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Centre for Environmental Policy

Multi-day energy storage's potential in 2030 Great Britain, as a solution to decarbonise the power sector

By
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A report submitted in partial fulfilment of the requirements for the MSc
04/09/2024

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Abstract:

Long duration energy storage is seen as a key component towards decarbonising the power sector whilst maintaining energy security. Discussions in Great Britain (GB) are increasingly being held on ways to properly incentivise technologies that can store energy cheaply for long durations. However, most solutions are not yet technologically or economically viable, and the literature as well as energy modelling on technologies that can store energy for multiple days such as iron-air batteries is scarce. This paper shows that multi-day energy storage can reduce curtailment, emissions and provide energy during long periods of system stress in GB's 2030 electricity grid. It also finds that energy capital costs need to be at least lower than 26€/kWh to breakeven from arbitrage, and that further revenue sources are most probably needed, even with capacity market payments. The results suggest that expanding variable renewables increases the profitability of multi-day energy storage, and charging during negative prices could become a significant source of revenue. Although arbitrage profits can exceed 220,000€/MW in certain scenarios, the uncertainty with capital costs and annual revenues warrants policy-makers, regulators and investors to design policies and markets for long duration energy storage to be profitable.

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Executive Summary

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Aims and Objectives:

This study aims to quantify the potential benefits multi-day energy storage can bring to Great Britain's power system in 2030 and calculate how cheap it needs to be in order to be a financially viable solution.

Therefore, the objectives to achieve these aims are to:
1. Explore multi-day energy storage's impact on CO_2 emissions, curtailment, fossil fuel plants, and how it can provide energy during system stress periods.
2. Quantify the annual profits from arbitrage and its breakeven capital costs
3. Provide evidence and discuss the potential need for additional revenues through market and policy changes.

Introduction:

As Great Britain (GB) expands its share of variable renewable energy to decarbonise the power sector, and electricity demand increases, the challenge of making electricity affordable, reliable and decarbonised arises (CCC 2023). Furthermore, the lack of flexibility that comes with renewables, and the current need for carbon-free technologies that can provide reliable electricity for long durations at a large scale, warrants further investment and innovation in potential solutions.

Therefore, long duration energy storage is seen as a necessary solution among others, to decarbonise the power sector and retain energy security (Aurora Energy Research 2022). A relatively novel technology that is being developed are iron-air batteries, which could store 100 hours of electricity, and can thus be classified as multi-day energy storage (Form Energy 2023a). Moreover, long duration storage needs to have very low energy capital costs to be cost-effective, and thus conversations over potential "missing money" for these types of assets are occurring (SONI 2023).

Finally, modelling and literature on long duration energy storage, particularly multi-day, is starting to grow. It is therefore of interest to contribute to the emerging studies and set multi-day energy storage (MDS) in the GB context and discuss the potential policy and market actions that may be required in GB.

Methodology:

The paper first collects data from numerous sources but most importantly ENTSO-E (2024a) and National Grid ESO (2024a) to create plausible scenarios for 2030. MDS details are sourced from Form Energy (2024b).

Then, the paper uses an electricity dispatch model named EuroMod, which matches demand and supply to determine a clearing price for every hour of the year (8760 hours), whilst minimising total system costs with respect to dispatch, interconnectors and storage (Mendes et al. 2024). Total system costs are the sum of variable costs, electricity curtailment and lost load costs. Results from the model for each scenario are then aggregated and analysed.

Furthermore, electricity dispatch graphs are then made to be able to zoom into shorter time frames and show the impacts MDS can have. With the "financial" results from the modelling, annual profits from arbitrage can be calculated. Then, the paper calculates the breakeven capital costs for each scenario using the net present value formula and different discount rates. Finally, the paper calculates at what price would capacity market payments have to be to reach different internal rates of return and sets the results in the GB context.

Results:

Main results differ based on the varying scenarios. Overall, multi-day energy storage (MDS) decreases curtailment in all scenarios, with higher wind generation leading to MDS decreasing curtailment further. The baseline scenario finds a 0.5% decrease in annual curtailment per GW of MDS. MDS also leads to gas and peaking plants being displaced, with a reduction in emissions in all but one scenario. The baseline scenario finds a 0.35 $MtCO_2$ reduction or 5% per GW of MDS. The 2010 climate year scenario finds that MDS can discharge for 32 hours out of 40 during a system stress event, showing how MDS can provide energy reliably for long durations.

For the financial results, the annual arbitrage profits per MW vary between 115,000€ and 228,000€ depending on the scenario in 2030. Thus, the breakeven capital cost also vary depending on the scenario and discount rates used. For a central 7.5% discount rate, the lowest breakeven capital cost is 12€/kWh and the highest is 22€/kWh depending on the scenario. Two scenarios that represent high and low profits are then selected to calculate how much more revenue would need to come from the capacity market to reach a 6%, 9% and 11% IRR, based on projected capital costs (Form Energy 2024b). The findings show that the high profits scenario would only require more revenue at higher rates of return, which do fall in line with current prices (EMR 2024). Overall, capacity payments are found to be required, with one price being higher than what is currently seen, suggesting even more revenue would be needed.

Discussion, conclusions, and implications:

The findings suggest that coupling renewables with MDS is beneficial both for variable renewables and for MDS. More variable renewables increased the price spreads and thus potential for arbitrage revenues, and more MDS decreased how much renewable energy is curtailed. Furthermore, gas prices can heavily influence the impact MDS has on emissions, which suggest storage decreases further emissions when renewable generation is high and gas generation is low. Another important finding is that negative pricing has a significant impact on the potential revenues for MDS. This suggests that as negative pricing increases, MDS can earn significant revenues from charging.
Moreover, the results suggest that arbitrage profits can in certain scenarios be enough to cover Form Energy’s projected capital costs. However, due to the volatility of arbitrage

revenues as well as the uncertainty of reaching such low capital costs of energy, MDS would need to engage in revenue stacking. Even when taking capacity market payments into account, it is unclear if the revenue is enough to meet the required rates of return investors would demand. Therefore, it is possible that more certain forms of revenue are required, which warrants potential policy and market changes for zero-carbon LDES assets.

However, certain limitations do need to be considered. Firstly, the model under-estimates storage revenues by more than 60% with perfect foresight. Moreover, certain constraints that could be added may increase the value of MDS and its revenue such as transmission constraints and unit commitment constraints. Furthermore, scenario analysis is by nature uncertain due to the numerous assumptions made such as capacities, efficiencies, climate years and costs. Also, directly including other markets in the model such as the capacity market and balancing mechanism, would increase the accuracy of results, and help determine if longer duration storage does indeed require policy and market changes to become financially viable. Finally, future work could include investment costs into a capacity expansion model to explore how MDS would affect total system costs in GB.

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List of Acronyms:

CapEx	Capital Expenditures
GB	Great Britain
LDES	Long Duration Energy Storage
MDS	Multi-day storage
VRE	Variable renewable energy
MW	Megawatt
GW	Gigawatt
IRR	Internal rate of return
kWh	Kilowatt-hour
RTE	Round trip efficiency
CCS	Carbon capture and sequestration
ERCOT	Electric Reliability Council of Texas
CCGT	Combined Cycle Gas Turbine
OCGT	Open Cycle Gas Turbine
ROCs	Renewable Obligation Certificates
NPV	Net Present Value
$MtCO_2$	Million tonnes of carbon dioxide
TWh	Terrawatt hours

1. Introduction:

To meet the Climate Change Committee's (CCC) Sixth Carbon Budget, Great Britain's electricity generation mix will need to emit almost zero emissions in 2035 (BEIS 2022). Further ambitions by the UK's new government to decarbonize the power sector by 2030 calls for additional zero-carbon solutions that can also provide energy security and affordability (Labour Party 2024). Additional challenges arise regarding the power sector's decarbonisation, as a significant increase in electricity demand is expected with future system stress events set to become more frequent, last longer and be more volatile as variable renewable energy (VRE) expands (LCP Delta 2024) (DESNZ 2023a).

As GB's power sector increases its variable renewable energy, the importance of developing solutions that can support the grid to meet energy demand is crucial. As the saying goes, "the sun doesn't always shine, and the wind doesn't always blow". Therefore, several solutions to increase flexibility and security must be promoted, which can range from interconnections and demand shedding to energy storage (Biancardi et al. 2024).

