

BREXIT & ENERGY

The British Electricity System Ten Years After Brexit

Ten years on, the UK has decarbonised faster than any G7 peer yet remains structurally dependent on gas and imports — and Brexit's uncoupling from the EU electricity market is driving a costly, contested return to the European framework.

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Executive Summary

The UK has retired 22.5 GW of fossil fuel capacity, eliminated coal entirely (the first G7 country to do so), and brought carbon intensity down from 445 g/kWh in 2009 to 126 g/kWh in 2025. Wind now meets 30% of electricity demand. Yet the system remains structurally dependent on gas, which still sets the wholesale price most of the time despite supplying only 30% of generation. A persistent north-south grid imbalance forces growing wind curtailment and has pushed balancing costs steadily higher since 2020, contributing to net electricity imports reaching 33 TWh in 2025 (12% of the electricity mix).

Brexit created regulatory separation from the EU's Internal Electricity Market without removing physical interdependence. The shift from implicit to explicit interconnector allocation raised day-ahead trading costs by an estimated £17 million a year (LCP Delta, 2024). Studies suggest that the wider effect on wholesale electricity prices reached £120-370 million in 2022 alone and could climb to £500 million over the current Parliament (Energy UK). The Multi-Region Loose Volume Coupling mechanism envisaged by the EU-UK Trade and Cooperation Agreement (TCA) missed its 2022 deadline and remains in concept validation. The situation is further complicated by the Windsor Framework, under which Northern Ireland operates within the EU wholesale electricity market while the rest of the UK trades on third-country terms.

Uncoupled carbon markets add further costs. Frontier Economics estimates the UK Treasury could forgo £3.5–8 billion from unlinked carbon prices and that the EU CBAM could transfer around £800 million from UK exporters to EU member states between 2026 and 2030. AFRY projects that CBAM could increase curtailment on the GB network by up to 50% (8 GW of offshore wind by 2040), with annual export-revenue losses of £900 million to £2.4 billion.

Recognising these costs, the UK is negotiating a return to the EU electricity framework. A December 2025 exploratory agreement indicates that access to the European electricity framework would require dynamic regulatory alignment (including on state aid and renewables targets), a role for the European Court of Justice on EU law questions, and a UK financial contribution. In March 2026, the Council linked market access to a permanent UK contribution to the EU cohesion fund, a condition the UK contests. The Swiss Bilateral III package (€375 million for electricity plus wider access) sets the precedent but may not translate directly to a single-

sector deal. The UK's failed attempt to join SAFE, the EU defence fund, over a contribution dispute in November 2025 illustrates the difficulty of bridging the gap.

Introduction

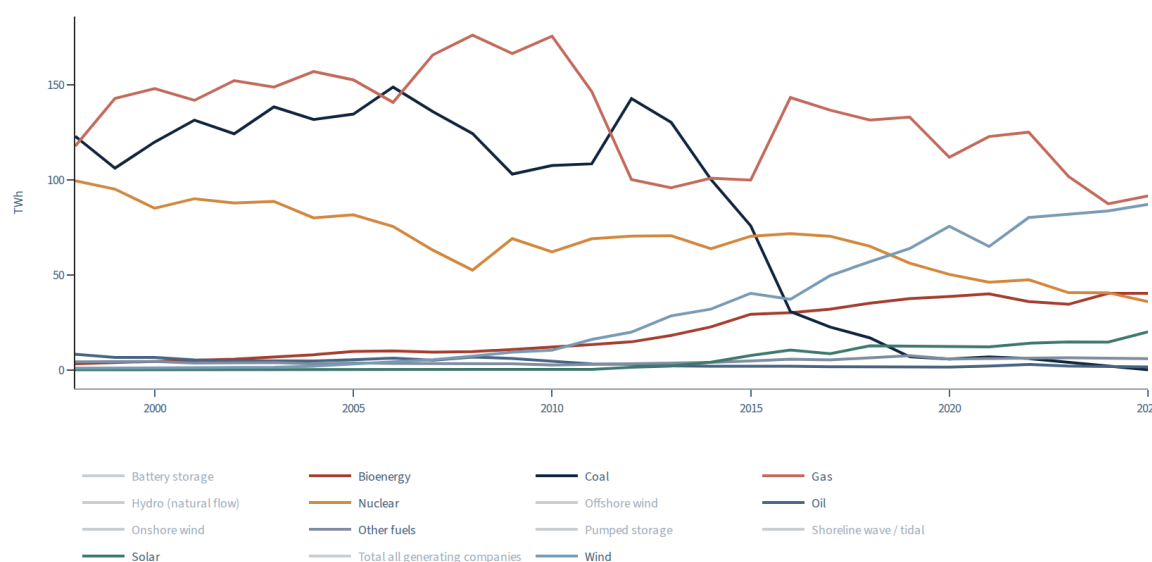
Over the past two decades, the United Kingdom has decarbonised its electricity system faster than any other G7 country. In 2000, the mix was still dominated by fossil fuels: gas accounted for around 40% of generation, coal for around 32%, and nuclear for around 22.5%. By 2025, that picture had changed markedly. Low-carbon sources accounted for almost 65% of generation, with renewables alone supplying more than half of UK electricity for the first time.

