting accuracy and operator readiness, the probability of regional rationing or blackouts in cold, still conditions becomes significant.

...and the trends are for falling demand-side response...

Trying to quantify this risk is challenging – there are very few comparable OECD electricity systems with similar levels of renewable penetration and synchronous requirements to produce a statistically "hard" probability. However, a range can be estimated based on three converging facts:

...I&C has largely left the demand response market following the abolotion of 'Triads'...

1. As noted earlier, the capacity buffer today, on a de-rated basis, is around 2.5 GW excluding wind and solar. With peak demand likely to remain just below 50 GW, the potential plant retirements give rise to a firm capacity deficit of around 10 GW on low wind days. These occur multiple times each winter, so the probability of at least one such event to 2030 is intrinsically high;

...these lost volumes have not been replaced by the Demand Flexibility Service which is almost exclusively provided by households

2. Historical frequency of tight-margin conditions: even before the expected retirements, NESO (and its predecessors) forecast de-rated margins of 6-9%, with multiple contingency actions such as activation of the Demand Flexibility Service, and the now defunct coal contingency. However, NESO uses average annual generation in its calculation of the margin which overstates what is actually available on low wind days – on days when wind output is 1% of the installed amount NESO's system margin can be wiped out[126]. Although there is now more wind on the grid, this year we have seen output at 0.65% of capacity;

3. Compounding factors increase the risk of a shortfall: ageing CCGTs are less reliable and see higher de-rating in cold weather (10-15%), retirements lead to declining inertia and stability headroom meaning the grid is less forgiving of supply/demand imbalances, inter-

126 https://watt-logic.com/2022/10/06/electricity-winter-outlook-2022-23/

connector may not deliver eg France importing in cold weather and during nuclear outages, and the high correlation between British weather and that in Benelux and Germany which all also rely in wind.

At least one significant system strerss event can be expected by 2030 - with 65-85% likelihood...

It is therfore reasonable to assume that at least one significant stress event where available firm supply plus interconnector imports is insufficient to meet demand without forced load reduction will occur between now and 2030. A probability range of 65-85% is credible. Given this risk of regional blackouts, the risk of a nationwide blackout can be expressed as the product of (i) the chance that a system stress event (under cold, still winter weather conditions) occurs, and (ii) that once it occurs, NESO fails to contain it using demand control and other tools. Under an optimistic, "technocratic" assumption, NESO recognises the problem promptly and sheds load decisively. Assuming only 5-10% of major shortfall events escalate into cascading system failure, applying this to the 65-85% risk of regional blackouts implies a full blackout risk of roughly 3-7% by 2030.

A 5-10% risk that a regional shortage translates into a full system collapse again has to be inferred from system characteristics since again there are not enough empirical data for frequency-based probability. There are four relevant factors:

1. Well-designed grids fail locally more often than nationally. The GB grid is strongly meshed, has protection relays, interconnectors and frequency containment reserves. The majority of severe events (eg the 2019 blackout) were partial and automatically contained;

..but there is a 5-10% risk of a full system collapse...

2. Fast protection acts even if operators are slow: under-frequency relays rate-of-change-of-frequency ("RoCoF") protection and islanding behaviour all reduce system-wide cascade probability;
3. However, weak grids with low inertia and reduced synchronous voltage control are more likely to fail as seen in Iberia in 2025, which raises the blackout risk above minimal levels;
4. There are some international examples which are instructive:
    a. The 2021 Texas shortage (Storm Uri) in which a regional blackout was prevented from cascading by load shedding;
    b. The 2025 Iberian blackout showed how weak inverter-based grids can experience rapid cascading failure;
    c. 2003 in Italy and 2003 in North-east US / Canada showed rare but real GB-comparable cascades triggered by operator delay or misjudgement.

The GB grid is well-designed but weakening. Already it has experienced voltage fluctuations particularly in Scotland. The expected retirements of synchronous generation will considerably weaken the grid, reducing both inertia and voltage control, particularly if generation located close to demand closes. This places **the risk of a cascading grid failure at low but not negligible - 5-10% is credible**.

...rising to 10-20% in a more pessimistic assessment

Under a more pessimistic behavioural assumption where NESO under-estimates the risk and is slow or reluctant to trigger load shedding, the probability of a cascading failure is higher, and plausibly 20-30%, which when combined with the regional blackout risk yields a **10-20% chance of at least one full system blackout to 2030**. However, should such an event occur where operator compliancy was a factor, it would be expected that lessons would be learned and procedures tightened. In that case, the forward risk of a subsequent full system blackout would fall back towards the underlying technical probability of around 5-10%.

Essentially we have a very high chance (65-86%) of regional blackouts or demand control out to 2030 based on a potential loss of 12 GW of firm generating capacity and a 5-10% risk this cascades into a full system blackout over the same period. This makes further electrification actively undesirable under expected system conditions.

Implications for gas in the GB energy mix

Gas will remain a critical component of the GB energy system through at least the 2030s, regardless of the pace of electrification. This is not primarily a question of policy preference, but of physical system requirements, asset availability and delivery risk across generation, networks and end-use demand. Even under optimistic assumptions for electrification, gas will continue to play a central role in ensuring security of supply, system resilience and operational flexibility during periods of peak demand and low renewable output.

Gas will remain critical to the UK's energy system for decades to come...

Government analysis implicitly acknowledges this reality. In its *Midstream Gas System: Update to the Market*, DESNZ emphasises that the gas system remains "essential for energy security" and that gas demand, while expected to decline over time, will continue to be highly seasonal and peak-driven for many years to come[127]. The report highlights the continued importance of gas for power generation, particularly during periods of high electricity demand, and notes that the gas transmission and storage system must be maintained to meet short-duration but very high peak flows. DESNZ assumes that "gas will continue to heat many of our homes and fuel hard-to-decarbonise industry for years ahead, and gas will retain a role post-2050" albeit using "carbon-neutral gas from green or offset sources".

...wishful thinking about the speed of the energy transition poses real risks to energy security

This is reinforced in the *Gas System in Transition: Security of Supply* consultation, which makes clear that even under scenarios of declining annual gas consumption, the system must remain capable of meeting extreme winter demand events[128]. The consultation warns that reduced utilisation does not equate to reduced infrastructure requirements, as security of supply is determined by peak demand rather than average throughput. This has important implications for both midstream investment and upstream supply resilience.

127 https://www.gov.uk/government/publications/midstream-gas-system-update-to-the-market/midstream-gas-system-update-to-the-market

128 https://www.gov.uk/government/consultations/gas-system-in-transition-security-of-supply

Policymakers assume the entire fleet of gas generation will still be required into the 2030s, albeit at lower utilisation levels....

...this means there is little to no tolerance for plant retirements absent replacements...

...and the gas pipeline infrastructure will continue to be vital to support this generation

Electrification shortfalls do not reduce the need for gas infrastructure - they prolong dependence on it

However, the consultation also states that "the pace and scale of the clean energy transition is driving the changing pattern of gas demand". While the *projected* pattern of gas demand changes in future scenarios, this change is not yet evident in observed system behaviour. Although total annual gas consumption has declined, this reflects reduced industrial activity rather than a structural shift in demand shape, and it has not been accompanied by a commensurate reduction in winter peak demand. Residential and commercial space heating continues to dominate extreme demand days, with cold winter conditions still driving system sizing and security-of-supply risk. Power-sector gas demand has become more volatile at the margin, but it has not replaced heating as the determinant of peak flows. **In practice, therefore, the gas system remains sized to meet winter extremes rather than average throughput, and assertions of a materially changing demand pattern are, at present, driven by projections rather than observed system behaviour.**

From a power-generation perspective, the continued role of gas is unavoidable. Under the Government's Clean Power 2030 ("CP2030") framework[129], around 35 GW of gas-fired generation is expected to remain connected to the grid to provide capacity, flexibility and system services. This implicitly recognises that variable renewable generation alone cannot meet demand securely during low-wind winter conditions, nor can storage technologies be deployed at sufficient scale by 2030 to fully substitute for dispatchable thermal plant. However, this requirement sits uncomfortably alongside the ageing profile of the existing gas fleet, as discussed earlier. Without intervention, there is a credible risk that a substantial share of the CCGT fleet exits the market before adequate replacement capacity is available.

Electrification outcomes materially affect this risk profile. If electrification targets for heating, transport and industry are met, gas-fired generation will be required to operate more frequently to support higher peak electricity demand during cold winter periods. If electrification targets are not met, gas will continue to be used directly in end-use sectors, particularly for space heating and industrial processes. In either case, gas demand does not disappear; it simply shifts between direct consumption and power generation.

This creates a structural asymmetry in policy risk. **Electrification shortfalls do not reduce the need for gas infrastructure; instead, they prolong dependence on it**. Yet current policy frameworks risk under-investment in both gas generation and gas networks by assuming rapid demand decline without fully accounting for delivery constraints or behavioural resistance. The Government's own analysis acknowledges this tension, noting that unmanaged decline in gas infrastructure could increase security-of-supply risks even as overall demand falls.

129 https://www.gov.uk/government/publications/clean-power-2030-action-plan/clean-power-2030-action-plan-a-new-era-of-clean-electricity-main-report

Electrification would not remove the need for gas infrastructure for several decades...

...declining UKCS inflows may also require construction of new gas infrastructure in the form of LNG import terminals

Gas must be treated as a strategic necessity and not just a residual fuel

Policy frameworks such as CP2030 should be stress-tested against scenarios in which electrification under-delivers, rather than assuming best-case uptake

Midstream risks are particularly acute. The Midstream Gas System Update highlights increasing reliance on imports, declining domestic production, and growing exposure to global LNG market volatility. It also notes that low utilisation rates can undermine the commercial viability of critical assets such as storage and transmission infrastructure, even though those assets remain essential for peak security. This raises the prospect of a system that is technically required but economically fragile, increasing the need for policy intervention or regulated support.

Taken together, these factors imply that gas must be treated as a core strategic system asset rather than a residual fuel. Maintaining adequate gas-fired generation capacity, ensuring the integrity of the midstream system, and providing credible investment signals for life extension and selective new build are all necessary to preserve security of supply. This is true whether electrification proceeds quickly or slowly.

The risk of failing to act is asymmetric. Over-investment in gas capacity carries political and policy costs, but under-investment carries the risk of capacity shortages, involuntary demand reduction and blackouts. International experience demonstrates that such outcomes are not theoretical and can result in material economic damage and loss of life. Against this backdrop, preserving sufficient gas capacity through the 2030s should be seen as a risk-management imperative rather than a deviation from decarbonisation objectives.

In practical terms, this suggests a need to stabilise the outlook for the existing CCGT fleet, including targeted support for life-extension investments and clearer signals on the long-term role of gas in the capacity market and ancillary services. **It also implies that policy frameworks such as CP2030 should be stress-tested against scenarios in which electrification under-delivers, rather than assuming best-case uptake.** Without such realism, the GB energy system risks being left exposed to precisely the security-of-supply challenges that current policy seeks to avoid.

Electrification targets in Norway, the Netherlands and Germany expected to cause generation shortfalls

Meeting Norway's electrification targets will require more power capacity

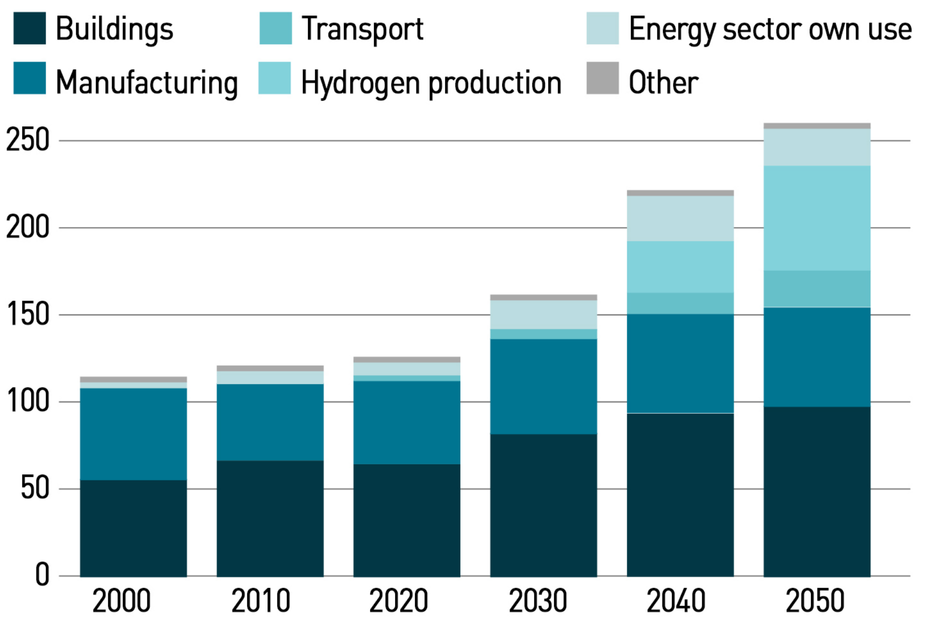
Norway's climate objectives are set out in the Norway's Climate Action Plan for 2021–2030[130], produced by the Ministry of Climate and the Environment.

Norway's decarbonisation agenda is well advanced, with ambitious plans to go further. National plans aim for all new cars and small vans to be zero-emission from 2025, with targets for zero-emission buses and trucks by 2030, and full electrification of publicly operated coastal ferries also by 2030, alongside very high heat-pump penetration in buildings.

These policies come on top of extensive existing electrification: buildings already rely on electricity for roughly 80% of energy use, and Norway has the highest heat-pump penetration in Europe. Cancellations of major blue-hydrogen export projects to Germany and of Shell's Aukra hydrogen hub also imply more decarbonisation will have to come from direct electrification rather than hydrogen exports.

Norway is already the second most electrified country in the world, but Statnett and the national Energy Commission both expect these electrification trends to push electricity demand significantly higher: Statnett's latest long-term analysis shows consumption rising from roughly 140 TWh today to between about 180 and 260 TWh by 2050, depending on how much new power-intensive industry and offshore petroleum electrification proceed.

