GB electricity market summary Q2 2026

April to June

Generation and contribution by fuel type

	Renewables	Renewables excl. Biomass	Gas	Nuclear	Net Imports
TWh	34.2	28.1	14.7	8.3	7.6
vs Q1 2025	-15.1%	-15.6%	-35%	-1%	+24%
vs Q2 2025	+7%	+10%	+5%	-12%	+4%

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Executive summary

Q2 2026 was dominated by geopolitical developments in the Middle East, with disruption to shipping through the Strait of Hormuz driving higher gas prices and increased volatility across European energy markets. Elevated National Balancing Point (NBP) gas prices underpinned wholesale electricity prices throughout much of April and May, while record levels of solar generation increasingly influenced intraday price patterns, contributing to more frequent periods of very low, and occasionally negative, wholesale prices. Towards the end of June, a period of exceptionally hot weather increased electricity demand and tightened system margins, resulting in elevated balancing prices and highlighting the role of flexible generation, interconnector imports and other balancing resources in maintaining system security. Although gas and power prices eased during the second half of June as concerns over LNG supply began to recede, the continued sensitivity of GB energy markets to both geopolitical events and weather-driven system conditions remained a defining feature of the quarter.

Looking ahead, the forward power price for Q3 delivery strengthened during April and May as geopolitical tensions and higher gas prices maintained a significant risk premium. Prices eased through the second half of June as expectations around LNG supply improved, with the contract ending the quarter close to where it began. While seasonal demand and continued renewable generation may help moderate market conditions, the forward market continues to reflect uncertainty surrounding global gas markets, weather conditions and geopolitical developments. As a result, short-term price movements are likely to remain sensitive to changes in market sentiment rather than following a clearly defined directional trend.

Q2 review

Gas prices: Day-ahead National Balancing Point (NBP) gas prices remained elevated and volatile through much of Q2 2026, as the market continued to price geopolitical risk associated with the conflict between the US, Israel and Iran. During April, disruption to shipping through the Strait of Hormuz kept concerns over Liquefied Natural Gas (LNG) supply at the centre of market sentiment. Although seasonal demand had eased following the winter period, uncertainty over LNG availability meant prices remained high, with repeated short-term spikes across the month.

Bullish sentiment continued into May, as the conflict remained unresolved and shipping disruption continued to affect LNG flows. Reduced LNG arrivals into the UK, as available cargoes were increasingly attracted to other markets during the period of heightened price volatility, tightened the domestic supply outlook and reinforced upward pressure on prices.

This kept NBP prices at elevated levels, with the market remaining highly sensitive to further developments in the Middle East.

Conditions shifted during June, as growing optimism around a potential US-Iran agreement and the possible reopening of the Strait of Hormuz reduced some of the risk premium that had built into gas prices earlier in the quarter. Prices fell materially through the second half of the month as expectations improved around LNG shipping flows and wider supply security. However, prices remained above pre-conflict levels, reflecting the fact that geopolitical risk had eased rather than disappeared.

Wholesale electricity prices: The wholesale power market closely mirrored developments in the gas market during Q2, with elevated fuel costs continuing to underpin prices throughout April and May.

As gas-fired generation remained the marginal source of electricity for much of the quarter, higher NBP gas prices translated directly into increased wholesale power prices across both spot and forward markets.

Alongside higher gas prices, renewable generation increasingly shaped intraday price patterns. Strong solar output, including a new instantaneous generation record of 15.42 GW on 23 April, frequently suppressed wholesale electricity prices during daylight hours, while periods of stronger renewable generation also contributed to very low, and occasionally negative, price periods.

Pressure on the system intensified towards the end of June, as record-breaking heatwaves elevated electricity demand while lower wind output tightened system margins. The National Energy System Operator (NESO) needed to procure additional balancing services, leading to exceptionally high balancing and intraday prices during peak demand periods. The period of system tightness was relatively brief, with wholesale prices easing towards the end of the quarter as gas markets softened in response to improving expectations around global LNG supply.

CCGT generation: Combined Cycle Gas Turbine (CCGT) stations continued to provide the flexibility required to meet GB electricity system demand throughout Q2. As renewable generation supplied an increasing share of daytime electricity demand, CCGT plants were called upon less as continuous baseload generation and more as a flexible source of capacity, responding to changes in renewable output and periods of higher electricity demand.

This changing operating pattern was particularly evident during periods of strong solar generation, when lower residual demand reduced the need for gas-fired generation and contributed to lower wholesale prices.

Conversely, CCGT output increased during the morning and evening demand peaks, as well as during periods of lower wind generation, reinforcing its role in maintaining system stability as renewable output fluctuated.

The period of tight operational system margins towards the end of June further demonstrated the value of flexible thermal generation, with CCGT stations providing the bulk of additional dispatchable capacity alongside interconnector imports.

Total GB electricity demand: Electricity demand followed a typical seasonal pattern during Q2, with milder spring weather reducing average consumption compared with the winter months. However, demand varied considerably through the quarter as changing weather conditions influenced both overall consumption and the timing of electricity use.

Demand remained relatively subdued through much of April and May, before increasing towards the end of June as exceptionally hot weather drove higher electricity consumption, particularly during the evening peak. The heatwave highlighted how quickly system requirements can change, with higher demand coinciding with lower wind output and tighter system margins.

Alongside these short-term weather-driven changes, policymakers and industry continued to emphasise electrification as a means of increasing electricity demand and making more effective use of expanding renewable generation. As low-carbon electricity supplies continue to grow, increasing demand from transport, heating and industry is expected to play an important role in improving system utilisation and supporting the wider energy transition.

Interconnectors: Cross-border electricity trading maintained its vital role in balancing the GB electricity system throughout Q2, providing imports during periods of tighter system margins while enabling surplus renewable generation to be exported when domestic supply exceeded demand. As renewable generation accounted for a greater share of electricity supply, interconnectors played an increasingly important role in moving electricity between neighbouring markets when supply and demand diverged.

However, the quarter also highlighted the operational challenges associated with cross-border flows. During May, NESO introduced precautionary limits on system operator trades in the opposite direction to the schedules prevailing in the day-ahead market trading on the interconnectors. Limits of 300MW of opposite direction trades were introduced across several interconnectors following concerns over such trading affecting neighbouring transmission systems. While intended to protect network stability, these restrictions reduced the level of import capacity available during tight periods, increasing reliance on domestic flexible generation and storage.