That shift rested on two developments that unfolded in parallel: the rapid phase-out of domestic fossil fuel generation, and a major expansion of renewables, especially offshore wind. Over the past decade, the UK has closed 22.5 GW of fossil fuel capacity, including 18 GW of coal. The symbolic endpoint came in 2024, when Ratcliffe-on-Soar, the last coal-fired power station in the country, closed. With that, the UK became the first G7 country to eliminate coal from its power mix altogether.

Wind now sits at the heart of the UK electricity mix. Total UK wind capacity has roughly doubled since 2017, reaching ~30 GW in 2024. That expansion has pushed the UK into the front rank of European wind markets. According to WindEurope's 2024 statistics, wind met 30% of UK electricity demand that year — behind only Denmark at 56%, and broadly in line with Ireland at 33%, Sweden at 31% and Germany at 30% (WindEurope 2024).

Electricity generation by fuel type

1998-2025, by fuel category (TWh)



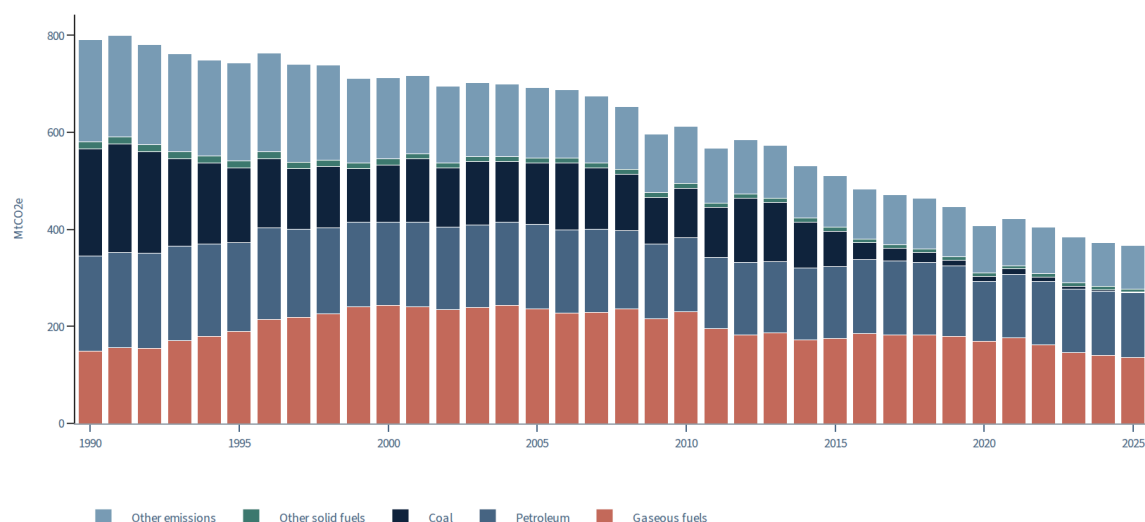
Source: Department for Energy Security and Net Zero (2025), Digest of UK Energy Statistics (DUKES): Electricity (Chapter 5), table 5.6.

As coal has exited the system and renewables have expanded, the carbon intensity of UK electricity has fallen sharply, from around 445 g/kWh in 2009 to 274 g/kWh in 2016, and then to around 126 g/kWh in 2025. This

transition is one of the main reasons UK territorial greenhouse gas emissions fell by 54% between 1990 and 2025. Over that period, emissions from electricity supply fell by 82%, making the changing electricity mix the single biggest driver of the UK's overall emissions decline (DESNZ 2026). Electricity supply now accounts for only 10% of total UK greenhouse gas emissions.