Norwegian electricity demand by sector (TWh)



Source: DNV

DNV's Norway Energy Transition Outlook[131] similarly projects that electricity use will increase by 60% to 2040, with electricity providing the majority of final energy demand. Demand for electricity is growing in all sectors, with road transport showing the strongest increase. New demand categories, such as oil and gas installations and data centres, are generally less price sensitive and could accept higher electricity costs than traditional industry. However, this will likely challenge Norwegian manufacturing's access to cheap electricity.

DNV believes that wind is the only scalable option for new power generation, and delays in deployment could result in a power deficit. It says Norway will see 13 GW of new onshore wind and 21 GW of offshore wind installed by 2050. It sees a role for solar, with 10 TWh in about 20 years' time, partly combined with batteries, but does not expect Norway to adopt nuclear power. It expects that demand growth will outpace supply, leading Norway to face a power deficit from the late 2020s, with net import averaging 10 TWh in the early 2030s. However, by the mid 2030s, new offshore wind production should return Norway to being a net electricity exporter.

DNV also identifies a need to accelerate grid expansion "to enhance flexibility, reduce bottlenecks, and optimise wind power". However, it also notes that Norway is not on track to reach its national emissions targets, saying that existing and planned policies are too weak to ensure the necessary step-change in sectors such as manufacturing, shipping, aviation, and agriculture.

> "Prior to 2030, wind installations will be minor, and rising demand will likely create an electricity deficit within five years, with average net import being 10 TWh in the early 2030s,"
>
> \- Energy Transition Outlook Norway 2024 – A national forecast to 2050, DNV

DNV has identified five prominent developments and dilemmas affecting Norway's transition dynamics:

(a) **Fossil fuel revenue deflects non-fossil investment**
As a primary supplier of oil and gas to Europe, Norway plays a critical role in EU energy security. Following the Russian invasion of Ukraine, Norway increased gas exports by around 10% - this alongside higher prices saw the Sovereign wealth fund grow to US$ 1.7 trillion in 2024, with a commensurate increase to the regular budget, under the 3% spending rule linked to the fund's value. This creates incentives for a slower transition away from fossil fuels.

Meanwhile the EU, Norway's main trade partner, is trying to accelerate its transition away from fossil fuel use, which has implications for Norway's future export revenues. Despite this uncertainty, the investment landscape remains skewed toward fossil fuels, while investment in non-fossil opportunities has largely stalled.

(b) **Rising demand from new power-intensive industries**
New hydropower development in Norway is constrained by environmental concerns and by cost-competition from other renewables. However, demand for electricity is growing, driven by electrification and new sources of demand such as data centres, and hydrogen and battery production, and the petroleum sector, while supply and transmission capacity are lagging. Data centres by Google and Green Mountain/TikTok are good examples, which, if fully built out, would require almost 9 TWh /yr. A power deficit is likely in the 2030s.

A durable power surplus is seen as the most important measure to ensure low and competitive domestic energy prices long term. The Energy Commission has identified a need for 40 TWh of new renewable generation by 2030 and 20 TWh from energy efficiency improvements in order to maintain a competitive advantage for Norwegian industry.

(c) **Power to municipalities on new renewable generation**
Norway signed the COP28 Global Renewables and Energy Efficiency Pledge to triple installed renewable energy generation capacity

130 https://share.google/cYC5SGODmsRNPeQNP

131 https://www.norskindustri.no/siteassets/dokumenter/rapporter-og-brosjyrer/energy-transition-norway/energy-transition-norway-2024.pdf

Norway remains officially committed to hydrogen...

and double the annual rate of energy efficiency improvements by 2030. However, decision-making over the expansion of renewable generation typically resides with municipalities where projects face opposition due to visual intrusion, conflicting land-use priorities, and questions concerning the equitable sharing of economic benefits. Public opposition has completely halted new onshore wind installations.

..but recent project cancellations highlight the economic risks of large-scale hydrogen export strategies

To distribute economic benefits more equitably, tax rules have been modified to pay a production tax to the host municipality, however the effect of this on new projects has yet to be seen. Offshore wind presents a slightly less contentious opportunity, though it requires significant investment and policy support to demonstrate 'first-of-a-kind' projects and build investor confidence.

(d) **Delay in implementation of EU policies creates business uncertainty**
Norway has yet to decide on implementation of the EU Clean Energy Package on which the EU reached agreement in 2019, with political tension in Norway about adopting further EU energy legislation. DNV believes this undermines regulatory clarity for Norwegian businesses.

A larger share of industrial decarbonisation will need to come from direct electrification

(e) **Predictable transition policies needed to unlock private investment**
For Norway to secure its position as a leader in low-carbon technologies and energy requires stable policy support to attract investment in nascent industries and associated infrastructure. Norway has taken steps in this direction for example with incentives targeting the maritime sector, with up to 80% capex investment support to hydrogen and ammonia.

Like NESO, Statnett assumes a significant role for demand-side flexibility[132] in balancing a decarbonised and highly electrified system. According to DNV, Norway's flexibility requirement has historically been between 1.0 and 1.5 GW, primarily met by hydropower. However, with increased variability on the supply side from offshore wind generation, and on the demand side from technologies such as EV charging, this requirement is projected to double to 3 GW by 2050. However new technologies are expected to fill this gap, for example vehicle-to-grid alone is expected to provide 25% of Norway's flexibility in 2050. To support a grid with significant renewable generation, DNV forecasts a need for 1 GW of pumped hydro, 6 GW of lithium-ion battery storage, and 2.9 GW of vehicle-to-grid capacity by 2050.

132 https://www.statnett.no/globalassets/for-aktorer-i-kraftsystemet/planer-og-analyser/lma/long-term-market-analysis-2024-2050-executive-summary.pdf

Norway is already one of the most electrified countries in the world..

Beyond the anticipated need for flexibility, significant grid expansion is also expected to be necessary to meet increasing electricity demand over the next three decades. Norway's total grid length is expected to increase from 370 thousand circuit-kilometers (c-km) to 605 thousand c-km, (a 60% increase). Both the high voltage transmission and low voltage distribution grids are expected to expand despite the grid's already substantial capacity. This growth will involve both physical expansion and enhancements through smart technologies and digitisation, particularly at the distribution level. Consumer-driven demand-response measures are expected to support peak shaving.

...but further electrification will drive electricity demand sharply higher...

In common with most countries, Norway's grid will have to respond to additional demand from EVs and greater electrification of heating and industry. However, Norway will also face additional demand from offshore oil and gas infrastructure as it too electrifies. New offshore and onshore power generation will also need to be accommodated which will involve significant growth in offshore transmission infrastructure. DNV forecasts that Norway's undersea transmission cables will expand five-fold, from 740 circuit-km in 2023 to 3,650 circuit-km in 2050.

..Statnett projects consumption rising from c140 TWh today to 180-260 TWh by 2050...

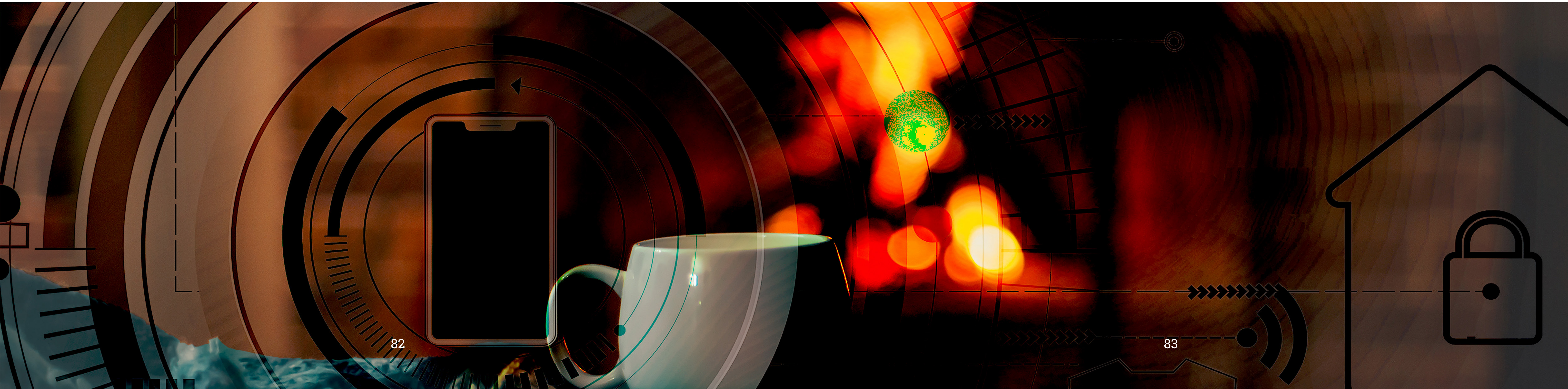
The DNV view, while detailed, is almost certainly too optimistic, and the gaps in its assumptions about flexibility, storage and interconnection are material. Norway's security-of-supply position is tightening much faster than DNV's scenarios suggest, and without either substantial new firm capacity or a political reversal on interconnectors, nuclear becomes the only scalable low-carbon option. DNV's scenarios rest heavily on four assumptions: that hydro can provide greater seasonal and balancing flexibility, that intermittency from large offshore wind expansions can be absorbed at low cost, that interconnectors will operate as a reliable source of balancing energy and that electrification (particularly offshore petroleum platforms) can scale without creating winter adequacy problems. Each of these assumptions now looks weakly evidenced.

...DNV forecasts that demand will increase by c60% by 2040 which it says can only be met by wind

Norwegian hydropower is highly flexible, but its flexibility is not unlimited: reservoirs are already being operated more aggressively than in previous decades, leaving less seasonal headroom. Statnett's own analysis shows winter adequacy margins narrowing sharply[133]. Consultancy firm, Thema has analysed[134] the power balance on behalf of the Energy Commission, and found that Norway's net generation surplus will decline towards 2030, and increase thereafter either though higher imports or more domestic electricity production. Thema also found that Norway faces a lack of peak load capacity that cannot be resolved without imports or flexible demand.

133 https://www.statnett.no/en/for-stakeholders-in-the-power-industry/our-analyses-and-assessments/long-term-market-analysis/

134 https://thema.no/en/news/will-the-future-power-system-be-sufficiently-flexible/



Norway faces a potential power deficit from the late 2020s...

The levels of storage deployment assumed by DNV are not realistic. DNV relies heavily on grid-scale batteries and vehicle-to-grid storage to manage intermittency. However, there are no large-scale storage projects under construction in Norway, and battery economics in a hydro-dominated system are extremely challenging, since price volatility is dampened by existing hydro flexibility. Seasonal storage in the form of hydrogen or ammonia is still far from commercial, and politically unpopular due to industrial land and safety concerns. This is not a mature solution on any reasonable 2030–2040 timescale.

...with average net imports of around 10 TWh in the early 2030s...

> "Norway's energy balance is expected to weaken over the remainder of the decade, with Norway potentially becoming a net importer of power in normal years. This change implies that there will be more years in which there is a larger and longer-lasting need to import power during the winter and spring. If 2030 were to be as cold and dry as we experienced in 2010, Norway would need an additional 35 TWh to cover total annual demand,"
>
> - Will the future power system be sufficiently flexible? Thema

...but political resistance to new interconnectors undermines assumptions that Norway can rely on imports to balance its grid

DNV's interconnection assumptions conflict with political reality. DNV assumes that Norway will remain a significant participant in the Nordic and continental balancing markets. This fails to recognise that following the construction of links with Britain and Germany in 2021-22, new interconnection has become politically toxic. There is cross-party resistance to any further interconnection and increasing calls to cap exports - public support for using Norwegian hydropower to stabilise Europe's wind fleet has collapsed. In fact, there is likely to be less rather than more interconnection, since the soon-to-expire lines of the Skaggerak link with Denmark are not expected to be replaced[135]. This is the biggest hole in DNV's outlook – its balancing model implicitly assumes free-flowing electricity trade, but the political mandate for this has evaporated.

Public opposition has effectively halted new onshore wind development leaving offshore wind as the only option

Finally, offshore wind cannot be treated as firmable by flexibility alone. Norway's planned offshore-wind build-out (30 GW by 2040) introduces enormous new intermittency, with potential swings of 60–80% in output across hours and days which cannot be smoothed by hydro alone. DNV's assumption that "all variability can be balanced by flexibility" is more of a hope than a forecast - battery storage technologies remain too short in duration, and there is insufficient evidence to guarantee that demand-side flexibility will emerge at the necessary scale absent some form of compulsion.

135 https://watt-logic.com/2025/02/21/norway-turning-away-from-electricity-interconnection/

Norway's grid is expected to expand by around 60%...

...assumptions about the role of flexibility in meeting these needs are likely too optimistic

This leaves Norway with effectively three alternatives: fall back on gas for firm capacity, which is feasible since several gas power stations (eg Kårstø and Mongstad) remain available; allow new interconnectors although this is likely to be politically almost impossible for at least a decade; or build new firm zero-carbon power, meaning nuclear. Norway has a strong engineering base, a political culture favouring pragmatic, evidence-based energy policy, a need for firm power, and limited alternatives. Small modular reactors are already being explored by several Norwegian industrial players. If Norway truly electrifies industry, transport and the continental shelf, nuclear is the only scalable firm option that avoids higher gas burn.

The Netherlands expected to see inadequate system margins after 2030

Tennet forecasts that Dutch electricity-system adequacy will deteriorate significantly after 2030...

The Netherlands has established comprehensive electrification targets across transport, heating, and industry as part of its climate strategy. These targets are a mix of binding and indicative commitments, supported by national legislation and EU directives. Many of these are rooted in the in the Climate Act 2019 (Klimaatwet)[136] which set legally binding greenhouse gas emissions reduction targets for the Netherlands. Flowing from the Act is the Climate Agreement (Klimaatakkoord)[137], which sets out policy objectives in various areas. While the Climate Act has full statutory powers, the Climate Agreement does not – the objectives set out in it are not legally binding on third parties unless subject to other legislation (ie they are binding on the government, but not on car makers, households and so on).

