Energy & Climate Intelligence Unit

Informed debate on
energy and climate change

ANALYSIS

Marginal Gains

How wind is pushing gas out of the power market and cutting costs

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Executive Summary

The gas crisis exposed a weakness in GB wholesale electricity markets, with volatile international gas prices driving up the running costs of gas generators that usually set the marginal price on day-ahead markets, dramatically inflating the price of electricity. The effect continues, and various options have been proposed to try to reduce this disproportionate influence of gas on electricity prices, to reduce costs now and insulate customers from future gas crises.

However, one solution is already at work, with renewables displacing gas power plants from the day-ahead market, such that prices are set by more efficient gas power plants or other sources. This mechanism is often cited in the debate over the clean power transition, but does not seem to have been quantified publicly.

This report illustrates the process of displacing gas power plants from the marginal pricing curve, focussing on wind capacity connected to the GB transmission networks. It attempts to estimate the impact on prices due to large-scale wind by considering the opposite situation, i.e. if there had been less (or no) wind capacity.

The analysis suggests that the day-ahead wholesale price in 2024 could have been up to 33% higher if there had been no large-scale wind capacity and gas made up most of the difference. That is, existing wind farms connected to the transmission grids may have cut the day-ahead price by up to a quarter (25%) in 2024, which is about £24–25/MWh off day-ahead wholesale prices, or about £27–28/MWh if losses are applied to convert to retail values.

Links between day-ahead markets and longer-term trades where the rest of the supply is traded mean that savings of a similar size are likely to be seen for all supply. In which case, cuts in prices due to wind power could roughly match the £27/MWh on bills that supports wind farms via the RO and CfDs.

Without the savings from wind power, the average day-ahead price of £73–76/MWh in 2024 could have been as high as £96–101/MWh. These results are relevant to the current CfD auction for new renewables (AR7), which has been criticised for having potential strike prices have that are higher than current wholesale prices. But without existing renewables displacing gas power plants, the differences would be much smaller or even reversed.

The results are also relevant to the wider debate over the clean power transition, highlighting a 'hidden saving' that can be viewed alongside the costs associated with renewables. Future analysis could consider the net effects, and how these are likely to evolve as some costs fall in the near future and the savings on marginal prices grow as more renewables are deployed.

Introduction

Wholesale power in Britain is traded via a mixture of routes, ranging from long-term contracts agreed several years ahead of time through to day-ahead and even intraday markets.[1] Day-ahead markets are perhaps the most familiar type of power trading, because they respond most rapidly to events such as changes in gas prices.

Day-ahead power prices on the GB markets are particularly responsive to gas prices because those markets use 'pay as clear' auctions: the price for all of the electricity sources is set by the most expensive power source (different generation technologies, storage and interconnectors) that is needed to meet demand from users of that market, known as the 'marginal price'.

There is an economic logic to marginal pricing, as it encourages the electricity providers to bid as low as they can in order to improve their chances of being below the cut-off point in the price ranking of the merit order. If they bid higher than they need to, they risk 'missing the cut' and not making any money at all. This pressure tends to keep overall costs lower, and hence saves money for customers, and this approach worked well enough in normal times.

Gas power plants have been setting the marginal price in the UK on the vast majority of occasions: 80-90% of the time in 2015-2019, and rising to almost 100% in 2020 and 2021.[2] This facet of the UK power market became more obvious during the gas crisis, with the costs of running gas power plants rising dramatically as international gas markets spiked to unprecedented levels, pushing marginal prices far higher than the costs of other electricity sources such as renewables, nuclear, storage and interconnectors.

But, sources of electricity other than gas reduce the number of gas power plants that are used in any given half-hour interval (the timing the market operates on). They displace gas power plants from the merit order, starting with the most expensive and working down. Therefore, day-ahead power prices are lower than if there had been lower levels of these other sources, with knock-on effects on prices for longer-term trades and hence overall power prices.

[1] The GB wholesale power market does not include NI, which is part of the Single Electricity Market (SEM) with the Republic of Ireland. Both NI and the RoI are connected to the GB market via interconnectors.
[2] Working Paper #1: The Role of Natural Gas in Electricity Prices in Europe (UCL, 2022, updated 2023)

The report presents analysis to quantify this effect, estimating how much higher the day-ahead power prices could have been, were it not for other sources of generation, focussing on large-scale wind farms. This is relevant for current debates about the pros and cons of new power projects. For example, the current CfD auctions could see strike prices that are higher than current day-ahead wholesale prices against which the strike prices are measured, but the differences could have been smaller (or even reversed) were it not for existing renewables projects displacing gas power and cutting the wholesale price.

