GB electricity market summary Q1 2026

January to March

Generation and contribution by fuel type

	Renewables	Renewables excl. Biomass	Gas	Nuclear	Net Imports
TWh	40.3	33.2	22.5	8.4	6.1
vs Q4 2025	+3%	+4.5%	+7%	+5.3%	-1%
vs Q1 2025	+20%	+25%	-16%	-7%	-22%

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Executive summary

Quarter 1 2026 was characterised by a combination of strong renewable output, weather-driven demand swings and increased gas market volatility following the outbreak of the war in Iran. Record wind generation, supported by storm activity in January, pushed total renewable output to new highs and contributed to periods of low power prices, even as curtailment remained a persistent feature of the system. Despite this, a cold spell in early January led to sharp increases in demand and short-term price spikes, with the system relying on imports and gas-fired generation. Conditions eased through February, but volatility returned in March as geopolitical developments drove a sharp rise in gas prices, feeding directly into higher power prices and increased market sensitivity. Overall, the quarter reinforced the growing influence of renewable generation on price formation and system dynamics, while highlighting continued exposure to gas market movements during periods of tighter supply and higher demand.

Looking ahead to Quarter 2 2026, the forward power price for Q2 2026 delivery was generally stable in day-to-day trading through January and February but then saw a sharp increase reflecting increased uncertainty following the volatility seen in March. The longer-term forward market, i.e. beyond Q2, currently shows lower prices, indicative of an expected return to normality. However, any escalation or de-escalation in hostilities could rapidly change the outlook.

Q1 review

Gas prices: Day-ahead National Balancing Point (NBP) gas prices in Q1 2026 opened at GBP 25.9/MWh and remained relatively stable in early January. From mid-month, prices rose steadily, reaching GBP 34.5/MWh on the 16th, driven by colder weather across Europe and increased heating demand. Prices remained elevated through the rest of the month, peaking at GBP 36.4/MWh on the 21st, as cold conditions persisted and Norwegian outages tightened supply.

At the start of February, the market shifted. Prices dropped to GBP 29.5/MWh as milder temperatures reduced demand and supply conditions stabilised. This marked the start of a broader downward trend, with prices falling to a quarterly low of GBP 24.9/MWh on the 16th. Despite some short-term fluctuations, the overall direction reflected a more balanced market compared to January.

Conditions changed again in early March - prices rose sharply from GBP 26.7/MWh on the 1st to GBP 47.0/MWh by the 3rd, following an escalation of conflict in the Middle East. Concerns over potential disruptions to global Liquefied Natural Gas (LNG) supply, particularly via the Strait of Hormuz, drove a rapid repricing of risk. The UK market was especially sensitive, with limited storage capacity amplifying the move and NBP briefly trading at a premium to the Dutch Title Transfer Facility (TTF).

Prices remained elevated and volatile through March, reaching a quarterly high of GBP 52.6/MWh, as fears over global supply security intensified. Although prices eased towards the end of the month, they remained well above February levels, closing at GBP 43.1/MWh on the 31st.

Wholesale electricity prices: Day-ahead wholesale electricity prices in Great Britain rose sharply in early January, driven by a cold spell that increased demand and tightened system margins. The day-ahead aggregated price reached an 11-month high of GBP 121.4/MWh on Nord Pool on the 7th, with hourly prices peaking at around GBP 182/MWh. During this period of system stress, the system operator secured imports at very high prices, reportedly exceeding GBP 1,000/MWh, highlighting the extent of short-term supply tightness.

As conditions normalised, prices eased through the remainder of January and into February, supported by milder weather and improved system balance. Day-ahead prices moved back towards more moderate levels, with fewer extreme price events.

In March, wholesale electricity prices became more volatile as higher fuel costs fed through into the power market as a result of geopolitical tensions. With gas-fired generation continuing to set the marginal price for much of the system, increases in gas prices lifted price levels and increased sensitivity to short-term supply changes. This was reflected in more frequent price swings and higher overall levels compared to February.

Wind generation reached new highs in Q1 2026, with total output of 29.2 TWh across the quarter - output was particularly high in January, which set a monthly generation record of 10.6 TWh. This was driven in part by a series of winter storms – Goretti, Ingrid and Chandra – which brought prolonged periods of high wind speeds across Britain. As a result, wind output remained elevated for extended periods, contributing significantly to system supply and enabling increased exports to neighbouring markets.

However, variability remained a key feature. During calmer periods, particularly in early January, lower wind output contributed to tighter system conditions and increased reliance on CCGT generation. At the same time, periods of strong wind later in the quarter coincided with low price hours and increased curtailment, reflecting ongoing transmission constraints within the GB network.

Wind output would have been even higher had it not been necessary to curtail output during periods of high wind. 3.6 TWh of potential wind output was effectively turned off via balancing mechanism bids accepted by the system operator[1] – meaning that wind generation could have been 11% higher had there been sufficient capacity on the transmission network to transmit the full potential output.

CCGT generation remained a key source of system flexibility in Q1 2026, with output totalling 22.5 TWh across the quarter. Gas-fired plants were particularly important during the cold spell in early January, when higher demand and lower renewable output required increased dispatch to maintain system balance.

As conditions eased into February, CCGT utilisation fell alongside lower demand and improved renewable output. However, in March, higher gas prices fed through into the power market, increasing generation costs and reinforcing the role of gas in setting marginal prices during periods of tighter system conditions.

Compared to Q1 2025, 16% less gas-fired generation was produced overall, and its share of total generation in GB fell from 35% to 29%, as higher renewable output displaced gas-fired generation across the quarter.

Total GB electricity demand showed significant variation across Q1 2026, largely driven by weather conditions. During the cold spell in early January, peak demand reached 47.3 GW – the highest figure since March 2018.