Energy storage is seen as vital to decarbonize GB's power sector, as it can provide power when generation does not meet demand. However, current energy storage technologies vary in terms of price, location and durations, which leads to different solutions solving similar yet different problems. Most of the storage capacity in GB is currently either pumped hydro or lithium-ion batteries (National Grid ESO 2024), with most projected capacity being in the form of lithium batteries, which tend to store energy cost-effectively for around 4 hours but could cover slightly longer durations (Denholm et al. 2023). Furthermore, a large portion of GB's power generation is expected to come from wind, which can lead to system stress events, as periods of low wind can last for longer than 4 hours, even up to a few weeks (Li et al. 2021). Therefore, many academics and government consultations have started to further stress the need for long duration energy storage (LDES), in order to provide energy during periods of low renewable energy generation (DESNZ 2024a) (Dowling et al. 2020). Aurora shows that up to 24 GW of LDES, which is eight times the current capacity, could be needed to decarbonise the power sector and ensure grid reliability (Aurora Energy Research 2022).

A relatively novel technology currently led by Form Energy is an aqueous metal-air electrochemical battery, or “iron-air batteries”. Due to its novelty, results and literature are scarce, however iron-air batteries are said to be able to provide 100 hours of energy (Form Energy 2023). This form of long duration storage could potentially provide capacity for stress periods that last a few days, due to its ability to store energy cheaply during longer periods than other storage alternatives.

Thus, this study focuses on the potential of multi-day storage (MDS), here in the form of iron-air batteries, in GB’s 2030 power sector. This paper aims to address the question of “What benefits can MDS bring to GB’s power sector in 2030? And how cheap would MDS need to be in order to be a financially viable solution in GB?”,

The objectives to answer these questions are to firstly use an electricity market model to quantify the benefits of MDS in terms of emissions, curtailment, and potential provision of energy during stress periods, exploring a wide range of scenarios for GB’s power sector in 2030. Then, the paper estimates the annual profitability of MDS for different scenarios, which allows the study to calculate the maximum capital cost for breaking even. This can show how financially viable MDS could be and can be compared to projected capital costs. Further calculations with potential capacity market payments will also help answer the question of financial viability. Finally, the paper concludes with broader discussions around MDS’s potential in GB’s 2030 power sector leading to further discussion on the potential “missing money” with MDS, exploring if further policy or market action is required.

2. Background

2.1) Long duration storage and multi-day energy storage today

In their report, BEIS, defines long duration storage (LDES) as being able to store energy for more than 12 hours (BEIS 2022). Multi-day energy storage (MDS) which can be defined as a subsection of LDES, can be described as storage that can continuously discharge for more than a day (Form Energy 2023). The only significant LDES GB currently has, is pumped hydro storage with around 2.6 GW of capacity (National Grid ESO 2024). Other technologies which tend to feature as LDES solutions, are compressed air energy storage and liquid air (ibid). As duration increases further, chemical forms of LDES such as hydrogen become cheaper which could provide more seasonal storage (Schmidt & Staffell 2023). However, one of the greatest advantages of electrochemical storage systems such as iron-air batteries, is their ability to be located in almost any location, unlike other similar storage such as pumped hydro and compressed air energy storage (Ziegler et al. 2019).

2.2) GB and VRE variability

Currently there are large quantities of relatively flexible fossil generation, 41GW of capacity (National Grid ESO 2024), which will have to be replaced in order to reach the GB's power sector decarbonization goals (CCC 2023). Furthermore, the new Labour government has increased its power decarbonization goals which further warrants solutions that can effectively replace fossil flexibility, especially if fossil plants see their operational load factor decrease and are further precipitated to close down (BEIS 2022).

Residual demand will increase and become more variable, with longer periods of high and low residual demand, and weekly fluctuations due to the increasing share of VRE (AFRY 2023) (BEIS 2022). As GB aims for a high share of electricity from wind, it is expected that it would have longer instances of excess or shortfall events, compared to solar-dominated grids which would see more intra-day variation (LCP Delta 2024). This is due to the multi-day and weekly variation of wind patterns (LCP Delta 2024). Therefore, in countries with potentially longer periods of system stress such as wind-dominant grids, the need for firm" (dispatchable and available) zero-carbon sources such as long duration storage and MDS is more pronounced (Staadecker et al. 2023) (Woodford et al. 2022).

2.3) Barriers to LDES deployment

Currently there are many uncertainties for long duration energy storage in the GB electricity system, such as revenue certainty, market design and large capital costs (LCP Delta 2024) (BEIS 2022). Furthermore, arbitrage revenue which is increasingly being a main source of revenue for storage assets (Modo Energy 2024) can be volatile, which is partly why long duration storage projects can be seen as a risky and uncertain investment (House of Lords 2024). This is especially the case for assets that do not regularly discharge, and thus make the bulk of their revenue from few periods. All of the above partly explain why GB is currently going through electricity market reforms with one of the main topics being how to properly incentivise LDES (DESNZ 2024a).

2.4) Alternatives to storage

Other alternatives to storage are flexible power generation, interconnections and demand-side response (Biancardi et al. 2024). Increasing interconnection can reduce the need for storage flexibility, however it still leaves the UK exposed to continent-wide Dunkelflaute and system stress periods (DESNZ 2023b). Dunkelflaute can be defined as a period of low wind and little sunlight (DESNZ 2023a), and thus low VRE generation. Furthermore, interconnectors do affect the utilization rate of storage, but not so much the cumulative capacity of storage needed (AFRY 2023). Demand-side response is still relatively novel and small in scale, and although it can help in reducing demand at certain system stress periods, its projections for GB remain relatively low (ENTSO-E 2024a) (National Grid ESO 2024). Since flexible renewable power generation remains low and most storage cannot provide energy for long durations, this research explores a potential solution for long periods (not seasonal) of renewable energy variability.

3. Literature Review

3.1) Iron-air and MDS costs in the literature

The literature on iron-air batteries mostly focuses on the electrochemistry of the battery such as McKerracher et al. (2014), more than its uses and economics. Most studies that discuss iron-air batteries in particular, are led by researchers involved with Form Energy such as Woodford et al. (2022). They argue the reason for using an iron-air battery as a potential way to reach ultra-low cost energy storage, is that the chemical cost of batteries acts as a floor, which for iron-air batteries in theory is very low, as low as 1.5$/kWh (ibid). However, Ziegler et al. (2019) shows that low chemical costs do not necessarily lead to low energy capacity costs giving the example of sodium-sulfur. It is clear though that having such as low chemical cost is already a theoretical advantage for reaching ultra-low energy costs, with low energy capacity costs being key to reduce total system costs (Sepulveda et al. 2021).

Other studies attempt to estimate the energy costs needed for MDS and LDES to be competitive. To be able to deliver cost-competitive baseload electricity, storage would need to reach costs of 20$/kWh according to Ziegler et al. (2019). To compete with peaking plants this cost would have to decrease even further (ibid). However, the technology they use to represent storage able to cost-effectively store for 100 hours has a round trip efficiency (RTE) of 75%, which is much higher than the MDS modelled in this paper. Whilst RTE is not as important for longer duration storage, lower RTE still represents higher costs (Mantegna et al. 2024). Similar studies have similar price ranges, albeit slightly lower in certain cases with capital costs needed reaching single digits per kWh to displace firm generation such as gas with CCS (Sepulveda et al. 2021) (Albertus et al. 2020). Most studies of this nature tend to focus on the US, which could yield different results in other regions.

Finally, another white paper modelling MDS in the GB power sector for 2030 explores least-cost resource portfolios (Form Energy 2024b). However, their paper aims to find what portfolio of resources would minimize total costs in a theoretical scenario that achieves a zero-carbon power sector, instead of focusing on how cheap MDS needs to be to be financially viable in GB.

3.2) Modelling LDES

Modelling and interest in longer durations of storage is growing, yet many long-term planning studies do not currently implement or accurately model these technologies. (Go et al. 2024) (BEIS 2022). Many argue that best-practice energy modelling for LDES needs to use linked time periods to properly capture multi-day energy shifting, ideally with an 8760 hourly resolution (Mantegna et al. 2024). Some argue that the value of LDES may be underestimated by grid planning tools due to not taking a multi-year focus into account (Dowling et al. 2020) and taking storage balancing horizons of only one day (Sanchez-Perez et al. 2022).

Furthermore, existing models can accurately model the annual average level of wholesale prices, but potentially do not accurately model the increasing variability in prices that comes with VRE (Mendes et al. 2024). Thus, inaccurately factoring for the variability of renewables, can overestimate renewables profits, and underestimate the profitability of storage (ibid).