Gas Prices and Marginal Power Pricing

The links between gas prices and day-ahead power prices are illustrated in Figure 1, which shows the time series for 2024.[3] This chart shows the following key points, which are discussed in more detail below:

- Power prices broadly follow the same trends as gas prices.
- There is a usually a clear lower bound on power prices, at about double the gas price, because gas power plants are typically c.50% efficient and so need two units of gas for every one unit of power that they generate.[4]
- There is a wide range of power prices, going up to much more than double the gas price, which is the result of moving up the marginal pricing curve and using gas power plants with higher and higher prices.
- Day-ahead power prices are sometimes lower than if they were set by the gas price, which is when no gas power is traded on that market and a different source (e.g. renewables, storage, interconnectors) sets the marginal price.

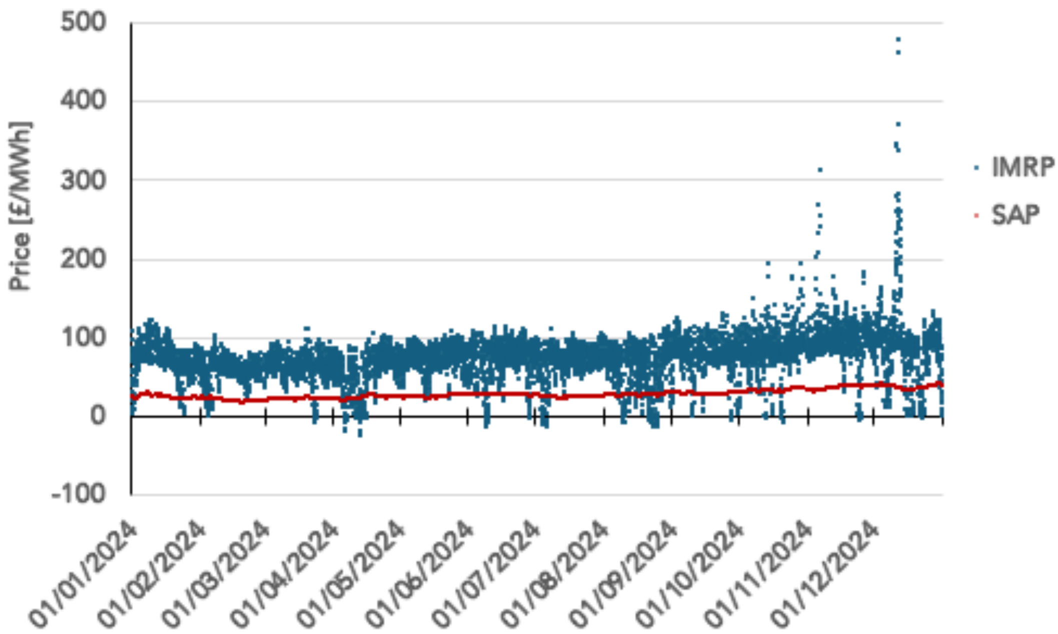

Figure 1: IMRP and SAP throughout 2024 (IMRP hourly, SAP daily)

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[3] Day-ahead power price is the Intermittent Market Reference Price (IMRP) that is used for CfD calculations (LCCC, accessed August 2025). The gas price is the System Average Price (SAP) offset by one day as a proxy for a day-ahead price, for illustrative purposes (NGG data published by ONS, accessed August 2025). See Methodology for more details.

[4] In 2024, the overall GB gas fleet was 48% efficient, using 179TWh of gas to generate 87TWh of electricity – see Energy Trends 5.6 (DESNZ, 2025). Some gas power plants can be c.60% efficient, but all power plants have other costs as well (e.g. transmission charges, carbon price, etc). But for these illustrative purposes, the rule of thumb is useful, that the lowest power price from a gas power plant is around double the gas price.