As temperatures increased through February, demand eased and system conditions became more balanced. However, short-term fluctuations remained, reflecting both weather variability and underlying structural growth from electrification and digital load.

Interconnectors remained a key contribution in Q1 2026, with net imports totalling 6.1 TWh, though down from 7.8 TWh in Q1 2025. Flows shifted frequently in response to changes in wind output and system demand.

In mid-February, exports to Norway via the North Sea Link (NSL) reached around 190.2 GWh over a single week, reflecting periods of strong wind generation in GB. However, reduced availability on key assets, including a temporary capacity reduction to 700 MW on the NSL in January, constrained flows during tighter conditions and increased reliance on more expensive domestic balancing options.

Key take aways

National Balancing Point (NBP)[2] gas prices in Q1 2026 traded within a wide range, rising from GBP 25.9/MWh at the start of January to a quarterly high of GBP 52.6/MWh on 19 March. Prices were driven by colder weather in January, which increased demand and tightened supply, followed by a period of easing in February as milder conditions reduced demand.

Volatility increased sharply in March, when geopolitical developments in the Middle East raised concerns over global Liquefied Natural Gas (LNG) supply, particularly via the Strait of Hormuz. This led to a rapid repricing of risk, with the UK market briefly trading at a premium to the Dutch Title Transfer Facility (TTF), reflecting the system's sensitivity to supply shocks and limited storage capacity.

Wholesale electricity prices in GB were highly volatile across Q1 2026, reflecting changes in both demand and fuel costs. Day-ahead aggregate prices peaked at GBP 121.4/MWh on 7 January during a cold spell, with hourly prices reaching GBP 182/MWh.

During this period, the system operator secured imports at prices exceeding GBP 1,000/MWh, highlighting the extent of short-term system tightness. Prices eased through February as milder weather and stronger renewable output improved system balance, before rising again in March as higher gas prices lifted overall price levels and volatility.

CCGT generation totalled 22.5 TWh in Q1 2026, down from 26.8 TWh in Q1 2025 and slightly below 23.8 TWh in Q4 2024. Gas accounted for 29% of total generation and remained the primary marginal fuel.

Although output declined year-on-year, CCGT plants continued to play a central role in system balancing, particularly during periods of lower renewable output and higher demand.

[1] 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
[2] Embedded generation is generation connected to the distribution networks, and which offsets the demand seen at transmission network level.
[3] NBP (National Balancing Point) gas price is the benchmark for UK wholesale natural gas trading.

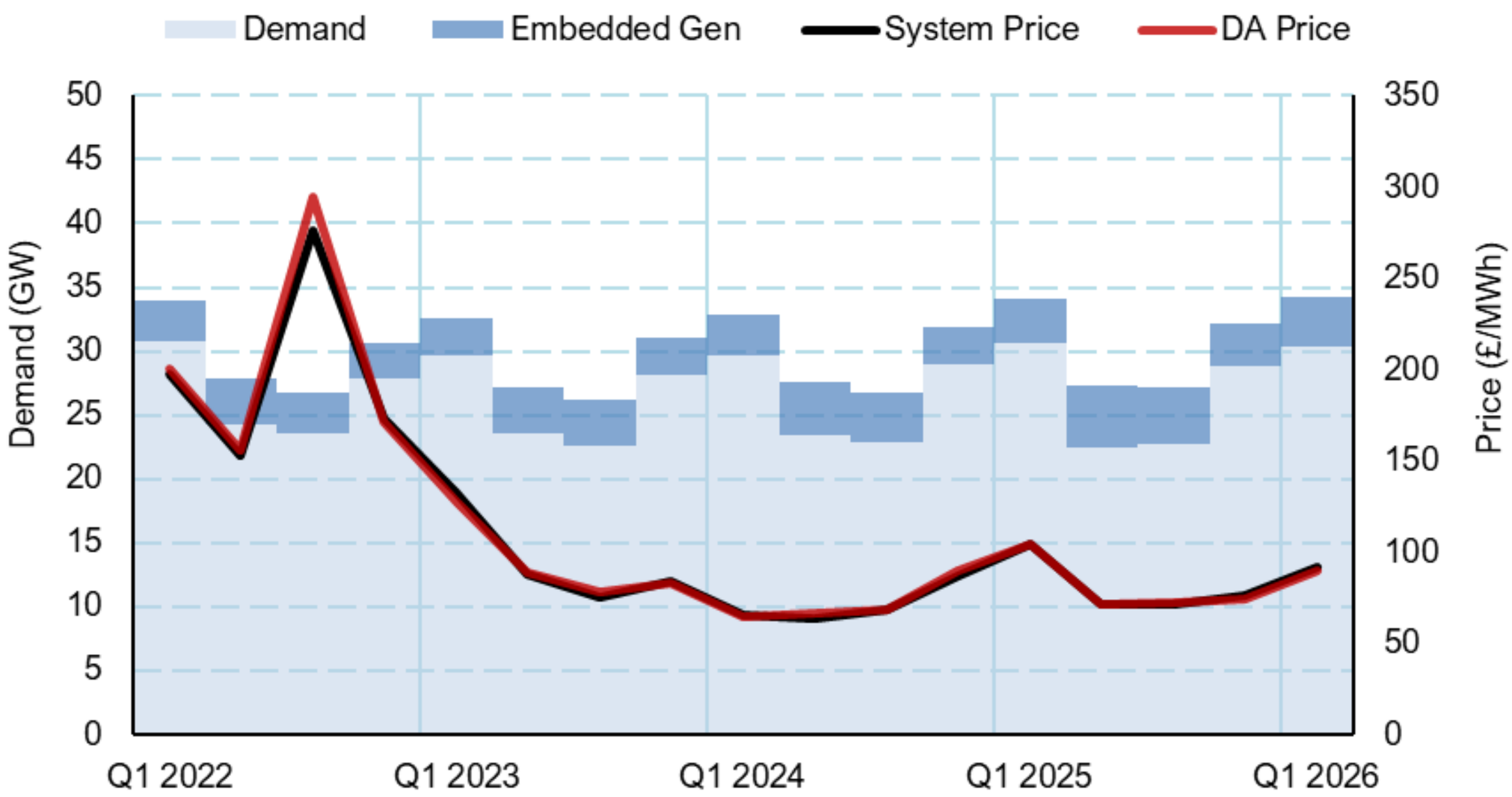


Figure 1: GB System Summary (Power) for Q1 2026

Key take aways

Wind generation in Q1 2026 totalled 29.2 TWh, up from 22.3 TWh in Q1 2025 and 24.9 TWh in Q1 2024. Wind accounted for 72.5% of total renewable generation during the quarter, maintaining its position as the dominant renewable source in Great Britain.