These constraints became particularly significant during the late-June heatwave, when higher electricity demand and tighter system margins increased the need for imports. NESO secured additional electricity from neighbouring markets at exceptionally high prices to maintain system security, highlighting both the value of interconnectors during periods of tight system margins and the costs associated with constrained cross-border flexibility.

Key take aways

National Balancing Point (NBP)[1] gas prices remained elevated through much of Q2 2026 as geopolitical tensions in the Middle East and disruption to shipping through the Strait of Hormuz maintained a significant risk premium across European and JKM gas markets. Reduced Liquefied Natural Gas (LNG) arrivals into the UK added further support to prices during April and May before optimism surrounding a potential US-Iran agreement eased supply concerns towards the end of June. Despite this decline, prices finished the quarter above pre-conflict levels, asserting the continued influence of geopolitical risk on wholesale gas markets.

Wholesale electricity prices closely tracked developments in the gas market during Q2 2026, with higher fuel costs underpinning prices through much of April and May. At the same time, growing renewable penetration increasingly influenced intraday price formation, with strong solar output contributing to more frequent periods of very low/negative wholesale prices. A record-breaking late-June heatwave temporarily tightened system margins and drove sharp balancing price spikes, demonstrating the continued sensitivity of the power market to periods of tight system margins.

CCGT generation remained a vital component in meeting the GB electricity system demand throughout Q2 2026. As renewable generation met an increasing share of daytime demand, gas-fired stations were increasingly operated as flexible assets rather than continuous baseload generation, responding to changes in renewable output and periods of higher electricity demand.

[1]NBP (National Balancing Point) gas price is the benchmark for UK wholesale natural gas trading.
[2] Embedded generation is connected to the distribution network, and which offsets the demand seen at transmission network level.
[3] Wind farm operators post bid prices at which they would be willing to reduce output if required and the system operator accepts bids as required to manage transmission system constraints and/or excess levels of wind generation during periods of low demand on the system.

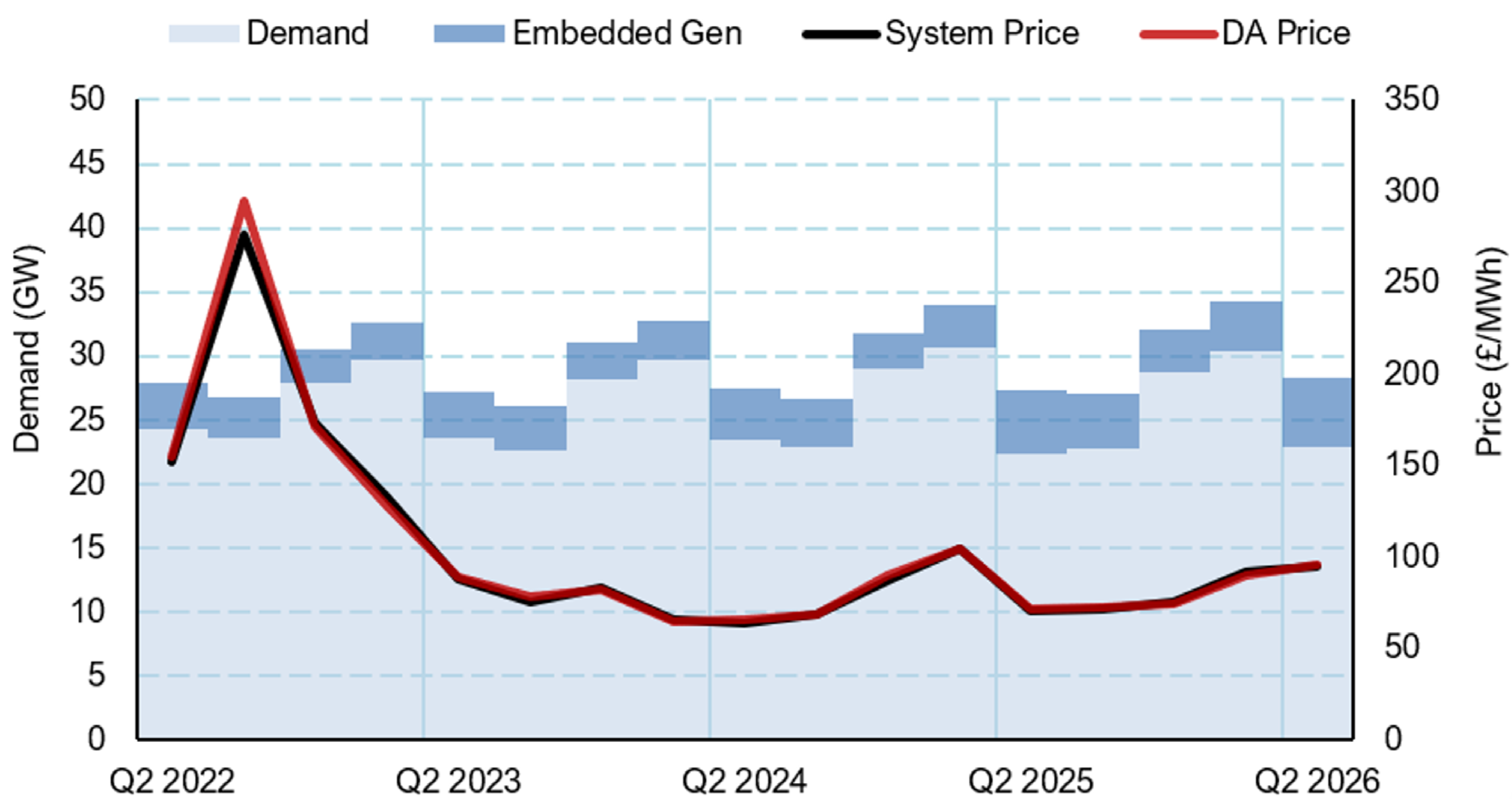


Figure 1: GB system summary (power) for Q2 2026

Key take aways

Wind generation totalled 18.9 TWh during Q2 2026, down from the exceptionally strong output seen during Q1 but broadly in line with seasonal expectations (7% higher than Q2 2025 and 10% higher than Q2 2024). Wind remained the largest source of renewable electricity, accounting for around 55% of total renewable generation, while continuing to play a significant role in reducing wholesale electricity prices during periods of stronger output. Although lower wind generation contributed to tighter system margins during the late-June heatwave, wind remained a key contributor to GB's low-carbon electricity supply.