The data about day-ahead prices can be combined with gas generation data to examine the links between the two. The data for 2024 is presented in Figure 2. This analysis uses data for the GB transmission network, as that data is publicly available and reliable, whereas data for distribution networks is less so (see more detail in Methodology). This chart shows the following key features:

- Most half-hours have prices in a broad band (c.£50–100/MWh in 2024) that rises gently with gas generation, reflecting that gas power plants are switched on in order of ascending price. The average annual price is within this band (e.g. c.£73–76/MWh for 2024 – see below).
- Higher gas prices result in higher power prices (see colour-coding in chart).
- Power prices can be below the broad band for a reasonable amount of the year (15% of the time in 2024), when gas generation is low and had been contracted via other routes, such that no gas power was traded on the day-ahead market and different power source set the marginal price.
- Negative prices do occur, when demand is very low and there is excess wind generation, but these events are fairly rare (e.g. 1.8% of half-hours in 2024).
- Prices rise steeply at high gas power levels, reflecting the high prices of the final few plants. Very high-power prices are very rare (e.g. over £150/MWh just 0.9% of the time in 2024) and have little impact on overall annual prices.

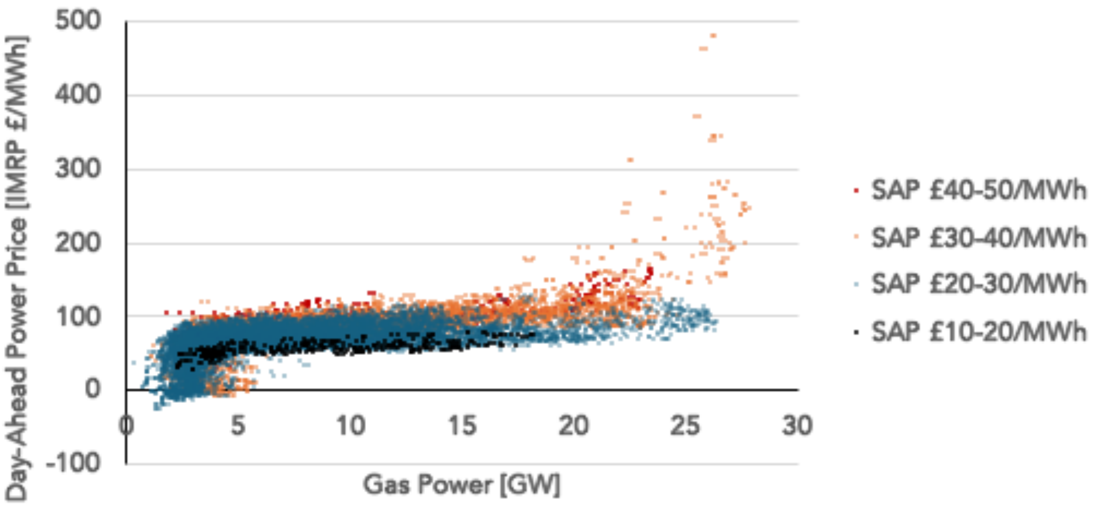

Figure 2: Day-ahead power price vs gas power generation level in 2024, split by gas price. Note that datasets overlap such that not all data points are visible e.g. blue band obscures some orange data points.

As seen in the chart, when gas is setting the day-ahead power price, the level of the power price can cover a wide range, depending on which gas power plant was setting the marginal price. This is because not all gas power plants are equal, with the older, less efficient plants having higher costs, for inter-related reasons: they need to use more gas for each unit of power that they produce; because of their higher costs, they are asked to operate less often and more intermittently, usually from a 'standing start' which is less efficient than simply increasing output; and their role as peaking plants in day-ahead markets means that they buy some (or most) of their gas on day-ahead gas markets where prices tend to be higher than in longer-term trades.[5] That said, this logic cannot explain some of the very highest prices seen during the worst of the gas crisis.

The frequency with which gas sets the marginal price can be calculated very precisely by sophisticated methods.[6] But a rough estimate can be obtained by counting the number of half hours in which the price was below double the gas price, suggesting that gas set the price about 15% of the time in 2024. This is in the range of 80–90% reported for 2015–2019, down from almost 100% in 2020–2021.

From these datasets, average prices for the year can be estimated. In order to obtain the exact value, one would have to know exactly how much power was traded on the day-ahead markets in each half-hour. But a reasonable estimate is that this value was around the level of i) the weighted average by the number of occurrences and ii) the weighted average by the volume of supply, which tend to be relatively similar. For example, in 2024, the average day-ahead power price was estimated to be around £73–76/MWh, which tallies well with various sources.