Periods of strong wind generation coincided with low price hours and increased balancing actions, limiting the full utilisation of available capacity.

Despite higher output, curtailment remained a key feature of the system, reflecting transmission constraints between northern generation and southern demand centres. 3.6 TWh of potential generation was turned down, equivalent to roughly 11% of total output.

Solar generation totalled 2.7 TWh in Q1 2026, slightly below 2.7 TWh in Q1 2025 and above 1.9 TWh in Q1 2024. Solar accounted for 6.6% of total renewable generation and 3.4% of total generation during the quarter.

Output remained limited compared to other quarters due to seasonal factors, although generation was broadly in line with recent Q1 levels.

Interconnectors remained a key component of the system in Q1 2026, with net imports totalling 6.1 TWh, down from 7.8 TWh in Q1 2025. France and Norway continued to be the main sources of imports, although flows varied significantly across the quarter.

Periods of strong wind generation enabled increased exports, including around 190.2 GWh to Norway over a single week in mid-February. However, reduced availability on key infrastructure, including a temporary reduction in capacity to 700 MW on the North Sea Link (NSL) in January, limited flexibility during tighter system conditions.

Total GB electricity demand, including embedded generation, reached 74.1 TWh in Q1 2026, compared to 73.5 TWh in Q1 2025 and 70.8 TWh in Q1 2024. At transmission system level, demand totalled 65.7 TWh, down slightly from 66.3 TWh in Q1 2025.

Variation across the quarter was driven largely by weather conditions, with a cold spell in early January pushing peak demand to around 44 GW, while milder conditions in February reduced overall system load. On average, transmission demand stood at 30.4 GW, compared to 30.7 GW in Q1 2025 and 29.7 GW in Q1 2024, while demand including embedded generation averaged 34.3 GW.

Figure 2: GB Prevailing Gas Price, Q4 2023 – Q1 2026

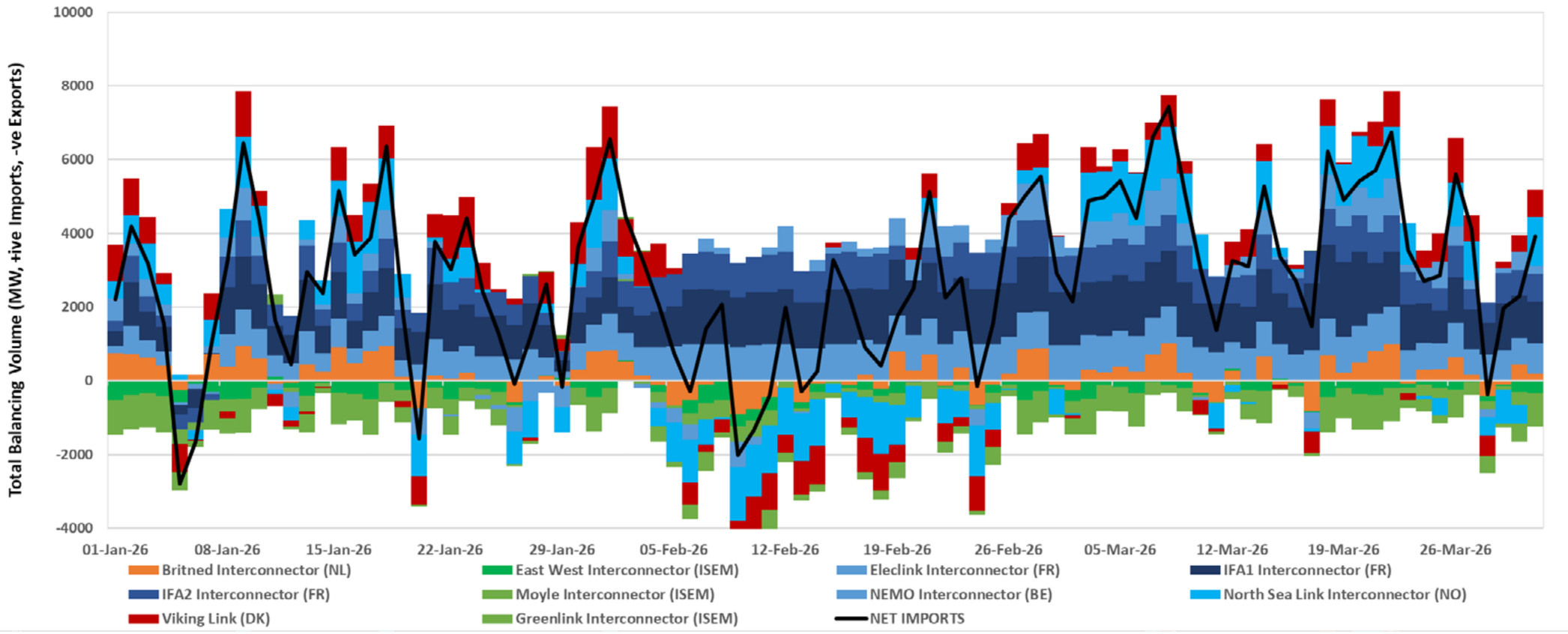


Figure 3: GB Physical Flows by Interconnector for Q1 2026

Key take aways

Nuclear generation totalled 8.4 TWh in Q1 2026, representing a 5% increase from the previous quarter and a 7% decrease from Q1 2025.

