DRAX GROUP
(DRX LN)

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12 January 2026

Price (p)	**893.00**
Shares in issue (m)	340
Mkt Cap (£m)	3,038
Net debt (£m)	1
EV (£m)	3,039
BVPS (p)	504

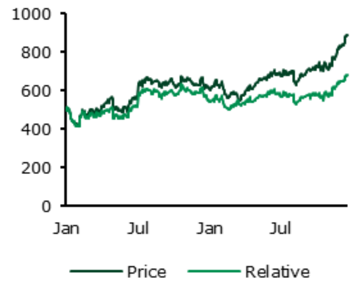
Share price performance	
1m	14.0%
3m	25.5%
12m	45.9%
12 m high/low	902/535
Ave daily vol (30D)	779,598

Longspur Valuation Est. (p)
Low 931, Central 1082, High 1226

Shareholders	
Vanguard Group Inc	7.7%
Dimensional Fund Adv	5.1%
Blackrock Inc	5.0%
Orbis Allan Gray Ltd	5.0%
Invesco Ltd	4.8%
Franklin Resources	3.5%
American Century Cos	3.1%
Credit Agricole Grou	3.0%
Royal London Asset M	3.0%
M&G Plc	3.0%
Total for top 10	43.4%
Free float	99.6%

Next news Ints Q3

Business description
Biomass, hydro and storage IPP



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ADDING STORAGE

Following the acquisition of BESS projects our forecasts and valuations now include both the initial three projects but also the development pipeline in our central and high valuation cases. While the pipeline will depend on securing grid connections, we think the diversity of the portfolio and the growing need for storage gives these a good chance of success in the medium term. We see battery storage as emerging from a low point as the impact of balancing market reforms and market tightening take effect. Our low case valuation of 931p now includes the initial BESS capacity and our central case of 1082p assumes the additional pipeline projects deliver this decade. Our high case valuation of 1226p also includes the pipeline but no longer assumes the Cruachan expansion opportunity.

260MW of BESS Projects Acquired

Drax has acquired a development portfolio of battery energy storage system (BESS) assets with 260MW of capacity from developer Apatura. The portfolio comprises three sites in Scotland and northern England and all are two hour duration projects giving 520MWh of energy storage. There is also an option over a further eight sites with a total capacity of 289MW. We see these assets as integrating well with the existing Drax portfolio offering the company's trading team real options across an increasingly volatile GB electricity market.

We Think This is a Well-Timed Acquisition

BESS projects have seen revenue weakness over the past few years impacting valuations. We see the Apatura acquisition as comparing well with similar recent acquisitions on a per MW basis. But we also think the timing is good with reforms to the balancing mechanism seeing better use of batteries, a pick up in ancillary services pricing and the potential for a tighter overall electricity market as the decade progresses.

Both Near Term and Pipeline Projects Add Value

We have modelled the acquired projects based on an assumed two hour storage arbitrage spread of £110/MWh. This should see the initial three projects deliver EBITDA of £24m when fully operational. The additional pipeline should add slightly more.

£,000 Dec	2023a	2024a	2025e	2026e	2027e	2028e
Sales	7,842	6,163	5,133	4,709	4,114	4,153
EBITDA	1,009	1,053	905	670	579	629
PBT	665	703	579	328	217	260
EPS	119.6	128.4	121.5	71.9	48.4	57.4
CFPS	121.7	143.9	89.2	68.8	32.3	130.1
DPS	23.1	26.0	28.6	31.5	34.7	38.2
Net Debt (Cash)	1,183	937	971	897	961	690
Debt/EBITDA	1.2	0.9	1.1	1.3	1.7	1.1
P/E	7.5	7.0	7.4	12.4	18.5	15.6
EV/EBITDA	4.2	3.8	4.4	5.9	6.9	6.3
EV/sales	0.5	0.6	0.8	0.8	1.0	1.0
FCF yield	0.1%	0.2%	0.1%	0.1%	0.0%	0.1%
Div yield	3.0%	3.4%	3.8%	4.2%	4.6%	5.0%

DRAX AND STORAGE

In October Drax acquired a development portfolio of battery energy storage system (BESS) assets with 260MW of capacity from developer Apatura. The portfolio comprises three sites in Scotland and northern England and all are two hour duration projects giving 520MWh of energy storage. The consideration will be £157.2m and this will be made in staged payments as the projects hit construction milestones with payments running from 2025 through to 2028. There are contractual protections for cost overruns and delay. The acquisition of the first two projects is expected to complete in 2025 with the third project in Q1 2026. Operation of the first site is expected in 2027. Especially attractive is an option over a further eight sites with a total capacity of 289MW.

We modelled the acquired projects based on our estimate of the current 2 hour storage arbitrage spread of £110/MWh in line with that seen in the lowest priced year this decade. This should see the initial three projects deliver EBITDA of £24m when fully operational. The additional pipeline should add slightly more.

We also see the acquisition as an important addition to the company's portfolio, notably widening the storage assets out from the Cruchan pumped hydro power station in Argyll. The acquisition is a very different type of storage with an ability to store 2 hours of energy as opposed to Cruchan's 16 hours. However, it is much more responsive with a response time of 100ms as opposed to the 30s achievable at Cruchan. While both seem very responsive, the electricity system has to balance in real time to protect the system frequency and extremely short response times are critical. In theory the system balances every 20 ms as it is a 50Hz system and 1/50 = 0.02. As a result, the new BESS assets give Drax an additional capacity in fast reacting storage.

The BESS assets also add to the overall flexgen portfolio and in fact all of Drax's generation assets offer much needed flexibility to the GB electricity system. But we see the real advantage is that Drax can add these assets to the range of real options available to its trading team. Unlike most operators of BESS projects who use third-party "route to market" providers, Drax has the skillset to make the most of these assets, not just on their own, but as part of a wider trading strategy covering the range of the company's assets.

BESS PROJECT VALUATIONS

In terms of ascertaining a valuation for operating BESS projects there is data available from asset sales. A number of projects have revealed pricing in the past few years. Notably the bids for Harmony Energy Investment Trust (HEIT LN) saw two competing bids, with the lower bid from Drax and with the final bid at a valuation very close to the published net asset value of the fund. Adding the project debt results in an EV/operating capacity figure of £0.9/MW. While we do not have pricing data for every deal done in the market, deals that have published values are showing a rise in valuation and we see the HEIT deal as a good benchmark especially given its matching to the calculated NAV of the fund.

UK BESS Sales With Price Information

Business	Stake	EV (£m)	MW	Date	£/MW
Harmony	100%	339.8	395.4	2025	0.9
Statera Energy*	75%	586.0	350.0	2024	1.7
Sheaf Energy	100%	210.0	294.0	2023	0.7
Red Scar	100%	32.8	49.0	2020	0.7
Bloxwich	100%	20.1	41.0	2020	0.5

Source: Infralogic, * Statera includes gas-fired generation

With the price for the Apatura projects including full build out we can value against these other completed assets sale. The deal price per kW was just £605, well below the price of the Harmony sale (£859/kW) and the Statera sale (£1,674/kW) although this latter included other gas-fired flexible generation assets with different economics. The average across five reported sales since 2020 has been £683/kW so we think Drax has paid a sensible price.

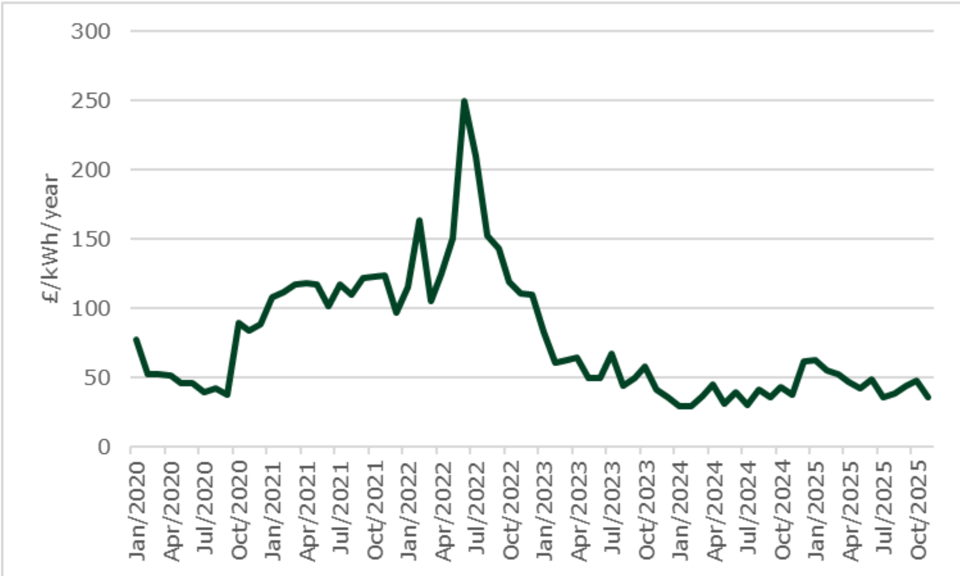
A GOOD TIME TO BUY BESS

We think Drax's purchase of the Apatura assets has been made at a particularly good time. BESS project economics have come under pressure in recent years thanks to three main pressures.

- Balancing mechanism practices have penalised batteries (poor skip rates)
- Ancillary services have seen market saturation and weak prices
- Rapid BESS deployments have grown competition across the market

These factors saw average revenues decline from a high point in June 2022 to a low point in July 2024 as represented by the Modo Energy GB index which represents the revenue performance of grid-scale lithium ion BESS in the GB market. While there has been some recovery in the index the recent values are not significantly above the low points.

Modo Energy GB Index



Source: Modo Energy

We think that both the drivers of this weaker revenue will reverse and additional factors will now drive up value for BESS projects over the next five years.

- Firstly reforms at NESO mean that balancing market participation is improving.
- The ancillary market while oversupplied is seeing better pricing and we think is likely to see stronger demand growth in the next few years as large nuclear and gas assets are retired.
- New BESS market entry has been limited by the grid connection reform. While opportunities still exist the more speculative projects are no longer going ahead.
- The retiral of nuclear and gas plant coupled with growing demand from EV charging, heat pumps and data centres creates a very realistic expectation of a tighter overall electricity market leading to more price volatility to the benefit of BESS arbitrage revenue streams.

BALANCING MECHANISM REFORMS

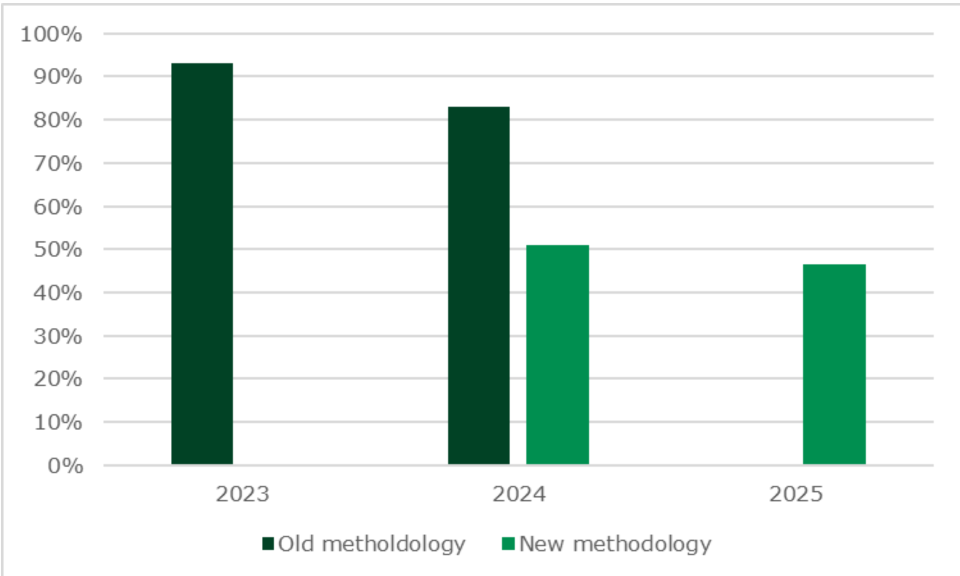
The system operator (NESO) has traditionally looked to fast acting gas generation to balance the system and this has been reflected in the operation of the Balancing Mechanism (BM), the UK's electricity system's central purchasing market for balancing the system in the half hour before delivery. As BESS capacity started to grow, it was noticeable that the Balancing Mechanism continued to select gas plant rather than batteries with some rules, such as limiting battery dispatches to 15 minutes, resulting in gas being chosen before batteries even when batteries were cheaper to run.