Guerra et al. (2024) analyse LDES' value to a system based on the type of dispatch model used, finding that a model with transmission constraints results in LDES reducing costs further. However, they only consider LDES with a maximum duration of 15 hours and so do not model for multi-day energy storage. Most studies however attempt to use capacity expansion models to capture LDES' full value to a system (Mantegna et al. 2024).

Other papers use production cost models, only using a 168-hour optimization horizon however (Thatte et al. 2024). The former paper gives a value for the amount of arbitrage revenue made per MW for LDES in ERCOT. Furthermore, they use a 192-hour rolling approach to simulate the year, and thus do not optimise for a continuous period of 8760 hours directly, which is more accurate but computationally intensive (Sanchez-Perez et al. 2021).

Most of these studies address: "given these assumed costs, what value does LDES bring to a system?". This paper focuses on: "How cheap does a technology need to be, to become economically viable and support decarbonization." Silva et al. (2024) similarly attempts to answer the latter question. They model 100-hour LDES for California's grid in 2050, using 8760-hour temporal resolution. However, their focus is slightly different as they look at how cheap MDS would need to be, to attain a certain annual level of system costs. When taking full system costs into account, they find that boundary costs need to reach single digits per kWh to keep the same system costs as their scenario without LDES. They do however include significantly more capacity from other shorter storage durations, which could decrease the value and revenue of MDS.

When it comes to LDES modelling for GB, modelling by LCP Delta that investigates long duration energy storage in the UK, finds that to maximise system benefits, assets/technologies with longer durations of storage capacity should be pursued as a priority, due to their ability to provide energy during long-periods of low renewable generation (DESNZ 2024a). In their modelling, LCP Delta find that the longer the duration of storage, the larger the impact on emissions (LCP Delta 2024). However, iron-air MDS was not modelled in this report due to its technology readiness level (TRL).

Furthermore, a paper has modelled pumped hydro LDES in Scotland to see how it impacts system costs in 2050, which includes 100-hour storage configurations (Pudjianto & Strbac 2022). Most of the system cost savings from LDES comes from a reduction in low carbon generation (CCS, nuclear, hydrogen-based generation). Other savings include network reinforcement costs, and decreasing network congestion. They also find that the longer duration configuration (100 hour) doubles the benefits compared to lower LDES durations, but that having a high power rating is also beneficial. LDES is more effective at capturing excess wind generation than short duration, as the energy storage volume matters more than the power rating. However, the multi-day pumped hydro technology modelled has a much higher efficiency (75%) than the iron-air batteries modelled in this paper (42%), which would reduce its potential benefits. Finally, they also modelled 2 GW 200 GWH long duration storage to see how it deals with week-long stress events and find that extending the stress period from 3 days to 1 week doesn't change the asset's value much, and that extending the stress period to a couple of weeks, reduces the system benefits that MDS brings due to low power capacity.

Finally, a Royal Society paper examines the need for long duration energy storage in 2050 (Royal Society 2023). Some technologies that can discharge for a day or two are modelled, albeit with different efficiencies. However, the focus of the paper is different as it quantifies the need for LDES based on future demand, with capital costs being assumed instead of looking at how cheap multi-day energy storage needs to become.

In summary, few models use 8760 hourly resolutions whilst implementing multi-day energy storage, especially for GB, which is a novelty this paper aims to pursue.

4. Methodology

To acknowledge the uncertainties of the GB power sector in 2030, this paper develops a wide variety of plausible scenarios following ENTSO-E, National Grid and Bloomberg New Energy Finance projections.

With the modelling results, the paper first looks at the potential benefits MDS brings by comparing scenarios with and without MDS. Then it determines how cheap MDS would need to be to reach financial viability and if it needs capacity market payments. To do this, the profitability of MDS from arbitrage in the wholesale market is calculated for each scenario, and subsequently the capital costs needed in order to be profitable are determined ("breakeven capital costs").

Finally, there will be a discussion of the results and potential policy implications regarding MDS as a potential solution to help decarbonise the power sector.

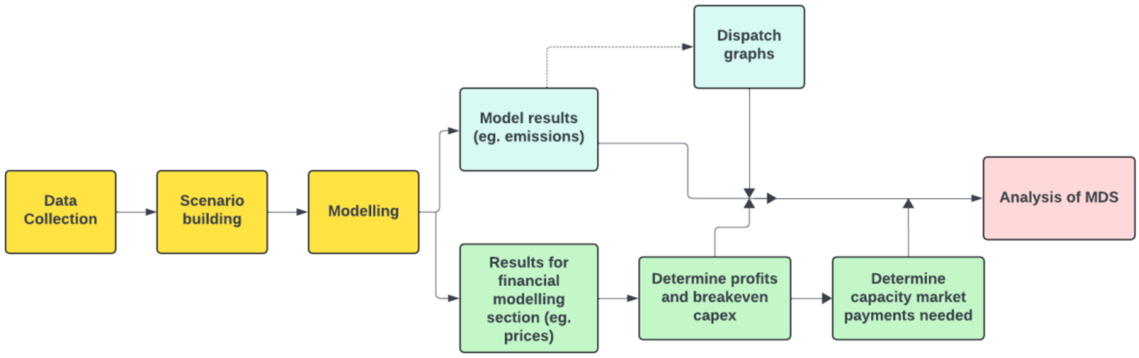

Figure 1: Methodology flow diagram

4.1) EuroMod electricity market model

This paper uses EuroMod, which is a dispatch electricity model (Mendes et al. 2024). EuroMod was chosen for this research, as it is a model that aims to provide more accurate electricity prices, and importantly for this paper, more accurate storage revenues. Furthermore, using a model that also considers the European electricity market, instead of solely looking at GB, properly takes interconnectors into account by including potential balancing from international trade (Collins et al. 2018), which increases price accuracy.

EuroMod enhances a classic linear dispatch electricity model by changing the total system cost function from a stepwise linear form to a quadratic form, and adding a linear post-processing stage. This allows the model to better represent daily price variation, and thus price spreads which is key to determine accurate storage revenues. The model integrates a zonal European market structure which mimics the market clearing mechanism, accounting for power system and network constraints. This paper will give a short explanation of the working of the model, however a complete explanation of the details of the model can be found at Mendes et al. (2024).

EuroMod is a bottom-up model of the European interconnected power system, which covers 27 countries: Austria, Belgium, Bulgaria, Czech Republic, Switzerland, Germany, Denmark, Estonia, Spain, Finland, France, Great Britain, Greece, Hungary, Ireland, Italy, Lithuania, Latvia, Netherlands, Norway, Poland, Portugal, Romania, Sweden, Slovenia, and Slovakia. Each country is represented as an individual aggregated node, not taking within-country transmission into account.

For every hour of the year (8760 hours), it matches demand and supply to determine a clearing price, whilst minimising total system costs with respect to dispatch, interconnectors and storage. Total system costs are the sum of variable costs, electricity curtailment and lost load costs.

The model includes individual generation and storage technologies, including 6 generation and 4 storage technologies (lithium batteries and 3 types of hydro). However, this research has added MDS, represented by iron-air batteries, and has made the distinction between CCGT and OCGT capacities for GB, in order to better represent peaking plants. This can help see the interactions between long duration storage and peaking plants.

There are operational constraints on hydro, gas for combined heat and power and thermal plant cycling. Unit commitment of individual power stations and optimal load flow are not modelled. However, unit commitment costs such as startup costs of different thermal technologies are included to try and mimic unit commitment temporal constraints.

EuroMod proposes two improvements to the total system cost function to account for generators having imperfect behaviour:

1. to allow generators to bid or to sell electricity at prices which deviate from their average variable cost
2. To apply a linear transformation on the resulting modelled prices so that they better reflect the volatility of prices seen in real power markets.

EuroMod is written in GAMS and solved using CPLEX. The dispatch across 27 countries for one year of 8760 h can be solved on a desktop computer in about 15 min.

This research focuses only on the potential revenue from arbitrage in the wholesale market using EuroMod, not including ancillary services and other markets which should represent significant portions of the revenue for LDES (Carbonell & Moreira 2023). Due to uncertainty with the future of certain markets and policies such as the capacity market, only the wholesale market was directly modelled. However, based on certain scenario results, it will explore capacity market revenues needed to reach a certain internal rate of return outside the model.