Aggregate generation excluding imports but including embedded generation3, reached 71.2 TWh in Q1 2026. This reflects total consumption of 77.3 TWh minus net imports of 6.1 TWh. Output was supported by strong renewable generation, with renewables accounting for just over half of total generation during the quarter.

GB consumption, defined as generation plus imports, reached 77.3 TWh in Q1 2026, broadly unchanged from 77.4 TWh in Q1 2025 and above 75.1 TWh in Q1 2024. Imports continued to play a key role in the system, particularly during periods of high demand and lower renewable output.

Renewable generation reached 40.3 TWh in Q1 2026, compared to 33.7 TWh in Q1 2025, accounting for 52% of total generation. Growth was driven primarily by increased wind output, with additional contributions from other renewable sources.

Higher renewable penetration contributed to lower price periods during high output conditions, while also increasing the need for flexibility during periods of excess generation.

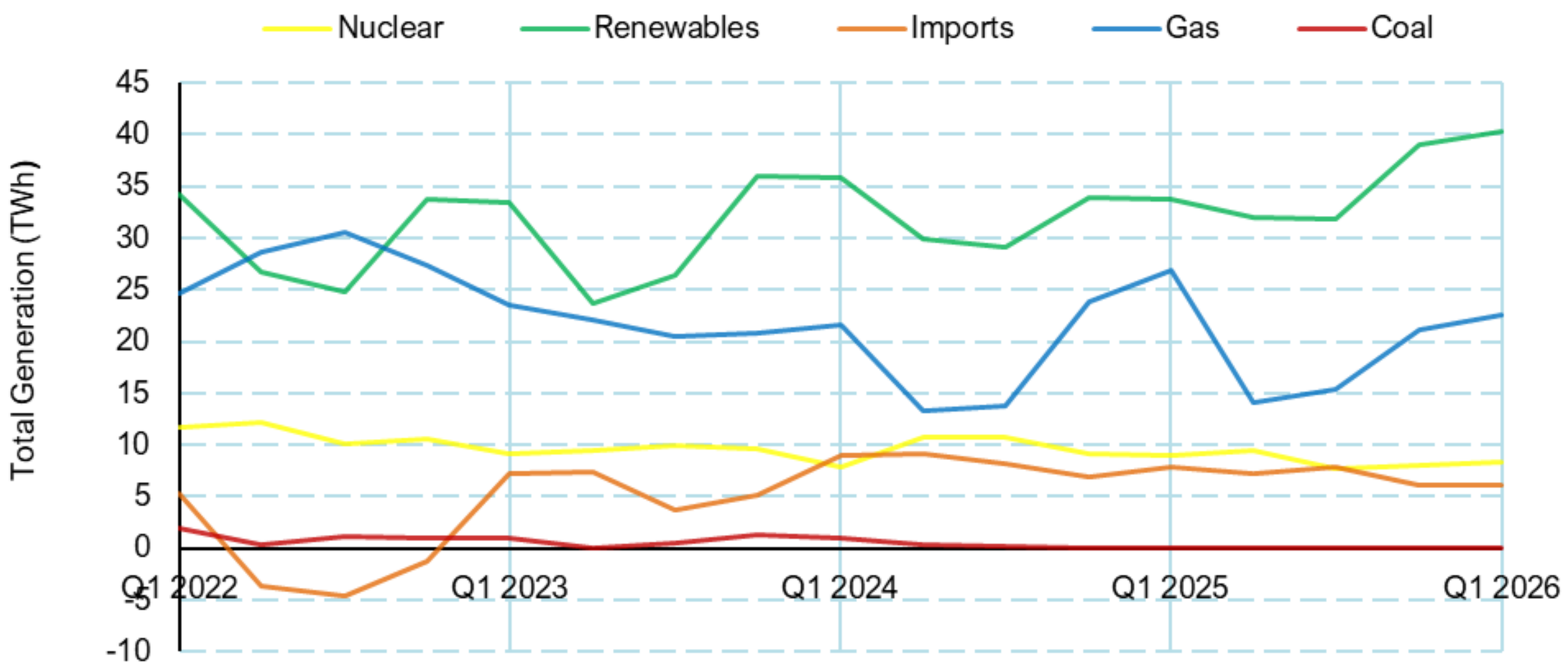


Figure 4: Total Quarterly Generation by Main Fuel Group, Q1 2022 – Q1 2026

Q2 outlook

The forward curve for Q2 2026 baseload power delivery showed a clear shift over the course of Q1. Prices traded in a relatively stable range through January, generally between GBP 69/MWh and GBP 77/MWh, before softening in February, where contracts briefly fell to around GBP 65/MWh.

This trend changed sharply in early March, with prices rising to above GBP 100/MWh and peaking at around GBP 109/MWh on 19 March. Although prices eased towards the end of the quarter, they remained elevated at around GBP 98–101/MWh, indicating a higher overall pricing level for Q2 delivery compared to earlier in the quarter.

Looking ahead, the forward market reflects a higher degree of uncertainty following the repricing seen in March. While seasonal reductions in demand and continued renewable output may act to ease market conditions, the outlook remains sensitive to developments in global gas markets.

Ongoing geopolitical uncertainty, including developments in the Middle East, introduces a wide range of potential outcomes. As a result, Q2 price formation is likely to remain responsive to changes in supply expectations, weather conditions and system availability, rather than following a clearly defined directional trend.