Finally, the day-ahead price is a useful indicator of prices of power that has been traded earlier, and hence of overall prices. Most longer-term contracts are indexed such that the provider can receive a price that more closely reflects the situation at delivery. Also, data from Ofgem shows that each unit of power is on average traded multiple times before delivery (the 'churn rate') e.g. 2.6 times in 2024,[7] and trading nearer to delivery will see the price tend towards the day-ahead price.

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[5] These older gas power plants have lower fixed costs (i.e. no capital costs left to pay off), and can cover their fixed cost via the capacity market, so these should not be the cause of extremely high prices.
[6] Working Paper #1: The Role of Natural Gas in Electricity Prices in Europe (UCL, 2022, updated 2023), also published as The role of natural gas in setting electricity prices in Europe (Zakeri, et al, 2023)
[7] Electricity Trading Volumes (Ofgem, accessed September 2025)

Non-Gas Sources Cutting the Marginal Price

Any electricity source other than a gas power plant can displace some of the gas power plants in the day-ahead markets, starting with the most expensive and working down the merit order. This reduces the marginal price that is paid to all sources that are contracted via that market. This displacement happens most obviously with sources operating in the day-ahead market, but it also happens indirectly due to sources that trade via longer-term contracts.

Directly on the day-ahead markets, the bigger the non-gas volume (e.g. renewables, storage, interconnectors, etc) that enters the day-ahead market with prices that are competitive with gas power, the lower the volume that will have to be obtained from gas power on the day-ahead market, so the fewer gas plants are needed to meet that part of the demand, and hence the lower down the gas power marginal pricing curve the price is set. In some cases (as seen in Figure 2), the day-ahead price can be below that which would be set by gas, because no gas power is traded on that market (but some has still been traded via other routes e.g. longer-term contracts for baseload generation).

Indirectly, the more non-gas generation volumes (e.g. some renewables, old nuclear plants, etc.) that are available for longer-term trading, the less gas power is used for those contracts, leaving a bigger range of gas power plants available for the day-ahead market and increasing the competition that pushes the least efficient gas plants out of the merit order.

The effect of cutting day-ahead prices is dominated by wind, which provides the largest volumes. Indeed, the role of gas on the day-ahead market is evolving to be primarily a back-up when wind output is lower. Wind and other renewables displace gas power plants by offering lower wholesale prices. Early renewables with RO support can bid lower, knowing that they will receive the wholesale price plus the RO support to cover their costs. Newer renewables with CfDs can bid low because they will receive their strike price irrespective of their bid price. Some CfD renewables have strike prices that are below wholesale prices, and so return the difference to customers.[8]

[8] The occasional (but infrequent) operation of intermittent generation at low levels (and/or with imperfect weather forecasts) increases the role of peaking power plants (including gas) with higher prices, but this is but this is dealt with by Balancing Mechanism rather than day-ahead wholesale markets.

Marginal Prices with Lower Wind Capacity

The analysis has sought to estimate how the absence of non-gas power sources could affect day-ahead power prices. This was done by considering how much of that non-gas source might have been replaced by gas power, and hence how much further up the gas power marginal price curve the day-ahead market would have cleared. More detail is given in the Methodology section.

The analysis considered what might have happened if there had been lower wind capacity connected to the transmission network, with the level ranging from 0% to 100% of the actual levels in 2024. The main components of the calculations are illustrated in Figure 3, for the case of zero large-scale wind capacity. This shows the results of processing the data in bands of 1GW of gas power output: the number of half hours at which gas was operating in each band; and the average day-ahead price in each band. The exercise was repeated using the net supply provided (GWh), rather than the number of half-hours, with similar results.

In 2024, with wind power operating, the distribution of gas power output (green line) peaked quite low i.e. it was at 2–3GW and 3–4GW more often than any other band. The simplified marginal price curve (black line) follows the trend seen in the full dataset in Figure 2. The overall average price for the year is the weighted average of the prices and number of half-hours at which each price occurred.