Greenhouse gas emissions by type of fuel, 1990–2025

MtCO₂e · Gaseous fuels, Petroleum, Coal, Other solid fuels, Other emissions · 2025 figure provisional



Source: Department for Energy Security and Net Zero (2026), 2025 UK Greenhouse Gas Emissions: Provisional Figures — Statistical Release, Table 4a

1. Key drivers of the transition

In 2019, the UK became the first major economy to put a net zero target into law, committing to reach net zero emissions by 2050 with the Climate Change Act of 2008. But the policy architecture behind the transition was built much earlier, and in stages. After privatisation in the 1990s, the UK introduced its first support mechanism for low-carbon electricity: the Non-Fossil Fuel Obligation, which ran from 1990 to 2002, requiring electricity suppliers to contract for specified volumes of non-fossil fuel generation (Ofgem n.d.). The mechanism was pioneering in its use of competitive auctions, but in practice much of the support flowed to nuclear rather than new renewable capacity. It was followed by the Renewables Obligation, which remained in place until it closed to new applicants in 2017. That did much more to drive early renewable deployment, especially offshore wind, though at a relatively high cost.

A more decisive shift came in 2014 with the introduction of Contracts for Difference (CfDs) under the Energy Act 2013, replacing the Renewables Obligation with a more disciplined, auction-based support mechanism. CfDs provide developers with long-term revenue certainty by fixing a “strike price” for electricity, typically over 15 years, with payments adjusting according to the gap between market and contract prices. This reduces investor risk while limiting consumer exposure to high power prices. CfDs are now the UK's main support mechanism for low-carbon power. Since 2014, they have supported around 39 GW of projects, with 10 GW operational by 2025. The latest allocation round alone secured 14.7 GW of new capacity, including 8.4 GW of offshore wind.

Another important driver was the Carbon Price Support (CPS), introduced in 2013 to add a UK carbon price on top of the EU Emissions Trading Scheme. It strengthened incentives to shift away from fossil fuels at a time when EU carbon prices were low, but raised costs for British generators relative to continental competitors. The CPS contributed to the rapid phase-out of coal, but its role diminished as coal exited the system. Critics argued that it increased the cost of decarbonisation by taxing electricity emissions more heavily than those in other sectors. In April 2026, the government announced that the CPS will be scrapped from 2028 on the grounds that it is no longer fit for purpose.

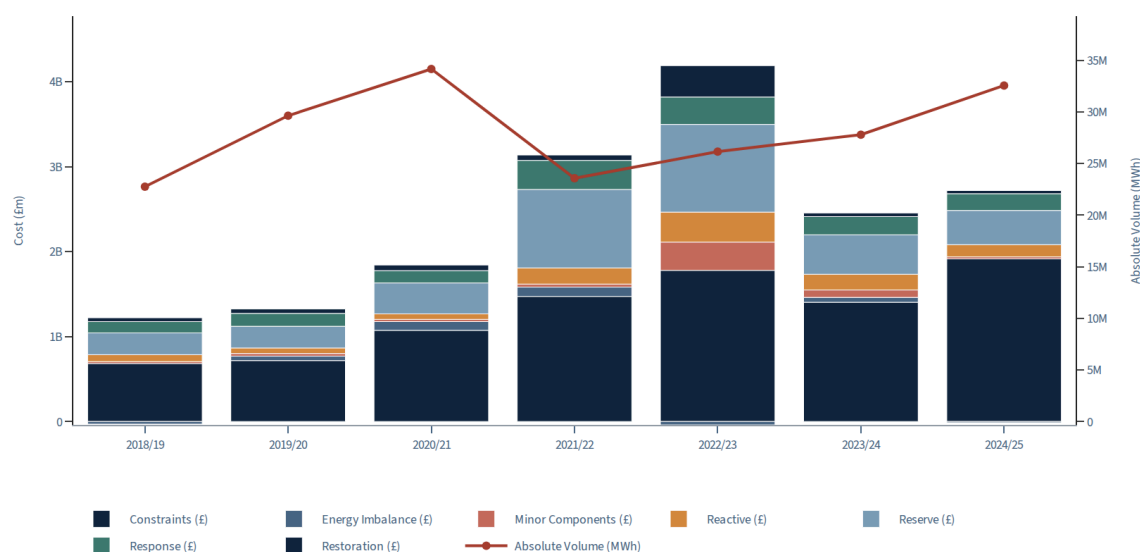
Policy support alone does not explain the British transition. Institutional design and geography also played a part. The clearest institutional advantage was the Crown Estate seabed regime, which owns and manages almost all the seabed around England, Wales and Northern Ireland and therefore sits at the centre of offshore wind development. A single national seabed authority has allowed for more coordinated leasing and spatial planning. Because Crown Estate profits are returned to the Treasury (£1.1 billion in 2024/25), the model also creates fiscal headroom.