Solar generation reached 8.0 TWh during Q2 2026, the highest quarterly output on record, reflecting both favourable weather conditions and continued growth in installed capacity. On 23 April, instantaneous solar generation reached a new GB record of 15.42 GW, while higher daytime solar output increasingly displaced conventional generation and contributed to more frequent periods of low and negative wholesale electricity prices.

Interconnectors remained an important source of flexibility throughout Q2, importing electricity during periods of tighter system margins while enabling surplus generation to be exported when domestic supply exceeded demand. However, operational restrictions on cross-border transfers for system reasons in the opposite direction to the prevailing market position reduced the level of import capacity available during periods of tight system margins, increasing reliance on domestic flexible generation. The quarter reinforced the increasingly important role of interconnectors in balancing a more weather-dependent electricity system.

Total GB electricity demand followed a typical seasonal pattern through the quarter, with milder spring weather reducing average consumption compared with the winter months. However, changing weather conditions continued to influence daily demand profiles, culminating in a sharp increase in electricity demand during the late-June heatwave. Alongside these short-term fluctuations, policymakers and industry maintained their focus on increasing electricity demand through electrification to improve utilisation of expanding renewable generation.

Figure 2: GB prevailing gas price, Q2 2023 – Q2 2026

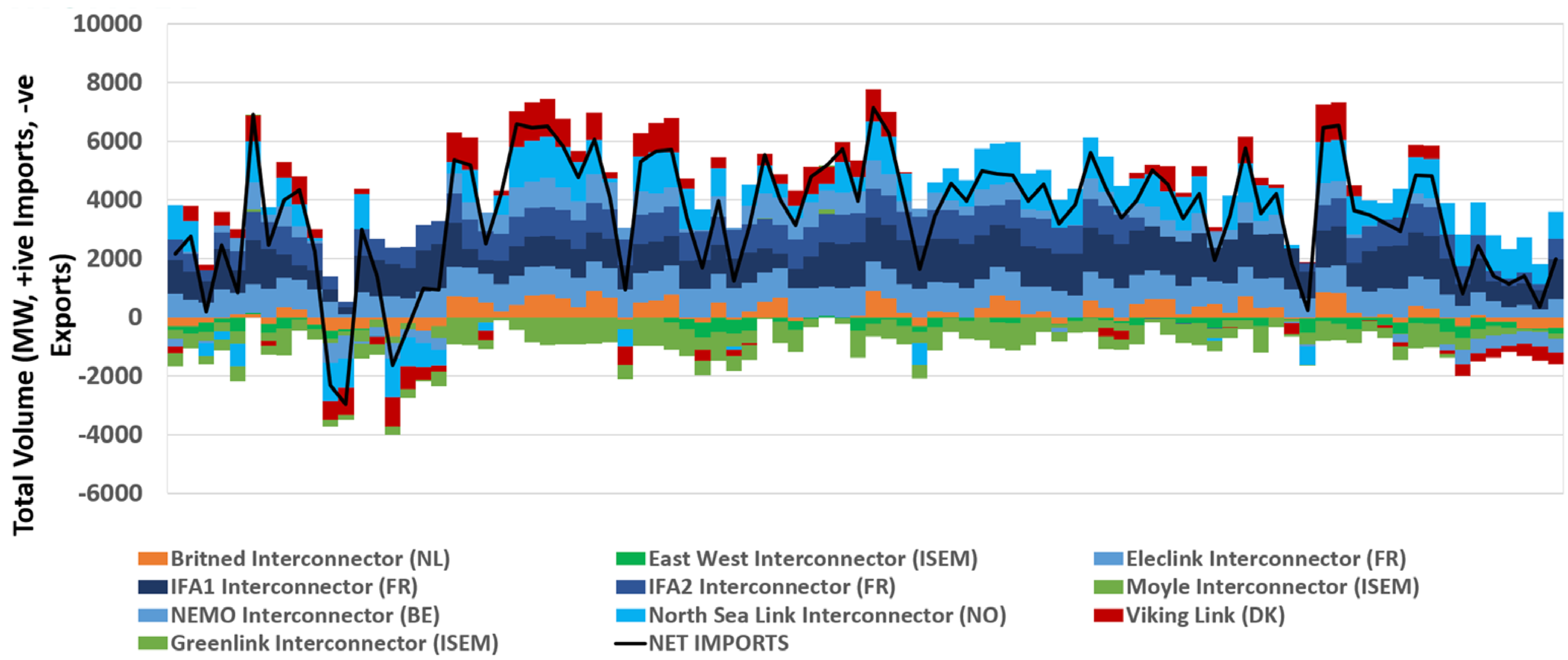


Figure 3: GB physical flows by interconnector for Q2 2026

Key take aways

Nuclear generation totalled 8.3 TWh during Q2 2026, broadly unchanged from the previous quarter but down 12% to Q2 2025 levels. Nuclear continued to provide a reliable source of low-carbon baseload generation, accounting for 13% of total GB electricity generation.

Aggregate generation excluding imports but including embedded generation2, totalled 57.2 TWh during Q2 2026, an increase from 55.4 TWh in Q2 2025. The generation mix continued to shift towards lower-carbon sources, with renewable generation accounting for more than half of total output while fossil fuels contributed 23%.

GB consumption, defined as generation plus imports, totalled 64.8 TWh during Q2 2026, up from 62.7 TWh in Q2 2025. Although average demand reflected typical seasonal conditions, the quarter highlighted the growing variability of electricity consumption, with periods of strong renewable output reducing daytime system demand and the late-June heatwave driving sharp increases in evening demand. This changing demand profile continued to increase the value of flexible generation and cross-border trading.

Renewable generation totalled 34.2 TWh during Q2 2026, accounting for 53% of total GB electricity generation, the highest share of any fuel group. Renewables continued to displace fossil fuel generation across much of the quarter while exerting greater influence over wholesale price formation and system operation.

As renewable penetration continued to increase, the need for flexible generation, storage and interconnection became increasingly evident during periods of lower renewable output.