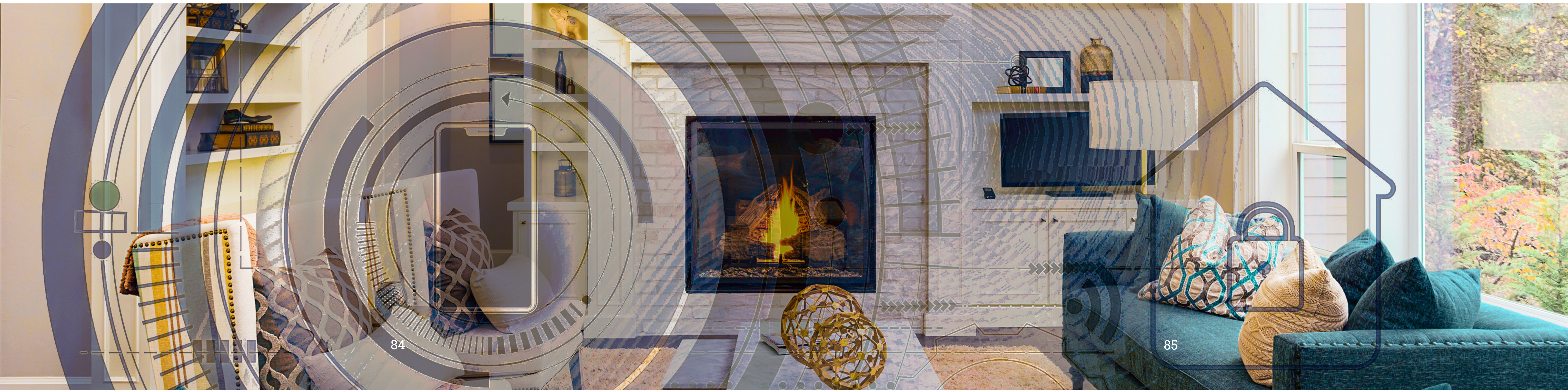
... and projects loss-of-load probabilities far exceeding acceptable standards

Recently the Dutch authorities have begun to worry about the impact the growth in heat pumps will have on electricity demand, and consider that without action to strengthen electricity grids, 1.5 million SMEs and households could experience a power outage in the period to 2030[138], in the worst case scenario. One option under consideration is to use the ISDE subsidy to incentivise heat pumps with smart controls which would prevent all

136 https://climate-laws.org/document/climate-act_4bc4

137 https://www.klimaatakkoord.nl/documenten/publicaties/2019/06/28/national-climate-agreement-the-netherlands

138 https://www.rijksoverheid.nl/documenten/kamerstukken/2024/04/25/kamerbrief-versnelling-en-uitbreiding-maatregelen-netcongestie-flevoland-gelderland-en-utrecht-fgu



units drawing power from the grid at the same time, effectively staggering demand (subject to ensuring consumer protections around consent), however such measures are unlikely to be introduced before 2026.

In 2022, grid operators saw an explosive growth in demand for electricity connection requests[139] - more than 53 GW of transmission capacity were requested from Tennet, compared with a historic average of just 6 to 8 GW. The whole country is to one degree or another being affected by grid congestion. Problems on the high-voltage network are already affecting large energy users, who can no longer get a grid connection in some areas. The Minister for Climate and Energy Policy, Rob Jetten, warned in a letter to the Dutch Parliament that small users - including households - may face the same problems, and be unable to secure grid connections. If no flexible electricity capacity can be found, the "physical limits" of the grid could be reached in some areas as early as 2025, with a risk of outages affecting households between 2026 and 2029[140].

Tennet warns of inadequate system margins after 2030

The Netherlands is following a very aggressive electrification pathway with rapid EV roll-out, deep building decarbonisation and a strongly electrified industrial sector. The official Roadmap to Electrification in Industry suggests that by 2050 some 80–130 TWh of industrial energy demand could be electrified, more than today's total industrial electricity use and greater than national electricity consumption in 2023. According to the Environmental Assessment Agency (PBL), net electricity consumption in the Netherlands is projected to increase from 109 TWh in 2023 to 138 -159 TWh by 2030[141]. On the generation side, the Netherlands has moved very quickly on wind and solar: renewables already supply roughly half of domestic electricity generation in 2024 according to the International Energy Agency[142]. The offshore wind roadmap foresees at least 21 GW of offshore wind by 2032 and 30-40 GW by 2040, having recently reduced it from 50 GW which was deemed "unrealistic and unnecessary"[143].

> "Security of supply remains within acceptable limits until 2025. After that, the increasing demand for electricity combined with the decline of coal-fired power plants, gas plants, biomass plants and nuclear power plants will result in a greater need for imports. This development is not unique to the Netherlands. Neighbouring countries will also start importing more electricity. Together, we will have to match available production capacity to avoid shortages,"
>
> - Security of supply, Tennet

However, grid operator Tennet is forecasting an increasingly tight electricity system[144], noting that not only will domestic margins fall below adequate levels from 2025, but that this will also be the case in neighbouring countries, threatening imports. In the 2025 edition of its Security of Supply Monitor[145], Tennet said that security of supply in the baseline scenario remains within the four-hour loss of load probability standard, but that from 2030 the situation will deteriorates rapidly. The reason for this is the trend

139 https://www.tweedekamer.nl/kamerstukken/brieven_regering/detail?id=2023D27812&did=2023D27812

140 https://www.rijksoverheid.nl/documenten/kamerstukken/2023/10/18/nieuwe-maatregelen-netcongestie

141 https://www.rabobank.com/knowledge/d011428288-the-dutch-electricity-sector-part-3-developments-affecting-electricity-markets

142 https://www.iea.org/countries/the-netherlands/energy-mix

143 https://www.offshorewind.biz/2025/07/17/dutch-govt-lowers-2040-offshore-wind-target-50-gw-unrealistic-and-unnecessary/

144 https://www.tennet.eu/security-supply

145 https://www.tennet.eu/nl/over-tennet/publicaties/rapport-monitoring-leveringszekerheid

From 2025 onwards, domestic margins are expected to tighten...

in the Netherlands and surrounding countries of a decrease in conventional capacity, along with a significant increase in electricity demand. According to Tennet, the growth in capacity from demand response, storage, and sustainable generation will be insufficient to compensate for this. Its forecasts suggest that in both reference years 2033 and 2035 the loss of load probability standard of four hours will be significantly exceeded, by 12.6 and 9.2 hours per year, respectively.

...with increasing reliance on imports that may not be available during regional stress events

Tennet explicitly identifies generation mix choices in neighbouring countries as a risk factor, and urges the Dutch Government to monitor the situation with a view to co-ordinating decisions on capacity mix. Tennet also recommends, expanding demand-side response, exploring capacity mechanisms and incentivisation of medium- and long-duration storage.

Demand-side response and long-duration storage are assumed to play a material role...

Tennet offers a far more grounded assessment of future resource adequacy than comparable Norwegian analyses. Where Statnett and DNV rely heavily on unproven future storage, optimistic assumptions about wind integration, and an enduring surplus of hydro flexibility, Tennet is explicit that Dutch security of supply will deteriorate significantly after 2030 unless urgent action is taken. Its modelling highlights the structural loss of dispatchable thermal capacity, strong growth in electricity demand, and insufficient expansion of low-carbon flexibility resources. This frank recognition of tightening adequacy margins marks a notable shift from the arguably more complacent tone taken by many of its peers.

...despite limited evidence that they will be deployable at scale in the 2030s

However, Tennet still relies on two categories of flexibility that remain largely unproven at the scale required - demand-side response and long-duration energy storage. Industrial demand response in particular is intrinsically limited by process-integrity and safety constraints, while commercial and residential flexibility is fragmented, behavioural, and cannot be guaranteed during the multi-hour winter scarcity periods that drive adequacy risks. In both cases, prices generally need to be high to consistently secure capacity - the experience in Britain was that 2 GW of industrial response evaporated when the valuable "triad"-based allocation of network charging was abandoned - these consumers did not migrate to the Demand Flexibility Service as hoped[146]. In practice, meaningful volumes of demand-side flexibility are unlikely to emerge without some degree of compulsion, which remains politically unpalatable.

The Netherlands is pursuing one of Europe's most aggressive electrification pathways...

Similarly, no long-duration storage technology has been deployed at scale in Europe, and the economics of hydrogen storage, flow batteries or compressed-air systems remain speculative. (While some system operators such as NESO include pumped hydro in the category of "long-duration storage", most pumped hydro can only operate for around five hours before pumping is required. This is far short of the multi-day storage actually required to cover low-wind conditions that can persist for days or even weeks – the longest such weather pattern in the 38 years to 2024 lasted for 55 days[147].) While Tennet rightly acknowledges uncertainties, its modelling still assigns these resources a material contribution during the 2030s despite the lack of evidence that commercially viable projects will be operating by then.

...but grid congestion and declining firm capacity are emerging as binding constraints...

The result is that even Tennet's more realistic outlook underestimates systemic vulnerabilities. Imports cannot be relied upon during regional cold still spells, and the deterioration of gas-plant economics raises the risk that dispatchable capacity will retire faster than assumed, as major maintenance or life extension investments are unattractive (and supply chains are long). Long duration storage and demand side response may eventually support system flexibility, but they cannot substitute for firm, controllable generation (and there are doubts as to whether it will be possible to maintain stability in inverter-dominated grids[148]). Without timely investment in new dispatchable capacity, whether gas, nuclear, or both, the country's security of supply will weaken into the 2030s, regardless of how aggressively wind, solar and interconnectors expand.

...without timely investment in new dispatchable capacity, security of supply is likely to weaken through the 2030s

146 https://watt-logic.com/2024/12/29/falling-dsr-participation/

147 https://arxiv.org/abs/2410.00244

148 https://watt-logic.com/2025/10/24/location-location-location-managing-voltage-in-weak-grids/

Further challenges exist around grid capacity. Tennet received around 65 GW of new connection requests in 2024 alone - an order of magnitude above historic levels - and grid congestion now affects almost the entire country. In practice this means that even if headline renewable-capacity targets are met, electrification plans risk stalling because large industrial sites, data centres and even housing developments cannot secure timely grid connections. Concerns over grid congestion were a major factor in the decision to move away from full electrification of heating and to mandate hybrid systems instead.

Germany has identified a need for more gas-fired generation to ensure energy security

Germany targets climate neutrality in 2045, 5 years earlier than the rest of the EU

The 2016 Climate Action Plan[149], the 2023 Climate Action Programme[150] and the Federal Climate Change Act ("Klimaschutzgesetz")[151] have all set targets and policies for decarbonisation. The 2016 plan introduced legally binding targets, though these were adapted in 2024 to allow flexibility between sectors (some can be over the target if others are under), though the overall national target remains binding. Under Germany's Climate Change Act, the national economy-wide target is to reduce greenhouse-gas emissions by at least 65% by 2030, compared to 1990 levels, and to achieve net-zero by 2045. The Act sets annual emissions budgets for six sectors: energy, industry, transport, buildings, agriculture, and waste and others.

German sectoral emissions targets as set out in the Federal Climate Change Act as amended in 2024

	Annual emission budgets (MT CO_{2e})										
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Agriculture	70	68	67	66	65	63	62	61	59	57	56
Buildings	118	113	108	102	97	92	87	82	77	72	67
Energy	280		257								108
Industry	186	182	177	172	165	157	149	140	132	125	118
Transport	150	145	139	134	128	123	117	112	105	96	85
Waste and Other	9	9	8	8	7	7	6	6	5	5	4

Source: Federal Climate Change Act

Electrification could reverse Germany's falling electricity demand, potentially increasing from around 525 TWh in 2023 to potentially more than 1,000 TWh by the mid-2040s

Germany's electrification trajectory is the most ambitious of the countries considered in this report, driven by a strict legally binding economy-wide emissions reduction requirement of at least 65% by 2030 versus 1990 and climate neutrality by 2045, with sector-specific budgets for energy, buildings, transport and industry. According to Germany's System Development Strategy[152], gross electricity demand in Germany is expected to reverse its decade-long downward trend, and grow from 525 TWh in 2023 to more than 950 TWh in 2035 and as much as 1 100 - 1 300 TWh in 2045. Industrial demand is expected to grow from 214 TWh in 2023 to 250 - 320 TWh in 2035 and 300 - 400 TWh in 2045. These estimates are based on comprehensive long-term scenarios[153] covering the electricity, gas and hydrogen systems.

On the supply side, Germany aims to achieve at least 40% renewable energy in final energy consumption by 2030 (this target is not mandated by law). Germany also has a target for renewables to account for 80% of total final electricity demand, with solar PV set to increase from 99 GW in 2024 to 215 GW in 2030, onshore wind growing from 63 GW in 2024 to 115 GW in 2030,

149 https://www.bundesumweltministerium.de/en/publication/climate-action-plan-2050-en
150https://www.bundeswirtschaftsministerium.de/Redaktion/EN/Downloads/C/climate-action-programme-2023.pdf
151 https://www.gesetze-im-internet.de/englisch_ksg/englisch_ksg.html#p0029
152 https://www.bmwk.de/Redaktion/EN/Publikationen/Klimaschutz/2024-system-development-strategy.pdf?__blob=publicationFile&v=6
153 https://langfristszenarien.de/enertile-explorer-de/index.php

and offshore wind from 9 GW in 2024 to 30 GW in 2030[154].

While Germany has rapidly expanded renewables, grid bottlenecks are now slowing deployment

20 GW of new renewables were installed in 2024 with renewables generating 54% of electricity in Germany in the first half of 2025. The expansion of solar PV is almost on track to meet targets with 17 GW added in 2024 versus some 19 GW per year needed to meet the 2030 target. 3.3 GW of wind was installed in 2024, short of the 12 GW needed to meet 2030 goals[155]. More recently, in October 2025, Germany announced an intention to slow the deployment of renewables due to the slow expansion of the electricity grid[156]. This reflects the fact that grid bottlenecks and system management costs are now the primary constraints on the energy transition, overtaking the previous capacity challenges.