Geography reinforced those institutional advantages as Scotland benefits from some of the strongest offshore wind resources in Europe. Offshore wind projects in UK waters achieve high capacity factors, which are a key driver of project economics and system performance, typically exceeding 30% and approaching 40% in favourable conditions. That has given the UK an unusually strong natural base for offshore wind. Scotland already accounts for around 16% of installed offshore wind capacity, with almost 3 GW operational, and a large and growing development pipeline.

2. Continued dependencies

The heavy concentration of generation capacity in the north of the GB electricity market is also one of the system's most persistent structural weaknesses. The GB electricity system is structurally imbalanced: generation is concentrated in the north while demand is centred in the south, and the transmission network has not been upgraded fast enough to bridge that gap. As a result, Scottish wind generators face among the highest Transmission Network Use of System (TNUoS) charges in Europe. When electricity cannot be transported south, the system operator curtails output through the Balancing Mechanism, paying generators to reduce generation. This has driven a steady rise in both constraint volumes and balancing costs since 2020, reflecting growing congestion as renewable capacity expands faster than the grid (NESO).

Outturn balancing costs and volumes, 2018/19 – 2024/25



NESO: <https://www.neso.energy/industry-information/balancing-costs>

These dynamics help explain why the UK remains dependent on gas and electricity imports. In 2025, gas generated only around 26% of UK electricity, yet it continues to set the wholesale price the majority of the time. Transmission constraints, the concentration of generation in Scotland, and uniform marginal pricing reinforce this outcome: when low-cost wind cannot reach demand centres in the south, the system relies more heavily on gas-fired generation, and the marginal pricing mechanism transmits those higher costs across the market.

This dependence is reinforced by the decline of domestic gas production from the North Sea. Output has fallen in recent years, increasing reliance on imports, particularly from Norway and LNG markets. Because gas is globally traded, even imports from close partners do not shield the UK from external shocks, as demonstrated in 2022 when disruptions to European gas supply drove up UK electricity prices. Limited gas storage further increases exposure to volatility compared with countries such as France and Germany.

The UK also remains reliant on electricity imports through interconnectors. Net imports reached around 33 TWh in 2025, equivalent to roughly 12% of the electricity mix, with France the largest supplier. This reflects both structural price differences and system design: UK wholesale prices are often higher than those in neighbouring markets, making imports economically attractive.

These effects are reinforced by the shift from conventional generation to more intermittent renewables. While the UK increasingly depends on wind, France continues to benefit from a large nuclear fleet providing stable, low-marginal-cost baseload power. The result is a system in which network constraints and market design reinforce one another: when cheap wind cannot be fully utilised, more expensive gas sets the price, contributing to persistently higher wholesale prices and sustained reliance on imports.

3. Brexit's energy bill: an integrated market unbundled

As the case of interconnectors makes clear, Brexit did not produce a clean physical unbundling of the UK and EU electricity markets. If anything, the UK's reliance on electricity imports from continental Europe has increased rather than diminished. In practice, the GB electricity market remains deeply entangled with the EU's Internal Electricity Market, even though it now sits outside the legal and institutional framework that once governed that relationship.

The key change is that Brexit created regulatory separation without removing physical and commercial interdependence. On paper, that gave the UK more formal sovereignty over the rules governing its electricity market. In practice, however, interconnection now comes with an inefficiency premium. Recognising that it is neither feasible nor desirable to solve this by disconnecting markets, the UK is now seeking a route back into the EU's electricity framework.