The problem can be clearly seen by looking at skip rates. A skip is a non-economic dispatch decision. When the system operator dispatches a unit that has a higher price than the most economic unit, the economic unit is said to have been "skipped". This will happen for technical reasons such as transmission system limits on the economic unit or better dynamic features on the selected unit. Some skips are unavoidable but not all. The skip rate is the total number of avoidable skips divided by the total number of BM actions. There are in fact two measures of skip rates with the BM skip rate using a denominator of all possible BM actions and the PSA skip rate using a more targeted measure.

From 2023 onwards, the system operator introduced a series of reforms to improve actions in the Balancing Mechanism. These included the Open Balancing Platform in December 2023 which brought in a new bulk dispatch algorithm and a new 30 minute rule (up from 15) in March 2024. The bulk dispatch algorithm increased the number of short duration battery dispatches, mainly one minute dispatches, and the new 30 minute rule has seen an increase in 20 minute dispatches now that there is no longer a 15 minute limit.

The changes are having an impact. In 2023 PSA skip rates for batteries were 93%. Unfortunately, some of the methodology for calculating skip rates has changed so later statistics are not directly comparable. However the fact that the current level is so significantly lower at 41% suggests that the reforms are having some material level of impact.

Battery Skip Rates



Source: NESO, Modo Energy

For technical reasons skip rates will never be zero but the improvements do appear to be resulting in more dispatches for batteries in the BM which will have a positive impact on revenues going forward.

ANCILLARY SERVICES REVENUE IMPROVING

While the key ancillary services served by BESS projects have suffered from market saturation, pushing down prices in 2023 and 2024, there has been a bounce back in 2025. This was in part due to providers including higher risk premia to counter tighter enforcement of non-delivery penalties but the market has also benefited from higher procurement volumes. We show the prices for dynamic containment below as a key indicator of potential revenues.

Dynamic Containment (Low) 3 Month Rolling Average

Source: NESO

We see the longer term outlook as continuing to be positive as the market faces tightening out to 2030 as we outline next.

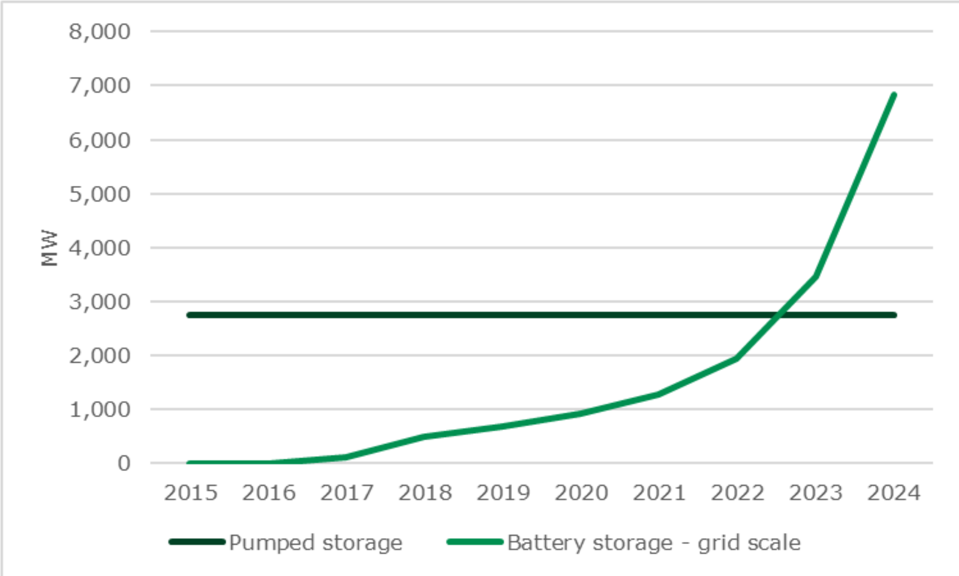
GRID CONNECTION REFORM

The system operator has cut 153GW of battery capacity from the queue to get a grid connection. While this still leaves 34GW of capacity with connections before 2030 it does represent a considerable shake out. Some of the rejected capacity will be able to apply in future rounds, NESO has said that there will not be any new battery projects allowed until the current ones are ready and the application window opens again. The full impact of this is explored below.

BESS CAPACITY DEVELOPMENT

The GB electricity market has already seen over 6GW of BESS projects connected which has resulted in a degree of overcapacity in some of the ancillary services markets pushing attention to the price arbitrage element of the revenue stack.

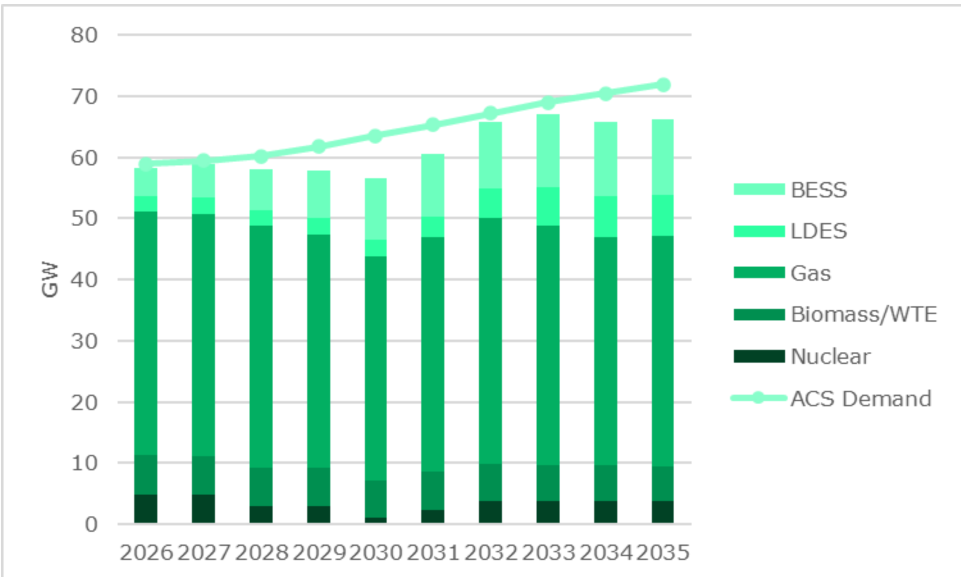
Grid Scale Electricity Storage on GB Network



Source: Digest of UK Energy Statistics 2025

Beyond this there is potentially considerable storage capacity looking to be deployed. There is over 60GW of storage capacity with planning permission. However, only 34GW now have connection agreements, only 20GW of these projects have capacity market agreements and a significant proportion of these do not have allocated capital so are likely to be delayed or cancelled. The National Grid's Future Energy Scenarios (FES) shows 18GW of new battery capacity being added out to 2030 which feels a realistic forecast of what can be readily delivered given the constraints of grid connection, financing and delivery.

GB Grid Firm Capacity and Peak Demand

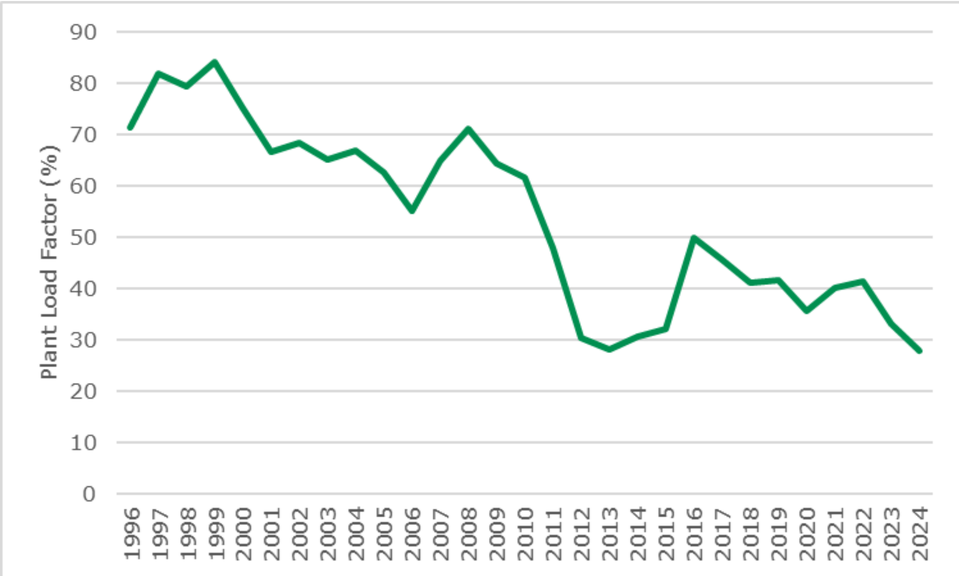


Source: Longspur Research based on National Grid's FES Ten Year Scenario

In simple terms looking at the make up of GB power capacity, the amount of storage needed is that required to cover periods where wind is not blowing and interconnectors are not available. This latter is likely in period of high pressure systems that could site over large areas of northern Europe. Solar is not available to meet the peak demand in any year because these peaks occur after dusk. As a result the capacity required to meet the peak demand is made up of nuclear, biomass and gas. On top of that storage must fill the gap with both short and long duration storage playing a role. To date this has been sufficient. However using the FES assumptions of new storage deployment it looks like the market could be under pressure from 2028 onwards. This is when the two nuclear plant at Hartlepool and Heysham 1 close down. The gap gets worse after that and even assuming the new units at Hinkley C are commissioned in 2031 and 2032, there remains a gap.

While more BESS projects could enter the market it is also worth considering the status of the older gas generation units. The FES assumes 1.3GW of CCGT closures in 2029 and almost 3GW in 2030. But by 2030 over 14GW of GB gas capacity will be more than 30 year's old, the typical design life of a CCGT. Additionally, as renewables form a greater part of the capacity mix, gas plant is used less with reducing load factors. Built mainly as baseload or "two shifting" plant, they are seeing more intermittent usage in the new market dominated by intermittent renewables.

GB CCGT Load Factors



Source: Digust of UK Energy Statistics

This puts them under greater mechanical stress and could limit the potential for working life extensions and could even put their current lives under question. As a result, we think there is potentially a greater gap to be filled by storage over the next few years.

We see this as driving higher peak prices as gas plant must try and gain a return from fewer annual hours of operation. Additionally, the greater proportion of intermittent renewables is likely to increase volatility in the system again creating better revenue opportunities for battery storage.

In summary we think the timing of the Apatura acquisition is very good coming after a period of weakness for BESS projects and before the benefits of grid reforms and a tightening firm market are felt.

THE NEED FOR STORAGE

INTERMITTENCY AND VOLATILITY

Wind generation only generates power when the wind blows and the wind does not blow all the time (except possibly in Shetland). Solar obviously does not generate power at night but also sees output vary with cloud cover. These variations in output are referred to as intermittency. The problem of intermittency is exacerbated by difficulties in predicting the timing of that intermittency. While there are now better forecasting techniques available, they do not remove all of the uncertainty in output from these types of generation. This is true of both wind where wind speeds can vary continuously and solar where unpredictable cloud cover can reduce output by as much as 90%.