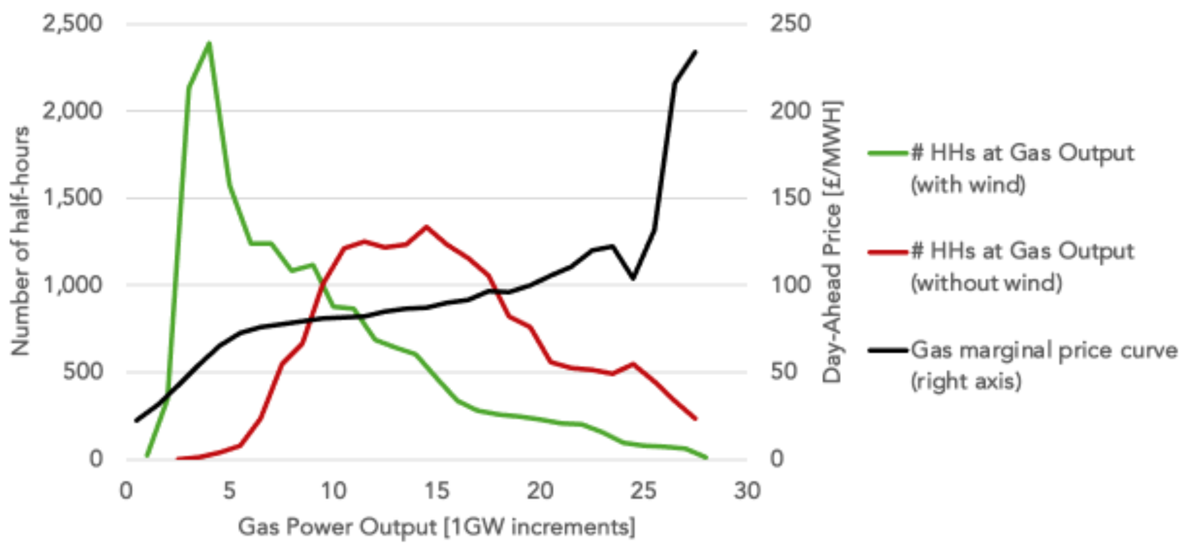

Figure 3: Distribution of gas power and marginal price curve in 2024, along with modelled gas power distribution in absence of large-scale wind power, in increments of 1GW of gas power.

It was envisaged that the generation shortfall would been made up mostly by gas, which would shift the distribution of gas power output to higher levels (red line), with higher marginal prices occurring more often.[9] Where this would mean that the line would exceed the maximum gas power, other technologies would supplement supply. The results are summarised in Figure 4, with ranges for the average annual day-ahead price: weighted by occurrence (HHs); and weighted by supply (GWh}.

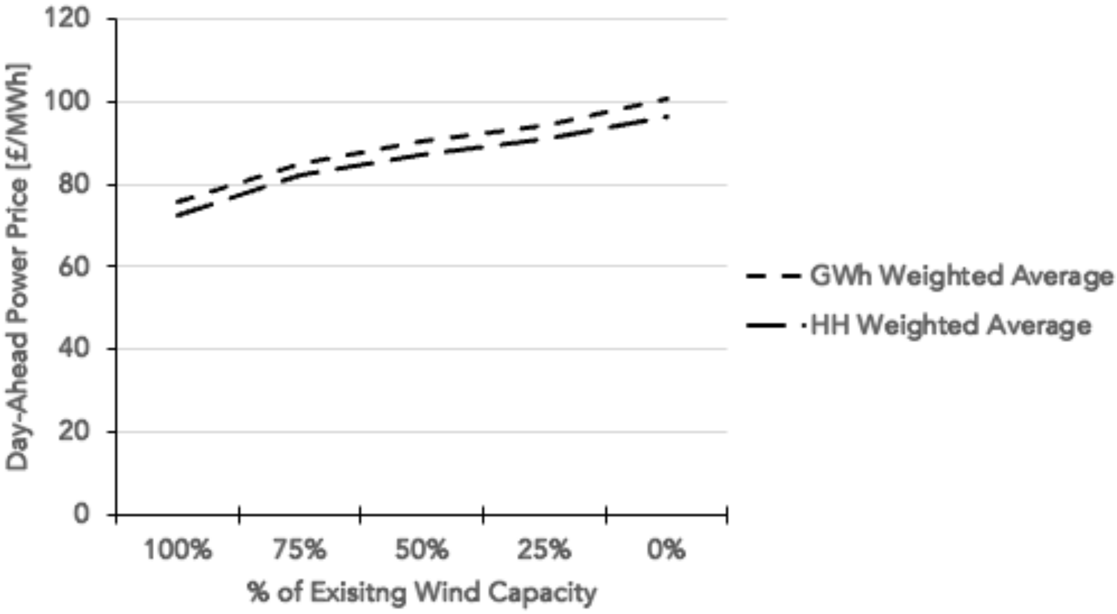

Figure 4: Estimated day-ahead prices with different levels of transmission-connected wind capacity, ranging from 100% to 0% of actual capacity in 2024.

