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Greenwheel Insights

Expensive electricity: Does Draghi's Diagnosis apply to the UK?

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Executive Summary

- **The Draghi Report on European Competitiveness identified high electricity prices** relative to other major economies **as a fundamental obstacle to European competitiveness** and economic growth.

- At the same time, **high electricity prices slow down the electrification of industry** and the wider economy - crucial to driving down emissions.

- This **challenge is even greater in the UK, where industry faces among the highest electricity prices is the world** – 45% above the EU average in 2023.

- **Draghi identifies seven core drivers** for high electricity prices in the EU. **At least four of these drivers are even more pressing in the UK**, while none are appreciably less material (see summary on following page).

- These four **include a greater role for gas in setting electricity prices**, **inadequate grid infrastructure and market integration**, **infrastructure planning and permitting** barriers, and the **distribution of network and policy costs** across consumers.

- A range of measures may be taken to reduce high and volatile prices in both the EU and the UK. **Three priority areas for policymakers in the UK could include the following**:

1. **Accelerate deployment of low-carbon power and grids.** This would reduce how often gas sets the electricity price and associated volatility. Swift action on planning, permitting and grid connections is required.

2. **Reform the electricity market to transfer the cost advantages of decarbonisation to consumers.** This includes a potential reintegration with EU electricity and carbon markets, facilitation of low-carbon PPAs, and a quick and clear decision and roadmap for the structural reform of the wholesale electricity market.

3. **Examine allocation of costs for grids and historic renewables subsidies**. The government could investigate increasing network cost discounts and options for removing policy costs from electricity prices for industrial consumers, including reviewing current exemption qualification criteria.

	Drivers for high industrial electricity prices in the EU	How does the UK compare?
Dependency on gas imports and exposure to spot markets	**The EU is the world's largest importer of natural gas, with imports accounting for 90% of demand** in 2023. **EU gas prices have escalated compared to the US, driven by Covid-related shocks and the conflict in Ukraine.** **The EU is more dependent on volatile spot markets** for natural gas than its competitors. Gas is also **bought by a myriad of public and private actors,** meaning import prices may be higher on average than if bought through a single EU buyer.	**Although the UK is far less dependent on imports** (45% of demand in 2023), **the UK and European gas markets are highly interconnected – meaning wholesale gas prices track closely.** The UK exported nearly half its domestic production in 2023 through pipelines to the EU, mainly to the Netherlands and Belgium, accounting for around 5% of EU total demand. **The UK's demand for gas is set to decline**, although even under a decarbonisation pathway aligned to net zero by 2050, the pace of production decline is likely to outpace declining demand, **increasing import share**.
Marginal gas and coal power prices impact electricity prices	**EU electricity markets are based on marginal spot pricing.** Natural gas power plants are often the marginal plant bought online to satisfy marginal demand in many European economies. This means **EU electricity wholesale prices are substantially driven by underlying gas prices** - although this varies by country. **High gas prices mean high electricity prices.** This may be the case at least until the mid-2030s, when gas generation is likely to be increasingly displaced.	**Natural gas drives the wholesale electricity price in the UK almost all the time, and more than in any EU country. This means electricity wholesale prices in the UK are particularly sensitive to natural gas markets.** Recent gas price spikes have led UK wholesale electricity prices to be at the upper end of the range and sometimes exceed those experienced in any EU country.
Underdeveloped long term contracts solutions hinder benefits from increasing renewable roll-out	**Long-term electricity supply contracts, like power purchase agreements (PPAs), may reduce exposure to high and volatile electricity prices. The EU market for PPAs remains significantly underdeveloped** compared to the USA, for example. **Uptake among energy-intensive industries in the EU is particularly nascent**. Key reasons include lack of financial guarantees for counterparty risk, a limited market risk appetite, companies' credit worthiness, and contract complexity.	**The UK is one of the most mature and attractive markets for PPAs in the world, however uptake among energy-intensive industries remains small,** for the same reasons as in the EU. **In some EU countries** (e.g. France, Italy), **governments have facilitated PPAs for groups of industrial offtakers. No such government-facilitated arrangements exist in the UK**.
Higher carbon costs than other regions in the world	Under the EU Emissions Trading System (EU ETS), **emissions from electricity generation face one of the highest carbon prices in the world.** As the marginal electricity price-setter is usually gas or coal, **this carbon cost is passed on to electricity consumers** through wholesale prices – although some EU member states compensate some electricity-intensive industries for this. Carbon prices applied to power generation in China and California have less than half the impact on wholesale electricity prices – while most of the US has no carbon price at all.	**Following Brexit, the UK introduced the UK ETS to replace membership of the EU ETS**. The UK ETS mirrors the design of the EU ETS, and prices initially tracked closely. However, since early 2023, the **UK ETS price is significantly lower than the EU ETS price**. **The UK also applies a 'carbon price floor' (CPF) to electricity generation,** to support the low EU ETS price when the CPF was introduced in 2013. This means that **the total carbon price paid by UK generators remains comparable to that paid by generators in the EU.**
Physical network bottlenecks may increase during the energy transition	**The EU's power network infrastructure is challenged by the electrification of the economy and the growth of intermittent and distributed renewable generation.** When generators and consumers sit on opposing sides of a grid bottleneck, system operators pay the original generator (usually renewables) to reduce supply and pay a generator on the same side of the bottleneck as the consumer to increase supply instead (usually fossil fuel). Such **'redispatching' across grid bottlenecks between member states cost EU electricity consumers nearly €4 billion in 2023 and could increase to €50-100 billion by 2040** if bottlenecks are not addressed.	Grid bottlenecks between electricity supply and demand led to **redispatching costs of nearly £1 billion in 2023, recovered through electricity prices. If key grid bottlenecks are not addressed** but the renewable rollout under the Clean Power Plan is delivered, **redispatch costs could rise to nearly £13 billion in 2030**. **Net imports through electricity interconnectors to the EU accounted for nearly 8% of UK electricity demand in 2023**. Following Brexit the UK left the EU single energy market, **making electricity trade between the UK and EU markets more complex and costly.** This decoupling cost an additional £130-370 million in 2022 and may rise to over £500 million by 2029.
A lengthy and uncertain permitting process for new power supply and grids	**Permitting is a significant barrier to the development of new power generation capacity and grid infrastructure**. In some member states, the process for large wind energy projects can take up to nine years. Almost no country manages to realise permitting within the 2-3 years EU legislation requires. As well as slowing the shift to clean energy, permitting delays **may significantly increase project costs and subsequently electricity prices**.	**Grid connection times in UK are among the worst in Europe**, **The current connection queue has around 4x the capacity needed to power a net zero economy by 2050**. Difficulties in obtaining a grid connection is cited as one of the main obstacles to energy investment in the UK. **This delay is driven both slow grid buildout and permitting delays**. The time between planning application and decision is supposed to be 18 months but takes over 4 years on average.
Higher and non-homogeneous taxation and subsidies	**In 2023, non-network taxes, levies and charges accounted for a quarter of the average electricity price faced by industry in the EU -** although in many cases industrial consumers can recover some of these costs, reducing the burden to 10% on average. However, **such charges vary significantly by member state.** **The USA has no federal taxes on electricity consumers,** although network charges are typically higher. In 2019, **comprised taxes <5% of the average industrial electricity price in the US.**	**In the UK, non-recoverable taxes, levies and charges make up 20% of the average industrial electricity price** – higher than the average EU rate of 10%. **While many key EU economies** focus the recovery of network and policy costs from smaller industrial and household consumers to **shield electricity-intensive industry, the UK has spread these costs relatively evenly across consumers.** In the EU, prices available to the largest industrial consumers are around 44% lower than the smallest consumers. In the UK, the difference is just 33%.

Source: Greenwheel as at March 2025.

PREFACE: The Investor need

"Energy, and particularly electricity, is core to economic prosperity and security. High electricity prices accounts for much of our industrial competitive disadvantage to the US and China; a big reason why Europe is losing its industrial base. Electricity is also core to decarbonisation efforts. We cannot solve either issue in isolation from the other. Decarbonisation efforts must underpin competitiveness, while to try deliver cheap electricity without decarbonisation is a long-term loss to the climate, prosperity and security."

John Teahan

Portfolio Manager, UK & Global Climate Engagement Strategies

Published in September 2024, **the 'Draghi Report' on EU Competitiveness**[i] **identified high electricity prices relative to other major economies as a fundamental obstacle to European competitiveness and economic growth**. At the same time, **high electricity prices slow down the electrification of industry and the wider economy crucial to driving down emissions**.