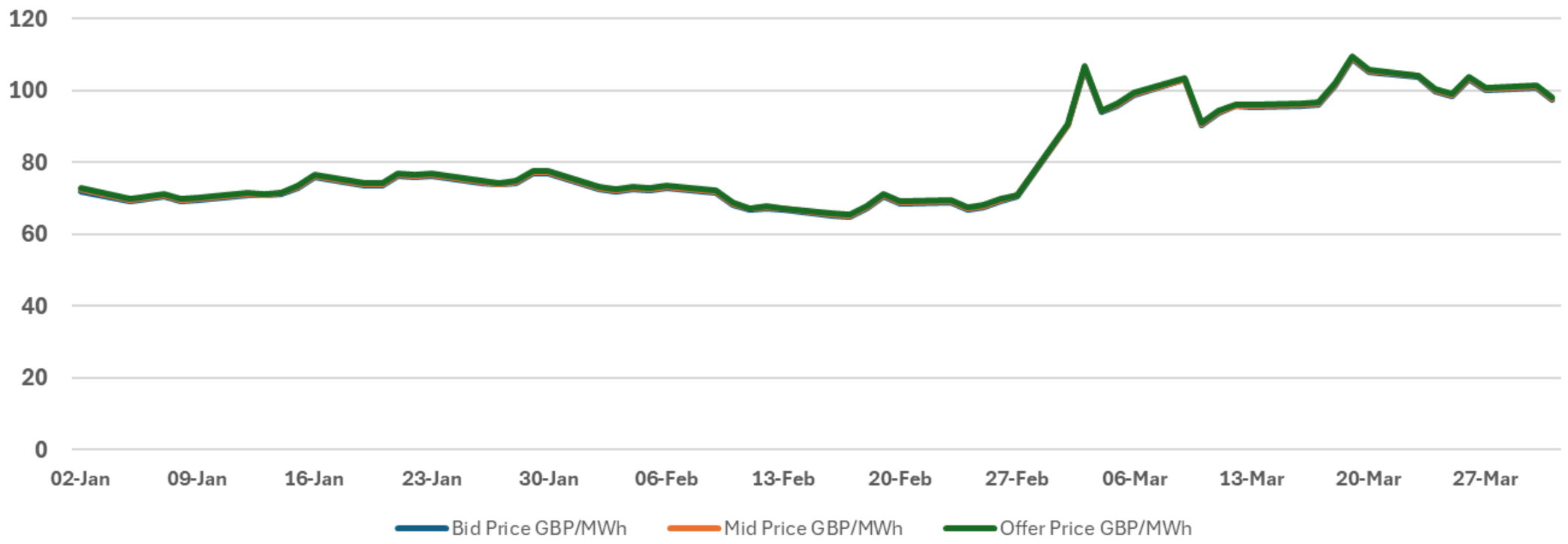


Figure 5: GB Baseload Power Contract Evolution for Q2 2026

The quarterly temperature profile continues to play a key role in shaping demand and price dynamics in GB. Historically, Q1 temperatures have typically ranged between around 3°C and 5°C, with colder outliers such as 2018 and more recent years generally clustering towards the milder end of the range. In Q1 2026, average temperatures reached 4.8°C, in line with recent years, although intra-quarter variation remained significant, with a colder spell in early January followed by more moderate conditions through February.

This variation emphasises the continued sensitivity of winter demand to short-term weather patterns. Periods of colder weather can quickly increase system load and tighten margins, while milder conditions tend to ease pressure on both gas and power markets.

Negative price trends provide further insight into evolving system dynamics. While Q1 has historically seen fewer negative price events than the spring and summer months, their frequency has increased in recent years as renewable capacity has grown. However, Q1 2026 recorded only a limited number of negative price hours, reflecting the interaction between demand levels and periods of high wind output.

Looking ahead, the combination of expanding renewable capacity and variable demand profiles suggests that negative price events may continue to occur under applicable conditions, particularly during periods of strong wind and lower demand.