Timing Impact of Intermittency

Source: IEA

The renewables industry sometimes counters criticism of intermittency with the proposition that intermittency is reduced or even eliminated by the geographical diversification that comes with large portfolios of projects at different locations. However, the most recent academic work suggests that this effect is overplayed and that grid scale fluctuations in output are correlated between projects.

Long periods of low wind when combined with cloudy weather reducing solar output are known as dunkelflaute or dark doldrums. On average there are 50 to 100 hours of such periods occurring in Northern Europe in each of the months of November, December and January when such events are defined as those lasting 24 hours or longer.

Storage required to meet lost wind output at an offshore wind farm

	Lost hours	Missing power	Missing power (MWh)*	Storage (MWh)*
Largest gap	82	100%	1,005	1,124
Average gap	13	69.40%	145	162
Smallest gap	1	7.70%	16	18

Source: Project Neos Public Report, * assumes peak demand at 16.4MW

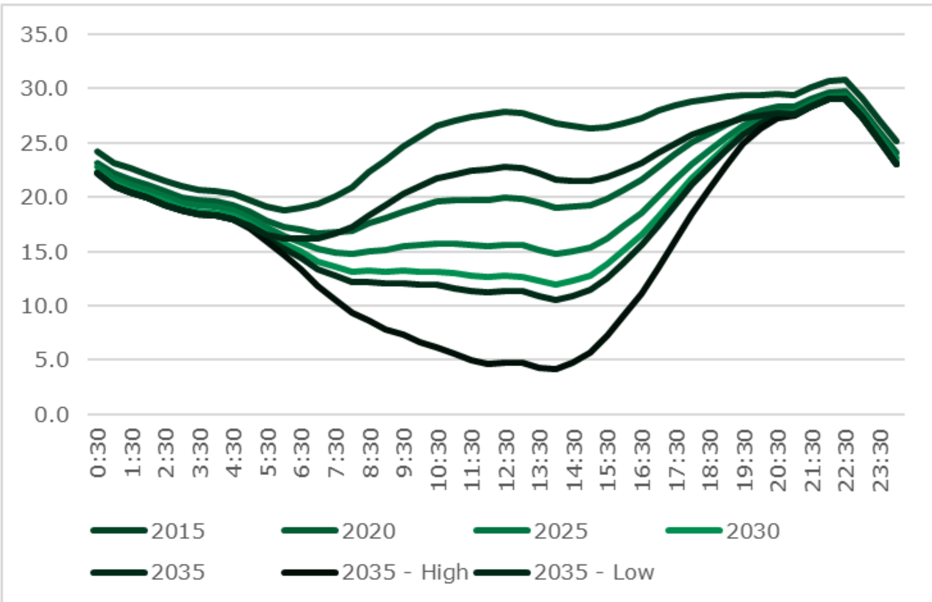
The intermittency problems created by renewable generation are well known in terms of the longer duration issues of daytime versus nighttime for solar and windy days and calm days for wind. However, short term volatility is less generally understood outside the industry. In terms of value it is potentially as large an issue. Output from renewables is constantly varying and, despite sophisticated inverters and other controls, this puts pressure on system frequency. So in addition to displacing the synchronous generation which minimises frequency imbalance, renewable generation makes it worse by sending out a volatile supply to the grid.

Within day timing issues – The Duck Curve

One impact of increased renewable energy capacity and in particular solar is the creation of a "Duck Curve" in the daily demand profile. The potential impact of significant solar capacity on demand was first raised by the California Independent System Operator ("CAISO"). California used to see energy demand on the grid rise in the middle of the day and be fairly flat across the afternoon before rising to a peak in the early evening. Solar is recognised as negative demand because of its distributed nature. With considerable solar on the Californian system, demand now begins to fall from 11am as this capacity kicks in. Then in the late afternoon, as the sun wanes and solar starts to come off, demand rises very steeply into the early evening peak. This can be represented on a demand graph showing how demand is expected to behave as even more planned solar capacity is added out to 2020. The shape is said to resemble something that quacks.

The graph shown is for the GB grid based on embedded renewables and shows that the issue is just as relevant here as in California.

Duck Curve



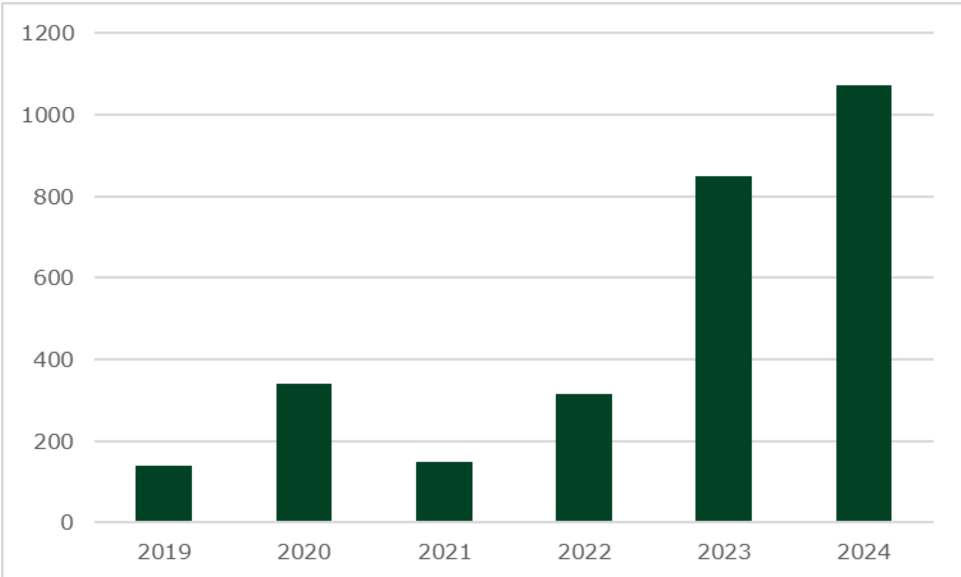
Source: National Grid

The key message of the duck curve is that the grid used to have to deal with a small ramp up in demand in the later afternoon or early evening but now has to deal with a much more marked ramp up. This puts pressure on the system and increases demand for flexible and responsive capacity including storage.

MARKET STRUCTURE ISSUES

Liberalised electricity markets such as that in the UK normally work on some kind of bidding arrangements where marginal costs are a key determinant of who will win bids. Most renewable energy technologies are characterised by high capital costs but low operating costs. This is the benefit of not requiring any fuel so that the only significant cash cost item is maintenance costs. As a result, marginal cost per unit can be very low compared with other generation technologies. This is often compounded by support policies. Where there is a feed-in-tariff, green certificate scheme such as the Renewable Obligation, or price support such as the Contract for Difference (CfD) scheme, these can be seen as negative costs that effectively put the marginal cost into negative territory. In other words, renewable generators will be prepared to bid a negative price in order to receive at least some of their policy support. This has resulted in more negative pricing events in the GB market. While new rules in the CfD scheme will see new projects with a bidding floor at zero there remains a significant proportion of capacity that can bid negatively so we see this phenomenon persisting for some time.

Negative pricing periods in balancing mechanism



Source: Elexon

When enough low marginal cost assets are present in a market, low or negative prices result in uneconomic returns (missing money) for generators. As a result, this puts pressure on incumbent generators who suffer from low prices. It is also likely to lead to low investment, exacerbating security of supply issues in the medium and longer terms. While the capacity market attempts to address this, it is not necessarily sufficient to forestall many of the problems.

However, we think the other side of this argument is that storage and other flexible capacity picks up the “missing money” by being able to buy low or negatively priced electricity when renewable generation output is strong (on windy, sunny days) and then sell it when renewable output is low (calm evenings).

WHAT ARE THE SOLUTIONS?

The problems of place mean that some plant is curtailed out of the system because of its location. More well located plant must be able to be dispatched to make up for this loss. Timing issues require plant that is flexible and for the specific issues of frequency, spinning reserve is the main solution. Pricing issues are really about economic curtailment and again flexible generation is the main solution. So the main solution to all these issues is to have flexible, dispatchable power sources that can make power available when you want it and where it is most useful.

Key generation technologies in the UK

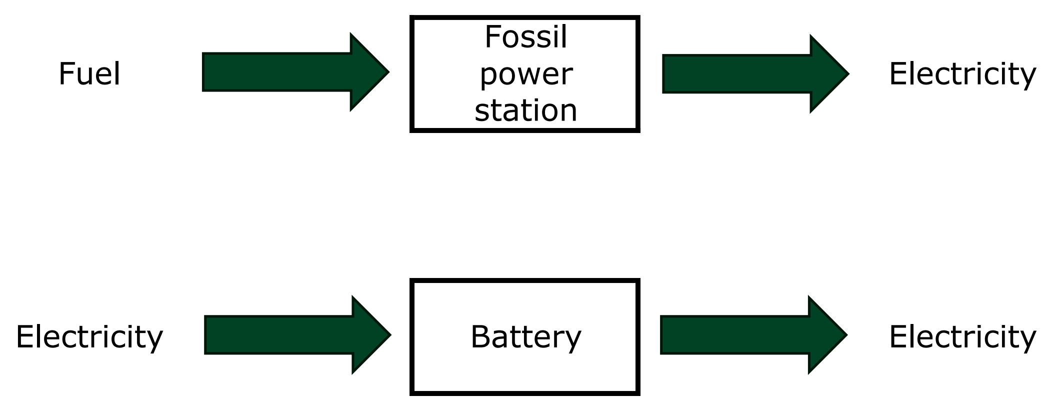
Generation technology	Dispatchable?	Ramp rate (%/min)	Inertial constant (MW)
CCGT	Yes	2.2	6.0
Wind	No	1.0	0.0
Solar PV	No	0.4	0.0
Nuclear	No	1.5	6.0
Biomass	Yes	1.6	6.0
Pumped hydro	Yes	360.0	4.5
OCGT	Yes	21.0	5.0
Natural flow hydro	Yes	360.0	4.5

Source: Longspur Research, Central Power Research Institute (India), IEA

Flexible generation and storage

Storage can be looked at as a type of power station. A traditional power station takes fuel and converts it into electricity. Storage also does this but in the case of storage the fuel is electricity.

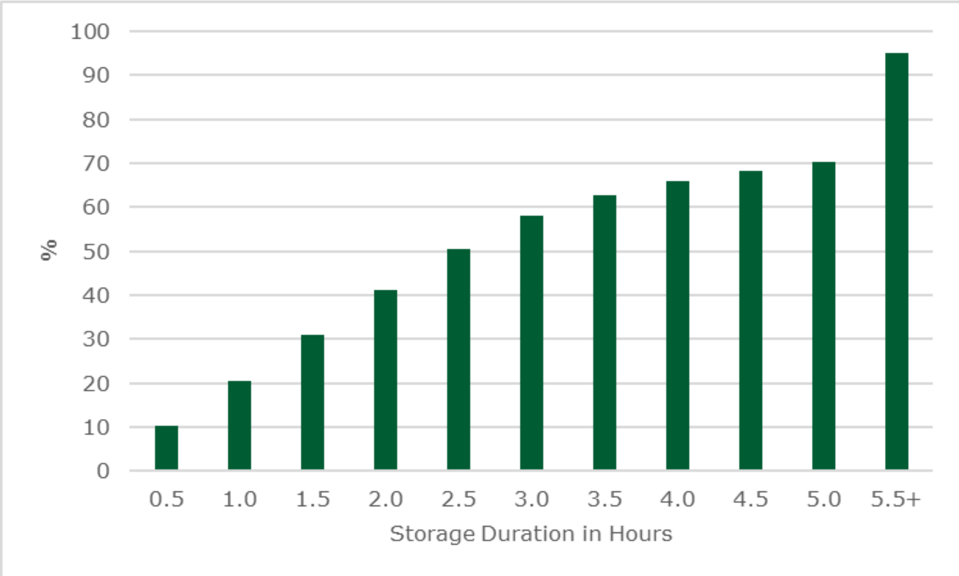
Power stations and storage



Source: Longspur Research

Unfortunately, battery storage is only dispatchable for the duration of storage it has available and this limits its use for addressing the growing issues in managing the grid. In fact the Capacity Market penalises short duration storage for this reason. With a typical duration of two hours, most batteries in the Capacity Market are derated to just over 40% of their nominal capacity.