This challenge is **even more pressing in the UK**[1]**, which faces some of the highest industrial electricity prices in the world** – 45% above the average price in the EU in 2023, and 4x average prices in the USA. Figure 1 compares prices between selected countries, with key global economies highlighted.

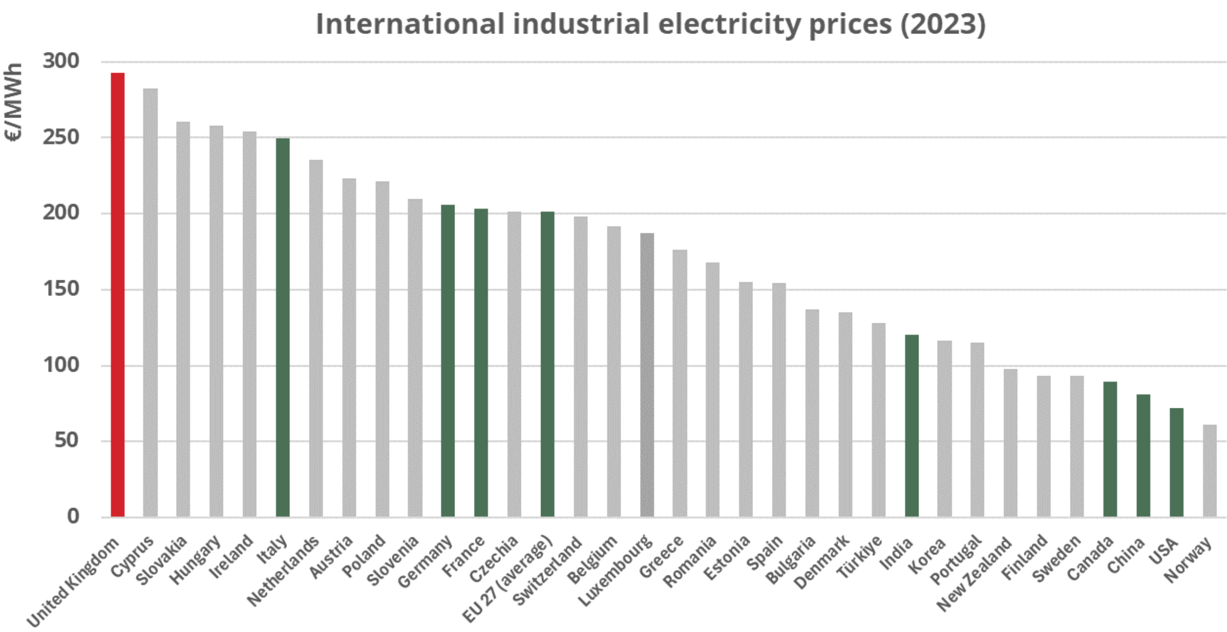

Figure 1 - International industrial electricity prices in 2023. Data sources: DESNZ (2024); Lee (2024); EIA (2024); Xiao & Zhao (2024); Statista (2024). Graphic created by Greenwheel.

[1] Most the data and discussion in this paper refers to UK for simplicity, but uses data limited to Great Britain, excluding Northern Ireland. This is because despite being part of the UK, Northern Ireland and the Republic of Ireland share a single electricity grid and market.

The UK's statutory Climate Change Committee (CCC) recognises that **industrial decarbonisation through electrification presents an opportunity** to boost investment in UK manufacturing and **gain a competitive advantage in low-carbon production**, and that **this will need a supportive policy environment, including competitive electricity prices**, to attract investment and maintain and grow electricity-intensive industry.[ii]

This paper reviews the key drivers behind high electricity prices in the EU as identified by the Draghi Report **and assesses the extent to which they can also explain the high electricity prices facing industry in the UK**. It **also highlights key avenues for action for policymakers in the UK to pursue**, drawing in part on the Draghi Report's recommendations to EU policymakers.

Key drivers behind high industrial electricity prices in the EU and UK

The Draghi Report identifies seven root causes driving high electricity prices in the EU.[2] **This section** briefly summarises Draghi's diagnosis for each of these (with supplementary analysis where useful) and **examines the extent to which they also apply to the UK**.

1. Dependency on gas imports and exposure to spot markets

Draghi's Diagnosis

The EU is the world's largest importer of natural gas, with imports accounting for 90% of domestic demand in 2023.[iii] Around 30% of these imports came from Norway via pipeline. Liquified Natural Gas (LNG) accounted for over 40%, with around half of this from the USA. Russian pipelines served around 40% of EU gas imports in 2021, reducing to around 9% in 2023 and to zero by the start of 2025[iv] - although Russian LNG imports grew to over 6% of imports in 2023 (see Figure 2), and have grown further since.

Natural gas wholesale prices in the EU began to escalate and diverge from US prices in late 2020, driven by Covid-related shocks and the conflict between Russia and Ukraine. The USA is the world's largest producer of gas and a net exporter, with low prices driven by low-cost shale resources and insulation from external shocks.[v] The EU's dependency on Russia for gas imports sent its gas prices peaking at well over 10x those in the US in August 2022. They have reduced significantly since as EU demand declined and alternative supply (primarily LNG) was secured, but they remain more than double pre-Covid levels, and 4x US prices (see Figure 3).

Other factors also contribute. This gas is bought by a myriad of public and private actors, without leveraging the EU's market power. This means **import prices may on average be higher than if bought through a single EU buyer**, and inter-EU competition can raise prices further, as happened during the Energy Crisis in 2022.[i]

[2] An eighth was also identified, "Higher volatility and non-transparent financial markets for energy", with a focus on market concentration in gas derivative trades. This issue is also present in the UK (e.g. FSB, 2023) but is not assessed here to keep focus on more structural issues and solutions.

The EU is currently more dependent on spot markets for purchasing natural gas than its competitors, and less on long-term supply contracts. A key driver is the reluctance of companies to sign long-term contracts due to demand uncertainty, leading gas importers to rely on the spot market and to easily adjust their import portfolio in relation to final gas demand.[i]

The EU's need to import natural gas will gradually diminish, but this will take time. If the EU adopts a target of 90% emissions reductions by 2040, gas demand is projected to reduce by two-thirds by 2050.[vi] However, under current policies, demand is projected to reduce by 10% by 2030 and halve by 2050.[vii]

How does the UK compare?

Domestic production of natural gas meets over half of domestic demand, while **imports met around 45% of natural gas demand in the UK in 2023**. Around half of these imports come via pipeline from Norway, and half from LNG. In turn, over half of imported LNG came from the USA (Figure 2).

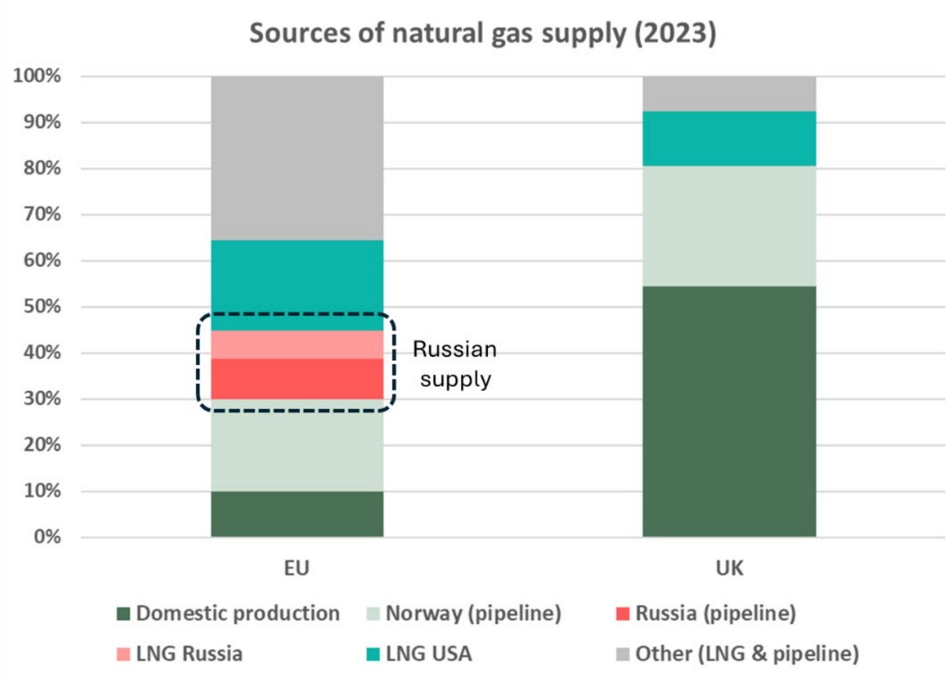

Figure 2 - Sources of natural gas supply in the EU and UK in 2023. Data sources: Eurostat (2024); European Council (2025); DESNZ (2024) – DUKES Tables 4.2 & 4.5. Graphic created by Greenwheel.