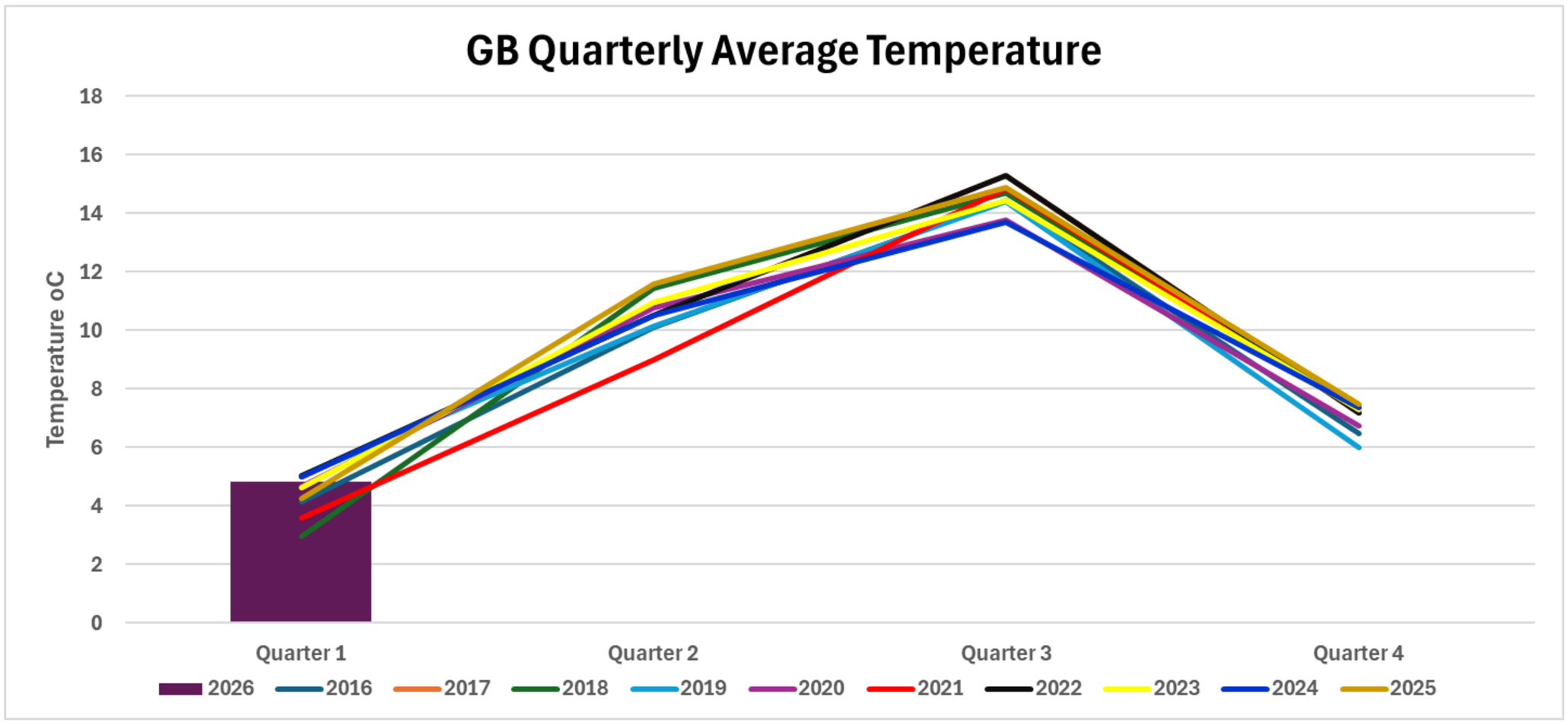


Figure 6: Average Q1 to Q4 Temperature Change from 2016 to 2026

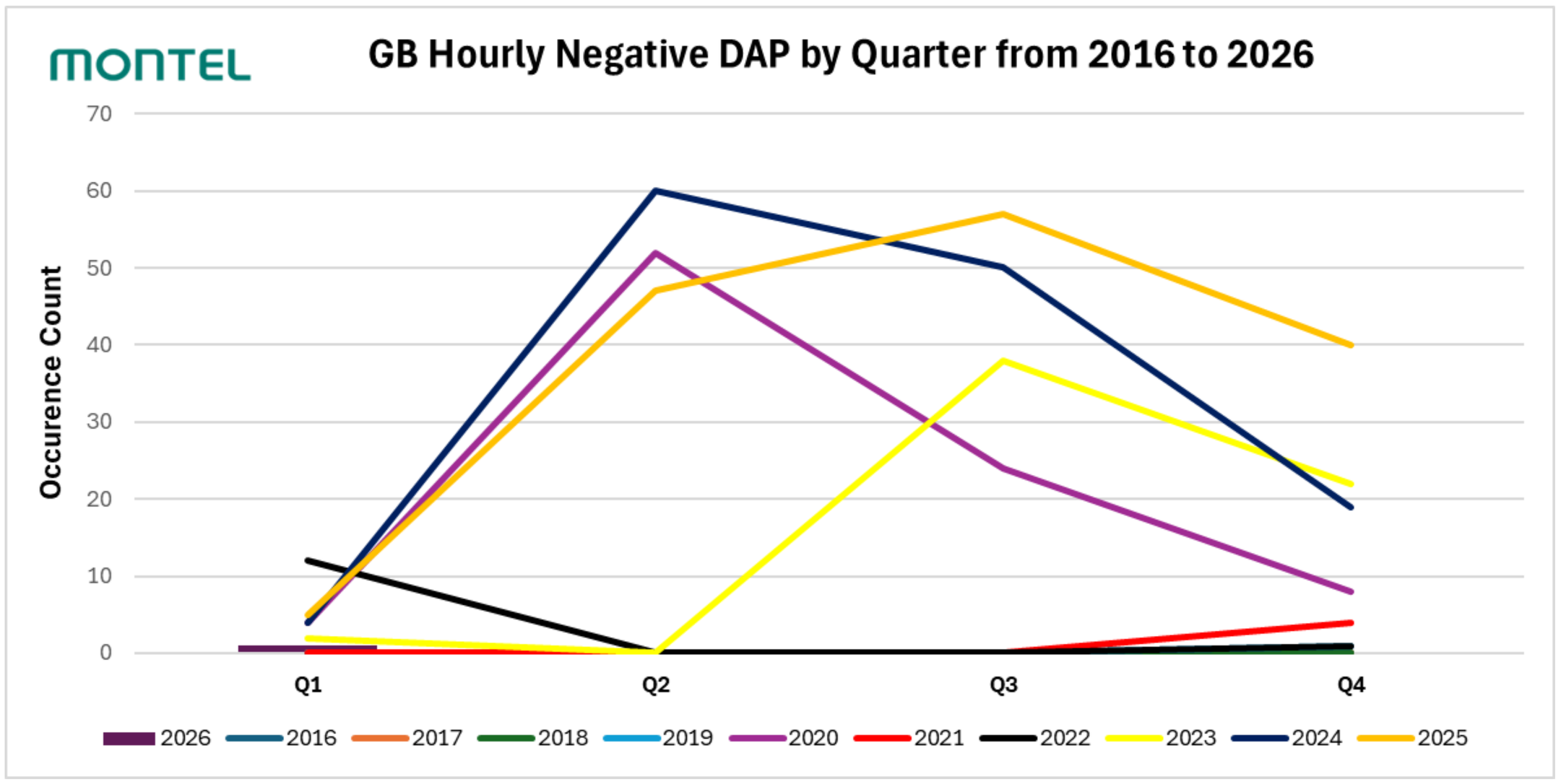


Figure 7: Average Q1 to Q4 Negative Hour DAP Count from 2016 to 2026

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 DESNZ2. Note that all percentages are given as a percentage of total generation including imports.