Capacity market derating of storage according to duration



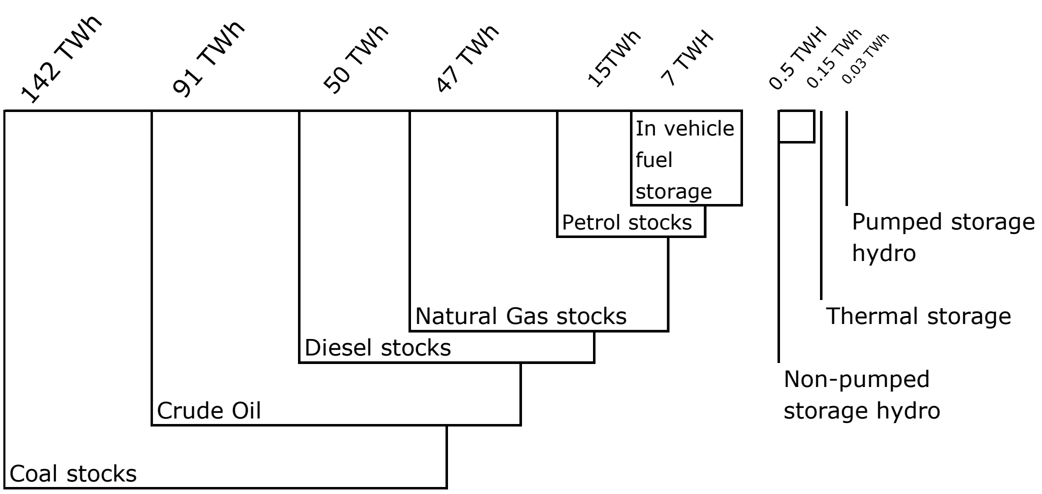
Source: National Grid

Battery storage can have longer durations but this gets expensive. Batteries also degrade if cycled too often, limiting their usefulness. Long duration storage is a key solution and we see demand growing as renewable penetration increases. The key form of long duration storage in the GB market is currently pumped hydro with Drax owning 440MW out of a total of 2,900MW at its Cruachan power station, with an additional upgrade of 40MW now funded from the Capacity Market and planning secured for a possible 600MW expansion.

Thermal generation as storage

Looked at the other way round, thermal generation is a form of storage with the storage medium being the fuel which locks up energy through chemical storage. In fact, the old fossil fuel energy world stored enormous amounts of energy in its fuel stores.

Energy Storage in the UK, 2015



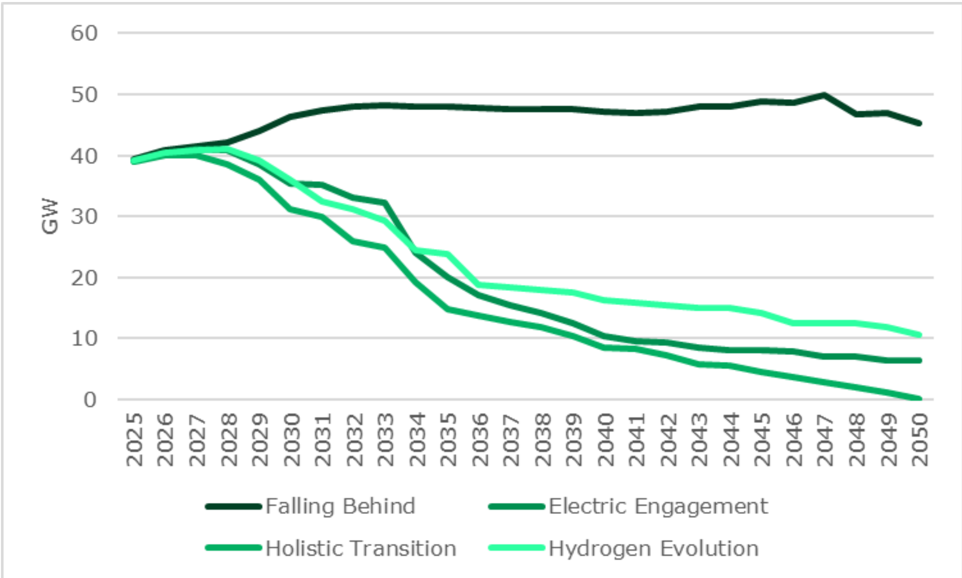
Source: Simon Gill, University of Strathclyde, 2015

In the case of Drax, the Drax biomass units represent significant storage assets. Drax Power Station has c.300,000 tonnes of biomass storage capacity. The chemical energy contained in this biomass represents 650,000MWh of dispatchable energy.

Gas generation

Gas generation also represents storage with gas stored in pipelines acting as a large battery that can be dispatched via both combined cycle and open cycle gas power stations. Gas generation is currently the main provider of flexibility in the GB market but it will not be so forever because it is a fossil fuel with emissions of between 365 gCO_2e/kWh and 488 gCO_2e/kWh. Existing gas plant are beginning to come to the end of their useful lives. New build stations have been announced but are limited and have not sufficiently responding to capacity market incentives. Uncertainty over the cost of carbon which impacts gas plant through the UK Emissions Trading Scheme make investment decisions risky. With the exception of the Falling Behind Scenario, the FES forecasts all show a reduction in unabated gas generation from 2028 onwards. The falling behind scenario would need to see new gas capacity replacing retiring capacity and so far that is not especially evident.

Unabated gas capacity forecast



Source: National Grid

Nuclear

Nuclear is not flexible and not really dispatchable. It is always on so is less useful in managing the system although it does provide inertia as synchronous generation. Perhaps the biggest issue with nuclear is that while it does serve some of the needs of the system, existing capacity is closing down and new capacity takes a long time to build, normally longer than expected.

Grid reinforcement

Grid investment in network reinforcement will help and National Grid investment plans include spend of £42bn by 2026. However new transmission and distribution lines can only remove some of the issues. Specifically, frequency and voltage issues are mainly a function of the move to asynchronous distributed renewables and not mitigated by new connections.

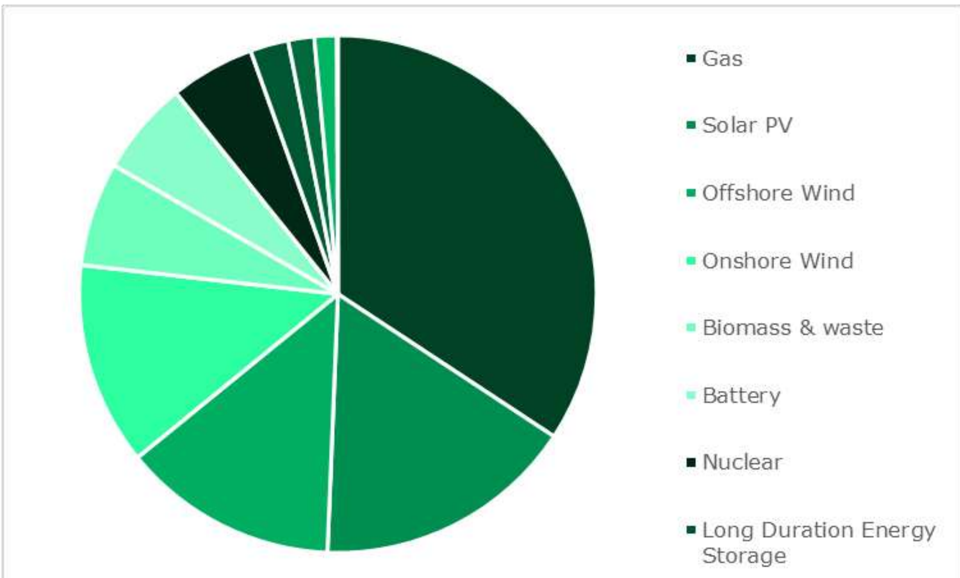
Demand side flexibility

Demand side actions are an important part of the armoury, and this can provide additional flexibility with the Demand Flexibility Service launched in 2022. However, while the ESO has paid for an average of 251MW of demand reduction this winter, the actual demand flexibility delivered was only 70% of that contracted. This reflects changes in consumer behaviour with initial enthusiasm starting to wane. It makes predicting demand side response more difficult making alternative solutions more attractive.

LOSS OF FLEXIBILITY IN THE SYSTEM

The GB market is dominated by intermittent renewables and combined cycle gas turbines, together accounting for well over 75% of capacity as of September 2025. CCGTs provide both flexibility and spinning reserve. Further flexibility is provided by biomass generation, mainly Drax, and by pumped storage and smaller diesel and open cycle gas generation. Nuclear provides additional spinning reserve.

GB generation capacity

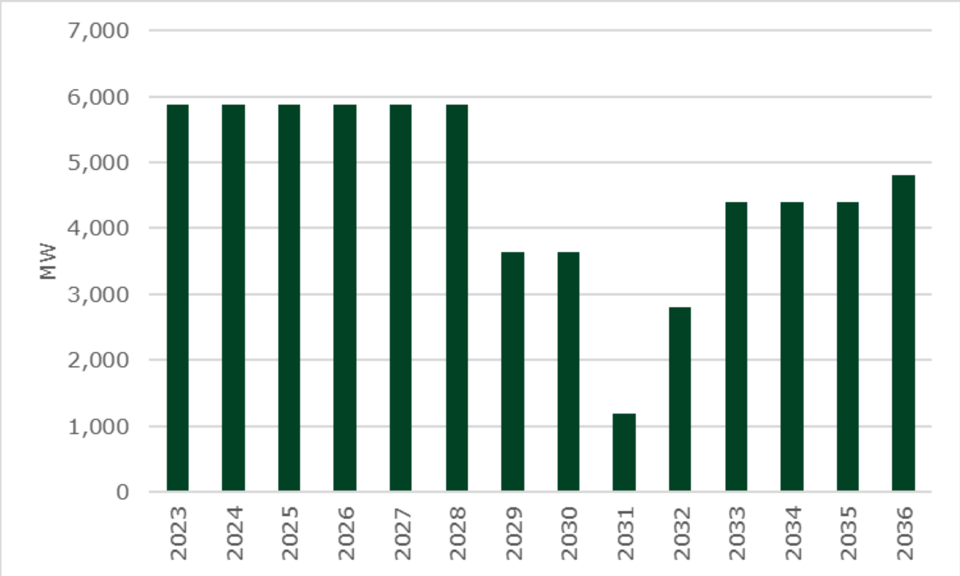


Source: National Grid

Closures and lack of replacement

The problem is that nuclear is closing with most existing plant shut by 2031 taking out 4,685MW of spinning reserve. While the two new nuclear projects at Hinkley and Sizewell will rectify this there is still a noticeable drop in capacity between 2029 and 2032 assuming the new projects can be completed in a reasonable time.