Constraints and Wind Curtailment continued to be a prominent feature of the GB power market in Q2, with around 2.4 TWh of potential wind generation turned down via negative Balancing Mechanism (BM) bids3. This was equivalent to approximately 15% of total potential wind generation, up from 11% in Q1, despite wind generation being around 35% lower quarter-on-quarter.

This reflects the continued mismatch between the location of renewable generation and electricity demand, with periods of strong wind output in Scotland exceeding the available transmission capacity to move electricity south, resulting in higher levels of wind curtailment. It is also a feature of intervals of high renewable output occurring during periods of low system demand.

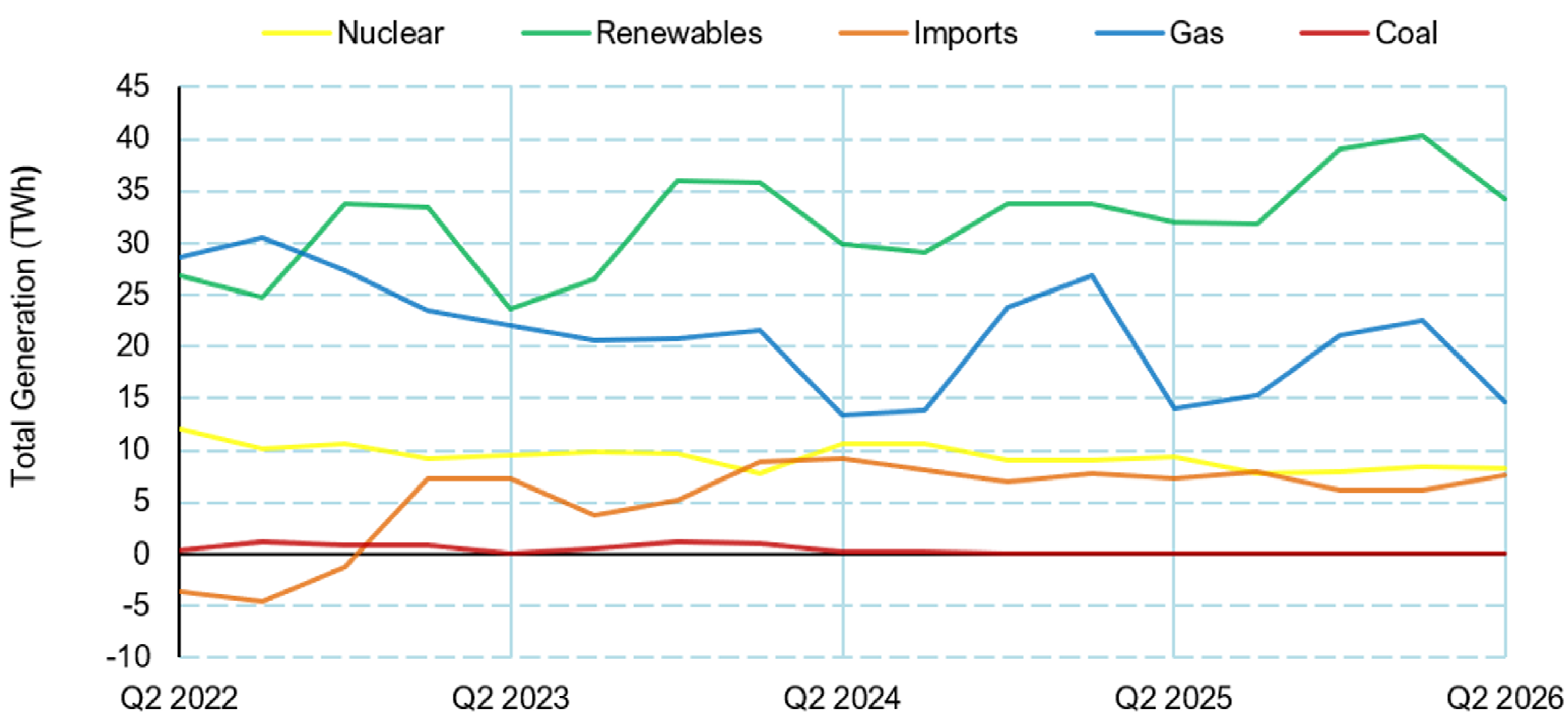


Figure 4: Total quarterly generation by main fuel group, Q2 2022 – Q2 2026

Temperature and negative pricing

Weather conditions played an important role in shaping GB electricity market dynamics during Q2 2026. The average country-wide air temperature over the 3-month period was 11.3°C, generally in line with recent years, although the quarter was characterised by significant variation between cooler conditions early in April and an exceptionally warm period towards the end of June.

While milder temperatures through much of the quarter contributed to relatively subdued seasonal electricity demand, the late-June heatwave demonstrated how rapidly system conditions can change. Maximum temperatures exceeded 40°C during the final week of June, increasing evening electricity demand and placing additional pressure on system margins at a time of lower wind generation. The result was a greater reliance on dispatchable generation and electricity imports to meet peak demand.

Negative wholesale electricity prices remained a regular feature of the GB power market during Q2 2026. The quarter recorded 49 negative hourly settlement periods, broadly in line with the elevated levels seen in recent years, reflecting the continued interaction between strong renewable generation and relatively subdued spring demand.

Unlike the winter months, where higher demand typically limits the occurrence of negative prices, Q2 provides more frequent conditions where renewable output can exceed system requirements, particularly during periods of strong solar generation. While the number of negative price periods was slightly lower than in Q2 2025, it remained well above historical levels, highlighting how the growth of renewable generation is continuing to reshape wholesale market behaviour.