With nuclear already closed and coal set to exit by 2038 there are growing concerns about generation adequacy

Germany has already completed its nuclear phase-out and legislated to exit coal by 2038. Although the Government hopes to exit coal by 2030, it has said it does not plan to legislate for this. Although Germany does not have a specific target for closing gas-fired power generation, it has a target of 100% fossil-free generation by 2035 which implies that the exit will need to take place over the coming decade. The IEA[157] expects the EU ETS to be the primary driver for declining natural gas generation. However, these plant closures (alongside rising demand) are raising concerns about generation adequacy.

154 https://www.agora-energiewende.org/about-us/the-german-energiewende/what-are-the-targets-of-the-german-energiewende#:~:text=Germany's%20Energiewende%20targets%20climate%20neutrality,electrification%20and%20renewable%20energy%20expansion.
155 https://www.verbandsbuero.de/energiewende-in-deutschland-rekordausbau-erneuerbarer-energien-und-netzausbau-im-fokus/
156 https://news.sustainability-directory.com/energy/germany-slows-renewable-roll-out-to-match-lagging-power-grid-expansion/
157 https://www.iea.org/reports/germany-2025/executive-summary

Germany's energy regulator and government now acknowledge the need for 22–36 GW of additional firm generation by 2035...

In 2024 the German Government announced a Power Plant Strategy to address this issue, targeting 12.5 GW of new natural gas-fired power plant capacity that could later run on hydrogen. This would consist of up to four tenders[158] for 2.5 GW under the Power Station Strategy in the short term. These gas-fired power stations are to be fully converted to hydrogen between 2035 and 2040, with the specific conversion date to be set in 2032, and are to be set up in locations where they are useful to the system. In addition the Strategy envisages 2 GW through the conversion of existing gas-fired capacity to enable hydrogen use, and 500 MW of "sprinter plants" that could operate on hydrogen from the outset. However, so far no tenders have been run under this scheme.

.... concluding that variable renewables, demand response and storage alone are not enough

> "We are already experiencing strained grid situations on certain days and during extreme weather conditions. The grid must not be stretched to its limits. The Federal Network Agency's report shows that we need to take action and expand our dispatchable capacity, particularly new gas-fired power plants. The report projects a need for 22 to 36 gigawatts by 2035. Action is needed now,"
>
> - Katherina Reiche, Federal Minister for Economic Affairs and Energy

Slow pace of grid reinforcement adds further resource adequacy risk

As in the other countries assessed in this report, electrification plans imply rising electricity demand alongside a much more weather-dependent generation mix, with limited new dispatchable capacity and continuing uncertainty around the scale and timing of green-hydrogen deployment. A slow pace of grid reinforcement adds further risk. Germany has begun to publish increasingly explicit assessments of its future resource-adequacy risks, mirroring the concerns raised in Tennet's Dutch analyses. In September 2025, Bundesnetzagentur (BNetzA) released a new security of supply report[159], assessing supply–demand balances out to 2035. The regulator concluded that while security of supply can be maintained in the medium

158 https://www.bundeswirtschaftsministerium.de/Redaktion/EN/Pressemitteilungen/2024/02/20240205-agreement-on-power-station-strategy.html

159 https://www.bundeswirtschaftsministerium.de/Redaktion/DE/Pressemitteilungen/2025/09/20250903-bundesnetzagentur-legt-bericht-zur-versorgungssicherheit-strom-vor.html

While Germany has rapidly expanded renewables, grid bottlenecks are now slowing deployment

term, this is contingent on a substantial volume of new dispatchable generation being commissioned over the next decade. In its central scenario, Germany will require between 22 GW and 36 GW of additional controllable capacity by 2035 to offset the retirement of coal and nuclear units and the rising electrification of heat, transport and industry. This represents one of the clearest official acknowledgements yet that variable renewables alone cannot support Germany's decarbonisation strategy. The regulator also called for more demand-side flexibility.

With nuclear already closed and coal set to exit by 2038 there are growing concerns about generation adequacy

Parallel analysis[160] undertaken by the four German transmission system operators (50Hertz, Amprion, Tennet DE and TransnetBW) reinforces these concerns. Their joint study on the development of a future capacity mechanism warns that Germany faces an emerging structural shortfall of 20–25 GW of firm capacity, which "far exceeds the planned tender volumes of the Power Plant Strategy". The analysis also highlights that investor confidence in building new gas- or hydrogen-ready plant remains weak under the current energy-only market design, implying a high risk that the required firm capacity does not materialise without formal capacity-market support. The study recommends preparatory steps toward an explicit capacity mechanism, something Germany has long resisted for political reasons, but which now appears inevitable.

Germany's energy regulator and government now acknowledge the need for 22–36 GW of additional firm generation by 2035...

Taken together, the emerging German evidence base places its adequacy outlook closer to Tennet's candid Dutch assessment than to the more optimistic assumptions underpinning Statnett or DNV in Norway. While the German reports highlight the value of flexibility resources, they do not pretend that demand-side response and long-duration storage can reliably replace dispatchable capacity in the 2030s.

.... concluding that variable renewables, demand response and storage alone are not enough

Rather, the official view is now that significant volumes of new firm generation are required, and that policy reform, most likely in the form of a capacity mechanism, will be necessary to deliver it in time. Germany therefore offers a case study in how high-renewables policy ambitions ultimately collide with the physical requirements of system adequacy once coal and nuclear exit the fleet. This realism on the need for new gas-fired power generation is one UK policymakers would do well to adopt.

160 https://www.netztransparenz.de/en/Electricity-market-design/Capacity-mechanism/4TSO-study-on-the-development-of-a-capacity-mechanism-for-the-German-electricity-market

Conclusion

There is a widening disconnect between the UK's electrification ambitions and the practical realities of delivering them. In heating, consumer resistance, slow installer growth, and high capital and running costs make rapid heat-pump deployment implausible. In transport, EV mandates are running ahead of public willingness to adopt, while grid and charging-infrastructure constraints remain severe. Industrial electrification is constrained not by technology but by economic viability, with de-industrialisation, driven by high electricity prices reducing demand far more rapidly than electrification can increase it. Across all sectors, both NESO's and the CCC's modelling rests on optimistic behavioural and technological assumptions that are neither well-evidenced nor consistent across scenarios.

Simultaneously, the power system on which electrification depends is entering a period of acute vulnerability. Up to 17 GW of firm generating capacity is at risk of retirement by 2030, including ageing CCGTs and the entire AGR fleet, and there are no credible replacement plans aligned with the realities of global equipment lead times. Renewables cannot provide security during low-wind winter events, and reliance on interconnectors is dangerous when neighbouring systems face similar weather patterns. Emerging risks in the gas transmission network further threaten the availability of fuel for power generation precisely when it is most needed.

The inevitable conclusion is that the electricity system will struggle even to maintain today's demand reliably, let alone accommodate the 7–10 GW of new load implied by electrification agendas. AI data centres are therefore likely to adopt off-grid solutions, and large-scale electrification of heat and industry appears improbable before 2030 and likely not for several years after that. Without decisive policy action, the UK faces a rising probability of regional rationing, blackouts and cascading grid failures.

These concerns are reflected in other European markets. Despite its already highly electrified economy, Norway will struggle to meet expected demand with current generation resources. The same is true in the Netherlands and Germany. While the Dutch system operator, Tennet, has expressed clear, and more realistic concerns than articulated by either Statnett in Norway or NESO in the UK, it falls short of the assessment in Germany that new gas-fired generating capacity will be necessary in order to ensure security of supply in the 2030s.

Persistently high electricity prices will continue to undermine electrification goals. While the Government continues to assert that gas is expensive and volatile, and that it is necessary for both energy security and affordability to "get off gas", the inconvenient truth is that gas was only expensive briefly and it is almost always cheaper to generate electricity with gas than wind and solar, once the full costs to consumers are included.

To restore Britain's energy security, the UK Government must urgently pivot from aspirational modelling to credible planning. This requires rapid life-extension support for ageing gas generation; accelerated procurement of new dispatchable capacity; reform of network investment incentives to prioritise resilience; and a realistic reassessment of electrification timelines. Net zero targets cannot be allowed to override the imperative of public safety. Security of supply must once again become the foundational principle of UK energy policy.

Appendix 1: Efficiency levels per heating technology

The heat pump efficiencies are set out in the FES assumptions workbook. The rest are based on industry norms:

Holistic Transition	2025	2035
ASHP	2.90	3.50
BioLPG boiler	0.90	0.92
Biomass boiler	0.85	0.88
Fossil fuel communal heating	0.85	0.87
Low carbon district heating	0.90	0.92
Low carbon district heating	2.90	3.50
Low carbon district heating	0.85	0.87
Electric resistive	1.00	1.00
Electric storage	1.00	1.00
Gas boiler	0.90	0.92
GSHP	3.30	3.60
Hybrid (ASHP + BioLPG boiler)	1.75	2.25
Hybrid (ASHP + BioLPG boiler)	1.75	2.25
Hybrid (ASHP + Electric resistive)	2.05	2.44
Oil boiler	0.88	0.90

Hydrogen Evolution	2025	2035
ASHP	2.90	3.10
BioLPG boiler	0.90	0.92
Biomass boiler	0.85	0.88
Fossil fuel communal heating	0.85	0.87
Low carbon district heating	0.90	0.92
Low carbon district heating	2.90	3.10
Electric resistive	1.00	1.00
Electric storage	1.00	1.00
Gas boiler	0.90	0.92
GSHP	3.30	3.60
Hybrid (ASHP + BioLPG boiler)	1.75	2.25
Hybrid (ASHP + BioLPG boiler)	1.75	2.25
Hybrid (ASHP + Electric resistive)	2.05	2.44
Hybrid (ASHP + Hydrogen boiler)	1.75	2.25
Hybrid (ASHP + Hydrogen boiler)	1.75	2.25
Hydrogen boiler	0.90	0.92
Oil boiler	0.88	0.90

Electric Engagement	2025	2035
ASHP	2.90	3.10
BioLPG boiler	0.90	0.92
Biomass boiler	0.85	0.88
Fossil fuel communal heating	0.85	0.87
Low carbon district heating	0.90	0.92
Low carbon district heating	2.90	3.10
Electric resistive	1.00	1.00
Electric storage	1.00	1.00
Gas boiler	0.90	0.92
GSHP	3.30	3.60
Hybrid (ASHP + BioLPG boiler)	1.75	2.25
Hybrid (ASHP + BioLPG boiler)	1.75	2.25
Hybrid (ASHP + Electric resistive)	2.05	2.44
Oil boiler	0.88	0.90

Falling Behind	2025	2035
ASHP	2.90	2.90
BioLPG boiler	0.90	0.92
Biomass boiler	0.85	0.88
Fossil fuel communal heating	0.85	0.87
Low carbon district heating	0.90	0.92
Low carbon district heating	2.90	2.90
Electric resistive	1.00	1.00
Electric storage	1.00	1.00
Gas boiler	0.90	0.92
GSHP	3.30	3.60
Hybrid (ASHP + BioLPG boiler)	1.75	2.25
Hybrid (ASHP + BioLPG boiler)	1.75	2.25
Hybrid (ASHP + Electric resistive)	2.05	2.44
Oil boiler	0.88	0.90

Norway

Norway's climate objectives are set out in the Norway's Climate Action Plan for 2021–2030, produced by the Ministry of Climate and the Environment.

Transport

Norway's National Transport Plan 2018–2029 sets out a number of targets for new zero emission vehicles:

- All new passenger cars and small vans are to be zero-emission vehicles from 2025;
- New local buses are to be zero-emission vehicles or run on biogas from 2025;
- By 2030, all new large vans, 75% of new long-distance coaches and 50% of new trucks are to be zero-emission vehicles;
- By 2030, goods distribution in the largest urban centres is to be virtually emission free.

The targets are based on the assumption that zero-emission technologies in the different transport segments will mature so that they become competitive with conventional solutions.

The Plan was updated in the National Transport Plan 2022–2033[161] which is designed to reduce transport sector emissions by 50% by 2030 but the policy targets outlined above were unchanged. The targets assume certain improvements in technological maturity are delivered.

Norway's vehicle taxes create strong incentives to choose zero-emission vehicles. The Institute of Transport Economics has estimated that if all CO_2-differentiated taxes and grant schemes are taken into consideration, the implicit carbon price for passenger cars in Norway was at least NOK 12 500 per tonne CO_2 in 2019 and at least NOK 11 200 in 2020. The Government intends to make zero-emission vehicles the natural preferred choice for heavy vehicles as well cars, but with biofuels rather than electrification being the primary route to decarbonisation. All new local buses should be zero-emission or run on biogas by 2025 - in fact this target was met in 2023[162].

Norway's unique geography, with countless fjords, islands, and coastal towns means ferries are an important element of connectivity. Norwegian ferries carry thousands of passengers, vehicles, and goods every day, in areas where bridges and tunnels are not feasible. Traditional diesel ferries have been heavy polluters, producing significant amounts of CO_2, particulate matter, and noise, accounting for a considerable share of Norway's overall transport-related emissions.

As a result, the Government has set a target that all publicly operated ferries operating along the coastline should be zero-emission by 2030. From 1 January 2026, all tourist ships and ferries under 10,000 gross tonnes operating in Norway's UNESCO World Heritage fjords (such as the Geirangerfjord and Nærøyfjord) must be zero-emission. Larger passenger ships have until 1 January 2032, to comply[163]. The world's first all-electric car ferry, MF Ampere, was put into service on the Sognefjorden in 2015. In 2020, 26 ferry services were electrified, and by 2025 there were 80 electric ferries in operation[164], representing more than half of all ferries operating certain ferry services in the country[165].

More broadly across Norway's maritime sector, decarbonisation plans include energy efficiency measures, battery technology, shoreside electric power, hydrogen, ammonia and biofuels. Although Norway's decarbonisation targets for transport are not legally binding, the combination of policy signals, funding and infrastructure investment makes sustained transport electrification highly likely.