The legal architecture of UK-EU electricity market negotiations

The Trade and Cooperation Agreement (TCA), signed on 30 December 2020, has governed UK-EU relations since the end of the transition period. It facilitates trade and investment between the two sides, but it does not replicate the Single Market. The UK is therefore no longer part of the EU's integrated regulatory frameworks, including those that govern energy. Part Two, Title VIII of the TCA covers energy. It sets out high-level provisions on electricity market competition, interconnector trading, network development, security of supply, technical cooperation, the promotion of safe and sustainable energy, and trade in energy goods and raw materials.

At the May 2025 UK-EU Summit, both sides reaffirmed their commitment to the TCA and agreed to extend energy cooperation, later formalised through a Partnership Council decision enabling the continuation of the energy title beyond its June 2026 expiry. The two sides also adopted a Common Understanding, under which they committed to explore the conditions for possible UK participation in the EU's Internal Electricity Market, including access to electricity trading platforms across day-ahead, intraday and other relevant timeframes. This sits alongside the TCA rather than amending it: it is a political framework for future negotiation, not a legally binding market-access agreement.

One of the clearest post-Brexit inefficiencies lies in cross-border electricity trading. Once EU and GB electricity markets separated in regulatory terms, interconnector trading moved from implicit to explicit allocation. Under implicit allocation, interconnector capacity is assigned automatically as part of the trade itself. Before Brexit, the EU's Single Day-Ahead Coupling system allocated capacity and matched prices at the same time. After Brexit, no equivalent mechanism remained in place for the UK. Traders have instead had to bid separately for interconnector capacity and electricity, border by border, creating more uncertainty, weaker price transparency and less efficient use of interconnector infrastructure.

The TCA envisaged a more efficient day-ahead trading model based on Multi-Region Loose Volume Coupling (MRLVC), and tasked UK and EU transmission system operators with developing the necessary technical procedures. However, the April 2022 deadline was missed, and the framework remains under development. As of 2025, MRLVC is still in a concept-validation phase, with key design and implementation challenges unresolved. As a result, progress has been slower than anticipated, and the model continues to face technical and operational uncertainties.

The picture is further complicated by the asymmetry between Great Britain's electricity market and the Single Electricity Market on the island of Ireland, where Ireland and Northern Ireland continue to operate as one wholesale market with physically interconnected grids and a single cross-border trading framework. After Brexit, the Windsor Framework established a separate protocol for Ireland and Northern Ireland designed to preserve an open land border, in line with the Good Friday Agreement of 1998. The practical result is that Northern Ireland remains governed by EU wholesale electricity market rules, while the rest of the UK trades with the EU on third-country terms under the TCA.

This matters both for the rest of the UK and for its negotiations on re-entry into the Internal Electricity Market, including access to electricity trading platforms. Any future arrangement would need to be legally coherent with the regime already in place in Northern Ireland under the Windsor Framework. It is difficult to see how two overlapping but potentially inconsistent legal frameworks for electricity trading could operate sustainably within the same state.

Economic costs of uncoupling

The cost of post-Brexit electricity trading inefficiencies are likely to be material. Estimates suggest that day-ahead interconnector trading costs have risen by around £17 million a year (LCP Delta, 2024). Energy UK argues that the wider effect on wholesale electricity prices reached between £120 million and £370 million in 2022 alone, and could rise to £500 million over the course of this Parliament at current prices.

A larger cost, however, may prove structural rather than only transactional. Inefficient trading also deters investment in shared infrastructure such as Multipurpose Interconnectors (MPIs), where offshore wind farms are linked to more than one country at the same time. Two such projects are currently planned between Great Britain and the EU. Energy UK's analysis of European Commission data suggests that MPIs could reduce the cost of meeting the wider North Sea target of 300 GW of offshore wind capacity by 2050 by up to £13 billion. As the North Sea becomes more central to Europe's renewable strategy, the chilling effect on this kind of infrastructure may matter more than the direct trading costs themselves.

There is also a wider economic cost to the UK's uncoupling from EU climate policy frameworks, especially the EU Emissions Trading System (ETS) and the Carbon Border Adjustment Mechanism (CBAM). Frontier Economics estimates that, if UK and EU carbon prices remain misaligned over 2025–30, the UK Treasury could forgo between £3.5 billion and £8 billion in revenue compared with a scenario in which the two markets were linked. The same analysis projects that the EU CBAM could transfer up to £800 million from UK exporters into the EU budget by 2030 across affected sectors. In the power sector, the implications could be particularly sharp, especially for electricity exports and curtailment on the GB network.