Over Q1-3 2024 UK natural gas production and demand both fell on 2024 levels, due to declining fields in the North Sea and reduced demand for gas in electricity generation. Import dependency remained stable, although the share delivered from Norway grew to nearly 80%. LNG imports fell, although the USA's share grew to 70%.[viii]

The UK is also highly dependent on spot markets for importing LNG, which in turn sets the wholesale gas spot market price in the UK. Long-term supply contracts from Norway are also linked to the spot market, and domestic producers also benefit from LNG-driven spot pricing.[ix]

Although the UK is far less dependent on imports, the UK and European gas markets are highly interconnected – meaning wholesale gas prices track closely (see Figure 3). The UK exported nearly half its domestic production in 2023 through pipelines to the EU, mainly to the Netherlands and Belgium, accounting for around 5% of EU total demand.[x]

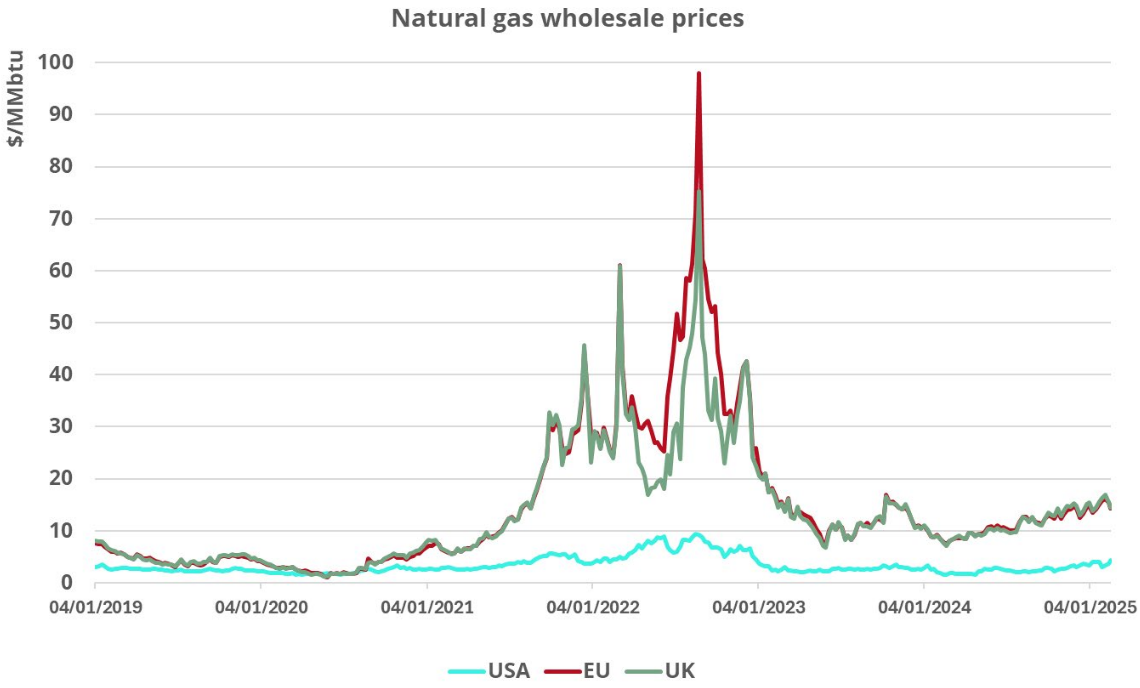

Figure 3 - international natural gas wholesale prices. Data source: Bloomberg. Note: Data represents futures prices for UK (NBP), Netherlands (Dutch TTF) and USA (Henry Hub). NBF Graphic created by Greenwheel. Past performance is not a guide to future results.

Future demand for gas in the UK will depend on policy action, although the share of imports is likely to increase in over the coming decade, even under a Net Zero pathway. UK gas production is set to halve by the mid-2030s and halve again by 2050.[xi] Even under a Net Zero scenario this is roughly the pace of gas demand reduction to the mid-2030s, although the rate of demand destruction then begins to outpace production declines.[xi] However, under current policies, gas demand in 2050 is 20% higher than today as gas for power grows post-2030, alongside gas for home heating.[xii]

2. Marginal gas and coal power prices impact electricity prices

Draghi's Diagnosis

The EU electricity market is based on marginal spot pricing. Primarily due to its nature as a dispatchable generation technology with significant capacity across the continent, gas plants are often the marginal plant bought online to satisfy marginal demand in many European economies.

This means that despite generating just 20% of European electricity, on average gas power plants set EU wholesale electricity prices 63% of the time in 2022.[i] This means **EU electricity wholesale prices are substantially driven by underlying gas prices** - although the extent to which this is the case varies significantly by country (see Figure 4).

High gas prices therefore mean high electricity prices at least until the mid-2030s, when fossil fuel generators may be increasingly displaced in the EU's power mix.[i]

How does the UK compare?

The characteristics of its generation and interconnection profile means that **natural gas drives the wholesale electricity price in the UK almost all the time, and more than any other European country**. In 2021, natural gas plants provided 40% of electricity generation,[xiii] but is estimated to have set the wholesale electricity price 97% of the time (see Figure 4). This is not likely to have changed substantially in the meantime.

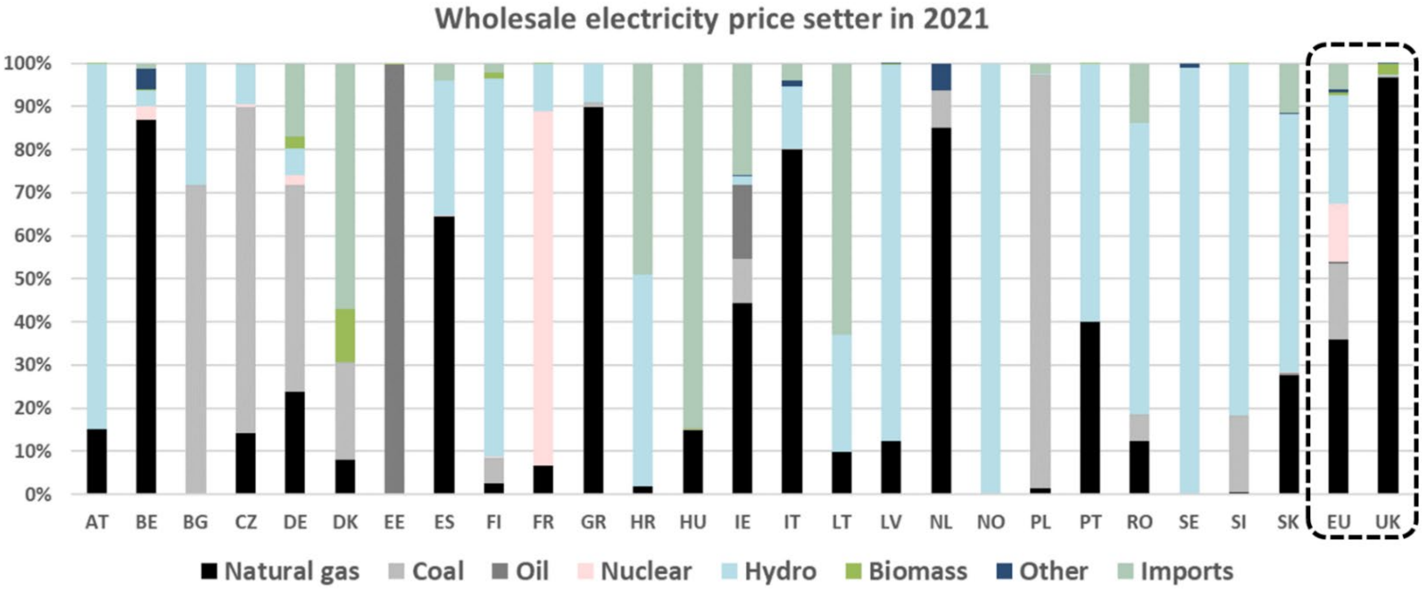

Figure 4 - Technology setting the wholesale electricity price in European countries in 2021. Data Source: Zakeri (2023). Note: UK = Great Britain. Graphic created by Greenwheel. Past performance is not a guide to future results.