161 https://www.regjeringen.no/en/documents/national-transport-plan-2022-2033/id2863430/
162 https://www.sustainable-bus.com/news/27-europe-cities-target-zero-emission-bus-fleet-2030/
163 https://www.offshore-energy.biz/norway-scales-up-maritime-climate-rules-with-new-zero-emission-targets/
164 https://businessnorway.com/articles/norway-showcases-award-winning-electric-ferry-technology
165 https://bellona.org/news/arctic/2025-05-short-sea-shipping-must-be-electrified-insights-from-norway

Heating

Buildings account for more than half of the electricity consumption in Norway, and electricity accounts for almost 80% of the total energy consumption in buildings, the majority of which is used for heating. The Norwegian government began subsidising heat pump installations in 2001, resulting in Norway having the highest number of heat pumps per capita in Europe. By 2020 the number of heat pumps in Norway was estimated to be 1.3 million[166], with 60% of homes having a heat pump by 2022[167].

Like the UK, Norway has a building energy certification scheme[168], but it is considered more rigorous than the UK equivalent since it focuses on heat losses and carbon dioxide emissions rather than heating cost, and involves detailed calculations of heat losses reducing subjectivity.

Building codes and regulations: Norway has stringent building codes that require new buildings to meet high energy efficiency standards. The TEK17 Building Code forbids the use of fossil-fuel based heating in new buildings and has maximum energy demand levels for buildings[169] that can be more easily met using heat pumps. The SAK10 Building Regulations impose liabilities[170] on building companies to ensure compliance with energy efficiency and energy performance standards in Norwegian buildings. If a building does not meet the required energy performance standards, the building company could be held liable. This includes potential legal and financial liabilities if the building fails to comply with regulations, leading to penalties or the need for costly rectifications.

Public awareness campaigns: The Norwegian government, through Enova and other agencies, has run public awareness campaigns to educate citizens about the benefits of heat pumps, including cost savings, environmental impact, and long-term efficiency.

Research and development funding: The Norwegian government also invests in research and development to advance energy efficiency and decarbonisation of heating[171]. Research institute, SINTEF, which is partly funded by the Norwegian government, has an extensive programme[172] relating to heat pumps.

In 2023 the Norwegian Government announced[173] its intention to evaluate a new target of reducing the energy consumption of buildings by 10 TWh by 2030, compared with 2015. So far this target has not been adopted. The Government increased Enova's budget[174] by NOK 180 million in 2024 to strengthen efforts to promote more efficient energy use and a more flexible energy system. However, the government intends to reduce Enova's overall budget in 2026, which may impact the funds available for heat pump subsidies[175].

In 2024 the Norwegian government introduced new state planning guide-

166 https://www.sciencedirect.com/science/article/pii/S2213138822008773
167 https://www.nature.com/articles/s41560-022-01104-8
168 https://www.nve.no/energy-consumption-and-efficiency/energy-labelling-of-housing-and-buildings/
169 https://www.dibk.no/regelverk/byggteknisk-forskrift-tek17/14/14-2?_t_q=varmepumpe
170 ttps://www.dibk.no/regelverk/sak/3/12/12-6?_t_q=energieffektivitet
171 https://www.forskningsradet.no/portefoljer/energi-transport-og-lavutslipp/portefoljeplanen-for-energi-transport-og-lavutslipp/prioriteringer/tematiske-prioriteringer/
172 https://www.sintef.no/ekspertise/sintef-energi/varmepumpeteknologi/
173 https://www.regjeringen.no/no/dokumenter/handlingsplan-for-energieffektivisering-i-alle-deler-av-norsk-okonomi/id2998036/?ch=1
174 https://www.regjeringen.no/no/aktuelt/enova-okes-med-400-millioner-kroner/id2996214/
175 https://www.regjeringen.no/en/whats-new/securing-the-economy-society-and-country/id3124364/

Buildings account for more than half of Norway's electricity consumption

lines for climate and energy[176]. The guidelines are intended to ensure municipal, regional and state planning helps to support national climate goals as set out in the Climate Act, and facilitate land use and solutions that reduce greenhouse gas emissions, maintain the areas' ability to absorb and store carbon and support the transition to a low-emission society; efficient and flexible energy use; development of renewable energy; a circular economy and that society and ecosystems are prepared for and adapted to a changing climate.

Norwegian building regulations are among the strictest in Europe...

The guidelines seek to ensure that municipalities work to achieve the lowest possible emissions and strive towards zero emissions in all their activities. They must adopt and promote climate-friendly and energy-efficient solutions in their own operations, and in their purchases of goods and services in accordance with the regulations on public procurement. They must reduce energy use in their own operations and implement measures that increase energy flexibility where relevant. This must be done in a way that takes climate into account. Municipalities and county authorities, in their role as social developers, should actively facilitate the reduction of emissions and energy consumption by businesses and citizens, and the transition to a low-emission society and a circular economy. This should be done in dialogue with relevant stakeholders in areas such as recycling and reuse.

... fossil-fuel heating is banned in new buildings

Municipalities must also cooperate with district heating concessionaires to optimise the use of local heating resources, and they must cooperate with grid companies in their assessment processes, including in identifying the need for expansions in power grid capacity or alternatives to grid expansion or reinforcement.

In September 2025, the Norwegian Ministry for Local Government and Regional Development published a National Architecture Strategy[177]. It says that The Norwegian Building Authority will bring forward proposals for public consultation to amend the energy and climate requirements in the building regulations. Key goals are to promote more energy-efficient buildings and more climate-friendly construction work. The Strategy states that buildings should be designed in ways that prevent heat loss, that ensure solar gain, provide sustainable lighting and flexible energy solutions contribute to efficient energy use. Municipalities are expected to play an important role, by having an overview of the possibilities for heating and cooling based on local energy sources, such as surplus heat.

176 https://lovdata.no/dokument/SF/forskrift/2024-12-20-3359

177 https://www.regjeringen.no/contentassets/506fc37d1bbc41d886e63011dfac3322/h-2565-e_space-for-quality_national-architecture-strategy_spreads_lr.pdf

Norway has the highest heat-pump penetration in Europe...

According to the Norwegian Heat Pump Association[178], the number of heat pumps sold decreased across all categories in 2024, with the total number of units sold down 22% compared to 2023, returning to 2021 levels. The Association considers that new building regulations expected later in the year will stimulate renewed demand, with more efficient models gaining popularity as well as a possible move away from the all-electric models that currently dominate the market.

...but use of wood for heating is stil widespread...

Norway is often held out as a heat pump success story and evidence that heat pumps work well in cold climates. But this is misleading – very many Norwegian homes use secondary heating. A 2017 survey of urban homes[179] found that the main heating source was electricity which represent 61%, followed by heat pumps (15%), district heating (9%), wood burning (7%), oil (4%) and other (4%). Around 62% of the responders had wood burning as a secondary heating source, and 7% as primary source. Previous studies referenced by the researches had concluded that fuelwood, along with heat pumps, are intensively used in detached houses in Norway and are used to reduce electricity consumption for residential heating.

...around 87.5% of Norwegian households have a wood-burning stove...

A 2019 study by the Norwegian Institute for Air Research[180] found that there were an estimated 2.1 million domestic wood burning heating installations in the 2.4 million Norwegian households, with an additional 900,000 in the 1 million cabins and summer houses of Norway. In other words, 87.5% of Norwegian households have a wood-burning stove and 90% of cabins and summer houses. By this measure, more homes have a wood stove than a heat pump.

....far exceeding the share of homes with heat pumps...

According to a 2022 survey by Norstat on behalf of Norsk Varme[181], nine out of ten Norwegians who have a fireplace use it, with one in five Norwegians burning wood as their main source of heating. Record high electricity prices at the time provided a strong incentive for the use of wood burning stoves, with many households lighting fires earlier in the year as a result, rather than waiting for the coldest weather. The survey found that half of Norwegians use their wood fires every day and 80% use them at least once a week. Between 2020 and 2022, 340,000 homes installed new wood stoves. Norwegians are increasingly installing outdoor fireplaces with 30% of homes having a fire pan for outdoor heating.

...wood burning is an informal but highly effective form of peak electricity demand management

While the Norwegian Government does not encourage the use of wood

178 https://www.novap.no/artikler/nedgangen-fortsetter-i-andre-kvartal

179 https://www.sciencedirect.com/science/article/pii/S0301479717300269

180 https://acp.copernicus.org/preprints/acp-2019-95/acp-2019-95-manuscript-version4.pdf

181 https://norskvarme.org/nordmenn-elsker-a-fyre-med-ved-halvparten-av-befolkningen-fyrer-daglig-nar-det-er-hoye-strompriser/

burning stoves, it does try to encourage people to replace older stoves with more modern versions which are more efficient and have lower emissions. It is also true that irrespective of intent, the use of wood burning stoves helps to protect the electricity grid at times of peak demand since on the coldest days people supplement or replace their heat pump use with wood fires which have a higher heat output. Electricity grid operator Statnett, in common with its counterparts elsewhere, has emphasised the need for alternative sources of heating to help support the power grid at times of peak cold weather demand. A 2022 report by Thema Consulting Group[182] available on the Norwegian Government's website found that over the next decade, the power balance will be weakened, and there may be a power deficit in normal years if the scenarios of high consumption growth and low output growth materialise.

Industry

Industrial electrification is a cornerstone of Norway's decarbonisation strategy...

In Norway, industrial electrification is a core pillar of decarbonising both onshore industry and the offshore oil and gas sector. The KonKraft partnership developed the climate strategy "The Energy Industry of Tomorrow on the NCS – Climate Strategy towards 2030 and 2050"[183] in 2020. The strategy describes the industry's efforts to achieve national and global climate goals. One of the KonKraft collaboration's primary aims is to cut greenhouse gas emissions from the Norwegian oil and gas industry by 50% by 2030 compared with 2005 levels, and to near zero by 2050. In parallel with reducing emissions from petroleum activities, a new and forward-looking energy industry will be built on the Norwegian continental shelf, comprising offshore wind, hydrogen, and carbon capture and storage ("CCS"). KonKraft is a collaboration arena for Offshore Norge, the Federation of Norwegian Industries, the Norwegian Shipowners' Association, the Confederation of Norwegian Enterprise (NHO), and the Norwegian Confederation of Trade Unions (LO), together with the LO members – the United Federation of Trade Unions and the trade union Styrke.

...electrification of offshore oil and gas installations is a priority

The oil and gas sector is Norway's largest industry. KonKraft's annual status report shows steady progress towards its 2030 goal - in 2024, emissions from the Norwegian oil and gas industry amounted to 11 MT CO_2e, a decrease of 0.48 M CO_2e compared to 2023. Despite high production in recent years and a new annual record for gas production in 2024, emissions on the Norwegian shelf continue to fall. The Norwegian oil and gas industry is on track to realising emission reductions, however, supply chain constraints and higher costs of critical equipment mean that some projects

182 https://www.regjeringen.no/contentassets/5f15fcecae3143d1bf9cade7da6afe6e/no/sved/vedlegg4.pdf

183 https://www.konkraft.no/contentassets/4d390ee086f548f086feee2a3765ea38/the-energy-industry-on-the-ncs.-climate-strategy-towards-2030-and-2050.pdf

that are currently in the maturation phase will not come on stream until 2032.

Power from the shore remains the most cost-effective decarbonisation option for offshore installations...

Electrification of oil and gas installations with power from the shore remains the primary measure for reducing offshore emissions. Since the last status update, all major planned and applied for power from shore projects have secured reserved grid capacity. Confirmed grid capacity is a key prerequisite for final investment decisions in these projects. Electrification projects approaching investment decisions include the area solutions for Halten Nord, Tampen, and Balder/Grane, and will collectively require a maximum of approximately 2 TWh of power. The electricity required represents a small proportion of national power demand.

Measures such as electrification with local offshore wind and power generation on offshore installations with CCS are generally more expensive than power-from-shore solutions and energy efficiency measures. Over the past year, offshore wind power with a direct platform connection has been removed from the portfolio of measures. Electrification of Ekofisk and Eldfisk through a connection to the Sørlige Nordsjø II offshore wind farm is no longer considered viable due to the high costs associated with modifying the installations. This means that the offshore infrastructure will rely more heavily on power supplies from the shore.

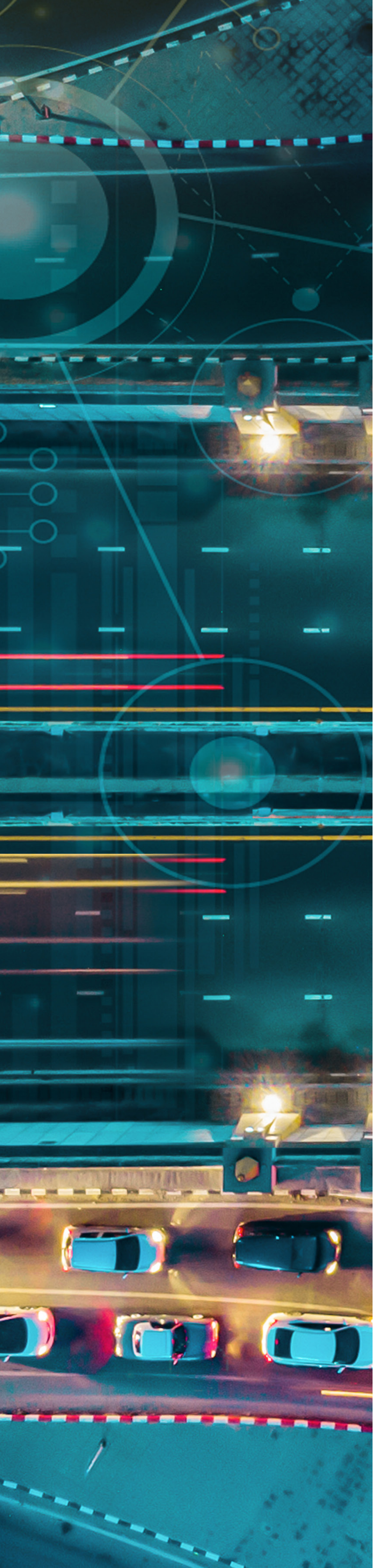
...offshore wind solutions and CCS have largely been abandoned due to cost

The share of emissions from industrial processes is relatively high. The Government believes that emissions from the use of fossil fuels, both for heating and for industrial processes, can be reduced through electrification and by using electric boilers and furnaces, and through the use of carbon capture and storage, and hydrogen. For example, the Government announced plans to co-fund the carbon capture project at Fortum Oslo Varme's waste incineration plant as part of the Climate Action Plan, however, the project has been on hold for several years due to cost concerns, only re-starting development in 2025[184].