Negative pricing in the model

Negative pricing results can be represented in two ways. Firstly, curtailment costs are set at 65€/MWh to represent the subsidies generators lose if they curtail, and hence recover by selling at negative prices (Mendes et al.2024) (Drax 2024). Thus, negative prices can be capped at -65€/MWh as this represents the point where the subsidies generators receive for generating, would no longer cover the cost of selling at a negative price, and thus generators wouldn't sell below this. However, these subsidies are supposed to represent Renewable Obligations (ROCs), where currently 30% of electricity generation receives these subsidies (HM Government 2023). However, the ROCs scheme has closed applications in 2017 (some in 2019), and the subsidies will end in 2037 (ibid). Therefore, since only a section of generators receives ROCs, only part of the renewable generators would follow this cap logic of not selling below -65€/MWh. Furthermore, as capacity increases, fewer generators in the wholesale market would act according to this logic as they don't receive ROCs.

Therefore, the second way to represent negative pricing is to simply follow the results from the linear transformation, which do not cap negative prices at -65€/MWh. Prices can go even lower in this case, with storage benefitting from further low prices to charge. For example, intraday prices reached £-120/MWh (around -142€/MWh) at a certain point in 2023 (Modo Energy 2023). Thus, both results where prices are capped at -65€/MWh and where prices can go below -65€/MWh will be shown and discussed to see how negative pricing can affect MDS profitability.

4.2) Calculating the profitability and breakeven capital costs of MDS

The short-run profitability of MDS is calculated from: the difference between the revenue from discharging (discharge volume per hour multiplied by price at that hour, summed for 1 year) and the costs from charging (charging volume per hour multiplied by price at that hour, summed for 1 year). This calculation does not take other variable costs and fixed costs into account such as maintenance.

Then, calculating the breakeven upfront capital costs of MDS, can be found where the net present value (NPV) is equal to zero, given: profits, the lifetime of the MDS asset, and different discount rates. Since MDS could probably act as a source of reliable energy due to its ability to store for several days, it might want or even need to secure capacity market payment contracts (Aurora Energy Research 2022). Therefore, this paper also calculates at what price would capacity market payments have to be to reach a certain IRR. Two scenarios were modelled with capital cost assumptions taken from Form Energy (2024b). This section therefore answers: "Based on capital cost projections from Form Energy, and profits found from modelling, how much extra revenue is needed to reach certain IRR values".

Since the model and data used in this paper are in Euros (€), all results will be expressed in Euros, except for certain cases to provide better comparisons for GB in Sterling (£) such as capacity market payments.

4.3) Data

The main sources of data for 2030 projected capacities are from ENTSO-E (2024a) and National Grid ESO's Future Energy Scenarios (2024).

Climate Years

The two climate years selected were 2009 and 2010. The year 2009 is the year ENTSO-E run for their capacity expansion model as they deem it to be the most representative climate year for Europe (ENTSO-E 2024b), and thus has been chosen as the baseline scenario climate year for this research. The year 2010 was chosen to represent a low-wind year in GB, with it being a 1-in-50 low-wind year, and was also used by AFRY in their report to the Climate Change Committee in their modelling (AFRY 2023).

Hourly data

Data used in the model incorporates hourly time series for demand, renewable generation and water inflows (Mendes et al. 2024). Hourly projected load and demand profiles for 2030 are sourced from ENTSO-E (2024). Hourly renewable generation for wind and solar is calculated by multiplying the 2030 offshore wind, onshore wind and solar PV capacities by their capacity factor from the selected climate years. This hourly weather and capacity factor data was sourced from Renewables.ninja, a tool developed by Staffell and Pfenninger (2016).

Fuel and carbon prices

Projected fuel prices are taken from ENTSO-E (2024a) and National Grid ESO (2024). Scenarios with both "high" and "low" gas costs are used to acknowledge the wide uncertainty in future gas prices. The high fuel costs (used in baseline scenario) come from National Grid's 2024 Future Energy Scenarios, and the low fuel cost from ENTSO-E. ENTSO-E and National Grid's baseline case have very similar carbon prices for 2030, with ENTSO-E being chosen.

Battery storage

Lithium battery storage projections used come from ENTSO-E (2024a) for most European countries, and Bloomberg New Energy Finance (BNEF), a commercial consultancy, for certain countries which includes GB (BNEF 2022) (BNEF 2024). "High" and "low" battery uptake scenarios use data from ENTSO-E, and National Grid ESO (2024) respectively.

The battery duration is 4 hours, with a 87% round-trip efficiency (ENTSO-E 2024b).

Iron-air (MDS)

Iron-air batteries, which represent MDS in this paper, have a duration of 100 hours, with a 42% round-trip efficiency in 2030 (Form Energy 2023b). For the NPV calculation, a 20-year lifetime of the asset was chosen (Form Energy 2024). Results are shown per GW of MDS capacity, however scenarios with MDS include 2 GW in order to better represent some self-cannibalisation of revenue that would occur when storage capacity increases (Schmidt & Staffell 2023).

Other important capacity assumptions

All generation and interconnection capacities come from ENTSOE, except for offshore wind which is capped at 50GW to represent the Government's target (CCC 2023). ENTSOE does not explicitly give biomass capacities and thus National Grid's projections for biomass were chosen. Nuclear capacity in ENTSOE's scenario is 5.5GW, which is 1GW higher than National Grid's. Realistically, this assumes Hinkley Point C provides

3.2 GW, Sizewell B provides 1.2 GW, and one of the two reactor sites set to close in 2028 is extended. To remain consistent with ENTSOE's capacity expansion model results, their nuclear capacity projection was chosen.

OCGT

Furthermore, this paper made the distinction between CCGT and OCGT to better represent peaking plants. OCGT capacity data comes from ENTSOE (2024), as well as the efficiency (ENTSO-E 2020). Estimated variable costs for OCGT use BEIS (2020) and Vatopoulos et al. (2012) as sources. Finally, to better represent the peaking abilities of OCGT, lower startup costs were added, with estimates from Oberg et al. (2022).

4.5) Scenarios

Baseline scenario

The baseline scenario uses 2009 climate weather data. The main assumptions to consider here are the climate year, the fuel cost, the battery capacity and offshore wind capacity (See Appendix).

Offshore Wind 50GW target not met

In this scenario, the 50 GW offshore wind in 2030 target is not met, with GB only reaching 34.4 GW. This figure is from ENTSOE's 2022 projections for 2030. Furthermore, the current installed offshore wind capacity in the UK is around 15 GW with another 13.3 GW in construction or committed through government support, leaving a 21 GW gap (Ember 2024). Thus, this scenario is plausible if offshore wind rollout is slow.

Low fuel price

This scenario is simply the same as the baseline scenario, however gas prices are 22.6€/MWh instead of 40.3€/MWh. The former figure is used by ENTSOE and comes from the IEA's 2022 Announced Pledges Scenario (IEA 2023).

Low Wind year 2010

In this scenario, the climate year used is 2010 instead of 2009, but with all the baseline scenario assumptions. For GB, this year is marked by historically low wind, and thus low wind capacity factors, as well as a particularly cold December month (AFRY 2023).

Stress event 2010

Similarly to AFRY (2023), an extra sensitivity test was run representing a wind lull stress event. The 30-day period with the highest residual demand from 2009 to 2019 was in Winter 2010 (AFRY 2023), which was the period chosen for this test. To represent a wind lull event, a capacity factor of 0.16 was chosen, as it was the lowest 30-day capacity factor from 2009 to 2019 in the UK, which happened in Summer 2018. In summary, this event combined low renewable generation and high residual demand during a 30-day period.

High and Low Lithium battery uptake

A scenario where lithium battery storage uptake reaches 24.6 GW in 2030 was first modelled, which represents a 5 GW increase compared to the baseline scenario, and comes from National Grid's "Electric Engagement" future energy scenario (National Grid ESO 2024).

A scenario where lithium battery storage uptake reaches 15 GW in 2030 is then modelled, which represents a 4.5 GW decrease compared to the baseline scenario. This figure comes from ENTSOE's capacity expansion model projections for 2030 (ENTSO-E 2024a).

No MDS

Finally, to be able to see the effects MDS has on different outcomes such as emissions and curtailment, counterfactuals of the scenarios without MDS have been modelled for clearer comparisons.

5. Results

5.1) Impact of adding MDS to the Baseline scenario

Emissions

Without MDS, the CO_2 emissions from the power sector are approximately 6,7 $MtCO_2$ in 2030. This figure is significantly lower than ENTSO-E and National Grid results, which project 14 $MtCO_2$ and 17 $MtCO_2$ - 28 $MtCO_2$ respectively (ENTSO-E 2024a) (National Grid ESO 2024). This is probably due to imperfect foresight and other constraints which increase how much fossil fuel plants need to be dispatched. However, National Grid's five-year forecast have emissions dropping to zero in 2030, aligning with the Government's new target (Labour Party 2024).