This means that electricity wholesale prices in the UK are particularly sensitive to the dynamics of natural gas markets. Gas price spikes have often led UK wholesale electricity prices to be at the upper end of the range or to even exceed those experienced in other European countries (see Figure 5; following page).

3. **Underdeveloped long term contracts solutions hinder benefits from increasing renewable roll-out**

Draghi's Diagnosis

Long-term electricity supply contracts, like power purchase agreements (PPAs), may reduce the exposure of industry to high and volatile electricity prices. This may be particularly the case for renewable and other low-carbon electricity supply, where PPAs can support new construction and help offtakers reduce their Scope 2 emissions.

Despite significant growth in PPAs since the Energy Crisis, **the EU market for corporate PPAs remains significantly underdeveloped** compared to the USA – despite individual countries like Germany, Spain and France being ranked as more attractive markets for corporate PPAs than the USA.[xiv] **Uptake among energy-intensive industries in the EU is particularly nascent**. Key reasons include lack of financial guarantees for counterparty risk, a limited market risk appetite, companies' credit worthiness, and contract complexity. [i]

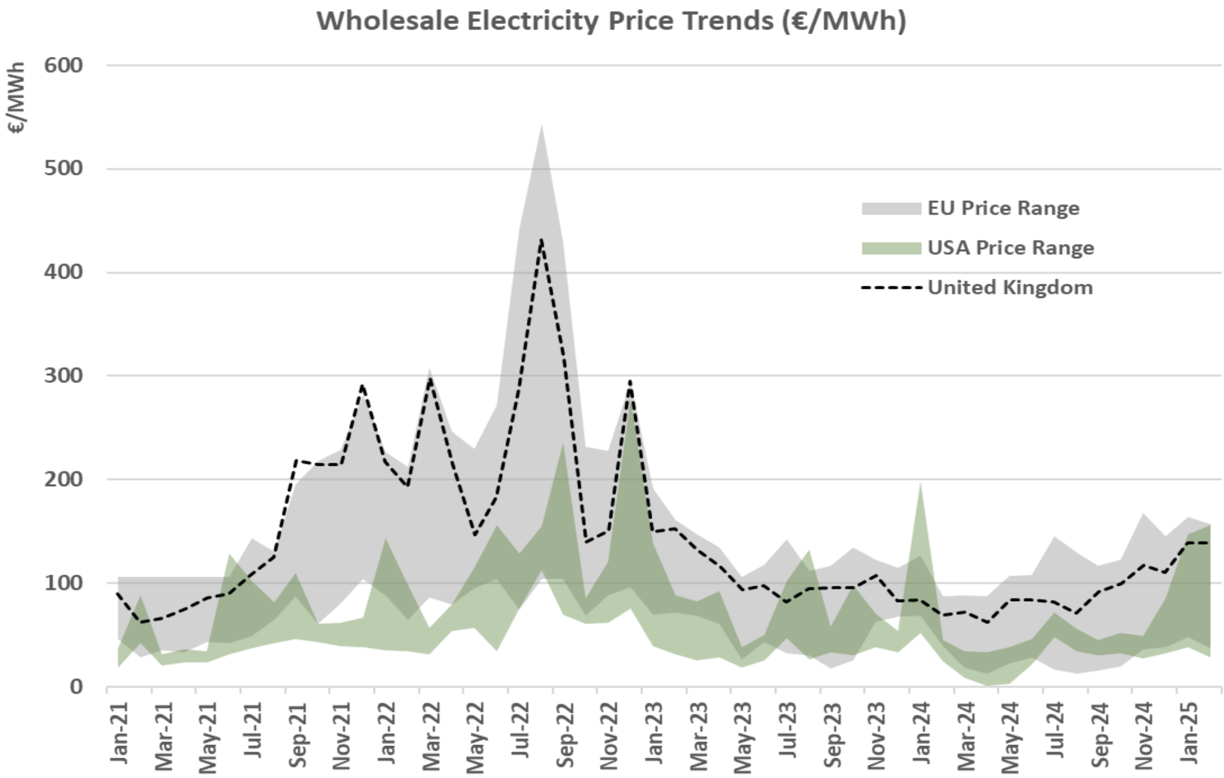

Figure 5 - Wholesale electricity price trends. Data sources: Ember (2025); EIA (2025). Note: EU and UK (GB) prices are monthly average values for day-ahead contracts. USA values cover prices at seven major electricity trading hubs (Mass Hub, PJM West, Indiana Hub, Mid-C, NP-15, Palo Verde & SP-15), with daily values converted to monthly averages. Graphic created by Greenwheel.

How does the UK compare?

The UK is one of the most mature and attractive markets for PPAs in the world,[xiv] with around 20% of projected renewable capacity in 2026 expected to be covered by a PPA. **However, uptake among energy-intensive industries is again small**. Most PPA offtakers are utilities, service sector firms (e.g. IT and retail) and other, non-energy-intensive industry.[xv] The barriers are as experienced in the EU, particularly counterparty risk and price sensitivity.[xvi]

The UK's primary mechanism for supporting new renewable generation is a two-way contract-for-difference (CfDs), where generators receive a fixed price for their generation, regardless of fluctuations in the wholesale electricity price**.** Fifteen-year contracts are granted in allocation rounds and awarded via reverse auction, with total capacity contracted in each round based on winning 'strike prices' and the total budget allocated by government. The UK was the first in Europe to introduce a CfD mechanism for supporting renewables, with at least ten EU member states now following suit.[xvii]

With the government as the counterparty, CfDs are generally less risky for developers and can deliver lower prices.[xv] However, **CfD allocations are limited in frequency and**

volume, and don't themselves directly pass-through cost benefits of renewable generation to end-users.

In some EU countries, governments have facilitated PPAs for groups of industrial offtakers. **No such government-facilitated arrangements exist in the UK**. For example, in France a consortium of major electricity-intensive firms ('Exeltium') in 2008 entered a 24-year supply contract for nuclear power from majority state-owned EDF at low, largely fixed prices aligned to baseload nuclear power.[xxxix]

4. Higher carbon costs than other regions in the world

Draghi's Diagnosis

Under the EU Emissions Trading System (EU ETS), **electricity generators in the EU face one of the highest carbon prices in the world** (Figure 6). As the marginal electricity price-setter is usually gas or coal, this carbon cost is passed on to consumers through whole electricity market prices.

The EU carbon price has been high and volatile in recent years. **Carbon costs accounted for around 10% of the average EU industrial retail electricity price in 2023**.[i] The carbon prices applied to power generation in China and California has less than half the impact on wholesale electricity prices, while most of the US has no carbon price on the sector at all.[i] **The EU ETS price is expected to more than double over the coming decade** under current policy settings.[xviii]

Although not mentioned by the Draghi Report, the **EU allows countries covered by the EU ETS to partially compensate large, energy-intensive industrial electricity consumers for the cost of carbon passed-through on electricity prices**. **However, just fifteen states do so**.[3] In 2022, such compensation cost these countries a combined €2.16 billion, although in all cases except Luxembourg, this cost was a relatively small proportion of EU ETS auction revenues in these countries.[xxi]

How does the UK compare?

At the end of the Brexit 'Transition Period' on 1st January 2021, **the UK left the EU ETS and established the UK ETS**. The design of the UK ETS mirrors the EU ETS with prices tracking closely until early 2023, when the UK government announced a significant increase in the supply of permits in the coming years. **The UK ETS price has been significantly below that of the EU ETS** since (see Figure 6, below).[xix]

However, **since 2013 the UK has placed an additional 'carbon price floor' (CPF) on electricity generation,** to underpin the low EU ETS price at the time, and to (successfully) encourage a shift away from the most carbon-intensive forms of generation – particularly coal power. The rate has been fixed at £18/tCO_2 since 2015.

[3] Austria, Germany, Belgum, the Netherlands, Greece, Slovenia, Slovakia, France, Finland, Luxembourg, Poland, Romania, Portugal, Spain and Norway.