The Rockwool plant in Moss south of Oslo received funding from Enova to replace fossil-fuel melting furnaces with a new generation of electric furnaces. The plant's large-scale electric melting technology reduced emissions by approximately 80% compared to the previous coke-burning furnace it replaced. The project was a pilot for the company globally.

While the Norwegian Government is still officially committed to hydrogen as a means of decarbonising its industries, state oil and gas company, Equinor, and oil major Shell have recently cancelled a number of hydrogen projects.

184 https://hitecvision.com/news/carbon-capture-in-oslo-becomes-a-reality/



In September 2024 Equinor announced it was cancelling[185] its proposed 10 GW "blue hydrogen" export pipeline from Norway to Germany, citing that the pipeline cost (~€3 billion) and the lack of long-term buyer commitments rendered the business case unviable. The project also included blue hydrogen production.

Just days later, Shell decided to scrap its plans for its hydrogen hub in Norway. The Aukra Hydrogen Hub was to be a large-scale production facility for clean hydrogen using natural gas from the local gas processing plant to produce 1089 tons (1200 tonnes) per day of blue hydrogen by 2030 and then double capacity by 2035 using blue hydrogen and green hydrogen from offshore wind farms. Like Equinor, Shell blamed market dynamics for the project's downfall[186].

These cancellations highlight the strategic and economic risks of large-scale hydrogen export value chains, even in jurisdictions with strong industrial hydrogen ambitions. They also imply a larger role for electrification in industrial decarbonisation.

The Netherlands

The Netherlands has established comprehensive electrification targets across transport, heating, and industry as part of its climate strategy. These targets are a mix of binding and indicative commitments, supported by national legislation and EU directives. Many of these are rooted in the in the Climate Act 2019 (Klimaatwet)[187] which set legally binding greenhouse gas emissions reduction targets for the Netherlands. Flowing from the Act is the Climate Agreement (Klimaatakkoord)[188], which sets out policy objectives in various areas. While the Climate Act has full statutory powers, the Climate Agreement does not – the objectives set out in it are not legally binding on third parties unless subject to other legislation (ie they are binding on the government, but not on car makers, households and so on).

Recently the Dutch authorities have begun to worry about the impact the growth in heat pumps will have on electricity demand, and consider that without action to strengthen electricity grids, 1.5 million SMEs and households could experience a power outage in the period to 2030[189], in the worst case scenario. One option under consideration is to use the ISDE subsidy to incentivise heat pumps with smart controls which would prevent all units drawing power from the grid at the same time, effectively staggering demand (subject to ensuring consumer protections around consent), however such measures are unlikely to be introduced before 2026.

In 2022, grid operators saw an explosive growth in demand for electricity connection requests[190] - more than 53 GW of transmission capacity were requested from Tennet, compared with a historic average of just 6 to 8 GW. The whole country is to one degree or another being affected by grid congestion. Problems on the high-voltage network are already affecting large energy users, who can no longer get a grid connection in some areas. The Minister for Climate and Energy Policy, Rob Jetten, warned in a letter to the Dutch Parliament that small users - including households - may face the same problems, and be unable to secure grid connections. If no flexible electricity capacity can be found, the "physical limits" of the grid could be reached in some areas as early as 2025, with a risk of outages affecting households between 2026 and 2029[191].

185 https://theelectricityhub.com/equinor-abandons-blue-hydrogen-plans-in-norway/
186 https://esgreview.net/2024/09/25/equinor-shell-cancel-european-hydrogen-megaprojects/
187 https://climate-laws.org/document/climate-act_4bc4
188 https://www.klimaatakkoord.nl/documenten/publicaties/2019/06/28/national-climate-agreement-the-netherlands
189 https://www.rijksoverheid.nl/documenten/kamerstukken/2024/04/25/kamerbrief-versnelling-en-uitbreiding-maatregelen-netcongestie-flevoland-gelderland-en-utrecht-fgu
190 https://www.tweedekamer.nl/kamerstukken/brieven_regering/detail?id=2023D27812&did=2023D27812
191 https://www.rijksoverheid.nl/documenten/kamerstukken/2023/10/18/nieuwe-maatregelen-netcongestie

Transport

In the coalition agreement[192], the Dutch government committed to the target of all new passenger vehicles sold in 2030 being zero-emission, whether hydrogen-electric or battery-electric. It believes this will result in an annual average of 400,000 electric passenger vehicles entering Dutch roads from 2030. The government has committed to developing the necessary refuelling and charging infrastructure however, the supply and operation of the charging equipment principally remains the responsibility of market parties. A charging requirement of 1.8 million public, semi-public and private charge points by 2030 has been identified. While this commitment is set out in the Climate Agreement, it is only binding on the government and not third parties. The Netherlands does not have a ZEV mandate equivalent to that in the UK, with obligations on manufacturers, and penalties for non-compliance.

The Zero-Emission City Logistics Green Deal[193] started with a several dozen signatories in 2014, from central government and municipalities to transporters and shipping companies, and from car manufacturers and research institutes to sector organisations and interest groups. Since then, it has developed into an initiative that has over 100 participants. The goal is to realise optimum zero-emission city logistics by 2025. As part of the approach, the local pilots – also called living labs – will be translated into a large-scale roll-out from 2020. Some major cities such as Rotterdam, The Hague and Utrecht have taken the first steps towards introducing a zero-emission zone.

From 2025, all new buses used in public transport should emit zero harmful exhaust gases, however there are signs this target has not been met as expected. While all new buses were zero emission as early as 2023, reports[194,195] early in 2025 indicated that there were ongoing issues with the supply of electric buses as well as charging infrastructure and wider electricity grid congestion. Although the Netherlands set an objective that all new public-transport buses entering service from 2025 would be zero-emission, delivery delays and electricity-grid congestion have forced operators to retain older diesel stock, including vehicles previously withdrawn from service. Belgian bus manufacturer Van Hool entered bankruptcy[196] in 2024 and was subsequently taken over by the Dutch group VDL, while Dutch manufacturer Ebusco experienced financial distress and the cancellation of large numbers of orders[197]. This indicates a gap between procurement policy and system-level readiness. There is no evidence of a return to procuring new diesel buses, but there are clear signs that older diesel models are being retained and used more than previously intended.

In 2016, all transport authorities active in the Netherlands had already signed the Administrative Agreement on Zero-Emission Regional Public Transport by Bus in cooperation with central government. As part of this agreement, the transport authorities require all public bus transport in their concessions to be 100% zero-emission by 2030 and all new buses entering service from 2025 to be zero-emission at the onset. All energy required by these battery-electric and hydrogen-electric buses should be fully renewable and generated regionally through solar panels or wind turbines, where possible.

In mid-2018, 32 municipalities signed the Administrative Agreement on Zero-Emission Target Group Transport with the Ministry of Infrastructure and Water Management. Target group transport is the transport for people who cannot travel independently, either temporarily or permanently, as a

192 https://www.rvo.nl/files/file/2019/06/Misson%20Zero%20Powered%20by%20Holland.pdf
193 https://www.iea.org/policies/3011-green-deal-on-zero-emission-city-logistics-green-deal-zes
194 https://www.sustainable-bus.com/news/netherlands-transition-electric-buses-grid-issues/
195 https://pvmagazine.nl/netcongestie-laad-en-batterijproblemen-fnuiken-uitrol-elektrische-bussen-en-doen-dieselbussen-terugkeren/
196 https://www.sustainable-bus.com/news/van-hool-vdl-crisis-future/
197 https://www.ebusco.com/ebusco-announces-further-details-of-its-turnaround-plan/

result of physical or mental disabilities.

The Netherlands has effectively mandated zero-emission public buses by 2030...

There is no clear publicly-documented nationwide binding mandate in the Netherlands that all new HGVs sold must be zero-emission from a certain date. The policies focus more on zones, incentives, and toll/fee differentiation rather than absolute sales bans or quotas for HGVs. While ambitious targets exist for freight/urban logistics, the national regulation for long-haul heavy trucks isn't clearly laid out. A new Dutch truck toll[198] is scheduled for launch on 1 July 2026, replacing the Eurovignette. The motor vehicle tax will be reduced to a minimum. As in neighbouring countries, both domestic and foreign owners of trucks over 3.5 tons will pay a rate per kilometre driven, with lower emission trucks paying lower rates. The toll will apply to almost all motorways and to a number of main provincial and municipal roads.

...with all new buses zero-emission from 2025...

...unlike buses and vans, there is no clear mandate for zero-emission HGVs...

In addition, from 1 January 2025, municipalities in the Netherlands are permitted to designate an urban area as zero emission, meaning no polluting vans and trucks are allowed to enter. The perimeter of these zones must cover at least the city centre and possibly surrounding neighbourhoods. Vehicles including vans and trucks may only enter if they do not emit any polluting substances, for example, running on electricity or hydrogen. Zero-emission zones should not be confused with environmental zone ("millieuzone"), which exclude certain diesel vehicles. There are subsidies available to help cover the costs of new zero emission trucks[199].

...policy relies on urban access restrictions, differentiated tolls and subsidies

Heating

The Netherlands is an interesting case study. Like the UK, the Netherlands has relied on its own natural gas resources, and actively encouraged the use of natural gas for space and water heating. However, since the mid-2010s, the Government pivoted and began to incentivise heat pumps, and by 2023, 1.9 million domestic heat pumps were in use, representing 23% of all households (assuming one heat pump per household, which is not necessarily the case). However, this success has been a double-edged sword, with heat pump related electricity demand adding to problems with electricity grid congestion. Since 2022, the Dutch Government has actively incentivised the installation of hybrid heat pumps as the preferred route in the short term for the decarbonisation of heating.

Rapid heat-pump deployment has driven electricity demand growth contributing to grid congestion...

Under the Dutch Climate Agreement, the Netherlands aims to significantly reduce its reliance on natural gas. In 2018, the Dutch Government announced an ambition to "close the gas valve" for 30,000 to 50,000 houses every year from 2021[200], and to make 1.5 million buildings natural-gas-free by 2030[201]. This transition is partly facilitated by promoting the use of heat pumps.

Grid congestion concerns are also driving policy interest in hybrid systems, with ministers suggesting that homes considering switching to fully electric systems should first consider whether there is electricity grid congestion in their area. One of the challenges with heat pumps is that they must be sized for the maximum annual heating requirement which in the Netherlands can involve ambient temperatures of -10°C. However, such low temperatures may only occur for ten days each year. Sizing a heat pump to manage this heating requirement can require a larger unit with a larger grid connection, possibly necessitating grid reinforcement, particularly if multiple households are specifying similarly large systems. A hybrid system allows smaller heat pumps to be used because the low temperature requirement can be covered by the gas boiler. Since the number of very cold days on which gas would be required is typically low, the climate impact of this choice is similarly small. Hybrid heat pumps would also be compatible with the use of green gas.

...prompting a policy pivot to hybrid systems

198 https://www.vrachtwagenheffingsbeleid.nl/english

199 https://business.gov.nl/sustainable-business/sustainable-business-operations/zero-emission-zones-in-the-netherlands/

200 https://zoek.officielebekendmakingen.nl/kst-33529-457.html

201 https://www.government.nl/topics/climate-change/national-measures

In his October 2023 letter to the House of Representatives, Minister Jetten said that hybrid systems allow users to switch between using gas and electricity and are therefore less burdensome for the electricity grid – hybrid systems can switch to gas at times of peak electricity grid demand if necessary to maintain security of electricity supplies. This solution is considered temporary, but is being evaluated for new buildings – the Netherlands, like the UK, has a housing shortage, and the ability to deliver the required number of low carbon homes is threatened by electricity grid constraints. The Government would like to ensure that grid constraints do not undermine the delivery of housing targets. Electric central heating boilers have already been banned as a result of congestion concerns, and the Minister also outlined plans to enforce the ban more strictly.

Hybrid heat pumps reduce peak electricity demand by switching to gas during cold spells, easing grid constraints

However, in May 2024 the proposed hybrid heat pump mandate was scrapped[202], and at this time, the Netherlands does not have any active heat pump mandate.

Industry

In the Netherlands industry electrification is a key pillar of decarbonisa-

202 https://www.bouwbeurs.nl/en/artikelen/nieuw-kabinet-schrapt-verplichte-hybride-warmtepomp

tion. The 2019 Climate Accord identified electrification as a key option for the reduction of CO_2 industrial emissions by 2030. The Roadmap to Electrification in Industry states that by 2050, 80 to 130 TWh of industrial energy demand - enough to meet at least 60 % of total needs - will be electrified[203]. The report suggests the additional electricity that industry will use, both directly and indirectly via conversion to hydrogen, could reach some 130 TWh by 2050, in addition to existing industrial electricity demand, demand from new industries, and growing demand from other sectors such as datacentres.

By 2050, industrial electrification in the Netherlands could require up to 130 TWh of additional electricity...

The potential is greater than the current total electricity use in the Netherlands, and three to four times greater than the current level of demand for electricity from industry. The minimum amount of electricity and green hydrogen that will be needed to meet emission-reduction targets, is estimated at 80 TWh. Other emissions-reduction options such as energy conservation, green gas, geothermal, and the current cap for carbon capture and storage, will also need to be maximised. The roadmap suggests that meeting the potential for electrification in 2050 will create demand for electricity equivalent to 26 to 46 GW of offshore wind power.

... more than today's total national power consumption

Dutch industrial electrification roadmap

	2030	2050
Electricity demand (TWh)	30-80	80-130
Reduction in CO_2 emissions (MT)	9-20	20-45
Generation (GW offshore wind)	10	26-46

Source: TKI Energie en Industrie, TNO, DNV, and MSG Sustainable Strategies

According to Institute of Sustainable Process Technology ("ISPT"), by 2030 the Netherlands could electrify at least 30 TWh of industrial demand (roughly a 9 $MtCO_2$ reduction) and potentially up to 80 TWh (c20 $MtCO_2$)[204].

By 2030, at least 30 TWh of industrial energy demand could be electrified...