The analysis suggests that, had there been only half as much wind capacity on the transmission system, with gas replacing most of the difference, the average day-ahead price in 2024 could have been up to £87–90/MWh, about £15/MWh (20%) higher than the value of £73–76/MWh seen in actuality. Had there been no large-scale wind capacity at all, with gas replacing most of it, the average day-ahead price could have been as high as £96–101/MWh, about £24–25/MWh (a third) higher, i.e. wind power cut the day-ahead wholesale price by up to a quarter (25%) in 2024.

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[9] This approach implicitly uses the 2024 GB transmission supply mix (minus some or all of the wind) as the counterfactual. Had less wind capacity been built over the past 20 years, other gas plants might have been built, but would not necessarily have had much effect on the marginal price curve. Whilst new gas plants would have been more efficient than some of the existing ones, and so would have had lower fuel costs, they would have had capital costs and financing which older plants have already paid off, eroding the efficiency advantage. Estimates consistently show that new CCGT plants would have had a levelised cost of electricity (LCOE) that was higher than wholesale prices when the plants were commissioned (Energy Generation Cost Projections, DECC/DESNZ, 2012 onwards). Recent estimates suggest that new gas plants would be more expensive than new renewables, even factoring in recent cost increases.

The impact on wholesale prices is significant in the context of CfD auctions, including Allocation Round 7 (AR7) that is running in 2025. CfD renewables receive (or pay back) the difference between the strike price and the day-ahead wholesale price, which could be as high as the Administrative Strike Prices (ASPs) stated in the action's rules.[10]

There has been some criticism that these ASPs (stated in 2024 prices) are higher than recent and forecast wholesale prices, at £113/MWh for offshore wind, £92/MWh for onshore wind and £75/MWh for solar, but there are two important considerations. Firstly, the actual strike prices will be known when the auctions are complete, and are likely to be lower than the ASPs, based on the results from previous actions. Secondly, as found by this analysis, the wholesale price is only where it is because of existing non-gas capacity displacing gas power plants. Without existing large-scale wind capacity, the day-ahead wholesale price in 2024 would in fact have been significantly higher than the ASPs for solar and onshore wind, and within about 10% of the ASP for offshore wind.

Another comparison that can be drawn is with the financial support provided to existing wind farms. The data about RO and CfDs was broken down to wind generation only, although it was not possible to break it down further to only those larger wind farms that are connected the transmission grid and that were included in the analysis. CfD costs for wind in 2024 amounted to about £8 per MWh of demand,[11] and RO costs for wind in 2024 were around £19 per MWh of demand,[12] totalling around £27/MWh. This is the price of support for all wind farms, and is paid by almost all demand (Energy Intensive Industries have some exemptions).

The saving on day-ahead wholesale prices due to large-scale wind farms amounts to a retail price saving of about £27–28/MWh, once losses are accounted for. Links between day-ahead markets and longer-term trades, where the rest of the supply is traded, mean that savings of a similar size are likely to be seen for all supply. If all wind power was included in the analysis, the day-ahead price would have been even larger in its absence, i.e. here would be a larger reduction in day-ahead wholesale prices. Taking these factors together, cuts in prices across all trades, accounting for all wind power, could roughly match the £27/MWh of support paid on bills to support wind farms via the RO and CfDs.

[10] Methodology used to set Administrative Strike Prices for CfD Allocation Round 7 (DESNZ, 2025)
[11] Data from Ofgem's Price Cap Model, Annex 2, and the LCCC's CfD Historical Data Dashboard
[12] Data from Ofgem's Price Cap Model, Annex 4, and adapted from Ofgem's 2023-24 RO Annual Report

Conclusions

The results of this analysis suggest that we are already experiencing significant savings on day-ahead wholesale prices due to wind generation displacing gas power plants. Further analysis could investigate savings on longer-term wholesale power trading and the overall impact on electricity prices.