As such, power generators in the UK pay two carbon prices – the UK ETS price and the CPF. This means although the UK ETS price is substantially lower than the EU ETS, **the total carbon price facing UK generators remains comparable to that faced by EU generators** (see Figure 6). As of January 2025, the carbon pricing comprised around 15% of electricity wholesale prices in the UK.[xx]

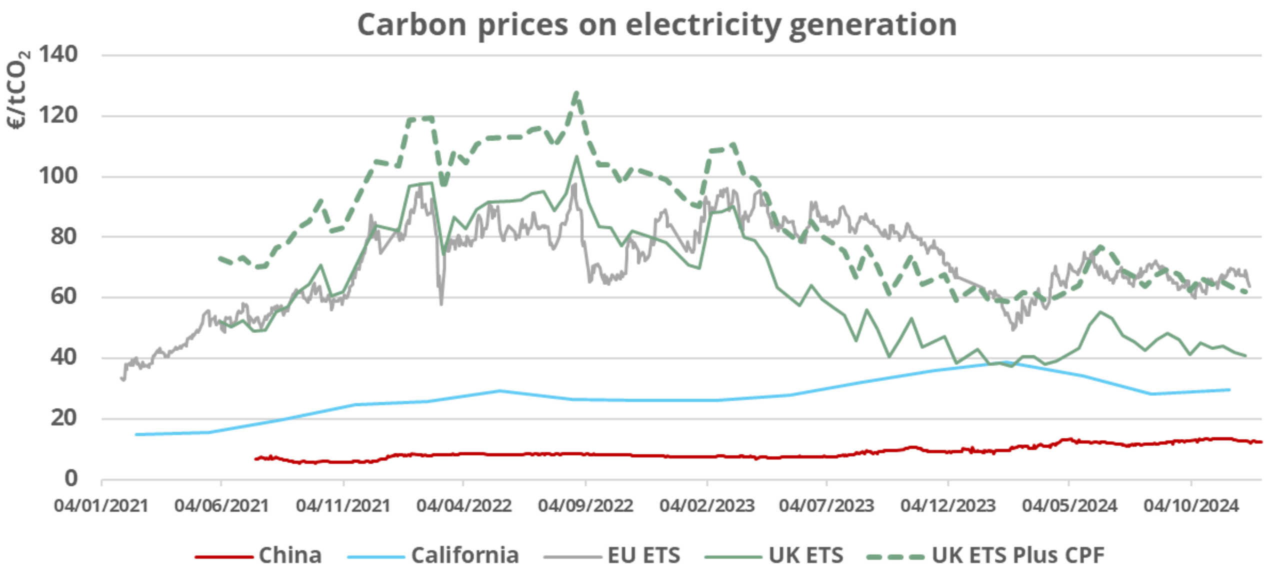

Figure 6 - Carbon prices applied to electricity generation. Data source: ICAP (2025). Graphic created by Greenwheel.

Mirroring the approach used in the EU, **the UK also partially compensates large, energy-intensive industrial electricity consumers for the cost of carbon passed-through on electricity prices**, from both mechanisms. Such compensation costs the UK government around £70 million/year.[xxi]

5. Physical network bottlenecks may increase during the energy transition

Draghi's Diagnosis

Physical network bottlenecks on both natural gas and power prevent a real EU Single Market from emerging. The integration of electricity and gas markets across Europe has reduced price variation across Member States and delivered savings estimated at approximately €34 billion a year for electricity consumers alone.[i]

The EU's power network infrastructure is faced with the challenge of electrification of the economy and the growth of intermittent and distributed renewable generation.[i]

When contracted generators and consumers sit on opposing sides of a grid bottleneck, system operators pay the generator (usually renewables) to reduce supply (often known as 'constraint payments') and pay a generator on the same side of the bottleneck as the consumer (usually fossil fuels) to increase supply instead. Such **'redispatching' across grid bottlenecks between member states cost EU electricity consumers nearly €4 billion in 2023**[xxii] **and could increase to €50-100 billion by 2040** if such bottlenecks are not addressed.[i]

The Commission estimates nearly **€600 billion in grid investment will be needed by 2030** if electricity supply and demand is to change in line with EU targets.[xxiii] Although some costs (such as redispatching) would reduce, **this investment means that grid costs to EU consumers are expected to increase sharply in the next decade**.[i]

How does the UK compare?

Power generation in the UK has changed significantly in recent years. In 2000, 95% of generation was delivered by large coal, gas and nuclear plants. By 2023 this has dropped to less than two-thirds, with variable renewables – mainly onshore and offshore wind – delivering a third.[xiii]

The UK government's Clean Power by 2030 target aims for 'clean' sources to account for at least 95% of power generation by 2030. This will require a substantial growth in solar and onshore wind, but particularly offshore wind (Figure 7).

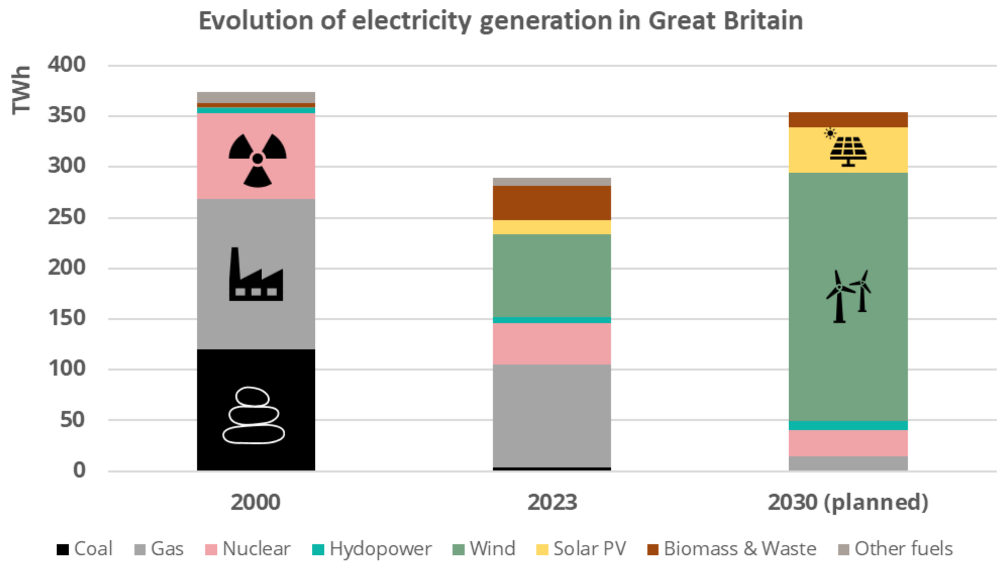

Figure 7 – Evolution of electricity generation in Great Britain. Data Sources: NESO (2024); DESNZ (2024). Graphic created by Greenwheel. Forecasts and estimates are based upon subjective assumptions about circumstances and events that may not yet have taken place and may never do so.

The rapid growth in distributed renewable capacity to date, both onshore and offshore, has changed the geography of power supply, and grid development is struggling to keep up.

Grid bottlenecks led to **redispatching costs of nearly £1 billion in 2023, recovered through electricity prices.**[xxiv] **This translates to around 3% of the average wholesale price** in 2023.[4] **Costs may rise to around £1.8 billion in 2025.** Most of this is due to inadequate grid capacity connecting Scotland's substantial wind generation to demand centres in England.[xxv]

If key grid bottlenecks are not addressed but the renewable rollout under the Clean Power Plan is delivered, **redispatch costs could rise to nearly £13 billion in 2030.**[xxvi]

[4] Electricity demand in the UK in 2023 was 316 TWh[xiii], with an average wholesale price of £108/MWh (Figure 5).