*GB Only (Excludes Northern Ireland)	Q1 2024	Q2 2024	Q3 2024	Q4 2024	Q1 2025	Q2 2025	Q3 2025	Q4 2025	Q1 2026
TOTAL GENERATION BY FUEL (TWh)									
Coal	1.0	0.3	0.2	0.0	0.0	0.0	0.0	0.0	0.0
Gas	21.6	13.4	13.8	23.8	26.8	14.0	15.4	21.1	22.5
Imports	9.0	9.2	8.1	7.0	7.8	7.3	7.9	6.2	6.1
Nuclear	7.8	10.7	10.7	9.1	9.0	9.4	7.8	8.0	8.4
Biomass	6.9	6.6	6.7	7.2	7.1	6.5	7.0	7.3	7.1
Wind	24.9	17.2	16.7	23.7	22.3	17.6	17.7	28.4	29.2
Solar	1.9	5.1	4.7	1.5	2.7	7.2	6.2	1.8	2.7
Hydro	2.1	1.1	1.1	1.5	1.6	0.7	1.0	1.6	1.4
RENEWABLES (Biomass, Wind, Solar & Hydro)	35.8	30.0	29.2	33.8	33.7	32.0	31.9	39.1	40.3
RENEWABLES Excl. Biomass	28.9	23.4	22.5	26.7	26.6	25.5	24.9	31.8	33.2
FOSSIL FUELS (Gas & Coal)	22.6	13.7	14.1	23.8	26.8	14.0	15.4	21.1	22.5
TOTAL GB GENERATION (excl. Imports)	66.1	54.4	53.9	66.7	69.6	55.4	55.0	68.2	71.2
TOTAL GB CONSUMPTION (incl. Imports)	**75.1**	**63.6**	**62.0**	**73.7**	**77.4**	**62.7**	**62.9**	**74.4**	**77.3**
Fossil Fuel Percentage	30%	22%	23%	32%	35%	22%	24%	28%	29%
Clean Percentage (Renewable & Nuclear)	58%	64%	64%	58%	55%	66%	63%	63%	63%
Renewable Share of Clean Power	82%	74%	73%	79%	79%	77%	80%	83%	83%
SHARE OF GENERATION (%)									
Coal	1%	0%	0%	0%	0%	0%	0%	0%	0%
Gas	29%	21%	22%	32%	35%	22%	24%	28%	29%
Imports	12%	14%	13%	9%	10%	12%	13%	8%	8%
Nuclear	10%	17%	17%	12%	12%	15%	12%	11%	11%
Renewables (Biomass, Wind, Solar & Hydro)	48%	47%	47%	46%	44%	51%	51%	53%	52%

Table 1: Quarterly generation summary Q1 2026 (TWh)

*GB Only (Excludes Northern Ireland)	Q1 2018	Q1 2019	Q1 2020	Q1 2021	Q1 2022	Q1 2023	Q1 2024	Q1 2025	Q1 2026
TOTAL GENERATION BY FUEL (TWh)									
Coal	8.1	2.8	2.9	2.0	1.9	0.9	1.0	0.0	0.0
Gas	32.7	32.2	23.1	28.4	24.6	23.5	21.6	26.8	22.5
Imports	5.4	6.2	5.8	6.4	5.2	7.3	9.0	7.8	6.1
Nuclear	15.5	13.1	12.2	10.9	11.7	9.2	7.8	9.0	8.4
RENEWABLES (Biomass, Wind, Solar & Hydro)	24.7	27.0	34.8	30.3	34.2	33.5	35.8	33.7	40.3
FOSSIL FUELS	40.8	35.0	26.1	30.5	26.5	24.4	22.6	26.8	22.5
TOTAL GB GENERATION (excl. Imports)	81.0	75.1	73.0	71.6	72.5	67.1	66.1	69.6	71.2
TOTAL GB CONSUMPTION (incl. Imports)	**86.3**	**81.3**	**78.8**	**78.0**	**77.7**	**74.4**	**75.1**	**77.4**	**77.3**
Fossil Fuel Percentage	47%	43%	33%	39%	34%	33%	30%	35%	29%
Clean Percentage	47%	49%	60%	53%	59%	57%	58%	55%	63%
Renewable Share of Clean Power	29%	33%	44%	39%	44%	45%	48%	44%	52%
SHARE OF GENERATION (%)									
Coal	9%	3%	4%	3%	2%	1%	1%	0%	0%
Gas	38%	40%	29%	36%	32%	32%	29%	35%	29%
Imports	6%	8%	7%	8%	7%	10%	12%	10%	8%
Nuclear	18%	16%	15%	14%	15%	12%	10%	12%	11%
RENEWABLES (Biomass, Wind, Solar & Hydro)	29%	33%	44%	39%	44%	45%	48%	44%	52%

Table 2: Year-on-year comparison of Q1 generation output (TWh and %)

3 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.