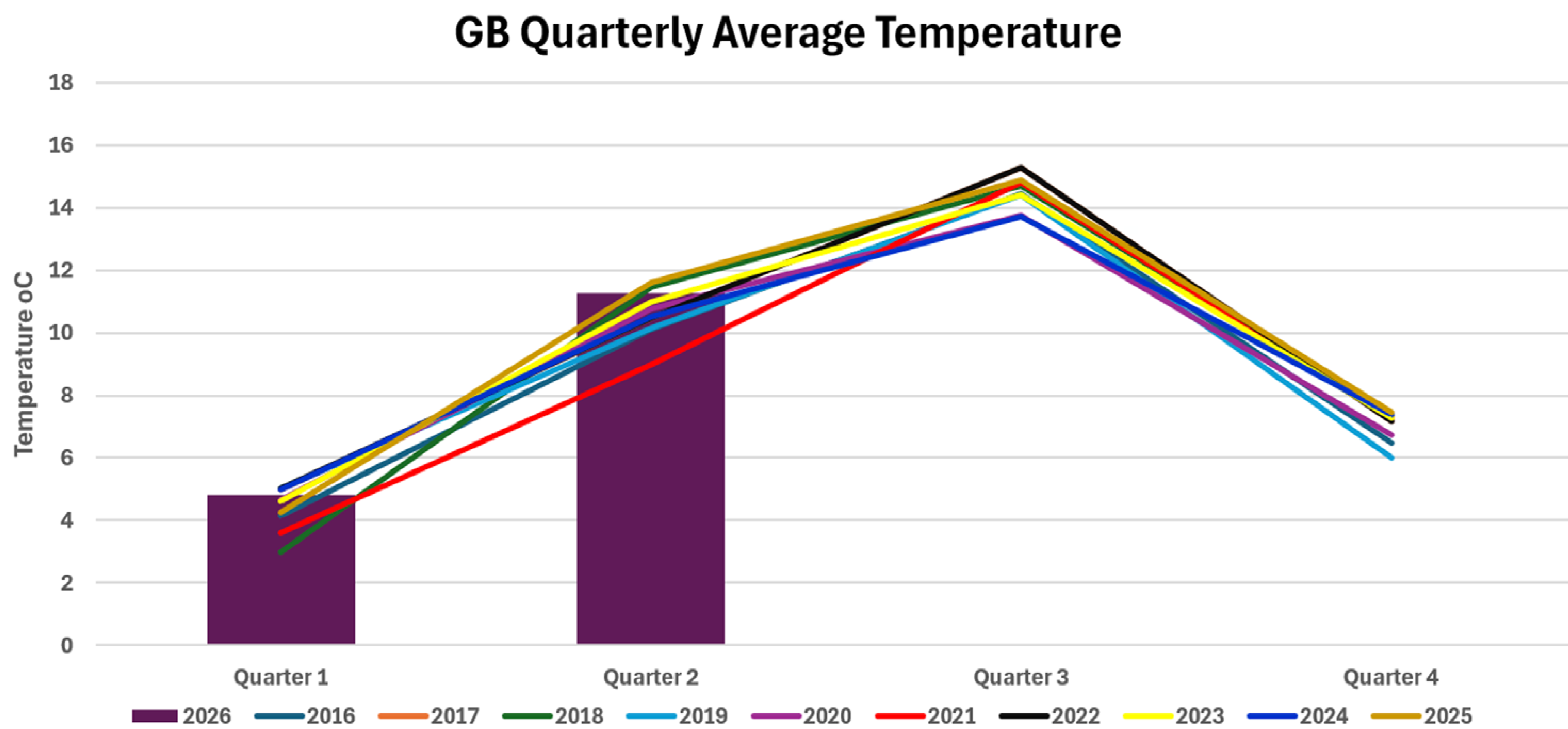


Figure 5: Average Q1 to Q4 temperature change from 2016 to 2026

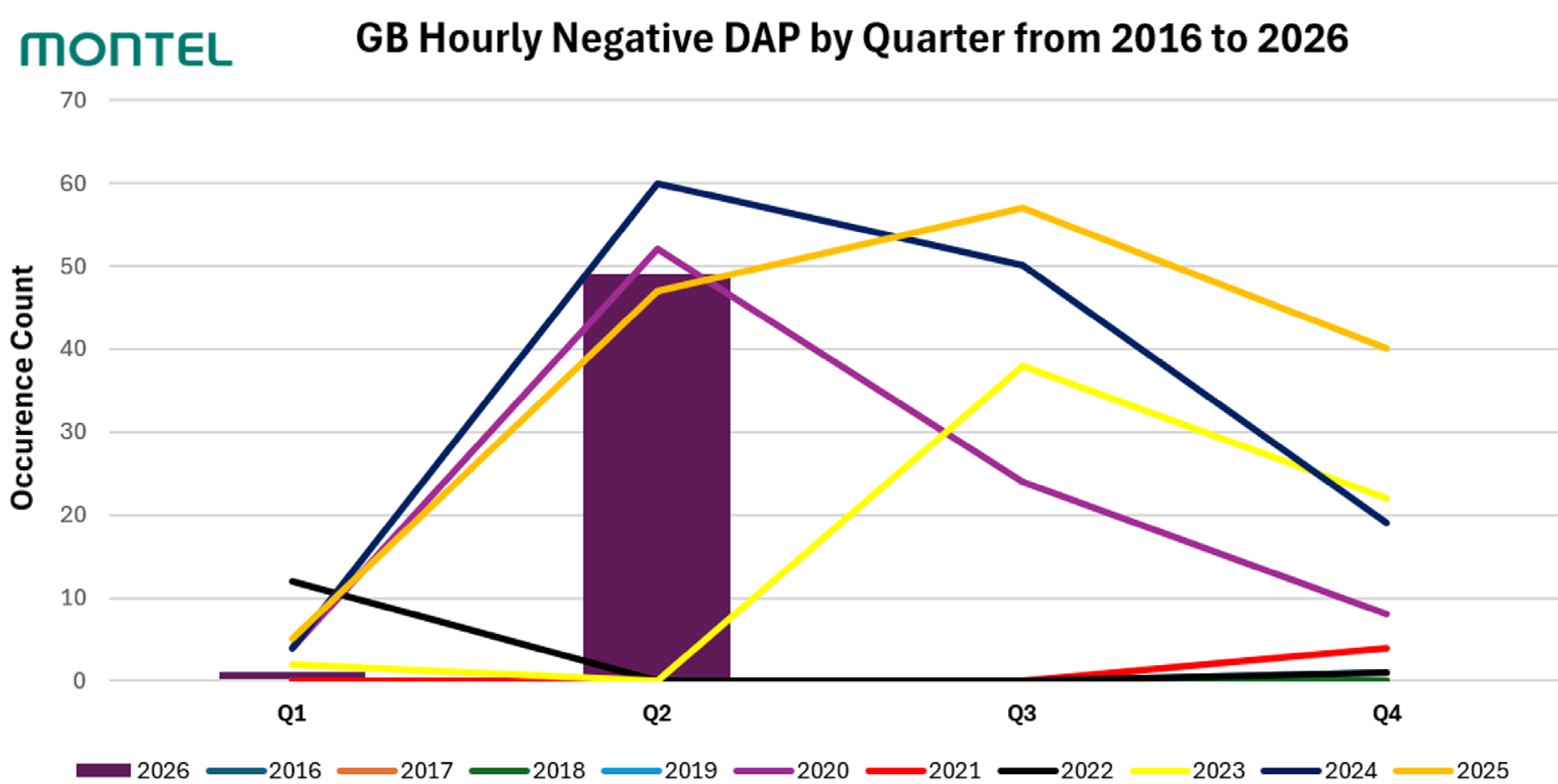


Figure 6: Average Q1 to Q4 negative hour DAP count from 2016 to 2026

Q3 outlook

The forward curve for Q3 baseload power delivery reflected the shifting market sentiment seen throughout Q2. Contracts strengthened during April and May, rising above GBP 100/MWh on several occasions as geopolitical tensions in the Middle East and higher wholesale gas prices continued to support a significant risk premium. Prices remained elevated into early June before easing through the second half of the month as improving expectations around LNG supply and the possible reopening of the Strait of Hormuz reduced concerns over global gas availability.

Although the contract retraced much of its early-June strength, it ended the quarter close to where it began, indicating that markets had removed some, but not all, of the geopolitical premium that developed during Q2. This suggests that participants continue to assign a degree of uncertainty to the outlook despite improving market sentiment.