The National Electricity System Operator (NESO) estimates **£60 billion in cumulative investment in new transmission infrastructure is needed by 2030** to overcome current and future grid bottlenecks.[xxvi]

If this investment is delivered on time, total constraint costs may remain largely stable but decline significantly per unit of electricity used. Of 88 projects requiring investment, nine have been completed and 68 are on track. If the remaining 11 projects are not delivered by 2030, redispatch costs could rise to £7.8 billion.[xxvi]

Great Britain is connected to the EU electricity market with nearly 10GW of interconnection capacity.[xxvii] **Net imports to the UK across electricity interconnectors with the EU accounted for nearly 8% of electricity demand in the UK in 2023**.[xxviii]

Prior to the end of the Brexit Transition Period in January 2021, **the UK was part of the EU's internal energy market**. This included the Single Day Ahead Coupling (SDAC) arrangements, **which allowed cost-efficient trading across interconnectors**. **However, the UK has since exited these arrangements**, **making electricity trade with the EU more complex and costly.**[xxix] This decoupling was estimated to cost UK electricity consumers £130-370 million in 2022, rising to over £500 million by 2029.[xxix]

6. A lengthy and uncertain permitting process for new power supply and grids

Draghi's Diagnosis

Permitting is a significant constraint for the development of new power generation capacity and grid infrastructure. In some Member States the permit-granting process for large wind energy projects, for example, can take up to nine years. Almost no Member State manages to realise renewable energy permitting within the 2-3 years that EU legislation requires.[i] As well as slowing down the shift to clean energy, **permitting delays may significantly increase project costs and subsequently electricity prices**.[xxx,xxxi]

Nearly 400 GW of wind capacity is in grid connection queues in just 8 EU countries.[xxxii] This is nearly double the EU's entire installed wind capacity in 2023[xxxiii] and is more than sufficient to reach 2030 deployment targets.[xxxii]

National and European environmental legislation results in complex requirements for impact assessments for the construction and operation of renewable energy and grid installations. **While the EU has developed initiatives to shorten permitting, some countries still face significant hurdles**, for example stemming from lacking administrative capacity.[i]

However, administrative delays for new electricity infrastructure are an issue around the world. At the end of 2023, 2,600 GW of capacity sat in the grid connection queue in the USA. This is double the size of the entire existing US power generation fleet, with the vast majority of queued capacity renewables and storage.[xxxiv]

How does the UK compare?

Grid connection times in the UK are among the worst in Europe, with some capacity being offered connection dates in the late-2030s.[xxxv] **The queue currently stands at over 700GW. Over 80% of this is proposed renewable generation and storage capacity**[xxxvi]**, and is around 4x what would be needed to power a net zero economy by 2050**.[xxxv] Difficulties in obtaining a grid connection is cited to one of the main obstacles to energy investment in the UK.[xxxvii]

This delay is driven both by permitting delays and slow grid buildout (discussed above), **which is in turn largely a result of permitting delays**. Almost all grid infrastructure and most utility-scale renewables (depending on size) must go through a national, rather than local, planning process. **The time between planning application and decision is supposed to be 18 months, but it takes over 4 years on average**. Projects must also conduct significant pre-application work, including environmental assessments and consultation with various stakeholders, with the depth and time required dependent on the complexity of the project.[xxxvii]

7. Higher and non-homogeneous taxation and subsidies

Draghi's Diagnosis

Electricity retail prices in the EU for industry includes various taxes, levies and charges, **which together can account for a substantial proportion of the final price**. Aside from network charges, this includes levies for environmental and social programmes – including subsides for renewables.[i]

In 2023, non-network **taxes, levies and charges accounted for a quarter of the average EU industrial electricity price.** However, **in many cases industrial consumers can recover some costs, reducing this to 10% on average.** However, the size of these components – and the proportion that may be recovered - varies significantly by member state (Figure 8).

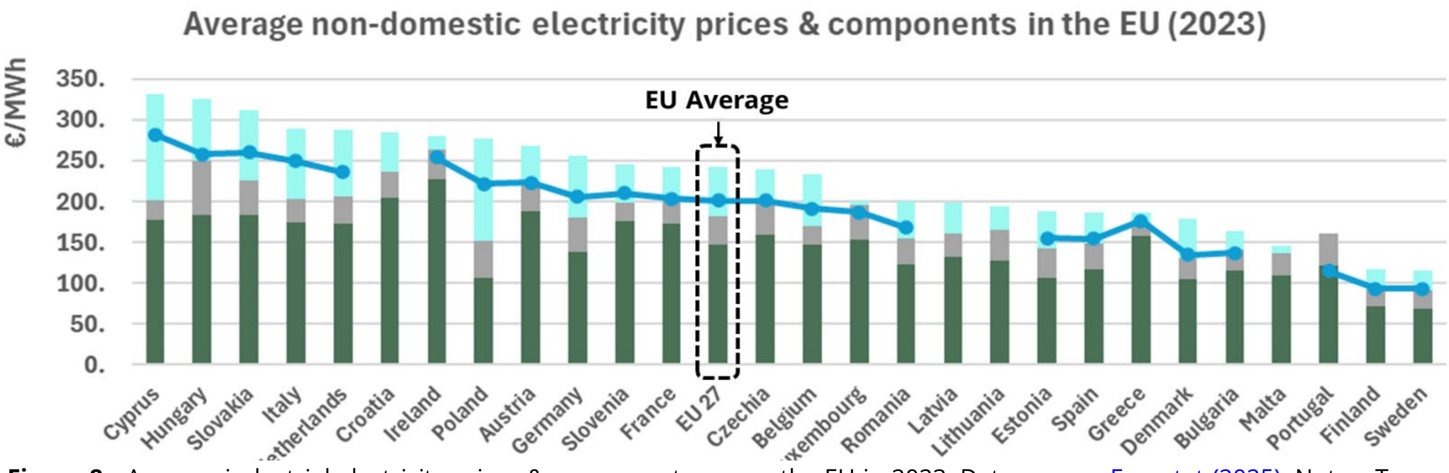

Figure 8 - Average industrial electricity prices & components across the EU in 2023. Data source: [Eurostat (2025)](). Notes: Taxes, levies and charges in Portugal are negative and excluded from the chart, but price excluding recoverable taxes and levies is correct. Prices exclude any indirect carbon cost compensation. Graphic created by Greenwheel.

The USA does not levy any federal taxes on electricity consumers, although network charges are typically higher.[i] In 2019, **taxes comprised less than 5% of the average industrial electricity price in the US**.[xxxviii]

How does the UK compare?

In the UK, non-recoverable taxes, levies and charges make up 20% of the average industrial electricity price – higher than the average EU rate.

However, in most countries the price varies by the size of consumer. **Prices available to the largest industrial consumers in the EU are on average 44% lower than the smallest industrial consumers. In the UK, the difference is just 33%**. In France, the largest pay a price one third of that available to the smallest (Figure 9).

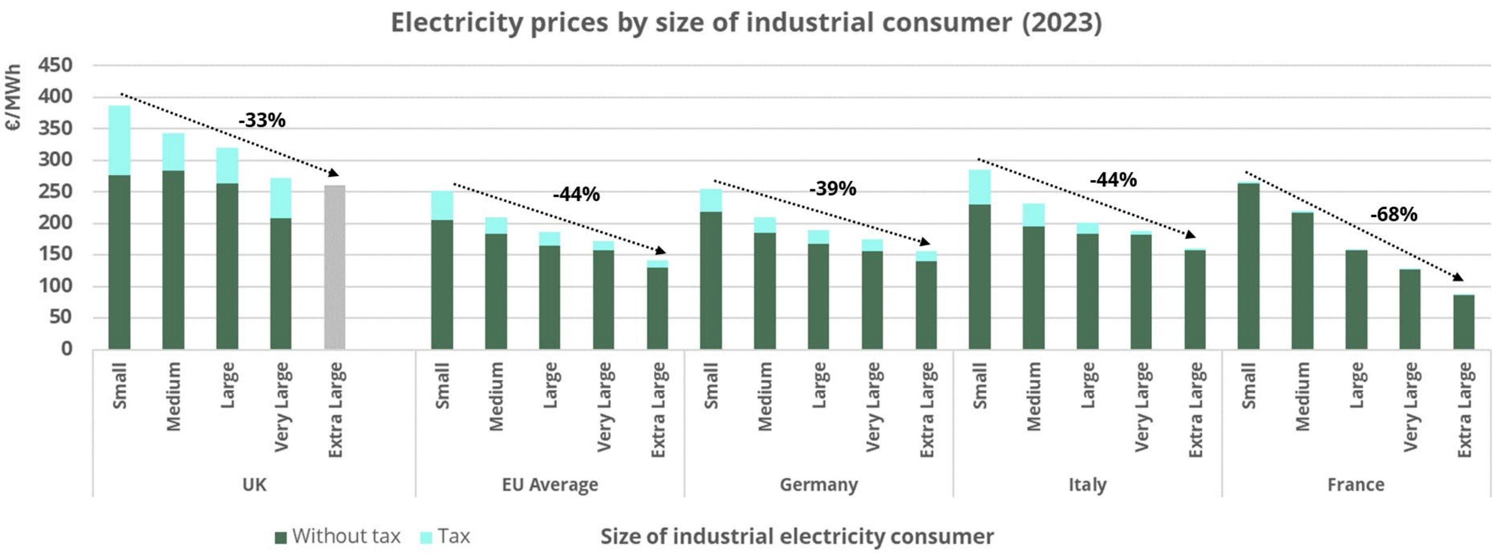

Figure 9 - Electricity prices by size of industrial consumer in 2023. Data Source: DESNZ (2024); Eurostat (2025). Notes: Breakdown for UK 'Extra Large' not available. Taxes are non-recoverable only. Consumer sizes are: Small (20 - 499 MWh/yr), Medium (2,000 - 19,999 MWh/yr), Large (20,000 - 69,999 MWh/yr); Very Large (70,000 - 150,000 MWh/yr), and Extra Large (150,000 MWh/yr). Prices exclude indirect carbon cost compensation. Graphic created by Greenwheel.