Adding 2 GW of MDS, reduced emissions to 6 $MtCO_2$ in 2030, which is approximately a 0.35 $MtCO_2$/GW reduction or a 5% reduction in this scenario.

Curtailment

Without MDS, the total curtailment is around 15 TWh in 2030, which is 5.5% of total yearly renewable generation. ENTSO-E project 25 TWh of curtailment, whilst National Grid's scenarios range from 10 TWh to more than 31 TWh.

Adding 2 GW of MDS, reduced curtailment to 12.3 TWh, representing 4.4% of total yearly renewable generation. Therefore, MDS reduced 0.5% of annual curtailment per GW of capacity. Figure 2 shows how 2GW of MDS reduces weekly curtailment during a year.

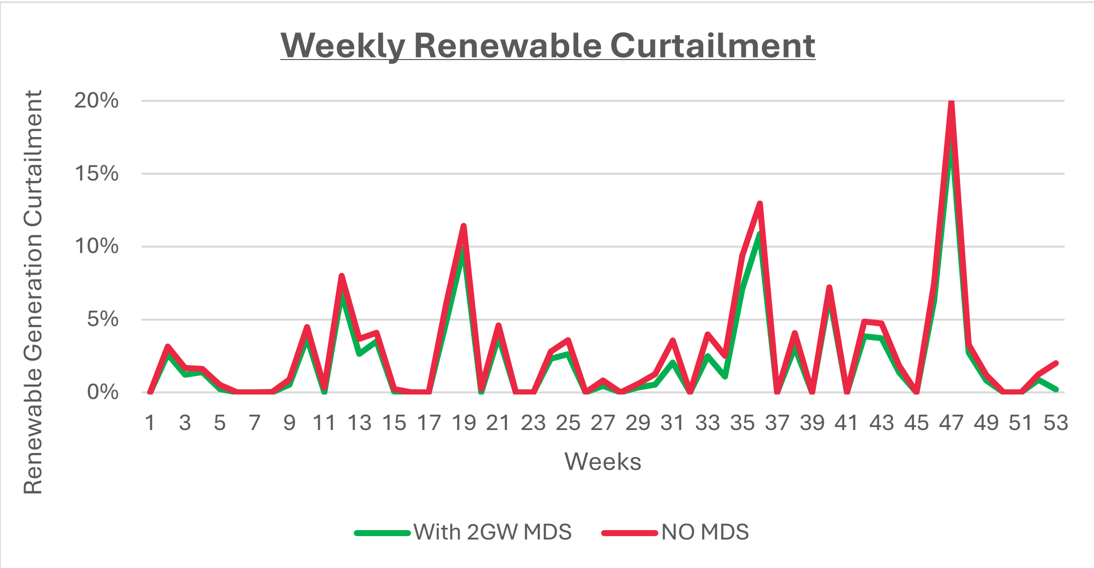

Figure 2: Weekly Renewable Curtailment Baseline

Wholesale prices

If prices are allowed to go below -65€/MWh, then the effect of adding 2 GW on prices is negligible. With negative pricing capped, the average annual wholesale price increases by 2€/MWh, from 48€/MWh to 50€/MWh. However, this effect is expected as adding a source of electricity demand to fixed supply capacities would naturally increase the price.

Fossil fuels

In the baseline scenario, which follows a 2009 climate year, no peaking plants (OCGT or Oil) are dispatched, whether MDS is added or not. Adding within-country transmission constraints and unit commitment temporal constraints would probably see peaking plants dispatch a few times. When it comes to gas (CCGT), without MDS the yearly generation is 17.6 TWh or 5.2% of total electricity supply. When adding 2 GW of MDS, the quantity of gas decreases to 16 TWh or 4.7% of all electricity supply. In other words, per GW of MDS, around 0.8 TWh of gas gets displaced.

Figures 3 and 4 show more clearly how MDS dispatches during a one-week sample in January.