...cutting emissions by up to 20 $MtCO_2$

As in the UK, recent developments in the Netherlands suggest increased uncertainty around the role of hydrogen, which would imply an increased role for electrification, particularly for industrial decarbonisation. In October 2024, the Environmental Assessment Agency ("PBL") warned that the Netherlands will almost certainly miss its 2030 electrolyser capacity goals and binding EU targets for renewable hydrogen use in industry by a large margin[205]. In its Climate and Energy Outlook 2024, PBL forecasts that the Netherlands will have 1.2-1.5 GW of electrolyser capacity installed by 2030 - less than half of its 3-4 GW target. PBL also sharply cut its forecast for renewable hydrogen consumption by Dutch industry, slashing it by more than half to 12-15 PJ /yr from the 27-40 PJ /yr it had predicted in last year's report.

Germany

Germany targets climate neutrality in 2045, 5 years earlier than the EU

The 2016 Climate Action Plan[206], the 2023 Climate Action Programme[207] and the Federal Climate Change Act ("Klimaschutzgesetz")[208] have all set targets and policies for decarbonisation. The 2016 plan introduced legally binding targets, though these were adapted in 2024 to allow flexibility between sectors (some can be over the target if others are under), though the overall national target remains binding. Under Germany's Climate Change Act, the national economy-wide target is to reduce greenhouse-gas emissions by at least 65% by 2030, compared to 1990 levels, and to achieve net-zero by 2045. The Act sets annual emissions budgets for six sectors: energy, industry, transport, buildings, agriculture, and waste and others.

Transport is Germany's weakest sector: emissions have exceeded the legal carbon budget every year since 2021

203 https://topsectorenergie.nl/nl/kennisbank/routekaart-elektrificatie-in-de-industrie/
204 https://ispt.eu/themes/electrification/
205 https://www.argusmedia.com/en/news-and-insights/latest-market-news/2621523-netherlands-way-off-2030-h2-targets-government-report
206 https://www.bundesumweltministerium.de/en/publication/climate-action-plan-2050-en
207 https://www.bundeswirtschaftsministerium.de/Redaktion/EN/Downloads/C/climate-action-programme-2023.pdf
208 https://www.gesetze-im-internet.de/englisch_ksg/englisch_ksg.html#p0029

German sectoral emissions targets as set out in the Federal Climate Change Act as amended in 2024

	Annual emission budgets (MT CO_{2e})										
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Agriculture	70	68	67	66	65	63	62	61	59	57	56
Buildings	118	113	108	102	97	92	87	82	77	72	67
Energy	280		257								108
Industry	186	182	177	172	165	157	149	140	132	125	118
Transport	150	145	139	134	128	123	117	112	105	96	85
Waste and Other	9	9	8	8	7	7	6	6	5	5	4

Source: Federal Climate Change Act

Transport

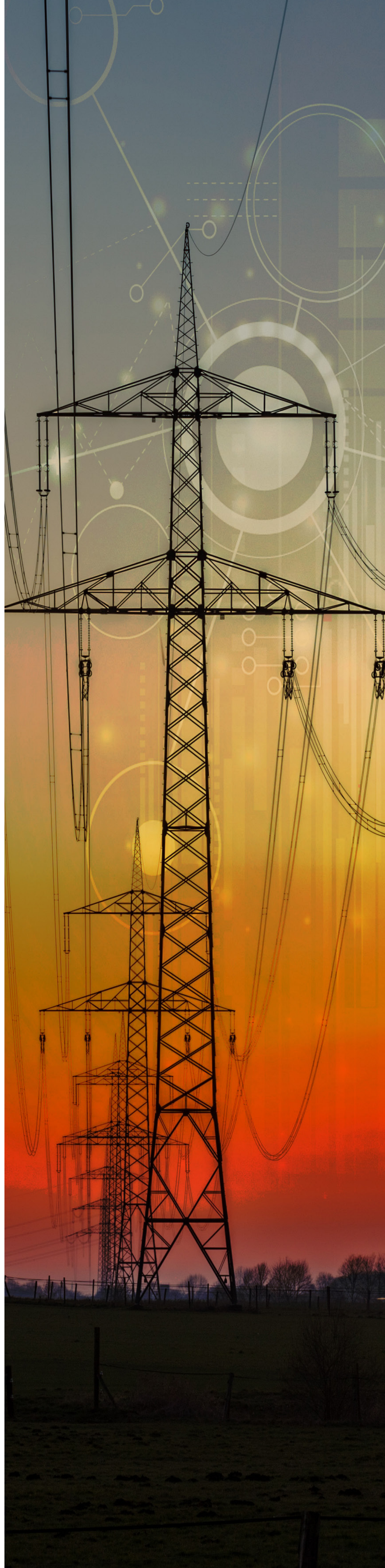
Transport accounted for almost 21.6 % of the country's greenhouse gas emissions in 2023[209]. In 2023 and the two previous years, the sector exceeded the sectoral carbon budget set out in the Climate Change Act. The Government's Climate Action Programme and associated transport measures include the ambition to decarbonise transport by promoting electric mobility, alternative power-trains, rail expansion, and carbon-pricing for transport fuels. Germany aligns with EU regulations for new light-duty vehicles to be zero emission from 2035. For heavy goods vehicles and freight, German policy signals include an aim that about one third of German truck mileage should be electric or powered by sustainable fuels by 2030.

Germany aims for 15 million registrations of fully electric vehicles by 2030 and a nationwide roll-out of charging infrastructure. Since May 2023, Germany has offered a nationwide ticket at €49 a month for all regional and local transport, used by around 10 million Germans. Planned measures include promotion of and renewable fuels and alternative engines for heavy-duty vehicles, and investment in rail infrastructure.

The "Master Plan for Charging Infrastructure II" is intended to deliver the charging infrastructure required to meet climate targets, and has mechanisms for the Federal Government to intervene if progress is too slow. The Climate Action Programme said that distribution grid operators would be required by law to expand their grids in such a way as to enable the smooth and convenient charging of 15 million electric vehicles by 2030, however no such law has been passed. The Programme also promised that the Federal Government would amend the Electric Mobility Infrastructure in Buildings Act (Gebäude-Elektromobilitätsinfra-struktur-Gesetz, GEIG) to implement the requirements of the amended EU Energy Performance of Buildings Directive, to expand the requirements for the charging point infrastructure in residential and commercial buildings, however so far this has not been done.

The Climate Action Programme also said the Federal Government would impose a statutory obligation requiring fuelling station operators to install at least one fast charging point per fuelling station within five years. In 2024 a draft law[210] to this effect was proposed, but so far it has not been passed. The draft law says that large petrol station operators (those owning at least 200 petrol stations) will need to offer at least one fast charging point for electric vehicles from 2028. These charging points will have a minimum capacity of 150 kWh. The Government said the move will add about 8,000 new fast charging points at across the country and should ad-

209 https://www.europarl.europa.eu/RegData/etudes/BRIE/2024/767182/EPRS_BRI(2024)767182_EN.pdf
210 https://www.cleanenergywire.org/news/fast-charging-points-become-mandatory-large-petrol-station-operators-germany



Germany is targeting 15 million EVs by 2030

dress the "chicken-and-egg problem" that electric mobility currently faces. However, the Federal Ministry for Digital and Transport did set up additional funding[211] for publicly accessible charging infrastructure in 2024, as set out in the Programme.

The Programme also said the Federal Government would make CO_2 neutrality a criterion for the approval of car sharing fleets from 2026 under the Car-Sharing Act (Car-Sharing Gesetz, CsgG), and that the "special programme for fleet electrification" (Sonderprogramm Flottenelektrifizierung) would promote the conversion of municipal and commercial fleets and mobility service providers to CO_2-neutral drive technologies. Neither of these has happened.

Charging promises lag legislation...

In 2021 Germany introduced CO_2 pricing[212] for fuels in the transport sector, rising over time and absorbed into the wider emissions-trading/regulation framework. Transport is one of the sectors excluded from the EU ETS, so the scheme in Germany included it within the country. Germany has also introduced subsidy and incentive packages for EV purchases, company-car tax relief, and infrastructure development.

...key laws mandating grid expansion and installation of charging infrastructure have yet to be passed

New incentives were introduced in 2025, a key feature of which is a special depreciation scheme, aimed at stimulating private and corporate investment in sustainable mobility. The plan also includes reductions in corporate tax burdens and the introduction of measures that lower energy and electricity costs, making EV use and charging more cost-competitive. New funding lines, low-interest loans, and improved access to infrastructure financing will support innovation in sectors like electromobility and charging infrastructure. The legislative package includes accelerated permitting processes for renewable energy, hydrogen infrastructure, and grid expansions, laying the groundwork for future-proof charging networks.

Germany has also introduced measures to encourage zero emission trucks. On 1 December 2023, a CO_2 differentiated HGV tolling scheme was introduced[213] in the form of a CO_2 surcharge of €200 per tonne of CO_2. Zero-emission trucks will be exempt from the toll until the end of 2025. After that, zero-emission vehicles will be charged at only 25% of the partial toll rate for infrastructure charges plus the partial toll rates for noise and air pollution. The mandatory HGV toll limit was lowered on 1 July 2024, with all commercial vehicles above a technically permissible maximum mass of 3.5 tonnes being included in the toll. Skilled craft businesses are exempted.

211 https://www.now-gmbh.de/en/news/pressreleases/funding-to-continue-for-commercially-used-fast-charging-points/

212 https://www.bundesregierung.de/breg-en/issues/climate-action/effectively-reducing-co2-1795850

213 https://www.bmv.de/SharedDocs/EN/Articles/StV/Tolling-Scheme/hgv-tolling-scheme-2018.html#:~:text=On%201%20December%202023%2C%20the%20CO2%20differentiation,tolls%20and%20the%20obligation%20to%20pay%20tolls.

Carbon pricing has failed to deliver cuts in transport emissions

There are also measures to promote the use of zero emission buses. The German Government has a target[214] to convert half of all city buses to electric drives by 2030. With the recently enforced Clean Vehicles Directive (CVD) and the Clean Vehicles Procurement Act (SaubFahrzeugBeschG), there is now a clear legal requirement for the proportionate procurement and operation of zero-emission buses. By 2030, all new buses procured through public tender will need to be zero-emission.

Despite this policy support, German transport decarbonisation remains slow

Despite these initiatives, progress towards decarbonisation in the German transport sector is lagging significantly. Transport remains one of the largest gaps to meeting the 2030 goal, with EV uptake and freight decarbonisation identified as under-performing. According to the German Environment Agency, the transport sector is currently a long way off its targets and will remain so until 2030[215].

Heating

Heating dominates final energy use: buildings consume 37% of Germany's final energy

Gas and oil are still dominant with c15 million buildings relying on fossil heating

Germany's residential and commercial sectors, accounted for 37.4% of final energy consumption in 2021. Of around 19 million buildings, 5 million are in the countryside or suburbs heated by oil without alternative options (connected to a network) and almost 10 million are in urban areas heated by gas. There are three major approaches for zero CO_2 emissions at the point of heating: heat pumps, district heating and switching the gas supply from methane to hydrogen. According to the Oxford Institute for Energy Studies[216], switching 15 million buildings to heat pumps based exclusively on renewable power is unlikely by 2045, due to the low roll out speed of renewables and heat pumps, a lack of storage solutions and a lack of capacity in the power system. Equally, a heat pump-only system with thermal power with CCS avoiding problems from a renewable-only energy supply,

214 https://share.google/06OmzZgExetrT7OHL

215 https://www.umweltbundesamt.de/en/press/pressinformation/germany-on-track-for-2030-climate-targets

216 https://www.oxfordenergy.org/wpcms/wp-content/uploads/2024/02/ET29-Decarbonising-Germanys-heating-sector.pdf

would still face problems with the limited roll out of heat pumps and limits of local power grid capacity. It suggests that a roughly equal split between heat pumps, district heating and the hydrogen (5 million buildings each) would be a more realistic approach to achieve net zero heating by 2045.

The Climate Action Programme sets out an ambition that by 2030, 50% of heat should be produced in a climate-neutral way. From 2024 onwards, German law required that at least 65% of the energy for all newly installed heating systems must come from renewable sources[217] (where technically possible). Heat pumps, district heating, biomass boilers, electric boilers, hybrid boilers (under certain conditions), solar collectors and gas systems that can be converted to hydrogen, meet this requirement. The new regulations will come into force for existing properties and those being built in already built-up areas when the individual local governments adopt mandatory heating plans which will have to determine the areas where heating networks will be expanded and which elements of the gas network are to be converted to hydrogen in the future. This was originally planned to be by 2026 for large municipalities (over 100,000 residents) and 2028 for small ones, however these targets have fallen away.

In 2024 Germany passed a new law[218] covering heating and cooling planning and the decarbonisation of heat networks. The new law requires building owners to switch from fossil to renewable heating technologies; operators of district heating networks to ensure the use of climate-friendly heat sources; and municipalities to identify and describe which heating technologies are or may become available, particularly with regard to gas, hydrogen and district heating networks. For municipalities, the level of requirement is based on the total population: municipalities and cities with a population of more than 100,000 are mandated to draft heat plans by 30 June 2026, while smaller municipalities have until 30 June 2028. Municipalities with fewer than 10,000 inhabitants can also use a simplified procedure.

By 2030, existing heating networks must be supplied with 30% renewable energy or unavoidable waste heat, 80% by 2040 and 100% by 2045. New heating networks from 2024 must be fuelled by at least 65% renewable energy or unavoidable waste heat. Municipalities must follow a three-step approach:

- Phase 1: inventory analysis - building types are analysed and recorded. Existing heating networks and heat sources are identified. This data is logged into a digital map of the area;
- Phase 2: an analysis of the potential for heat production through renewable energies. This includes the production of biogas, solar thermal energy and geothermal potential. In addition, other heat sources such as waste heat from industrial plants or waste incineration plants are considered;
- Phase 3: scenarios for the future heat supply must be developed, taking into consideration climate objectives and affordability.