Looking ahead, the forward market continues to reflect a wider range of potential outcomes rather than a clear directional view. Seasonal reductions in gas demand and continued renewable generation may help to ease price pressures, although developments in global gas markets, geopolitical events and weather conditions are all likely to influence market sentiment over the coming months. Domestically, the increasing influence of renewable generation, alongside the growing importance of flexible generation, storage and interconnection, is expected to remain a key feature of short-term price formation.

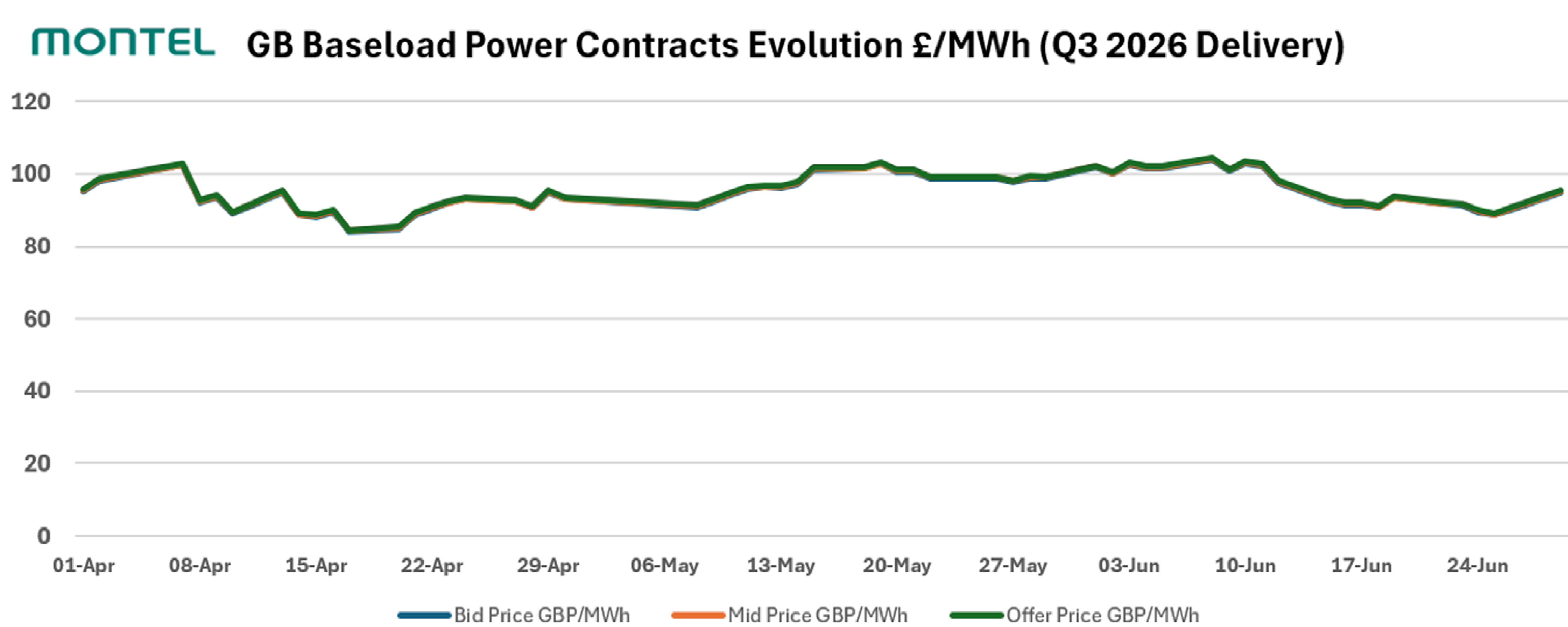


Figure 7: GB Baseload Power Contract Evolution for Q3 2026

Appendix: Supporting tables

The tables below show key statistics on generation in the quarter and all previous quarters over the last two years. Biomass and hydro values for the reporting quarter contain estimates for the embedded portion of the fleet, based on the same quarter last year as this data is published at a lag of ~3 months by DESNZ[2]. Note that all percentages are given as a percentage of total generation including imports.