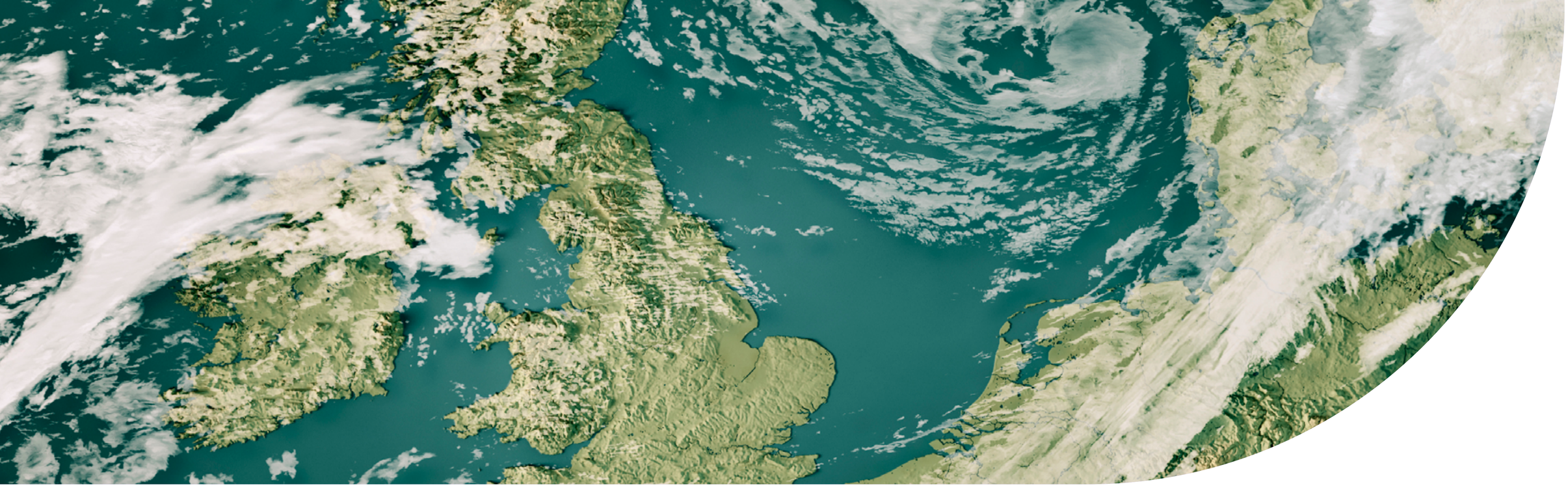
*GB Only (Excludes Northern Ireland)	Q1 2024	Q2 2024	Q3 2024	Q4 2024	Q1 2025	Q2 2025	Q3 2025	Q4 2025	Q1 2026
WHOLESALE PRICES (£/MWh)									
EPEX Day-Ahead Price	64.57	66.17	68.22	89.94	104.50	71.61	72.40	74.32	89.72
Nordpool Day-Ahead price	64.57	66.17	68.22	89.94	104.50	71.57	72.59	74.44	90.24
Within Day Price (MIDP)	64.57	64.12	68.31	87.79	102.14	70.86	72.14	74.36	91.15
WITHIN DAY PRICE BREAKDOWN (£/MWh)									
Off-Peak Hours	56.31	58.28	60.51	70.03	89.02	70.00	69.70	62.08	82.91
Peak Hours (excl Superpeak)	65.70	65.30	69.74	91.06	101.47	69.21	70.56	75.97	90.58
Superpeak Hours	79.41	73.26	81.04	116.82	134.48	78.79	83.39	96.93	112.03
SYSTEM PRICE (£/MWh)									
Maximum	177.71	156.47	200.00	669.21	2,900.00	423.85	263.58	487.00	750.00
Average	65.21	63.58	68.40	87.13	104.13	71.00	71.56	75.62	91.59
Minimum	-88.00	-91.82	-89.10	-75.00	-96.22	-87.32	-87.00	-30.00	-52.28
Domestic Demand (MW average)	29,655	23,479	22,932	28,947	30,693	22,383	22,697	28,772	30,420
Domestic Demand incl. Embedded Gen (MW average)	32,784	27,533	26,689	31,832	34,041	27,351	27,101	32,103	34,292
Domestic Demand (TWh total)	64.05	51.28	50.63	63.91	66.30	48.88	50.11	63.53	65.71
Domestic Demand Incl. Embedded Gen. (TWh total)	70.81	60.13	58.93	70.29	73.53	59.73	59.84	70.88	74.07

Table 3: Quarterly price summary Q1 2024 to Q1 2026

*GB Only (Excludes Northern Ireland)	Q1 2018	Q1 2019	Q1 2020	Q1 2021	Q1 2022	Q1 2023	Q1 2024	Q1 2025	Q1 2026
WHOLESALE PRICES (£/MWh)									
EPEX Day-Ahead Price	52.72	51.83	32.70	63.67	200.80	127.62	64.57	104.50	89.72
Nordpool Day-Ahead price	52.72	51.83	32.70	63.67	200.80	127.62	64.57	104.50	90.24
Within Day Price (MIDP)	54.16	50.39	30.95	59.62	194.30	128.27	64.57	102.14	91.15
WITHIN DAY PRICE BREAKDOWN (£/MWh)									
Off-Peak Hours	47.28	44.39	24.42	46.19	165.99	109.65	56.31	89.02	82.91
Peak Hours (excl Superpeak)	54.62	50.88	32.08	58.89	196.87	130.90	65.70	101.47	90.58
Superpeak Hours	68.24	62.35	41.95	93.27	249.86	161.45	79.41	134.48	112.03
SYSTEM PRICE (£/MWh)									
Maximum	990.00	195.00	2242.31	4000.00	4035.98	1950.00	177.71	2900.00	750.00
Average	57.41	50.63	32.30	62.04	197.64	132.51	65.21	104.13	91.59
Minimum	-150.00	-70.24	-66.25	-61.00	-90.32	-95.71	-88.00	-96.22	-52.28
Domestic Demand (MW average)	35,203	32,936	31,343	30,593	30,738	29,696	29,655	30,693	30,420
Domestic Demand incl. Embedded Gen (MW average)	37,725	35,493	34,280	33,148	33,968	32,532	32,784	34,041	34,292
Domestic Demand (TWh total)	76.04	71.14	67.70	66.08	66.39	64.14	64.05	66.30	65.71
Domestic Demand Incl. Embedded Gen. (TWh total)	81.49	76.67	74.05	71.60	73.37	70.27	70.81	73.53	74.07

Table 4: Year-on-year comparison of Q1 prices

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 BEIS 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 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.

About Montel

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