In 2024, the German Ministry of Economic Affairs and Energy tabled a draft law[219] for accelerating the expansion of geothermal energy installations, large heat pumps, heat storage units, and district heating grids in a bid

217 https://www.osw.waw.pl/en/publikacje/analyses/2023-09-14/germany-a-controversial-heating-law

218 https://energy-cities.eu/new-german-heating-law-boosts-local-heating-and-cooling-planning/

219 https://www.cleanenergywire.org/news/german-government-proposes-boost-renewable-heating-infrastructure

to push decarbonisation in the heating sector. The draft law implements the EU's renewable energy directive and labels the buildout of renewable heating infrastructure as a matter of "overriding public interest," a measure previously adopted to accelerate the deployment of wind and solar power.

In 2022, Germany set an ambition[220] to install at least 500,000 heat pumps per year from 2024. In 2003, 356,000 heat pumps were installed, however this number almost halved in 2024 to 193,000. Despite producers ramping up capacity, demand has so far has remained below expectations[221]. There is no gas boiler ban in Germany.

Germany is one of the few countries that has provided substantial public funding for residential hydrogen fuel-cell heating. These were supported largely through the KfW 433 programme ("Energieeffizient Bauen und Sanieren – Zuschuss Brennstoffzelle")[222] with grants of up to €28,000 for residential fuel-cell micro-CHP systems. It ran from 2016 to 2022 and supported several thousand installations. The rationale was originally to support fuel-cell combined heat and power (CHP), with hydrogen as a potential long-term feedstock. Many systems used natural gas today, with a future 'readiness' for hydrogen—the expectation being that hydrogen would replace gas in the pipeline network over time.

A 2021 report by the International Council on Clean Transportation[223] considered four options for the decarbonisation of heat: hydrogen boilers, hydrogen fuel cells with an auxiliary hydrogen boiler for cold spells, air-source heat pumps using renewable electricity, and heat pumps with an auxiliary hydrogen boiler for cold spells. It found that that air-source heat pumps would be the most cost-effective residential heating technology for 2050 and are at least 40% lower cost than the hydrogen-only technologies.

In 2023 National Hydrogen Strategy Update[224] it said that "in the heat sector, no broad application [for hydrogen] is seen by 2030, although the repurposing of gas distribution networks for hydrogen and the use of decentralised H_2 boilers are also to be made legally and technically possible." It goes on to say that "general speaking, the use of hydrogen in decentralised heat generation systems, according to current knowledge, will tend to play a subordinate role", with direct hydrogen use in space heating only seen beyond 2030, except in pilot projects.

Industry

Industry accounted for 23% of Germany's greenhouse emissions in 2023, and stayed below the sectoral carbon budget. In Germany, steel, chemicals and cement are the industries that cause the highest greenhouse gas emissions, while at the same time providing essential primary materials for German manufacturing. The most recent amendment to the Federal Climate Change Act requires a 58% reduction in industrial emissions by 2030, compared with 1990. According to the Climate Action Programme, for Germany to become a "climate-neutral industrial hub", a fundamental transformation of industrial production processes is required that is based

220 https://www.bundeswirtschaftsministerium.de/Redaktion/DE/Pressemitteilungen/2022/06/20220629-breites-buendnis-will-mindestens-500000-neue-waermepumpen-pro-jahr.html

221 https://www.cleanenergywire.org/news/heat-pump-sales-halved-germany-2024-industry-confident-better-times-ahead#:~:text=Clean%20Energy%20Wire.%20Sales%20of%20heat%20pumps,country%2C%20compared%20to%20356%2C000%20units%20in%202023.

222 https://www.bundeswirtschaftsministerium.de/Redaktion/DE/Evaluationen/Foerdermassnahmen/evaluation-of-the-kfw-433-programme-synopsis.pdf?__blob=publicationFile&v=1&

223 https://theicct.org/wp-content/uploads/2021/06/Hydrogen-heating-germany-EN-apr2021.pdf

224 https://www.bundeswirtschaftsministerium.de/Redaktion/EN/Publikationen/Energie/national-hydrogen-strategy-update.pdf?__blob=publicationFile&v=2&

on technical and digital solutions for decarbonisation, electrification, the use of hydrogen, flexibility, as well as energy, material and resource efficiency, circular economy, lightweight construction and the replacement of fossil-based raw materials with bio-based ones.

Industry is on track: emissions stayed within budget in 2023

In 2024, Germany launched Europe's first Carbon Contracts for Difference[225] ("CCfD") scheme designed to encourage companies to switch to climate-friendly technologies and production methods. Companies from energy-intensive industries that successfully participated in the preparatory procedure in summer 2023 could apply for 15 years of funding for their largest transition projects during a four-month window. The total funding volume was €4 billion.

Germany launched Europe's first Carbon Contracts for Difference scheme to encourage climate-friendly technologies and production methods in industry

> "Today is a good day for German industry, climate action and sustainable jobs in our country. First, the carbon contracts for difference help us promote tomorrow's modern, climate-friendly industrial facilities. This will create new technologies, value chains and infrastructure. Second, it helps industry worldwide to switch to climate-friendly production. And third, by introducing carbon contracts for difference we are setting new global standards for efficient funding with little bureaucracy."
>
> \- Robert Habeck, Federal Minister for Economic Affairs and Energy

The scheme is targeted at energy intensive industries with greenhouse gas emissions of at least 10 kt CO_2 per year and a high potential for emission reduction, such as the steel, cement, paper, or glass producers. The projects are expected to achieve an emissions reduction of at least 60% in the first three years and 90% by the end of the contract. Companies can choose how to achieve the emissions reductions (eg by using hydrogen, CCS or biomass) as the scheme aims to be technology-neutral.

The funding amount is calculated[226] based on the additional cost which the applicant incurs in comparison to continuing to operate its conventional system (the "Basic Agreement Price"). Additional costs include both construction (capital) and operating expenditure. The amount can be adjusted for (among other reasons) increased energy prices, and can include a mechanism to disgorge "green surplus revenue". The amount is updated annually, and payments are suspended if the grantee misses its targets for reducing emissions. In October 2025 Germany began consultations on a second round of the CCfD scheme.

Germany's approach to CCS is incoherent: carbon capture legal but carbon storage is effectively banned...

Carbon capture and storage /usage is another element of Germany's industrial decarbonisation plan. The Climate Action Programme set out plans for a Carbon Management Strategy ("CMS") whose aims would be to explore the potential for CCS as a means of decarbonising the industry and waste management sectors, including identifying sources of CO_2 capture, potential uses of CO_2 in a circular carbon economy, requirements and capacities for CO_2 storage, possible applications for CCS and CCU, and the legal and economic framework (including CO_2 transport infrastructure) for a successful launch in Germany.

...regulatory reform is under consideration

Ironically, although capturing carbon dioxide is already legal in Germany, storing it is practically illegal! Under Germany's current legal framework, permanent onshore CO_2 storage is generally not permitted at the federal level, but individual federal states (Länder) have the legal option to opt-in and allow it within their own territory through state legislation. However, many states have introduced complete bans on carbon storage, or projects were stalled due to public and political opposition and a lack of a clear legal framework. The original 2012 Carbon Dioxide Storage Act (KSpG) allowed states to prevent storage in certain regions and set a 2016 deadline for applications, which passed with no commercial projects submitted.

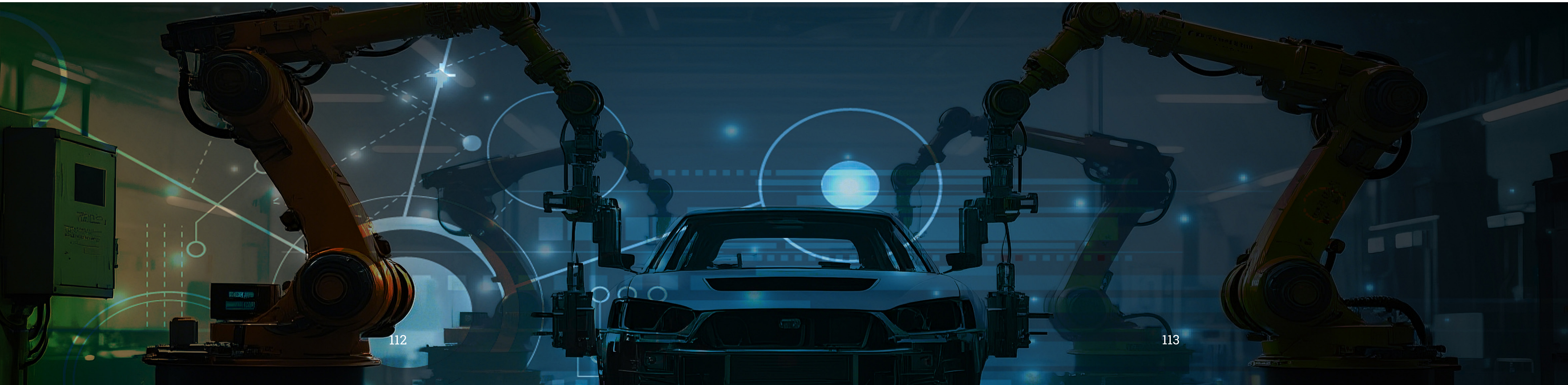
Recent legislative reforms[227] being debated in the German parliament are intended to open up large-scale commercial carbon storage primarily in offshore areas (Germany's exclusive economic zone and continental shelf, outside marine protected areas). The law reform aims to enable the permanent storage of carbon dioxide in underground rock formations under the seabed in the North and Baltic Seas for commercial purposes on an industrial scale, and to create a uniform permit regime for all carbon dioxide pipelines. The reform would also mean that the construction, operation and significant modification of carbon dioxide pipelines are in the "over-

225 https://www.bundeswirtschaftsministerium.de/Redaktion/EN/Pressemitteilungen/2024/03/20240312-first-round-of-carbon-contracts-for-difference-launched.html

226 https://sustainablefutures.linklaters.com/post/102j64w/

germany-initiates-first-tenders-for-carbon-contracts-for-difference

227 https://www.cleanenergywire.org/factsheets/qa-german-law-reform-permit-carbon-storage-and-transport



riding public interest", which makes planning and permitting procedures easier. The law reform would in limited cases even allow expropriation of land if it was needed for pipelines.

Germany also needs to make additional legal changes for its carbon storage plans, including reform of the country's rules forbidding the dumping of waste and other materials in the sea, as well as a law to ratify the amendment of the London Protocol to allow CO_2 export for storage offshore in other countries. The reforms are primarily aimed at industrial processes, and while gas-fired power generation will be included, coal-fired power generation is to be excluded.

Hydrogen is an important part of Germany's decarbonisation plans...

In 2023 the German cabinet agreed to double the national target for green hydrogen production by 2030 from 5 GW to 10 GW, with imports meeting 50–70% of the nation's total hydrogen demand. The government also plans to establish 1,800 kilometres of new and refurbished pipelines for a "hydrogen start-up grid" in Germany by 2027/2028. However, the Federal Audit Office[228,229] warned in October 2025 that the nation's hydrogen strategy is falling short of its objectives, saying that "it's time for a reality check," and that both supply and demand for hydrogen, particularly in the steel sector, remain far below expectations despite billions of euros in subsidies.

...the green hydrogen target has doubled to 10 GW by 2030

50–70% of hydrogen is expected to be imported - import costs could reach €25 bn by 2030

The report said that without adjustments, Germany will miss its 2030 targets for domestic green hydrogen production, and imports would be insufficient to bridge the gap. It also raised concerns over the high cost of green hydrogen, noting that permanent subsidies could place unsustainable pressure on the federal budget. Import-related expenses alone could amount to between €3 billion and €25 billion euros by 2030. This echoes the findings of a report by Fraunhofer[230], which found that it costs around €1,000 per ton to remove carbon dioxide from industrial processes – far more than the cost to release CO_2 into the atmosphere under the EU's Emissions Trading Scheme (which is currently trading at around €80 /t).

The Energy Transition Progress Monitor 2025[231], produced by consultancy

228 https://www.bundesrechnungshof.de/SharedDocs/Kurzmeldungen/EN/2024/energiewende-en.html

229 https://www.reuters.com/sustainability/germanys-hydrogen-strategy-requires-overhaul-meet-2030-targets-audit-office-2025-10-28/

230 https://www.isi.fraunhofer.de/content/dam/isi/dokumente/policy-briefs/policy_brief_air_carbon_capture_EN.pdf

231 https://www.cleanenergywire.org/news/

Hydrogen costs far exceed carbon prices: c€1,000/tCO_2 abatement versus c€80/t under the EU ETS

EY and the energy industry association BDEW found that lagging buildout of electrolysers for green hydrogen production, as well as large uncertainties over the fuel's price in the future, regulation and available infrastructure present a "significant investment hurdle" for hydrogen projects. The volume of hydrogen made using renewable electricity is stalling in Germany, and falling production from fossil gas puts an additional risk on the country's plan to build up a sizeable hydrogen market.

Falling conventional production is primarily due to demand constraints, with financial challenges across the industries that consume or produce hydrogen, including refineries, ammonia production, methanol production and chlorine production. A lack of sufficient demand, particularly in key sectors like green steel, is a major hurdle to the investment case for new hydrogen production and infrastructure. Currently, hydrogen production from fossil sources such as gas dominates German production, with green hydrogen from electrolysis accounting for a mere 0.5% of total hydrogen production in 2023. Of the 10 GW of electrolyser capacity targeted for 2030, only 1.6 GW have so far been secured.

The buildout of electrolysers is lagging while conventional hydrogen production is falling

Progress is being made on the pipeline network, with the first 525 km of repurposed pipelines expected to be ready in 2025, according to reports back in January 2025. 507 km of these pipelines will come from established gas pipelines repurposed for hydrogen. It remains to be seen whether this will be delivered on time, or uncertain if hydrogen will flow to end users immediately. The overall network plan has been called "over-ambitious" by auditors given the slow development of supply and demand who also warned the financing model for the hydrogen core network could expose public finances to double-digit billion-euro losses if hydrogen demand fails to materialise as anticipated. The cancellation of the hydrogen pipeline from Norway will clearly also have an impact on Germany's plans and likely lead to a greater role for electrification.

german-hydrogen-market-ramp-plagued-uncertainties-cooperation-france-promising-industry

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