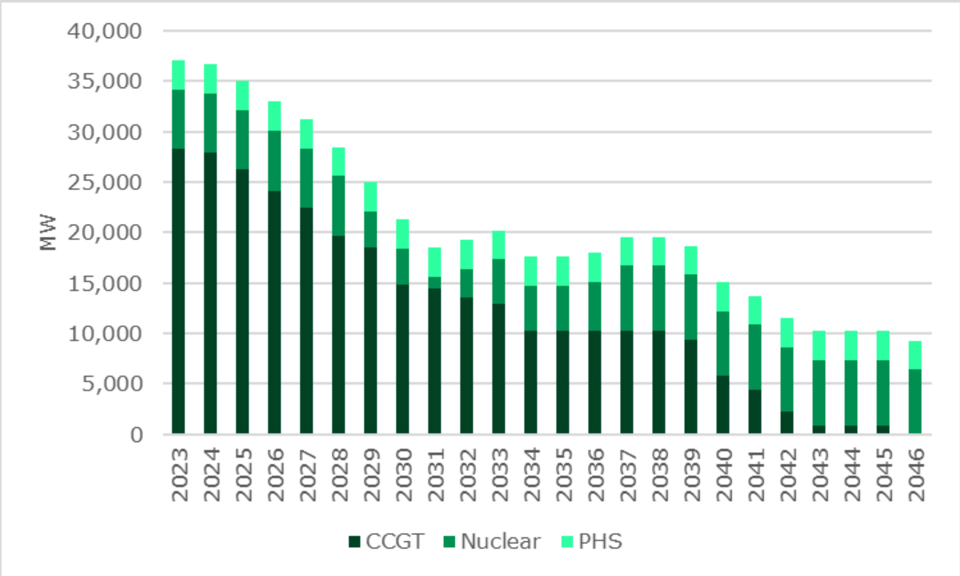
Closures of nuclear capacity in the GB market



Source: National Grid, Longspur Research

Additionally, the current fleet of gas generation is starting to get quite aged. Roosecote, the first CCGT in the UK, was commissioned in 1991, mothballed in 2012 and finally demolished in 2015 giving 21 years of useful life. If we were to assume a 30 year life for the existing fleet it can be seen that more than half of the UK's total spinning reserve is closed by 2031.

All spinning reserve



Source: National Grid, Longspur Research

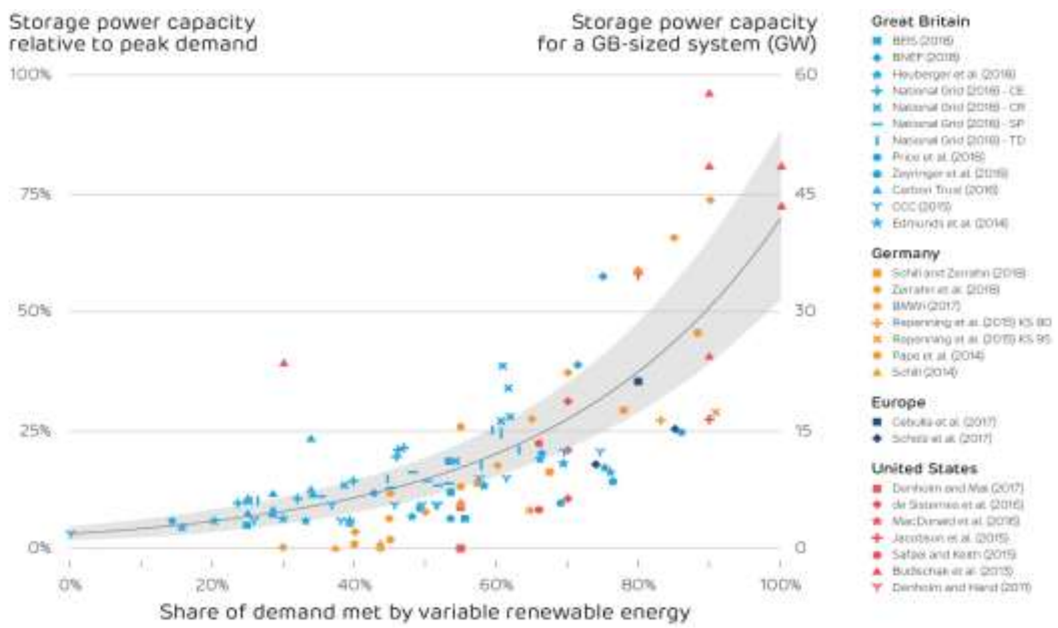
In straight generation terms this capacity loss is overshadowed by the growth in wind and solar. But that does not deliver spinning reserve nor flexibility. It was hoped that the Capacity Market would provide sufficient incentive for new CCGTs to be built. So far only four CCGTs have cleared the market auctions one of which has subsequently withdrawn. Eggborough, Kings Lynn A and Keadby II will deliver 2.7 GW of new capacity when completed. Additionally new gas capacity may emerge but with consenting and build times of around five years, a capacity crunch is looming. New nuclear is also hoped to replace the decline in spinning reserve but with the 3.2GW Hinkley Point C reactor again pushed back to at least 2029 there is a definite reduction in the second half of the current decade. Hinkley Point C was originally due to come online in 2017.

But it is not simply about replacing lost capacity. As the system becomes more dominated by intermittent renewable energy, the need for matching flexibility increases meaning we need to go beyond simple replacement.

THE NEED FOR FLEXIBILITY

Much academic work has been done on the need for storage and by extension flexible generation as renewable penetration increases. As we add more intermittent renewable energy, the demand for storage and long-duration storage in particular increases. The following meta study of research by Imperial College London shows this fairly clearly.

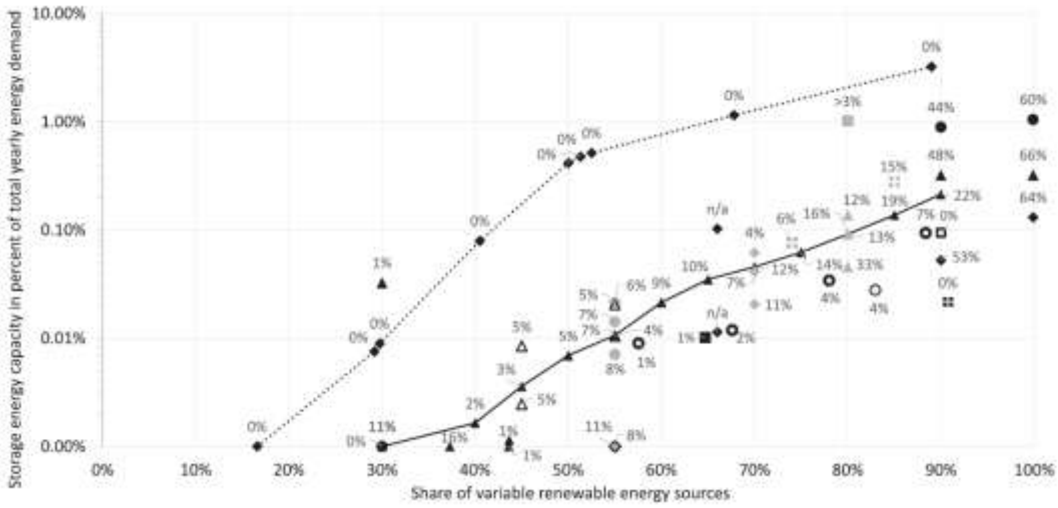
Storage capacity relative to renewable penetration



Source: Imperial College based on Zerrahn et al., 2018.

The Imperial work shows storage expressed as storage power capacity as a percent of peak demand. However, to really work out storage demand we need to know how much storage energy capacity is needed rather than power. The Imperial study draws heavily on another meta study; Zerrahn, A, Schill, W, Kemfert, C, On the economics of electrical storage for variable renewable energy sources, European Economic Review 108 (2018) 259–279. This shows the storage energy capacity as a percentage of total annual energy demand.

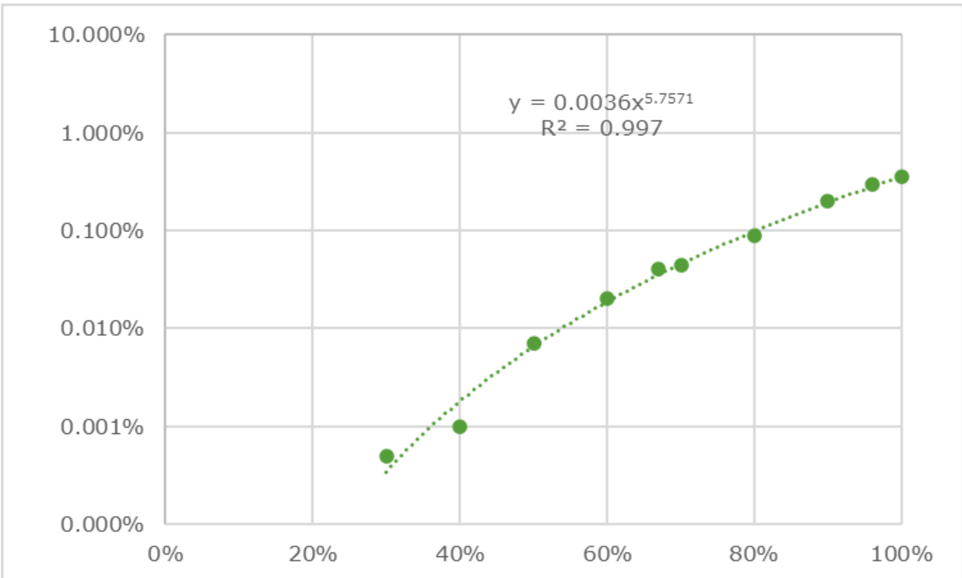
Storage energy requirements in recent research literature



Source: Zerrahn et al., 2018. Percentages show curtailment. Upper line assumes no curtailment.

We have plotted a trendline to this data to derive a relationship between variable renewable energy penetration and the required storage energy capacity demanded to minimise curtailment. Note that this does not eliminate curtailment but represents the least cost outcome. Even with significant energy storage, curtailment varies from 2% at 40% renewable penetration to 22% at 90% with 66% if there is 100% variable renewable energy supply. Our trendline has the equation $S = 0.036P^{5.7571}$ where S = storage as a percent of annual energy demand and P = variable renewable energy penetration.

Best fit line to Zerrhan et al.



Source: Zerrahn et al., 2018, Longspur Research

We can use this with the FES forecasts for renewable penetration to estimate demand for storage. This suggests that even the least ambitious FES forecast with 71% renewable penetration would mean storage of 0.3% of yearly electricity demand. It also represents storage demand of more than double the current storage "operating", "with planning", and "in planning", including existing and planned pumped hydro.

Storage required in UK for peak renewable penetration

Scenario	Max renewable penetration	Year	Storage required (GWh)	Lithium ion capacity (GWh)	Capacity (MW)
Falling Behind	71%	2041	1,488	248.0693	62,017
Electric Engagement	80%	2035	2,882	480.3234	120,081
Holistic Transition	83%	2035	3,632	605.3917	151,348
Hydrogen Evolution	78%	2036	2,529	421.4365	105,359

Source: Longspur Research, Department of Energy Security and Net Zero

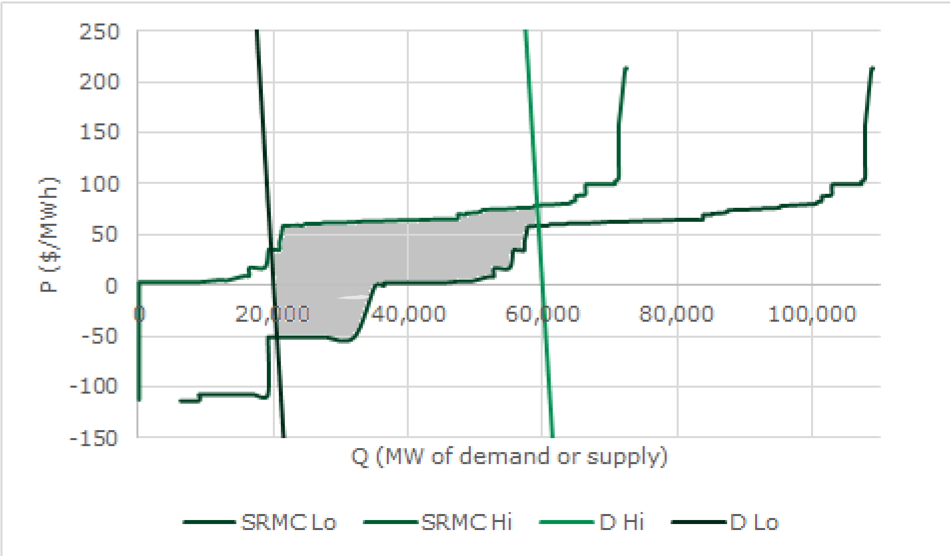
Clearly to solve curtailment the amount of storage required is very high indeed.