Another avenue of research could be the other electricity sources that also displace gas power plants, including interconnectors, and also renewables such as wind and solar connected to the distribution grids that serve to reduce the net supply required at the transmission level.

The 'hidden saving' on wholesale prices due to renewables is an important part of the discussion around our future supply mix, and could be considered alongside the costs associated with new generation sources, to show that the net costs of projects to-date has been lower than simply the costs that are often cited.

Looking ahead, these net costs are expected to shrink over time. Some costs will begin to fall soon, e.g. RO contracts will be ending from the mid/late 2020s onwards,[13] and new CfDs issued over coming years could pull down the average strike price of the CfDs portfolio overall.[14] Other costs will rise in coming years, but fall in the 2030s, e.g. the costs of building and operating electricity networks.

Savings via marginal pricing on the day-ahead wholesale market will grow as larger volumes of renewables displace more gas power plants more often. The clean power transition is on track to provide net savings each year based on the investments that have been made, and in the meantime will guard against volatility from the gas price.

[13] See Figure 7 in The UK's Clean Power Mission: Delivering the Prize (E3G & Baringa, 2025)
[14] See Weighted Average Strike Price on the CfD Portfolio Forecast Dashboard (LCCC, accessed September 2025)

Data Sources and Methodology

The analysis was conducted using publicly available datasets, which were aligned in time series accounting for their different date/time systems and time intervals.

Power prices: Intermittent Market Reference Price (IMRP) published by the LCCC, which it uses for calculating CfD payments, and which is viewed as being a very good representation of the day-ahead price. IMRP data is provided in hourly increments of calendar days, called settlement periods (SP): SP1 runs from midnight to 1am of a calendar day; and the changes between GMT winter and BST in summer mean that one day in March has 23 SPs and one day in October has 25 SPs. IMRP is published in £/MWh to the nearest £0.01. The IMRP dataset starts in mid-2016, and is complete.

Gas prices: There is no historical dataset of day-ahead gas prices that is both publicly available and detailed i.e. any that are publicly available either i) provide daily data only but for a short duration (e.g. the past year) or provide longer-term averages (e.g. monthly) over several years. The gas price does not play a detailed role in the analysis, and is simply used to split up data for illustrative purposes, and so a proxy for day-ahead prices was sufficient i.e. the System Average Price (SAP) published by the ONS (using data from National Grid Gas). Spot checks against actual day-ahead gas prices over the past 12 months (Trading Economics) suggest that the SAP is usually within 5% of the day-ahead price (and up to 10% sometimes). The SAP is the average price paid for gas balancing actions on the delivery day, i.e. offset by one day from the day-ahead market when gas generators would buy gas for contracts made on the day-ahead power market, so the SAP was used as a proxy offset by one day. SAP data is provided on a daily basis, for the calendar day, as the pressure 'buffer' in the gas grid gives enough tolerance that gas can be balanced over the course of a day, and so a single price for the day suffices for most purposes. SAP data is published in p/kWh, to the nearest 0.0001p, and was converted into £/MWh to the nearest £0.01/MWh.

Generation output and supply: Half-hourly generation outturn by fuel type (FUELHH) published by Elexon, whose datasets underpin most calculations in the power sector. This data covers sources that use the GB electricity transmission network i.e. larger generators, large storage, and interconnectors. Data for other sources (i.e. distributed generation that use only the distribution grids) is not collected with the same level of consistency or availability. So, the analysis used net supply on the transmission network (i.e. total sources minus exports plus imports) as a proxy for demand, excluding distributed generation, albeit that actual demand is scaled down a bit by losses and energy industry use. It should be noted, though, that distributed generation serves to reduce the required transmission net supply, so the rise of distributed renewables is indirectly affecting day-ahead marginal pricing. FUELHH data for generation, storage and interconnectors are provided in half-hourly settlement periods, and use UTC (Universal Time Coordinated aka Universal Coordinated Time aka 'Zulu' Military Time). The FUELHH dataset goes back to January 2016, and has some gaps i.e. most years have perhaps 10-20 half hours with no data entries at all, and some data entries spuriously list zero for certain technologies (e.g. when that technology was generating at a high level in the preceding and following half-hours). FUELHH data is published in MW, to the nearest 1MW. Generation output (in MWh) associated with any given FUELHH half-hour entry is half the power output (in MW).