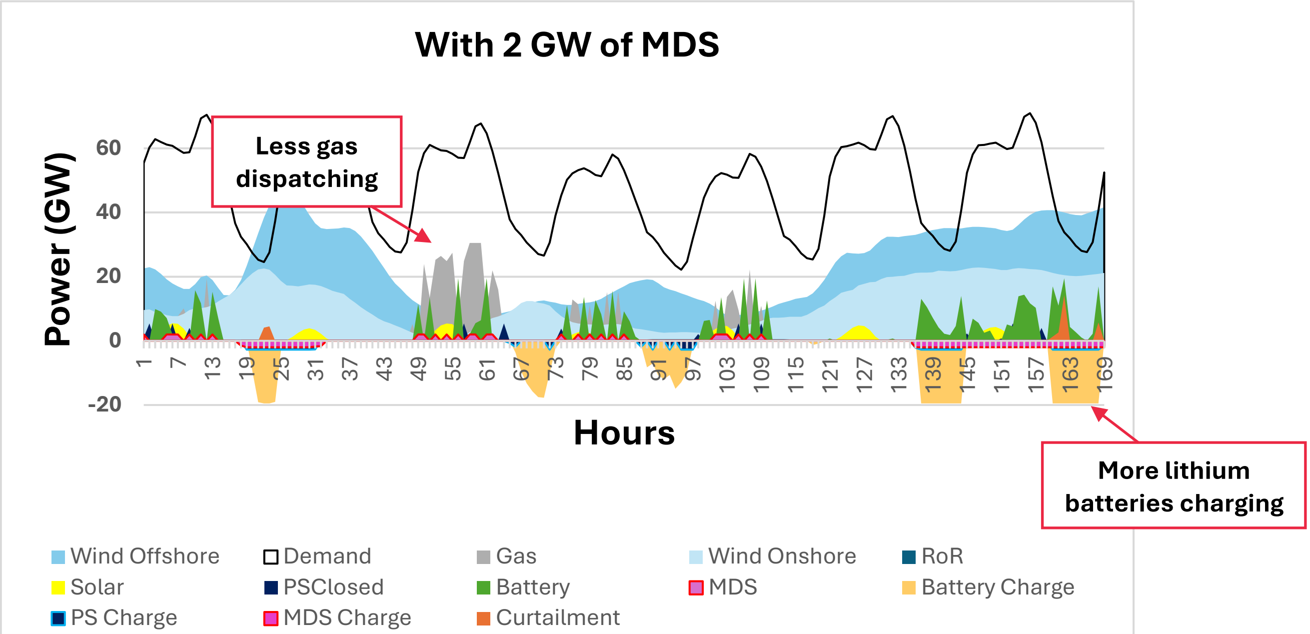

Figure 3: Dispatch with MDS

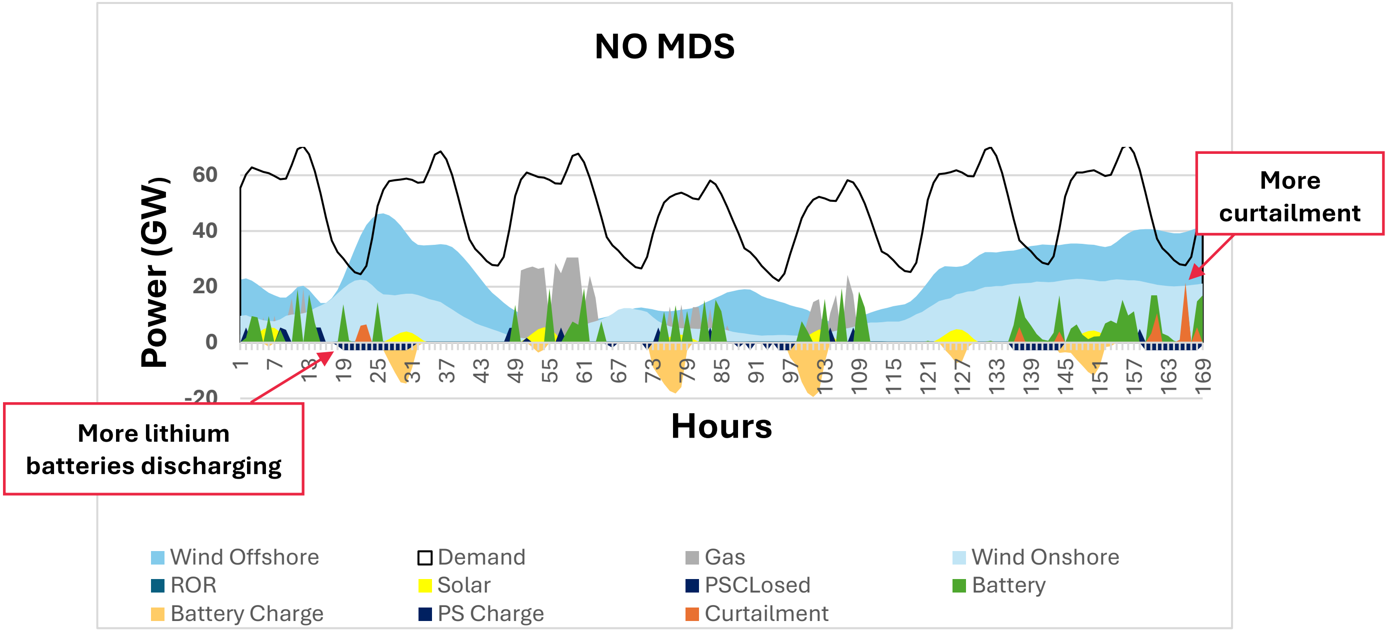

Figure 4: Dispatch without MDS

5.2) Scenario: 50 GW Offshore Wind not achieved

Emissions

Due to lower renewable capacity and thus generation, emissions with MDS reach almost 8.9 $MtCO_2$. Without MDS this figure is around 9.5 $MtCO_2$, which is a smaller decrease in CO_2 abated per GW compared to the 50 GW scenario. If there are more excess renewables to charge with, then more can be abated per GW.

Curtailment

Naturally, lower wind generation decreases how much wind can be curtailed. Thus, with MDS, curtailment reaches 3 TWh, which is 1.3% of total renewable generation. Without MDS, curtailment reaches 4 TWh, due to there being less wind to curtail in the first place.

Wholesale prices

At 34.4 GW of offshore wind capacity and with MDS, average wholesale prices increase to around 67€/MWh, much higher than if the 50 GW offshore wind target is met. With MDS the peak price is 136€/MWh compared to 150€/MWh without MDS, suggesting MDS can replace expensive generation when prices are high.

Fossil fuels

Due to lower renewable generation, gas is dispatched much more at 23.5 TWh, which is 7% of total supply. Without MDS, this figure goes up to 25 TWh, roughly 7.5% of total supply.

5.3) Low fuel price scenario

Emissions and Fossil fuels

Low fuel prices heavily increase the use of gas, which increases emissions. The amount of gas dispatched essentially doubles compared to the baseline scenario to 32.5 TWh, which is almost 10% of total electricity supply. Thus, with lower gas costs, emissions reach 12.3 $MtCO_2$ with MDS.

However, when looking at the effects MDS has within the low fuel costs scenario, MDS does not seem to reduce emissions according to the models' results. The quantity of gas dispatched is slightly higher with MDS, at around 32.5 TWh. Without MDS this number is 32.2 TWh, which is slightly lower. Therefore, the results find that emissions increase slightly with MDS: 12.3 $MtCO_2$ with MDS and 12.2 $MtCO_2$ without MDS. This can seem counter-intuitive as MDS charges with renewables, to then discharge and displace gas which would decrease emissions, as the other scenarios show.

However, some studies find that storage can increase emissions by raising demand, which can be supplied by high-carbon but cheaper sources such as coal, to later discharge and replace more expensive but lower-carbon fossil fuels such as gas (Beuse et al.2021). However, this does not seem to be the case in this scenario. Furthermore, since storage suffer from inefficiencies, this can change the load profile and alter the generation mix, and thus make it more carbon intensive (ibid) (Pim et al. 2021).

Nevertheless, the results do not show any periods where MDS charges with electricity from gas and is therefore not directly increasing emissions from charging. Moreover, results show that MDS decreases gas dispatch in certain periods as the combination between batteries and MDS fully displaces gas. However, these periods of fewer emissions are sometimes followed by periods of even higher emissions, which could partly explain the small increase in overall emissions. Furthermore, adding MDS seems to reduce annual net imports since MDS reduces the needs for imports in this scenario. Yet this reduction in imports in certain periods, seems to increase gas dispatch. To conclude on this point, MDS appears to have shifted dispatch behaviour in a way which results in annual emissions slightly increasing, but this also happens with batteries (see Appendix).

Figure 5 shows a summary of the effect adding MDS has on emissions for each scenario, with this particular scenario differing from the others.

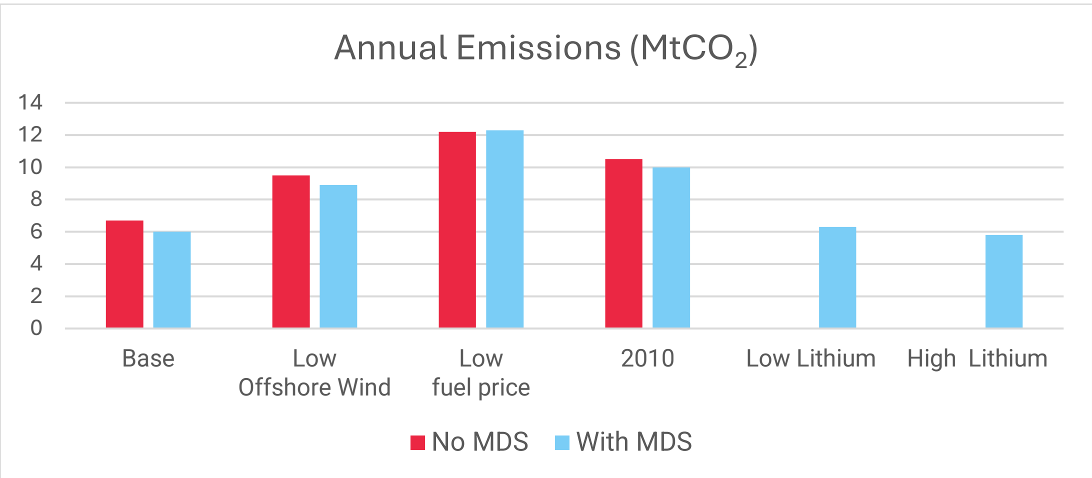

Figure 5: Annual emissions with/without MDS per scenario

5.4) 2010 Climate Year

Emissions

With 2010 climate weather data, emissions increase from 6 $MtCO_2$ in the base 2009 year, to 10 $MtCO_2$. Without MDS, this increases to 10.5 $MtCO_2$. Here MDS reduces emissions slightly less than using the 2009 year due to lower renewable generation using 2010 weather data.

Curtailment

Due to lower renewable generation, there is once again less electricity to curtail with curtailment reaching 8.1 TWh or 3% of annual renewable generation. Without MDS curtailment rises to almost 10 TWh or 4% of annual renewable generation. Figure 6 shows the impact MDS has on curtailment for each scenario.

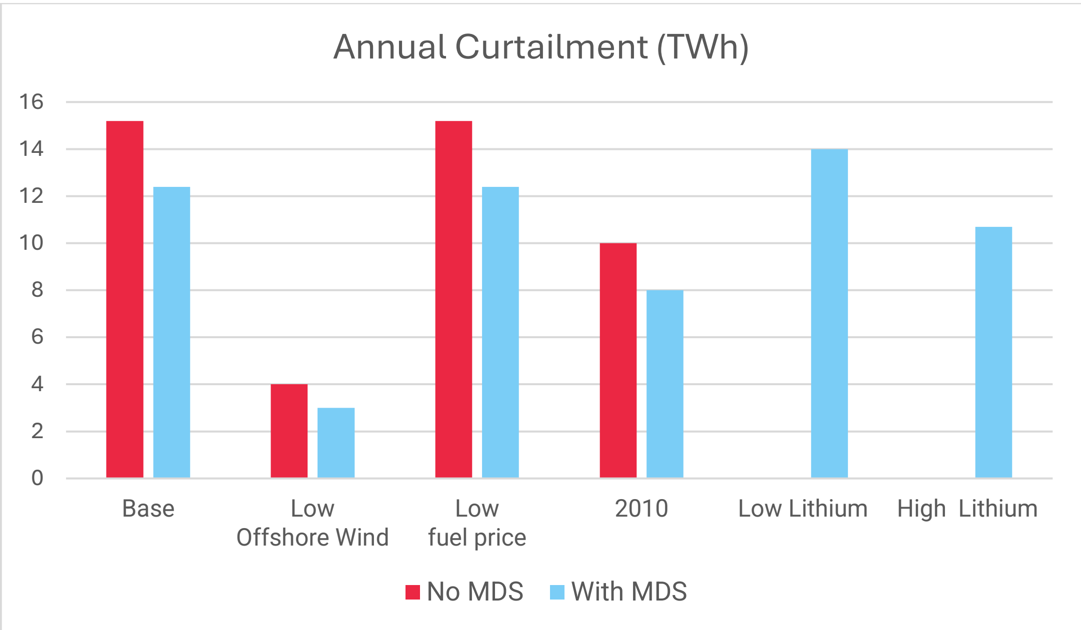

Figure 6: Curtailment with/without MDS per scenario

Wholesale prices

Average wholesale prices are higher in this scenario than the baseline scenario (57€/MWh vs 50€/MWh). Without MDS, 13 hours of "Lost Load" make the prices peak at 1000€/MWh, which is the penalty set in the model for not meeting load, as well as an extra hour peaking at 980€/MWh. This 14-hour period happens in late December due to a combination of high demand (peaking at 76 GW), and low wind capacity factors that reach 3% for a few hours. Adding MDS avoids this period of “Lost load”, with an annual max price of 168€/MWh.