STORAGE ECONOMICS

Storage economics can be complex with storage assets taking advantage of multiple market opportunities to form a revenue stack. We have simplified our analysis to focus on just the ability to conduct simple trades across time periods. There will be many additional aspects to consider but, on the whole, we see our analysis as presenting a strong base case for storage.

We can examine the economics of electricity storage using a traditional supply and demand graph. Because of the instantaneous nature of the market with demand changing every 20 ms (in a 50Hz system), we really need to show two demand curves, one with the peak demand in the year (D Hi) and one with the minimum demand (D Lo). Also, because intermittent renewable supply varies, we think it is helpful to show the limit points in two supply curves (based on short run marginal cost), one with all renewable capacity available (SMRC Lo) and one with no renewable capacity available (SRMC Hi). Prices across the year should all fall in the shaded area between the curves.

Electricity market supply and demand in a 60GW peak market



Source: Longspur Research, BNEF, National Grid FES

The average price for the year will be predominantly in the middle of the shaded area. It can be estimated using assumptions of average demand and supply. Full forecasts are available using Monte Carlo simulation techniques to capture the variation in demand and weather-related supply to pinpoint the exact point in the middle of this area.

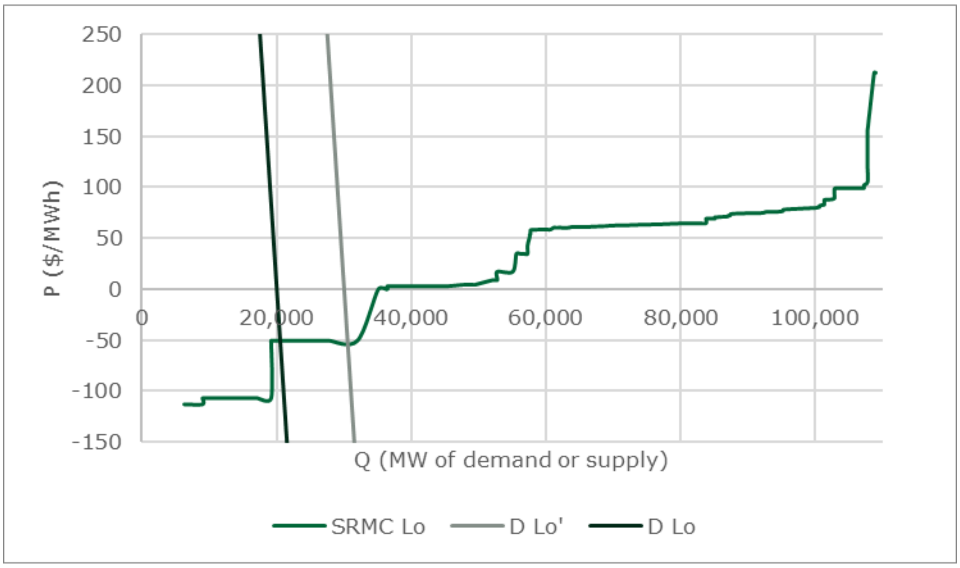
The low supply curve includes renewables with negative short run marginal costs resulting from subsidy programmes. The subsidy is only paid when the generator runs, so there is the potential that they are prepared to bid negatively, down to the level of subsidy. This may be rare but does happen and is increasing as more renewables are added to the system.

Adding storage

Storage is both a source of demand and supply. Storage charges as demand and discharges as supply. This charging and discharging can be delivered, and can change direction, more rapidly compared to any other assets on the grid. Charging will ideally take place when supply is at a maximum and demand at a minimum. With negative pricing, energy storage could be paid to charge.

Battery storage makes money by taking advantage of multiple opportunities across time between and within the various energy markets including the day ahead, intraday and imbalance markets. However, to understand the overall opportunity we simplify our analysis to an assumption that discharging will try to take place when demand is at a maximum and supply at a minimum. While storage will also sell services to the ancillary markets and the capacity market, it can make money from trading the difference between the high demand/low supply periods and the low demand/high supply periods. If we add storage capacity two things happen. The capacity moves the low period demand curve to the right to represent the additional demand caused by charging.

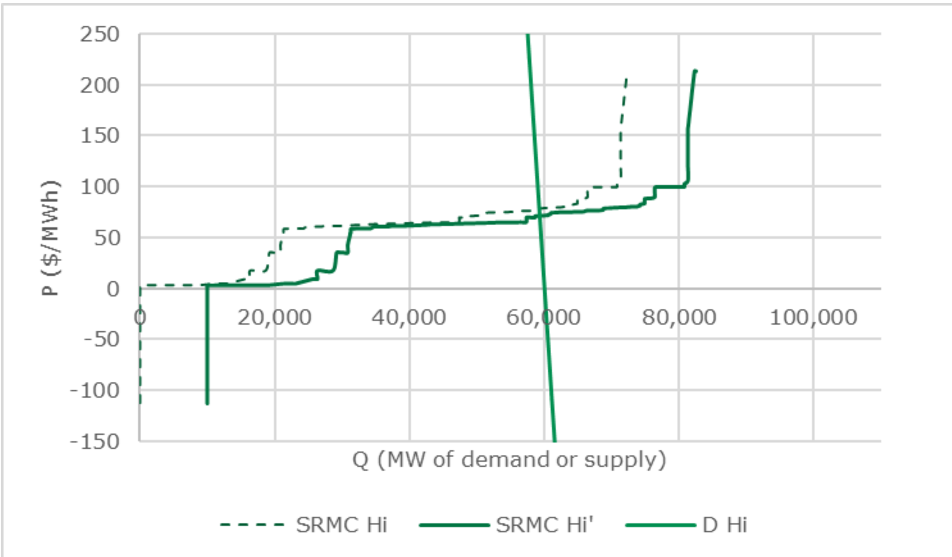
Impact of 10GW of storage charging



Source: Longsur Research

Then the high period supply curve is moved to the right (new supply is added), representing discharging.

Impact of 10GW of storage discharging



Source: Longspur Reseach

Looking at these graphs we can see that we can add over 30GW of new storage before the charging cost rises materially above zero and before the discharge price falls below £50/MWh. We would caution that this is the extreme range available, but it does give a useful illustration of the fact that trading spreads can remain attractive even with a lot of new storage capacity in the market. It also assumes that all this storage is effectively acting as a single resource when there are a range of opportunities for storage in the GB market which could add to the level of storage the market can accommodate.

30GW represents c.50% of the peak demand in our market example. This is below the current peak in the market but in line with expectations as heat pumps and EV charging become more prevalent. The overall outcome is a significant opportunity and if this opportunity presents itself in other similar markets, we are underestimating the opportunity for stationary energy storage systems globally.

PRICING OF TRADES

Power trading is just one element of the revenue stack of a typical battery installation, but it can deliver a high proportion of the value. The economics of power trading, or arbitrage to use the energy industry term, are based on the ability to buy power and charge batteries when prices are low and to sell power by discharging when prices are high. Our analysis of the past three years suggests that the average spread between high and low prices can be significant and make power trading a key part of the battery revenue stack. We think we can read forward from this recent past to show that projects can deliver even stronger returns as renewable penetration grows with planned developments of offshore wind projects in the North Sea, particularly under a Labour-led government who plan to quadruple offshore wind capacity, as well as double onshore wind capacity, and triple solar power.

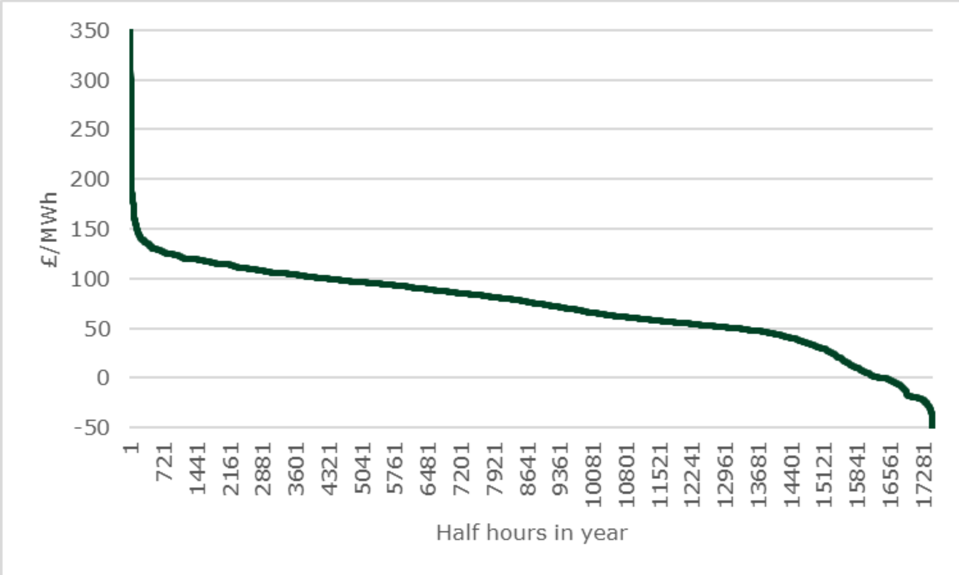
Power prices in 2022, and storage spreads in particular, were clearly exceptional. We also see them as an example of the way in which power markets are likely to develop going forward with relatively high gas prices determining peak and peak load prices, and higher renewables penetration keeping “off-peak” prices low. Low off-peak prices will occur more often as renewable penetration increases.

Power markets are seeing growing penetration of intermittent renewable energy in the form of wind and solar PV. At the same time gas prices have been rising and were already doing so before the Russian invasion of Ukraine. While they have already fallen back and may fall further, we think it is likely that, in Europe at least, they will remain higher than before 2021.

Broadly speaking, generators in electricity markets compete on the basis of their short run marginal costs. When renewables are running, they have a very low short run marginal cost. As renewables take up more of the system, low price periods become more frequent. However, when there are not enough renewables to meet demand, more expensive fossil fuelled generation becomes price setting. With high fossil fuel prices this makes these periods very expensive. Even when fossil fuel prices normalise, these periods are expected to remain expensive as fossil fuel generators will increasingly have to cover costs and margin over a shrinking number of operating hours.

We can look at the distribution of prices in what the power industry has historically termed a price duration curve with highest prices shown first at the left-hand end and low prices at the right-hand end.

Price duration curve 2024

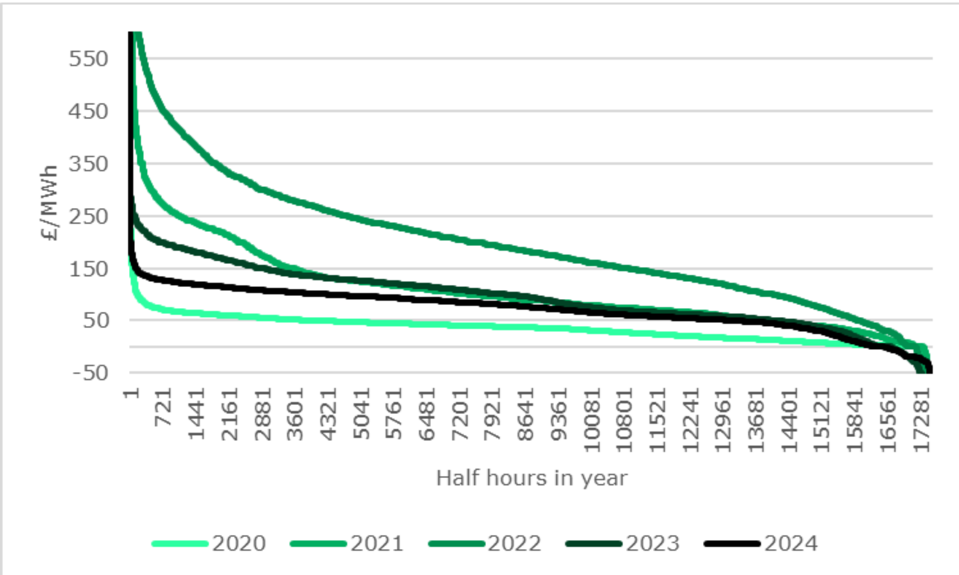


Source: Longspur Research, ELEXON

The experience in 2020 was unusual with exceptionally low demand due to COVID lockdowns. While this meant that there were relatively more periods when renewables were price setting, penetration rates remained low, so these periods were still not particularly frequent. With lower overall demand, pricing was weak across all periods.