A core issue is how CBAM defines the carbon intensity of electricity. If the methodology overstates the carbon content of UK exports, electricity exporters could face excessive carbon costs, undermining their competitiveness. AFRY estimates that the EU CBAM could increase curtailment on the GB network by up to 50%, equivalent to 8 GW of offshore wind by 2040. Because much of that electricity would otherwise have been exported, the resulting loss of export revenues could reach between £900 million and £2.4 billion a year at current wholesale prices. At that scale, reduced cross-border flows could begin to shape investment decisions, both for new projects and for the performance of existing assets.

Emerging reset framework

Following the May 2025 Common Understanding, the UK and the Commission agreed in December 2025 on the outcome of exploratory discussions concerning a future Electricity Agreement. The text is neither legally binding nor a formal negotiating mandate, but it is the clearest indication so far of what a future agreement could involve. The three most sensitive issues are dynamic alignment, the role of the European Court of Justice, and UK financial contribution.

On dynamic alignment, the text indicates that the UK would need to stay aligned with relevant EU electricity rules and apply them at the same time as the EU. The aim is to preserve a level playing field in electricity trading, renewables and state aid, while still allowing the UK to pursue objectives such as affordability, security of supply and grid stability within the EU framework. It also points towards alignment with EU renewable energy rules and an indicative overall renewables target, tying climate policy more closely to wider sovereignty debates in the UK.

The agreement would also require alignment with EU state aid rules where support affects the electricity sector or wider power market. Existing aid arrangements are likely to remain of value but future oversight is likely to require the establishment of a new independent UK authority with the European Commission. The Competition and Market Authority (CMA) does not currently have such a mandate, so primary legislation would be needed. In practice, this would narrow the UK's room to diverge in the design of its CfD regime and could draw it closer to EU industrial policy in electricity, especially where the Net-Zero Industry Act shapes support conditions, technology priorities or the use of non-price criteria in auctions. That matters politically because the UK has no equivalent framework.

On the role of the European Court of Justice, the text envisages independent arbitration, but with the Court remaining the final authority on questions of EU law. In effect, the UK could not benefit from an electricity agreement based on dynamic alignment while reserving the right to interpret the underlying EU rules for itself. That is politically and constitutionally significant because excluding any formal role for the Court was a central UK red line in the original Brexit negotiations, and the TCA does not give it that role in its own dispute-settlement system.

On UK financial contribution, the text indicates that participation in a future electricity agreement would require the UK to cover the relevant costs of the EU's work in this area. That is not part of the TCA itself, but of the Commission's wider conditions for participation in the Internal Electricity Market. A contribution to cover administrative or agency costs is not especially controversial in itself; the political sensitivity lies in whether that principle could widen once formal negotiations begin.

The December text was only the exploratory stage. On the same day it was published, 22 December 2025, the Commission sent the Council its formal recommendation to open negotiations. That broadly followed the exploratory text, but added one important element that had not been jointly agreed: a permanent, legally binding UK contribution to the EU's economic and social cohesion fund, scaled to the level of internal market access granted. In its Explanatory Memorandum to Parliament on 4 February 2026, the UK Government said explicitly that this went beyond the exploratory discussions. On 30 March 2026, the Council adopted a mandate authorising the Commission to negotiate two linked but legally separate agreements: one on the UK's participation in the EU internal electricity market, and one on its cohesion contribution. That hardened the EU position by treating the cohesion payment not as a clause within the electricity agreement, but as a parallel condition for market access.

The clearest precedent is Switzerland. When Bern signed Bilateral III in March 2026, bringing Switzerland into the EU's internal electricity market after exclusion in 2014, it agreed to pay €375 million into the cohesion fund. But that covered a much wider package, including free movement, food safety, procurement, research programmes and electricity. The UK, by contrast, is seeking electricity access alone, and London's argument is that any contribution should therefore be far smaller. Even so, the gap may prove difficult to bridge: the UK's attempt to join SAFE, the EU's defence fund, collapsed in November 2025 when the two sides could not agree on the size of the UK's financial contribution.

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