The primary reason for this difference is a divergence in how network and policy costs are recovered from electricity consumers. **While many European economies focus the recovery of network and policy costs from smaller industrial and household consumers to shield electricity-intensive industry, the UK has spread these costs more evenly across electricity consumers.**[xxxix]

Network charges for industrial consumers in most countries are set according to one or a combination of: size of network connection, location, and size and time of consumption.

From early 2023, network charges for industrial consumers in the UK became based on connection size and location only. The previous system was based on time of use, which some industries grew highly adept at working around to minimise their charges.[5] When

[5] This system was based on consumption during the 'Triad'; the three half-hourly periods with highest electricity demand between November and February (and separated by at least ten full days), determined after the event.

this reform took place, charges to these industries likely increased substantially, while charges to those less adept or unable to adjust their electricity demand likely fell.[xxxix]

In Germany, network tariffs are based primarily on consumption. In France and Italy, tariffs are primarily set by connection size. **In Germany, France and Italy network rates applied to the largest and most electricity-intensive industrial consumers are low relative to their UK counterparts**, **and in Germany and in France they may apply for a further 90% discount**.[xxxix]

By far the largest component of taxes and levies on industrial electricity prices in the UK and the largest EU economies is the recovery of costs for historic renewable subsidy mechanisms.

In Germany, France and Italy, the cost of these (and other) mechanisms for large or electricity-intensive consumers are often capped, mean that **effective rates decrease with increasing consumption**.[xxxix] Again, smaller consumers cover the cost.

In the UK, costs are recovered for three renewables subsidy mechanisms. These are the Renewables Obligation and Feed-in Tariffs (RO and FITs, for large- and small-scale renewables respectively, and which closed to new applicants in 2017 and 2019), and the ongoing Contracts for Differences (CfD) scheme (described above).

Although the RO and FiT schemes are now closed, contracts of up to twenty years means there will be (declining) costs associated with them to the late 2030s. The rapidly declining costs of renewables means that the ongoing CfD mechanism imposes much lower costs, with newly signed contracts likely to have a negligible net impact on electricity prices.[xl]

From April 2024, companies in electricity-intensive mining and manufacturing sectors and that pass business-level thresholds[6] are fully exempted from these costs, rising from 85% previously, with exempted costs again recovered from other electricity consumers.[xli]

Priority actions to tackle high industrial electricity prices in the UK

The Draghi Report highlights two objectives that should be pursued in parallel to address the competitiveness challenges the EU faces:

(1) The cost of energy must be lowered for the final user
(2) Decarbonisation must be accelerated

The Draghi Report highlights several specific proposals to achieve this. These broad objectives, and many of the proposals that underpin them, may also be applied to the UK. **From this mapping exercise fall three priority areas for policymakers to tackle the exceptionally high industrial electricity prices in the UK.**

[6] Manufacturing and mining sectors with a trade intensity of at least 4%, and an electricity intensity of at least 7%. Individual businesses in these sectors must also demonstrate their electricity costs are equivalent to at least 20% of their Gross Value Added (GVA) (Source: DBT, 2025)

1. Accelerate deployment of low-carbon power generation and grids

Accelerating the deployment of low-carbon power to meet the government's 2030 Clean Power Plan - and accompanying grid capacity - would displace significant volumes of gas. Although NESO suggest that achieving the Clean Power Plan would have limited effect on average electricity prices should gas (and carbon) prices remain stable, it **would reduce how often gas sets the electricity price, insulating electricity consumers from gas price volatility**. NESO estimate that gas power would set the electricity price around 15% of the time by 2030 if the Clean Power aims are achieved, while the potential costs to electricity consumers of a gas price spike like that seen in 2022 would be halved.[xxvi]

Investment in lower carbon power and grids requires appropriate incentives (discussed below), alongside **action on planning and permitting**. This is one of the key actions recommended by the CCC to enable the UK to achieve its decarbonisation goals.[ii]

Various reforms have been made or are promised. This includes updating the National Planning Policy Framework and infrastructure-specific National Policy Statements to favour renewables, grids and other infrastructure that enables Net Zero, with changes to come into effect at the end of 2025.

These reforms may help reduce planning and permitting barriers, but further action may be needed. This may include, as suggested by the National Infrastructure Commission (NIC), encouraging proactive spatial planning (including community engagement) and data sharing between projects to reduce repetitive environmental assessments.[xxxvii] **The UK and devolved governments jointly commissioned NESO at the end of 2024 to produce a Strategic Spatial Energy Plan (SSEP)**.[xlii] The aim is to set out **a spatial 'blueprint' for the UK's energy system development and align priorities and processes** across levels of governance. The SSEP **is yet to be developed and is set to be published in 2026, so whether it achieves these objectives remains to be seen**.

Action is being taken to reduce the existing grid connections queue, but implementation must be swift. As of early 2024, Ofgem – the UK's energy markets regulator - introduced requirements for projects in the queue to meet delivery milestones to demonstrate project progression (e.g. securing land and other forms of permitting), or be kicked out of the queue.[xxxv] In February 2025, Ofgem announced **that the current 'first come, first served' approach to the queue will end, and projects will instead be prioritised based on their readiness and criticality**.

New applications to join the grid queue have been halted while this reform is implemented. The regulator aims for the new system to be in place by in Spring 2025, with **the first connections under this new approach made from 2026**.[xliii] **The government should ensure this process is not delayed, monitor its impact, and adjust its criteria as necessary to minimise future delays**.

2. **Reform the electricity market to transfer the cost advantages of decarbonisation to consumers**

Under current electricity market structures in the UK, the potential for **a system based on clean power to reduce prices and volatility to consumers is not easily realised**. There are **three key areas of focus for policymakers to address this challenge**.

Reintegrate with the EU electricity and carbon markets

Recoupling with the EU's internal electricity market through the SDAC (or an equivalent) may reduce the cost of cross-border electricity trade. It **may also reduce future curtailment costs or wasted value** if electricity may be exported to the EU when supply in GB exceeds demand, and vice versa.

Despite policymakers both in the UK and the EU promising to explore solutions, little progress has been made to date. The current framework for negotiations concludes in June 2026, meaning that **discussions must move rapidly to avoid potentially taking a step backwards**.[xliv]

The EU's Carbon Border Adjustment Mechanism (CBAM) sets a carbon price on imports to the EU from sectors covered by the EU ETS from 2026 – including electricity. In concept, any carbon price paid on the production of imports before it reaches the EU is subtracted. However, due to the difficulty in determining whether an imported electron originates from renewables or fossil fuels**, CBAM adjustments will be on the average historical carbon intensity of the exporting country. This increases the cost of exporting even carbon-free renewable electricity from the UK to the EU**, potentially leading to greater curtailment.[xliv,xlv] This could in turn dampen the investment case for new renewables in the UK, or raise costs.[xlv]

A clear potential solution would be to link the UK ETS to the EU ETS. This would both align carbon prices and avoid additional export costs for EU electricity. The UK government has indicated it favours such a link[xlvi], which may be technically straight-forward given the very similar design the two systems share.[xix]

Linking the two systems may also facilitate the removal of the UK's CPF, which otherwise would elevate the carbon price facing UK generators significantly above those facing EU generators. Although the CPF was crucial in driving coal power off the UK grid over the last decade,[xlvii] it now risks simply driving up the cost of generating power from gas, and thus electricity wholesale prices.