*GB Only (Excludes Northern Ireland)	Q2 2024	Q3 2024	Q4 2024	Q1 2025	Q2 2025	Q3 2025	Q4 2025	Q1 2026	Q2 2026
TOTAL GENERATION BY FUEL (TWh)									
Coal	0.3	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	13.4	13.8	23.8	26.8	14.0	15.4	21.1	22.5	14.7
Imports	9.2	8.1	7.0	7.8	7.3	7.9	6.2	6.1	7.6
Nuclear	10.7	10.7	9.1	9.0	9.4	7.8	8.0	8.4	8.3
Biomass	6.6	6.7	7.2	7.1	6.5	7.0	7.3	7.1	6.2
Wind	17.2	16.7	23.7	22.3	17.6	17.7	28.4	29.2	18.9
Solar	5.1	4.7	1.5	2.7	7.2	6.2	1.8	2.7	8.0
Hydro	1.1	1.1	1.5	1.6	0.7	1.0	1.6	1.4	1.2
RENEWABLES (Biomass, Wind, Solar & Hydro)	30.0	29.2	33.8	33.7	32.0	31.9	39.1	40.3	34.2
RENEWABLES Excl. Biomass	23.4	22.5	26.7	26.6	25.5	24.9	31.8	33.2	28.1
FOSSIL FUELS (Gas & Coal)	13.7	14.1	23.8	26.8	14.0	15.4	21.1	22.5	14.7
TOTAL GB GENERATION (excl. Imports)	54.4	53.9	66.7	69.6	55.4	55.0	68.2	71.2	57.2
TOTAL GB CONSUMPTION (incl. Imports)	**63.6**	**62.0**	**73.7**	**77.4**	**62.7**	**62.9**	**74.4**	**77.3**	**64.8**
Fossil Fuel Percentage	22%	23%	32%	35%	22%	24%	28%	29%	23%
Clean Percentage (Renewable & Nuclear)	64%	64%	58%	55%	66%	63%	63%	63%	66%
Renewable Share of Clean Power	74%	73%	79%	79%	77%	80%	83%	83%	80%
SHARE OF GENERATION (%)									
Coal	0%	0%	0%	0%	0%	0%	0%	0%	0%
Gas	21%	22%	32%	35%	22%	24%	28%	29%	23%
Imports	14%	13%	9%	10%	12%	13%	8%	8%	12%
Nuclear	17%	17%	12%	12%	15%	12%	11%	11%	13%
Renewables (Biomass, Wind, Solar & Hydro)	47%	47%	46%	44%	51%	51%	53%	52%	53%

Table 1: Quarterly generation summary Q2 2026 (TWh)

*GB Only (Excludes Northern Ireland)	Q2 2018	Q2 2019	Q2 2020	Q2 2021	Q2 2022	Q2 2023	Q2 2024	Q2 2025	Q2 2026
TOTAL GENERATION BY FUEL (TWh)									
Coal	0.9	0.4	0.1	0.5	0.3	0.1	0.3	0.0	0.0
Gas	28.0	28.3	18.9	27.1	28.7	22.0	13.4	14.0	14.7
Imports	5.1	5.7	4.6	6.1	-3.6	7.4	9.2	7.3	7.6
Nuclear	15.5	12.3	11.2	10.8	12.1	9.5	10.7	9.4	8.3
RENEWABLES (Biomass, Wind, Solar & Hydro)	21.0	23.2	25.9	24.2	26.8	23.7	30.0	32.0	34.2
FOSSIL FUELS	28.9	28.6	19.0	27.6	29.0	22.1	13.7	14.0	14.7
TOTAL GB GENERATION (excl. Imports)	65.4	64.0	56.1	62.6	68.0	55.3	54.4	55.4	57.2
TOTAL GB CONSUMPTION (incl. Imports)	**70.5**	**69.7**	**60.7**	**68.7**	**64.3**	**62.7**	**63.6**	**62.7**	**64.8**
Fossil Fuel Percentage	41%	41%	31%	40%	45%	35%	22%	22%	23%
Clean Percentage	52%	51%	61%	51%	61%	53%	64%	66%	66%
Renewable Share of Clean Power	30%	33%	43%	35%	42%	38%	47%	51%	53%
SHARE OF GENERATION (%)									
Coal	1%	1%	0%	1%	1%	0%	0%	0%	0%
Gas	40%	41%	31%	39%	45%	35%	21%	22%	23%
Imports	7%	8%	8%	9%	-6%	12%	14%	12%	12%
Nuclear	22%	18%	19%	16%	19%	15%	17%	15%	13%
RENEWABLES (Biomass, Wind, Solar & Hydro)	30%	33%	43%	35%	42%	38%	47%	51%	53%

Table 2: Year-on-year comparison of Q2 generation output (2018-2026) (TWh and %)

[2] https://www.gov.uk/government/statistics/energy-trends-section-6-renewables/Renewables obligation: certificates and generation (monthly - Excel)

Table 3 below shows key statistics on pricing in the quarter and all previous quarters over the last two years. The wholesale and within-day prices shown are averages across the quarter, whilst the system prices are given with minimum, average and maximum values.[4]

Note that the values for domestic demand in Table 3 do not include interconnector demand.