2021 was a more normal year with renewable penetration as a percent of demand growing but gas prices also starting to rise leading to higher peak prices. 2022 saw high gas prices but demand had grown so renewables set prices less of the time.

Price duration curves for recent years

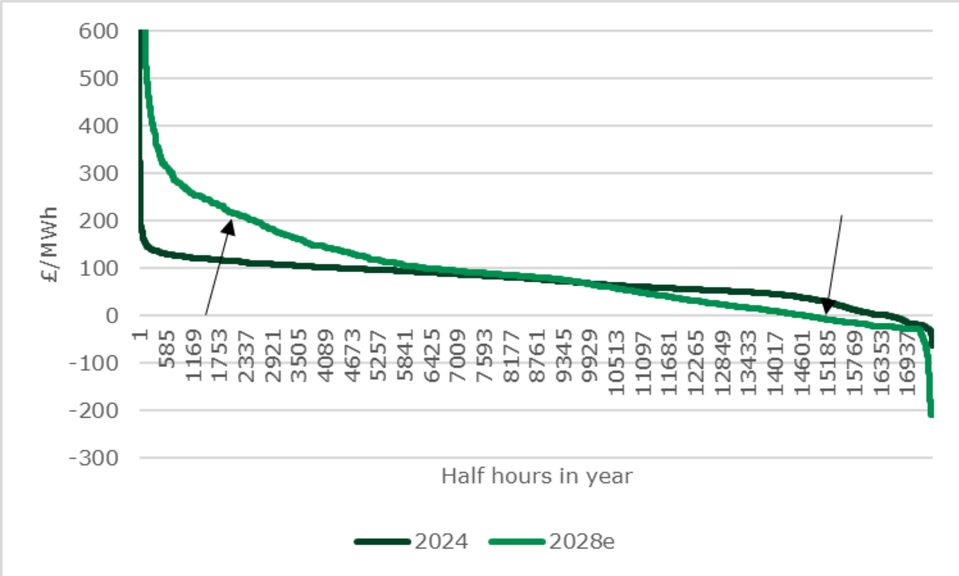


Source: Longspur Research, ELEXON

2023 and 2024 have seen gas prices to fall back below 2021 levels but to still remain well above 2020 levels as more reliance is placed on higher cost LNG trains as the UKCS sees further decline. We also expect renewable penetration to increase. The likely outcome is that high prices will drop compared with the exceptional 2022 outcome but remain above

2021 and a gradually more extended low-price regime will apply at the right-hand end of the curve.

Expected price evolution

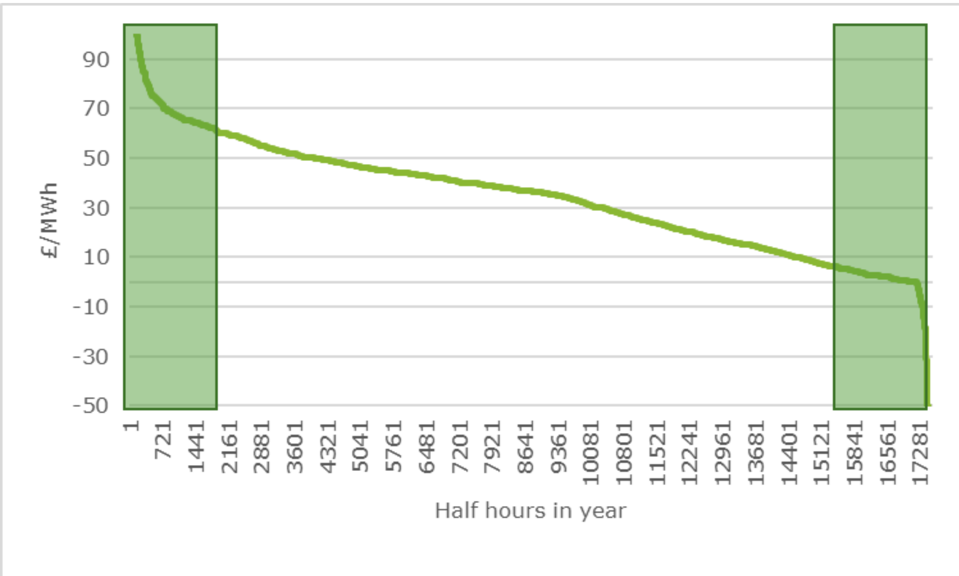


Source: Longspur Research, ELEXON

IMPACT FOR A TYPICAL BATTERY

Looking at the price duration curves we can estimate the average charging cost and discharging price assuming utilisation of 8.3% based on 2 hours of storage duration with one cycle a day (2/24=0.083). The resulting average spread will then be the difference between the average prices in the two green boxes below.

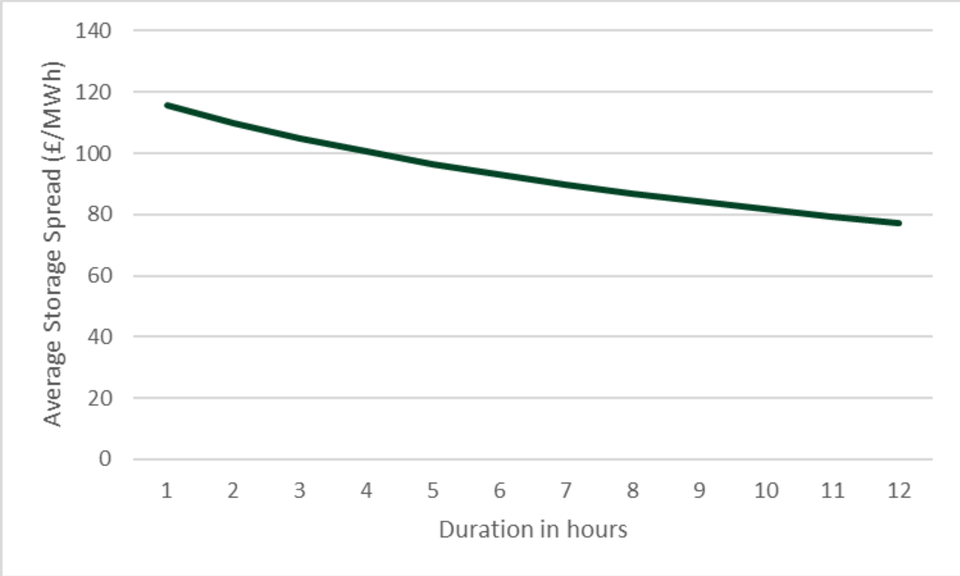
Calculating the storage spread



Source: Longspur Research, ELEXON

However this overestimates the benefits because the real economics are the ability to trade the highest and lowest two hours on any single day rather than the highest and lowest in the year. We can estimate this from the same data set and work out the average spread of the high to low price for each hour. In fact we can look at the average spread for each additional hour. For 2024 it can be seen that the first hour spread is £116/MWh. The second hour sees this drop to £103/MWh which is still attractive. We can plot the spread for each hour out to 12 hours as shown below.

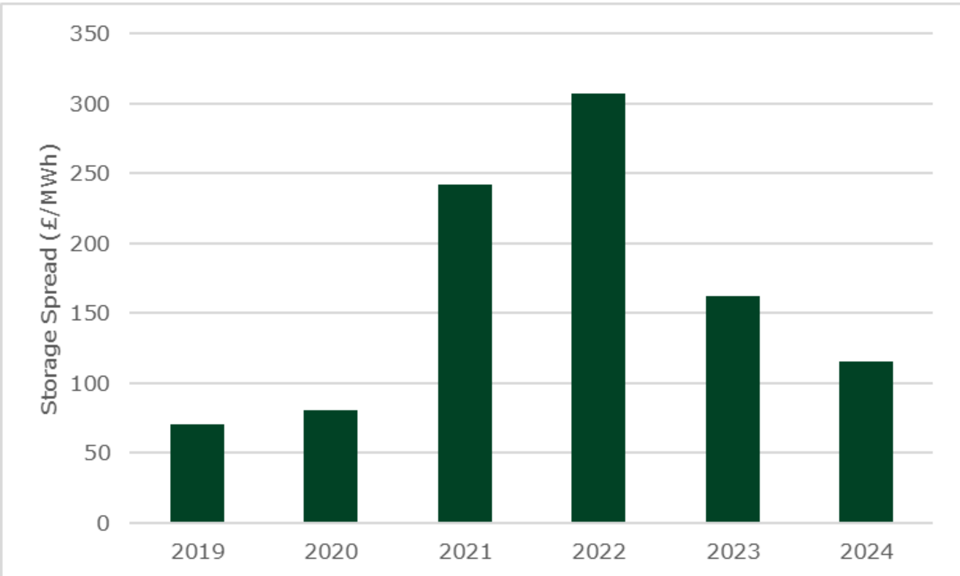
Average storage spread for each additional hour



Source: Longspur Research, ELEXON

Looking at the development of the first hour spread over time 2020 saw low demand due to COVID keeping the spread low. 2021 saw higher gas prices and the Russian invasion of Ukraine in 2022 saw even higher gas prices driving peak spreads. This has now fallen back although we see further renewable penetration having the potential to hold if not drive up spreads in the medium term.

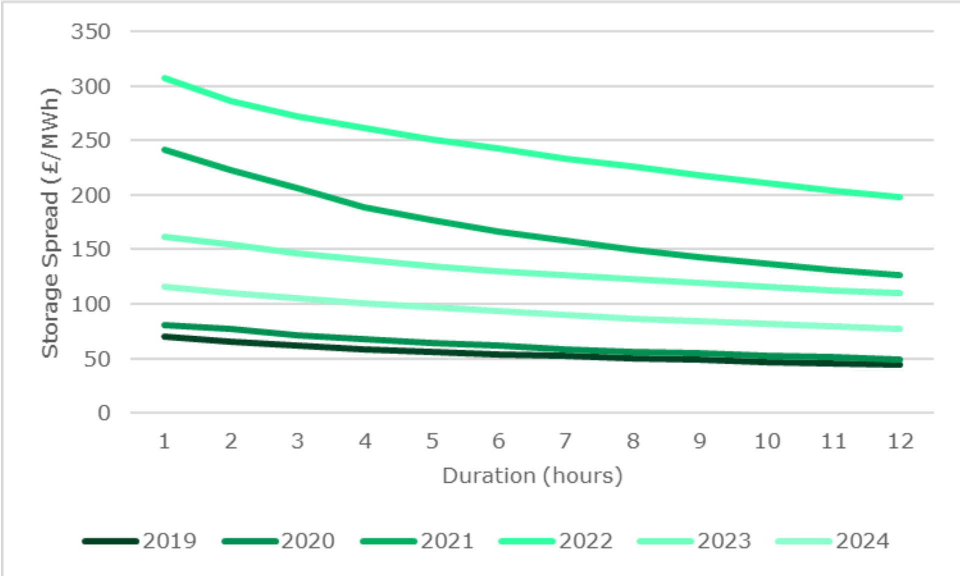
Average one-hour storage spread



Source: Longspur Research, ELEXON

At longer durations the variation in price spreads is lower although follows the same broad trend.