Discharging for long durations

To determine if the issue was just total capacity in that 14-hour period, or if MDS valuably charged before the stress event and discharged during the event, the same scenario but with 2 extra GW of lithium were added instead of 2 GW of MDS. With added lithium batters, there was similarly no “Lost load”, suggesting the stress event was caused more by a lack of power capacity, than energy capacity. However, MDS manages to discharge for 16 hours consecutively in this stress period without the need to recharge, discharging for 32 hours out of 40 hours.

Fossil fuels

In this scenario, gas is dispatched more as renewable generation is lower, reaching 27 TWh with MDS, and 27.3 TWh without MDS. In contrast to the scenarios with 2009 climate year data, peaking plants do dispatch with MDS and without. Without MDS, OCGT dispatches a few times at around 260 GWh per year, and oil at 15 GWh, primarily during high stress events. MDS manages to replace some peaking, with OCGT dispatching a few times at around 180 GWh per year, and oil at 7 GWh.

5.5) Stress Event

By focusing on a 1-week period during the stress event, one can better see how MDS affects other technologies and dispatch.

Figure 7 and 8 show this 1 week period, with and without MDS. The main findings are that MDS reduces gas dispatch “spikes” to charge lithium batteries. Figure 7 shows how MDS discharges during peak load hours, minimising battery discharges. More importantly, two gas “spikes” occur due to high demand from batteries, to meet future high peak load. These spikes are absent when MDS is included, suggesting MDS adds extra energy capacity that minimises electricity generation from gas.

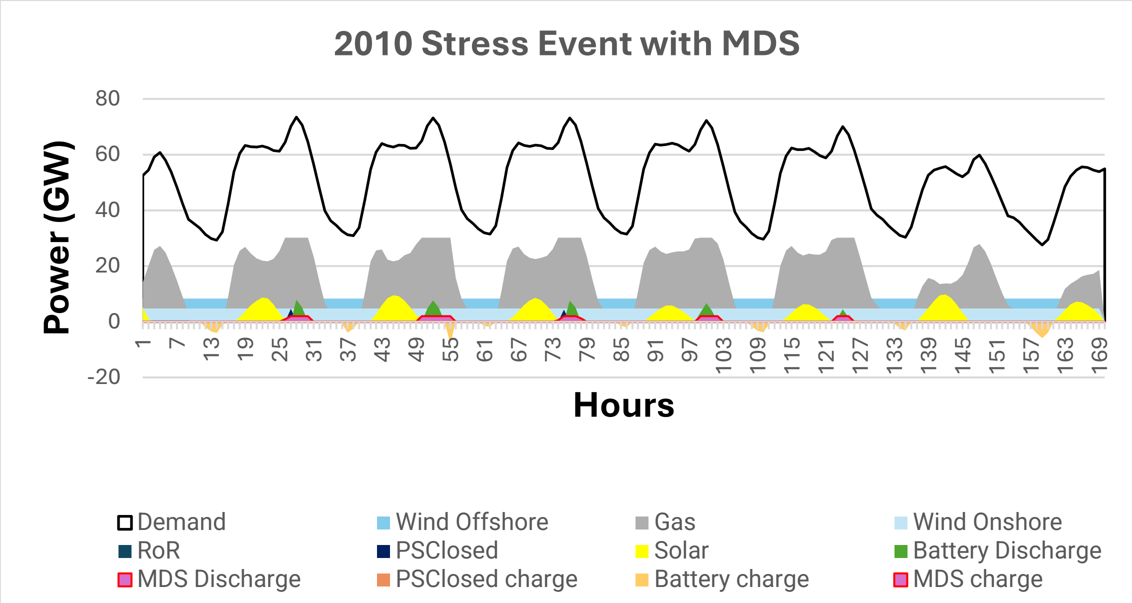

Figure 7: Stress event dispatch with MDS

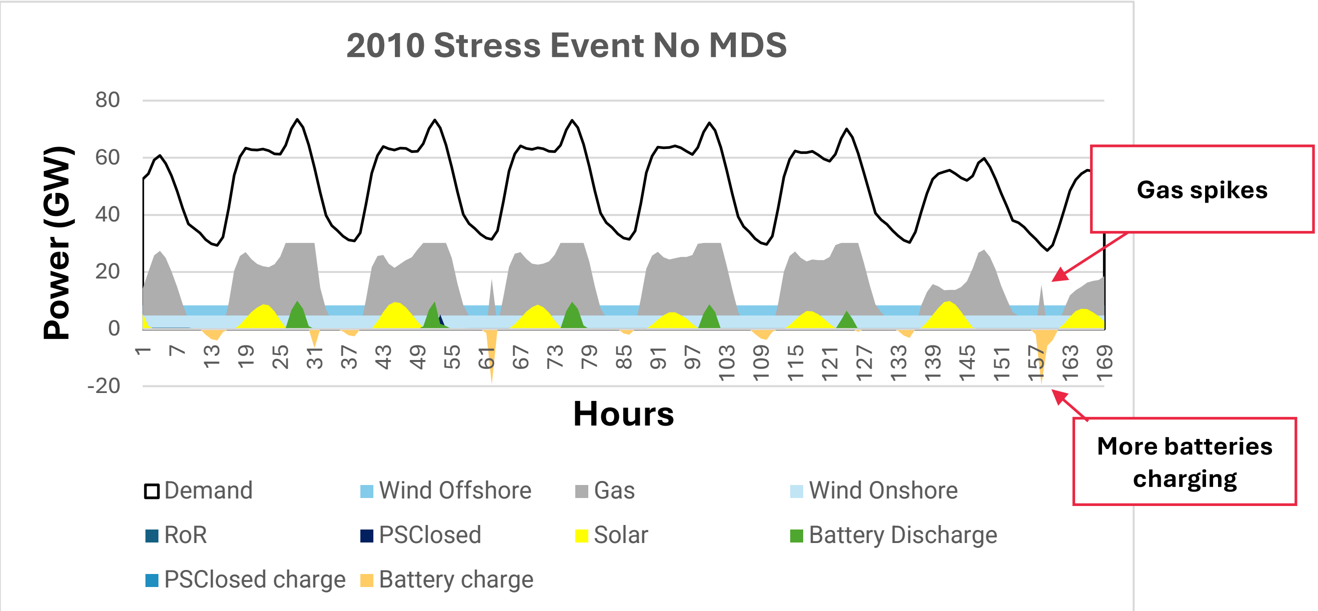

Figure 8: Stress event dispatch without MDS

Quick summary:

MDS reduces curtailment in all scenarios, especially when renewable generation and capacity are higher. More renewable generation also allows MDS to charge and discharge more, which reduces emissions in every scenario except when fuel prices are low as less gas is displaced. Finally, MDS can displace peaking units and provide energy for extended periods during stress events.

5.6) Profitability and breakeven CapEx results

Profits and breakeven capex costs calculated here, only consider arbitrage revenue.

The battery fully cycles around 12 times during the year. This means that MDS will have to make its revenue from fewer discharges, and thus relies more on larger price spreads for arbitrage.