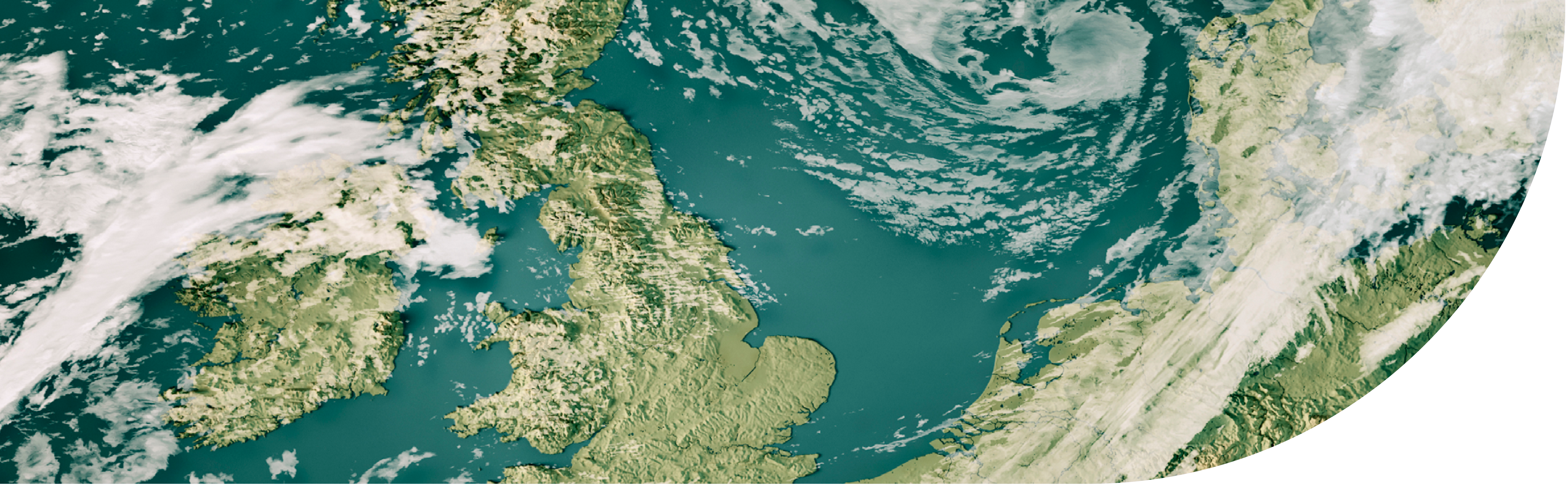
*GB Only (Excludes Northern Ireland)	Q2 2024	Q3 2024	Q4 2024	Q1 2025	Q2 2025	Q3 2025	Q4 2025	Q1 2026	Q2 2026
WHOLESALE PRICES (£/MWh)									
EPEX Day-Ahead Price	66.17	68.22	89.94	104.50	71.61	72.40	74.32	89.72	95.93
Nordpool Day-Ahead price	66.17	68.22	89.94	104.50	71.61	72.59	74.44	90.24	95.81
Within Day Price (MIDP)	64.12	68.31	87.79	102.14	70.86	72.14	74.36	91.15	94.50
WITHIN DAY PRICE BREAKDOWN (£/MWh)									
Off-Peak Hours	58.28	60.51	70.03	89.02	70.00	69.70	62.08	82.91	94.32
Peak Hours (excl Superpeak)	65.30	69.74	91.06	101.47	69.21	70.56	75.97	90.58	91.80
Superpeak Hours	73.26	81.04	116.82	134.48	78.79	83.39	96.93	112.03	104.55
SYSTEM PRICE (£/MWh)									
Maximum	156.47	200.00	669.21	2,900.00	423.85	263.58	487.00	750.00	800.00
Average	63.58	68.40	87.13	104.13	71.00	71.56	75.62	91.59	94.66
Minimum	-91.82	-89.10	-75.00	-96.22	-87.32	-87.00	-30.00	-52.28	-97.92
Domestic Demand (MW average)	23,479	22,932	28,947	30,693	22,383	22,697	28,772	30,420	22,847
Domestic Demand incl. Embedded Gen (MW average)	27,533	26,689	31,832	34,041	27,351	27,101	32,103	34,292	28,246
Domestic Demand (TWh total)	51.28	50.63	63.91	66.30	48.88	50.11	63.53	65.71	49.90
Domestic Demand Incl. Embedded Gen. (TWh total)	60.13	58.93	70.29	73.53	59.73	59.84	70.88	74.07	61.69

Table 3: Quarterly price summary Q2 2024 to Q2 2026

*GB Only (Excludes Northern Ireland)	Q2 2018	Q2 2019	Q2 2020	Q2 2021	Q2 2022	Q2 2023	Q2 2024	Q2 2025	Q2 2026
WHOLESALE PRICES (£/MWh)									
EPEX Day-Ahead Price	52.66	41.18	24.25	72.20	155.32	88.66	66.17	71.61	95.93
Nordpool Day-Ahead price	52.66	41.18	24.25	72.20	155.32	88.66	66.17	71.61	95.81
Within Day Price (MIDP)	51.61	41.00	23.49	71.80	149.28	87.98	64.12	70.86	94.50
WITHIN DAY PRICE BREAKDOWN (£/MWh)									
Off-Peak Hours	46.22	36.54	19.59	62.71	136.51	84.51	58.28	70.00	94.32
Peak Hours (excl Superpeak)	53.35	42.36	24.66	75.06	152.53	88.42	65.30	69.21	91.80
Superpeak Hours	57.74	46.23	28.21	81.01	166.86	94.30	73.26	78.79	104.55
SYSTEM PRICE (£/MWh)									
Maximum	158.00	375.00	100.00	1971.59	494.23	370.00	156.47	423.85	800.00
Average	50.53	41.23	24.76	74.85	152.31	87.58	63.58	71.00	94.66
Minimum	-92.38	-71.26	-70.49	-59.95	-69.49	-155.20	-91.82	-87.32	-97.92
Domestic Demand (MW average)	27,419	26,953	22,431	26,323	24,224	23,624	23,479	22,383	22,847
Domestic Demand incl. Embedded Gen (MW average)	30,677	30,132	26,023	29,719	27,866	27,165	27,533	27,351	28,246
Domestic Demand (TWh total)	59.88	58.86	48.99	57.49	52.91	51.59	51.28	48.88	49.90
Domestic Demand Incl. Embedded Gen. (TWh total)	67.00	65.81	56.83	64.91	60.86	59.33	60.13	59.73	61.69

Table 4: Year-on-year comparison of Q2 prices (2018-2026)

[4] Peak is 08:00 – 16:00 and 19:30 – 00:00; Super Peak is 16:00 – 19:30; Off-Peak is 00:00 – 08:00.



Notes on the report

The figures used in the report refer to GB only, unlike those reported by DESNZ that refer to GB and Northern Ireland. This selection has been made since the Northern Ireland electricity market is separate from the GB electricity market and is part of the Ireland all-island I-SEM market.

Generation levels by fuel from 2009 onwards are based upon National Grid fuel mix data published by Elexon as the BMRS FUELHH data, which give the operationally metered totals by fuel, down to a 5-minute resolution.

Solar Generation data comes from Sheffield University. Prior to 2009, individual plant data has been aggregated from our database matching the National Grid fuel-type relationships.
To account for embedded wind and solar, the National Grid forecasts for these generators have been used as if they were output figures. Embedded hydro and biomass have been accounted for using analysis of Ofgem data on certificate awards.

This embedded hydro and biomass data is published at a lag of approximately three months, so the reporting quarter will not have actual data for this section of these two fleets, instead values are estimated from the respective quarter of the previous year.

Within this report, levels of offshore wind have not been separated from the wind total. This is because this can only be reliably done using metered volumes at a generating unit level.

This is not a publicly available data stream, and figures can only be estimated. Final Physical Notifications (FPNs) at wind farms do not correlate well with metered volumes and so cannot be used reliably.

Price and demand data primarily come from Elexon (as does the FUELHH data), except for EPEX and Nord Pool day-ahead prices. Availability levels are calculated by totalling levels of recorded availability at all plants in the market.

About Montel

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