Develop and facilitate the market for long-term contracts for non-fossil generation

The contracts-for-difference mechanism is likely to be the main form of direct support for renewable rollout in the UK, and **drive the majority of growth in low-carbon capacity over the coming years**.[xliv] At the end of 2024 the government began consulting on a range of reforms to the CfD process to accelerate renewable deployment and manage costs.[xlviii]

However, CfDs alone are not likely to deliver the level of renewable build-out required to deliver a clean power system in the coming years. They also don't directly facilitate individual offtakers to receive the cost benefit of this buildout. **Private PPAs are likely to be required**.[xliv]

The government could investigate the potential to use its financial and convening power to underwrite PPAs, pool suppliers and potential offtakers, and facilitate tradable contracts. This may reduce barriers to industrial offtakers to renewable generators alike. For this reason, the EU's Clean Industrial Deal released at the end of February 2025 stated that the European Investment Bank (EIB) will pilot a programme to partially underwrite PPAs signed by energy-intensive industrial offtakers.[xlix]

Decide on and implement reforms to the wholesale electricity market structure

A wholesale electricity market based on marginal spot pricing is well suited to a commodity-driven system based on gas and coal but **is not well suited to an infrastructure-driven system such as that based on renewables and other forms of clean power**, where marginal costs are low or zero.[l]

The future of the wholesale electricity market is the focus of the UK's Review of Electricity Market Arrangements (REMA), launched in 2022 to "identify reforms needed to transition to a decarbonised, cost effective and secure electricity system".[li]

Two broad options for reform were put forward by REMA. The first is to maintain a single national market and price, but to split the market according to generation technology (**the 'split market' approach**). The second is to maintain a marginal spot pricing approach, but to split the current market into different geographic zones (**the 'locational marginal pricing' – or LMP – approach**).

Table 1 (following page) illustrates the key differences between these two approaches. Each broad approach may be implemented with several different specific designs, including with characteristics from the other.

Key decisions on the future design of the wholesale market under REMA were due to be taken by the end of 2024 but are now promised by mid-2025. Although the split market approach was initially dropped from the second round of formal consultation, no decisions have yet been taken and the government remains actively engaged on both pathways. [li]

Regardless of the option chosen, to provide confidence to investors the government should set out a clear, detailed and time-bound pathway for delivering these reforms as soon as feasible. As highlighted by the government's own independent organisations, NESO and the CCC, there is a critical need for clarity on this issue.[ii,xxvi] Without it, investors, developers and consumers have little foresight on the future shape of the market they will be operating in.

	Locational Marginal Pricing (LMP)	Split Markets
Description	**Great Britain would be divided into several zones operating as individual markets.** Wholesale electricity prices will vary between these zones based on local supply and demand dynamics.	**A single national zone market remains but generators are divided into two markets – one containing intermittent renewable generators** operating under fixed price contracts with prices passed to consumers, **and one containing 'dispatchable' (largely gas) generators** deployed when needed, and continuing to operate using a marginal pricing approach.
Key potential benefits	• Provides clear **locational price signals** for the build out of new power generation and storage. • **Removes constraint and redispatch costs and may reduce the need for grid build out** over time and prioritise those of greatest value. • **Some zones may experience very low and often negative prices** for much of the year, **incentivising siting of electricity-intensive industry** • **Some zones may experience high or volatile prices** for much of the year, **incentivising end-use flexibility** • **Already in use around the world,** including North America	• **Prioritises decoupling of gas prices from electricity prices**, reducing the average price available to consumers able to access split market contracts. • By maintaining a single national pricing area, **consumers are not required to relocate or wait for new, low-cost generation capacity to come online to receive lower prices**. • **Low cost, low-carbon market contracts or tariffs could be focused toward consumers with greatest need** (e.g. electro-intensive industries, low-income households). • **Could evolve from the current market design**, with capacity already on CfD contracts forming the core of the low-carbon market.
Key potential limitations	• **Prices for industry and consumers in some zones could grow significantly, and remain so for the long-term** if new low-cost supply cannot be built sufficiently to compensate • **Key electro-intensive industries may not be able to move to zones with persistently low prices driven by renewables** (e.g. northern Scotland) due to reliance on other infrastructure and skills. • **Increased uncertainty over future prices in different zones and price cannibalisation may undermine the investment case** for new generation capacity, putting decarbonisation goals at risk. • New renewable capacity in areas with the best resource may be discouraged due to low prices, **potentially increasing total system cost**. • **Substantial grid investment may still emerge to take advantage of arbitrage opportunities**, which may over time lead to effective re-harmonisation into a national price.	• **Does not introduce locational signals** for the build out of the new power generation and storage, so **still requires extensive planning and investment for grid build-out and maintains the need for redispatching.** • **Interactions between the two markets may be complex**, as well as with markets for ancillary services. **This may produce inefficacies in investment and system operation.** • **By targeting access to low-cost, low-carbon contracts or tariffs, other consumers may become more exposed to gas-based price volatility**, and a more CO_2 intensive electricity supply (increasing market-based Scope 2 emissions for corporates). • **A novel approach that has not been previously tried elsewhere**, meaning there is potential for unintended consequences.

Table 1- Locational Marginal Pricing vs Split Markets. Informed by various sources including: Citizen's Advice (2023); Grubb et al (2022); MacIver & Bell (2022); Aurora (2023). Graphic created by Greenwheel.

3. Examine allocation of costs for grids and historic renewables subsidies

From May 2025, energy intensive firms that meet key sector and business-level criteria[6] **may apply for a discount of up 60% on their network costs**, covered by a levy on other consumers.[iii] **The Government could review whether this should increase toward the 90% discount available in countries such as France and Germany**.

These same companies are now **also eligible to receive full exemptions from most policy costs recovered through electricity prices**. However, **eligibility may not extend to all sectors and companies facing competitiveness concerns**. This includes, for example, non-manufacturing but electricity-intensive activities such as data centres, or that have electricity costs below 20% of their GVA.

The Government could investigate two key potential routes to tackle this. **The first is to remove these policy costs from all electricity prices**. This has been proposed by a range of stakeholders, and is a key action proposed by the CCC in its recent advice to government on how to accelerate decarbonisation through electrification across the economy.[ii] However, recommendations vary as to whether these costs are reallocated to other energy prices (e.g. natural gas), or taken onto government books directly. Each option has different political and distributional implications.

The second is to review and as necessary extend the criteria for network discounts and policy cost exemptions. This allows for a more targeted approach to addressing competitiveness concerns but may raise costs for other electricity consumers, with potentially negative distributional implications and disincentivising further electrification for these users.

Endnotes

[i] Draghi (2024a)
[ii] CCC (2025)
[iii] Eurostat (2024)
[iv] European Council (2025)
[v] Salzman (2022)
[vi] ZCA (2024)
[vii] IEA (2024)
[viii] DESNZ (2025a)
[ix] Bradshaw et al (2024)
[x] DESNZ (2025b)
[xi] NSTA (2024)
[xii] DESNZ (2024b)
[xiii] DESNZ (2024c)
[xiv] EY (2024)
[xv] Aurora (2022)
[xvi] Energy UK (2024a)
[xvii] Kitzing et al (2024)
[xviii] BNEF (2024)
[xix] Frontier Economics (2024)
[xx] Ember (2025)
[xxi] Basaglia et al (2024)
[xxii] ACER (2024)
[xxiii] European Commission (2025a)
[xxiv] ELN (2024)
[xxv] Bloomberg (2025)
[xxvi] NESO (2024)
[xxvii] Ofgem (2025a)
[xxviii] DESNZ (2025c)
[xxix] Energy UK (2023)
[xxx] Longoria et al (2024)
[xxxi] WEF (2024)
[xxxii] Wind Europe (2024a)
[xxxiii] Wind Europe (2024b)
[xxxiv] LBNL (2025)
[xxxv] Ofgem (2024a)
[xxxvi] ENA (2024)
[xxxvii] Bianchi & Wentworth (2025)
[xxxviii] DESNZ (2024d)
[xxxix] Drummond et al (2021)
[xl] Cornwall Insight (2024)
[xli] DBT (2025)
[xlii] DESNZ (2024e)
[xliii] Ofgem (2025b)
[xliv] Energy UK (2024b)
[xlv] Taschini et al (2024)
[xlvi] Parker et al (2025)
[xlvii] MacDonald et al (2023)
[xlviii] DESNZ (2025d)
[xlix] European Commission (2025b)
[l] Grubb et al (2022)
[li] DESNZ (2025e)
[lii] Elexon (2025)

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