Average storage spread for each additional hour



Source: Longspur Research, ELEXON

CAPACITY MARKET LOOKING ATTRACTIVE

Also available in the revenue stack in the UK is the Capacity Market. While storage capacity is derated to reflect its availability to discharge during potential stress events, capacity market payments can still be an attractive addition to revenue. Pricing is on the increase and more batteries are participating with new projects eligible for 15-year contracts.

The capacity market is a government scheme run and administered by the system operator (SO) who are the National Grid. The SO runs auctions for capacity to be available in four years' time (T-4 auctions). Additionally, top up capacity needs are met through auctions for delivery in a year's time (T-1 auctions).

Auction winners must be available to operate if called in times of system stress. Failure to respond when called results in penalties worth 1/24th of the clearing price applied per MW for under-delivery in each settlement period with a cap of 200% monthly contract value and 100% annual contract value. Existing plants can get contracts for one year, or three for plants that carries out upgrades. New generation capacity can get 15-year contracts via T-4 auctions, although the duration of CM contract secured must reflect the plant's end of contract capability, taking into account degradation and the requirements of the extended performance testing for storage. In practice this means that many storage operators opt for CM contracts over a larger proportion of installed capacity for a shorter contract term, or a longer contract term but over a smaller proportion of capacity. Auctions pay as clear (i.e. everyone gets the clearing price).

The most recent auctions have seen a strong rise in pricing and battery projects are taking advantage of this with 107 battery units with 1.1GW of derated capacity winning contracts in the T-4 auction, the majority of which were new projects. Storage capacity is de-rated to reflect its duration, but the capacity market can still be an attractive addition to the revenue stack.

Capacity market auction results

£/kW/year	T-1	T-4
2018/19	6.40	19.40
2019/20	0.77	18.00
2020/21	1.00	22.50
2021/22	45.00	8.40
2022/23	75.00	6.44
2023/24	60.00	15.97
2024/25	35.79	18.00
2025/26	81.04	30.59
2026/27		63.00
2027/28		65.00
2028/29		60.00

Source:National Grid ESO, EMR Delivery Body

ILLUSTRATIVE BESS PROJECT ECONOMICS

We can summarise a BESS project economics assuming the current 2 hour arbitrage spread of £110/MWh together with a revenue stack including Dynamic Containment (low) revenue at today's pricing and a capacity market contract at the latest T4 auction price. We have used a higher overall capital cost than reported in the most recent Bloomberg New Energy Finance summary to include EPC margin and grid connection costs and to align with anecdotal evidence we are seeing in the market. The outcome is a project IRR of 11%.

Illustrative GB battery storage project

Item	£	Notes
Nominal Capacity of Project (MW)	260	
Rate Battery Capacity (MW)	286	Oversized in line with best industry practice to minimise degradation
Duration (hrs)	2	
DoD	85%	In line with above assumption
Site up time	99%	
Electricity - Wholesale/BM		
Spread (£/MWh)	109.61	2024 average 2 hour spread
DC opt out hours	6	
Running	8.33%	
MWh	159,717	Not included in electricity sold as spread pricing assumed
Arbitrage Revenue	17,506,077	
Dynamic services		
Availability Price (£/MW/hr)	2.0	Recent pricing (MTD average DC low)
Available hours per day	12	Opt out for remaining hours to participate in arbitrage
Nomination hours	0	Not included in electricity sold as ABSVD avoids purchases
Nomination MWh	0	As above
DC Revenue	2,218,369	
Capacity market		
Price (£/kW/year)	60.00	Latest T-4 auction price
Derating	64.79%	For 2 hours duration
CM Revenue	10,006,168	
Total revenue	29,730,614	
Electricity sold	159,717	
Net charging efficiency	100%	100% to reflect ABSVD allowance
Electricity consumed (MWh)	159,717	
Electricity price paid (£/MWh)	0	Revenue is net of charging costs
Total energy costs	0	
O&M etc costs	2,002,000	From BEIS generation costs for small PV
Upgrade maintenance	2,952,092	Cell replacement amortised over 25 years
Total operating costs	4,954,092	
EBITDA	24,776,522	
Life	25	
Capex	171,600,000	
Depreciation	6,864,000	
Tax	25.0%	
Tax charge net of interest shield	4,478,130	
Ungeared cashflow	20,298,391	
IRR	**11%**	

Source: Longspur Research Estimates

DRAX - KEY DATA

Drax owns over 6GW of grid connected power capacity in the GB market. Of the six main units at the 4GW Drax power station site in Yorkshire, four have been converted to burn biomass and associated safe fuel handling has been installed with appropriate levels of fire suppression. The remaining two units are unused but maintained. Drax has created a degree of vertical integration with retail businesses services serving large commercial and industrial customers. It has also built a biomass supply business to support its biomass generation. It acquired the 440MW Cruachan pumped storage scheme in Argyllshire from Iberdrola along with two run of river hydro schemes and has developed three OCGT flexible gas generation units. The assets allow it to dominate the GB electricity market, providing flexible generation as demand for this grows and expanding its flexibility offering. It can also expand geographically through its upstream biomass business and take this downstream to new BECCS projects.

BULL POINTS

- Low carbon spinning reserve as demand for inertia grows
- Long duration fast reacting storage as market becomes more volatile
- Exposure to carbon capture and storage at scale
- Major player in sustainble biomass supply

BEAR POINTS

- Exposed to policy changes
- BECCS technology still expensive
- Low carbon biomass argument not fully understood by all

CATALYSTS

- Settlement on BECCS support for Drax Power station
- Growth in flexibility income
- Biomass argument settled

VALUATION

Using a WACC of 8.8% gives us a valuation of 1082p. if we assume that the CCS does not go ahead and the pellets business stalls, the valuation drops to 931p in our low case. However if those assumptions are met and Cruachan is eventually expanded and two global BECCS plant are invested, we get a high case of 1226p.

RISKS

The UK electricity markets are all to a greater or lesser extent regulated and this leaves the company exposed to changing regulation and policy shifts. We think that the fact that Drax can meet many of the needs of the GB electricity system means that it will continue to be rewarded one way or another for its activities. We see BECCS as a key enabler of a net zero outcome in the UK and the legal commitment to a UK net zero outcome enshrined in the 2008 Climate Change Act reduces the risk of this solution not being adopted but as an oportunity for Drax it remains uncertain. Similarly the cap and floor mechanism to support long duration storage continues to have an uncertain treatment of cost overruns potentially limiting its value to the support of expansion at Cruachan.

FINANCIAL MODEL

Profit and Loss Account

£,000, Dec	2023a	2024a	2025e	2026e	2027e	2028e
Turnover						
Bioenergy generation	6,432	4,921	3,905	3,497	2,796	2,567
Pumped storage and hydro	355	223	258	245	285	334
B2B Energy Supply	4,958	3,786	3,229	3,458	3,703	3,965
Pellet production	822	942	905	898	958	1,172
Central, int gp and depn	-4,725	-3,709	-3,163	-3,388	-3,628	-3,885
Total turnover	7,842	6,163	5,133	4,709	4,114	4,153
EBITDA						
Bioenergy generation	703	814	638	395	266	211
Pumped storage and hydro	230	138	139	129	133	164
B2B Energy Supply	72	51	45	49	53	56
Pellet production	89	143	156	162	195	256
Central, int gp and depn	-312	-346	-333	-342	-366	-366
Operating profit	782	800	645	393	280	322
P&L Account	**2023a**	**2024a**	**2025e**	**2026e**	**2027e**	**2028e**
Turnover	7,842	6,163	5,133	4,709	4,114	4,153
Operating Profit	782	800	645	393	280	322
Investment income	0	0	0	0	0	0
Net Interest	-116	-97	-67	-64	-63	-62
Pre Tax Profit (UKSIP)	665	703	579	328	217	260
Goodwill amortisation	0	0	0	0	0	0
Exceptional Items	131	50	0	0	0	0
Pre Tax Profit (IFRS)	796	753	579	328	217	260
Tax	-196	-228	-149	-74	-46	-57
Post tax exceptionals	-40	0	0	0	0	0
Minorities	1	0	0	0	0	0
Net Profit	562	526	429	254	171	203
Dividend	-88	-97	-105	-115	-127	-140
Retained	474	428	325	139	44	63
EBITDA	1,009	1,053	905	670	579	629
EPS (p) (UKSIP)	119.56	128.40	121.48	71.91	48.38	57.41
EPS (p) (IFRS)	142.80	137.50	121.48	71.91	48.38	57.41
FCFPS (p)	121.72	143.95	89.17	68.79	32.35	130.14
Dividend (p)	23.10	26.00	28.60	31.50	34.70	38.20

Source: Company data, Longspur Research estimates

KEY POINTS

- Pricing drops revenue in FY 24 but profitability remains
- Net interest balanced between cashflow and capex
- Higher tax due to windfall tax in FY 23 and FY 24, lower in FY 25 as pricing starts to normalise with FY 27 revised on lower forward curve
- Dividend remains covered throughout

Balance Sheet

£,000, Dec	2023a	2024a	2025e	2026e	2027e	2028e
Fixed Asset Cost	5,022	5,377	5,776	6,131	6,552	6,662
Fixed Asset Depreciation	-2,322	-2,575	-2,835	-3,112	-3,412	-3,719
Net Fixed Assets	2,701	2,802	2,941	3,019	3,140	2,943
Goodwill	417	415	415	415	415	415
Other intangibles	82	68	68	68	68	68
Investments	131	105	105	105	105	105
Stock	621	842	701	643	562	567
Trade Debtors	977	470	392	359	314	317
Other Debtors	733	331	381	381	381	381
Trade Creditors	-1,540	-1,289	-1,074	-985	-861	-869
Other Creditors <1yr	-252	-81	-81	-81	-81	-81
Creditors >1yr	-624	-543	-543	-543	-543	-543
Provisions	-79	-96	-107	-119	-130	-142
Pension	0	0	0	0	0	0
Capital Employed	3,166	3,024	3,198	3,262	3,370	3,162
Cash etc	380	356	139	209	126	366
Borrowing <1yr	289	145	145	145	145	145
Borrowing >1yr	1,272	1,148	964	961	942	911
Net Borrowing	1,183	937	971	897	961	690
Share Capital	49	49	49	49	49	49
Share Premium	441	444	259	259	259	259
Retained Earnings	666	1,118	1,443	1,581	1,625	1,688
Other	814	466	466	466	466	466
Minority interest	12	10	10	10	10	10
Capital Employed	3,166	3,024	3,198	3,262	3,370	3,162
Net Assets	1,983	2,087	2,227	2,366	2,410	2,473
Total Equity	1,983	2,087	2,227	2,366	2,410	2,473

Source: Company data, Longspur Research estimates

KEY POINTS

- Working capital remains comfortable across period
- Goodwill reflects pellet acquisition in FY 21
- Net debt rises with capex and then drops with cashflow

Cashflow

£,000, Dec	2023a	2024a	2025e	2026e	2027e	2028e
Operating profit	782	800	645	393	280	322
Depreciation	228	253	260	277	299	307
Provisions	-4	12	12	12	12	12
Other	-6	-40	0	0	0	0
Working capital	112	111	75	66	18	-24
Operating cash flow	1,111	1,135	992	747	609	617
Tax paid	-180	-194	-228	-149	-74	-46
Capex (less disposals)	-430	-379	-449	-355	-421	-111
Investments	-22	-11	0	0	0	0
Net interest	-95	-82	-67	-64	-63	-62
Net dividends	-86	-94	-97	-105	-115	-127
Residual cash flow	298	376	151	74	-64	271
Equity issued	-141	-113	-185	0	0	0
Change in net borrowing	-174	-244	34	-74	64	-271
Adjustments	18	-19	0	0	0	0
Total financing	-298	-376	-151	-74	64	-271

Source: Company data, Longspur Research estimates

KEY POINTS

- Working capital reasonably balanced across period
- Capex programme to FY27 as guide then maintenance capex
- Windfall tax outflows in FY 24, but assumed negligible in FY 25

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