The overall day-ahead power prices from the historical data were calculated using two weighted averages: i) price weighted by number of half-hour occurrences, representing the situation where day-ahead trading applies to the same proportion of electricity regardless of the supply level; and ii) price weighted by supply volumes, representing the situation where the proportion of day-ahead trading increases with supply. Whilst it not possible to know the exact mixtures of trading in the day-ahead markets at each gas power level, these two weighted averages represent two plausible options, and the reality is likely to be within this range.

To estimate the impacts of removing a non-gas source, a simplified marginal pricing curve was generated, along with modified distribution curves of occurrence (and supply) for each level of gas power. The gas power dataset was split up into 1GW bands, and the other datasets were mapped onto these gas bands. Within each band were calculated: average gas power; average power price; and number of half-hour intervals during which has power was operating in each band. From these data lists, the overall price could be calculated for the year, as both a weighted average by number half-hour occurrences and a weighted average by demand (or rather, by the proxy of net supply on the transmission network), with the actual overall price. Then, the output power from gas and an proportion of the wind generation (0–100%) were added together for each half hour, and the averages calculated within each of the gas power bands. These combined values of gas and wind power were then mapped onto the banded gas power marginal pricing curve. Where the combined total power was below the maximum gas power seen in the year, the marginal price at that level was used: i.e. it was assumed that only gas would have been used to replace the non-gas source, pushing the marginal price to the right by that full amount. Where the combined total power exceeded the maximum gas power, three simple models were considered for the excess (see chart below for the example of 2024). First, simply omitting these events (i.e. all of the events above c.27.5GW in the chart), which is clearly unrealistic, but sets a lower bound on the overall price. Second, assuming that gas was used up to its maximum and then other sources above that, which would mean that the most expensive gas power plant set the marginal price in all of these events (spike at c.27.5GW in chart below), which is probably unrealistic, but sets an upper bound. Thirdly, it was assumed that these events would involve a range of solutions, with gas plants setting marginal prices sometimes, and non-gas sources other times, modelled by taking the events above the maximum gas power and distributing them as a symmetric 'wedge' on top of the last few bands of gas power (little bump below c.27.5GW on chart). These three distributions were applied to the gas power marginal pricing curve to obtain overall prices weighted by occurrence (and similarly for distribution curves of supply to give overall prices weighted by supply). All three of these methods gave similar results, with the wedge results being between the other two, e.g. for 2024 the results were £95–99/MWh by occurrence (wedge method £96/MWh), and £98–104/MWh by supply (wedge method £101/MWh).

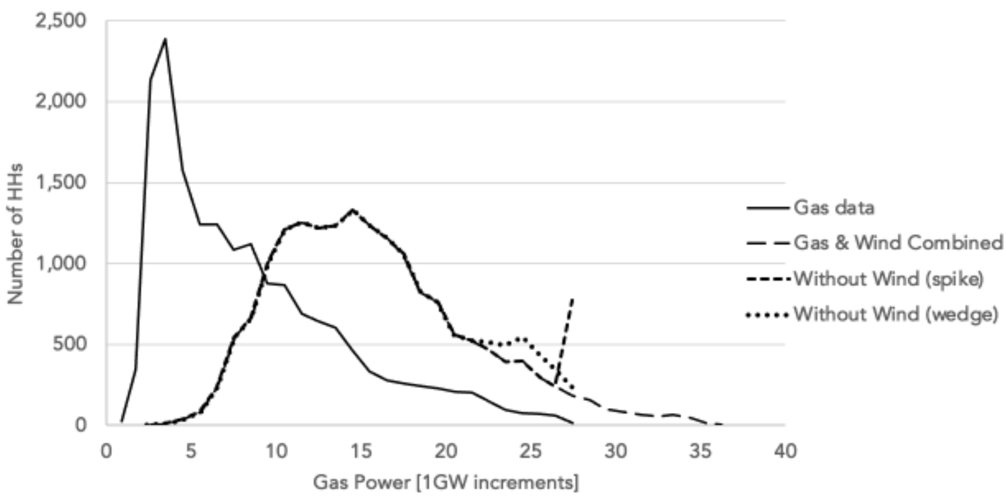

Figure 5: Distribution of number of half-hours in 2024 at each gas power band, i) from the dataset, and ii) simple models for the absence of wind capacity.