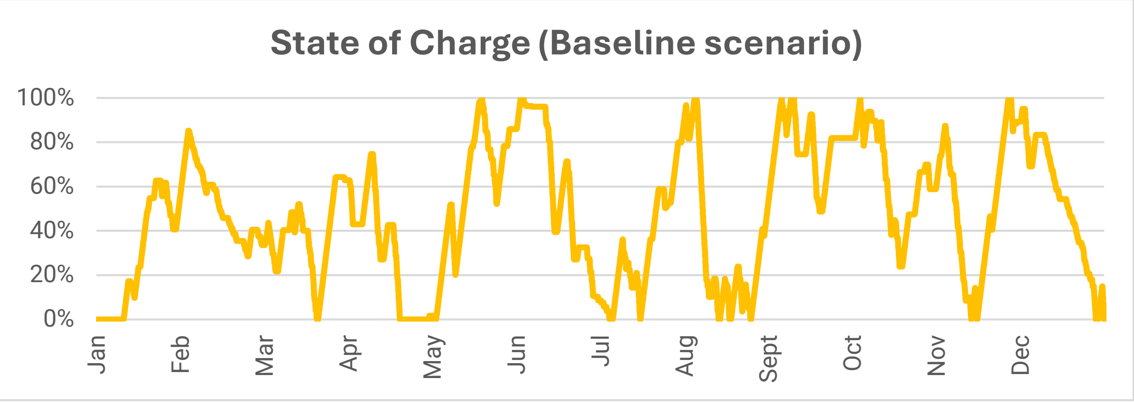

Figure 9: State of Charge of MDS

Baseline scenario: Profits

Profits are 205,000€/MW if negative pricing is capped at -65€/MWh , or 220,000€/MW if negative pricing can go below -65€/MWh. Interestingly, over a third of profits come from charging during negative prices (75,000€/MW if negative pricing is capped, and almost 90,000€ if uncapped). In other words, annual charging costs for the asset are negative, showing that renewables' volatility is important for MDS's arbitrage profits.

Baseline scenario: Break-even Capital cost

Since capital costs of batteries tend to be expressed in kW or kWh instead of MW, results will be expressed in that manner. Results use three discount rates: 5%, 7.5% and 10%.

Firstly, MDS would achieve a positive NPV with a capital cost under 2,600€ per kW, or 26€ per kWh, at a 5% discount rate. Since MDS can store energy cheaply for long durations, it has high power costs and low energy costs. Higher discount rates require lower capital costs around 21€/kWh and 17€/kWh, for a 7.5% and 10% discount rate respectively ("capped" negative pricing). If negative pricing is uncapped, breakeven capital costs can increase slightly to 27€/kWh, 22€/kWh and 19€/kWh, for 5%, 7.5% and 10% discount rates.

Different asset lifetimes would affect the breakeven capital costs. For example, the break-even capital cost increases to almost 31€/kWh for a 25-year lifetime with a 5% discount rate and uncapped negative pricing.

Low fuel costs scenario: Profits and breakeven

Gas prices seem to significantly impact MDS revenue. With uncapped negative pricing, annual profits are 190,000€/MW and 175,000€/MW if capped. With lower fuel costs, gas can become more competitive replacing storage in certain periods. More importantly, storage acts as a price-taker in the merit-order, so if clearing prices are lower due to gas having lower marginal costs, then storage will earn less when discharging. This can be clearly seen in the results as all of the decrease in profits compared to the baseline scenario comes from discharging and not charging revenue.

Due to lower revenue, breakeven capital costs are even lower at around 24€/kWh, 19€/kWh and 15€/kWh for 5%, 7.5% and 10% discount rates respectively, with uncapped negative pricing. These results show the need for extra revenue from other sources, even if Form Energy get their costs down to 20$/kWh (roughly 18€/kWh).

Lithium battery uptake scenarios: Profitability

These scenarios take the baseline scenario, with either higher or lower lithium battery capacity to see how it interacts with MDS.

When lithium battery capacity is lower at 15GW, the profit is 230,000€/MW with uncapped negative pricing, or 215,000€/MW if negative pricing is capped.

When increasing lithium battery capacity to 24.6 GW, some revenue is cannibalised. Indeed, the profit reaches 207,000€/MW (uncapped) or 195,000€/MW if negative pricing is capped.

Although the differences are small, most of the change in revenue comes from charging. Adding/removing lithium battery capacity impacts MDS mostly for charging as it increases demand and thus prices in certain moments, more than necessarily replacing MDS to discharge. Breakeven capital costs for both scenarios can be seen in figure 11.

2010 Climate Year: Profits and Breakeven capital costs

Modelling different climate years is crucial as revenues can fluctuate significantly between years (Royal Society 2023). Profits, with uncapped negative pricing are 167,000€/MW. This represents a 23% decrease in profits from arbitrage between two different years. This inter-annual volatility in arbitrage falls into the ranges found in Schmidt & Staffell (2023), although this looked at lithium batteries. Therefore, annual variability can heavily impact how cheap the technology needs to be.

Indeed, the break-even capital costs are 21€/kWh, 17€/kWh and 14€/kWh for 5%, 7.5% and 10% discount rates respectively. Compared to the 2009 climate year, this represents around a 5€/kWh decrease in capital costs needed to break even, which can seem small, but at these low prices certain costs can be particularly hard to decrease such as chemical costs which can act as a "floor" (Woodford et al. 2022).

Offshore wind target not met: profits and breakeven capital costs

With 34.4 GW of offshore capacity, profits decrease substantially. When negative pricing is uncapped, profits reach 133,000€/MW, and 115,000€/MW when capped. This large decrease in profits largely stems from the decrease in charging revenue whilst prices are negative. Indeed, compared to the baseline scenario, the drop in profit from charging is around 60,000€/MW. Less VRE means that negative pricing will occur less frequently and at higher prices.

In order to break even, MDS would need to have an initial cost of 15€/kWh when negative pricing is uncapped, and 14€/kWh when capped, using a 5% discount rate. At a 10% discount rate, the breakeven capital cost would need to be around 10€/kWh, or 1000€/kW. To put this into perspective with Form Energy's 20$/kWh target, their costs in this scenario and this discount rate would need to be more ambitious and reach around 11$/kWh. However, the model does under-estimate revenues for storage by around 65%, and MDS wouldn't get their entire revenue from arbitrage. Even so, it is clear that higher VRE penetration which increases price spreads is vital for MDS and storage as a whole.

Figure 10 shows a summary of each scenario's profits and Figure 11 the breakeven capital costs:

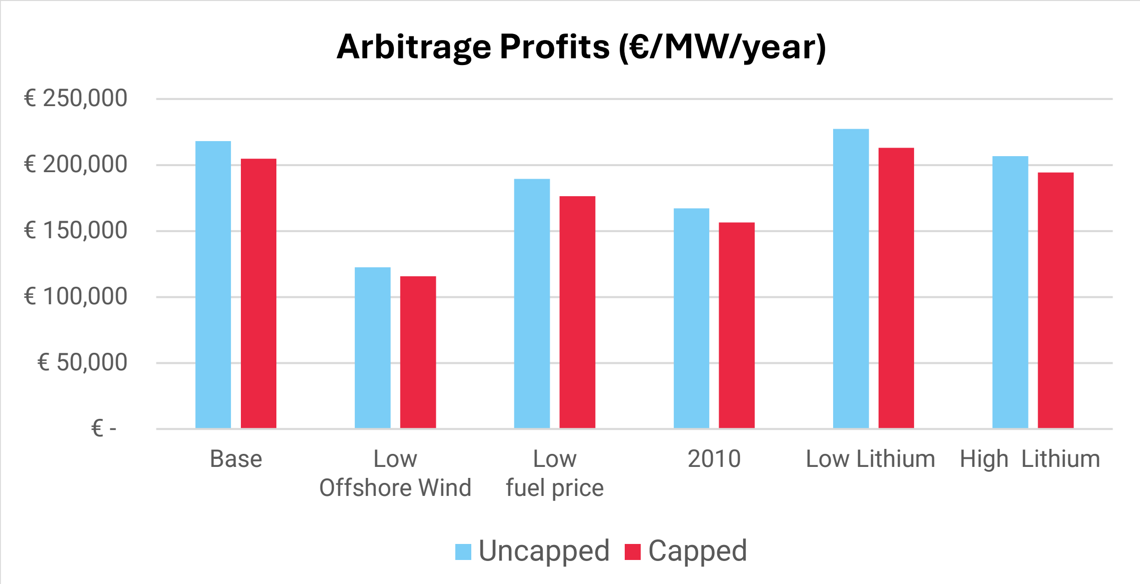

Figure 10: Arbitrage profits per scenario

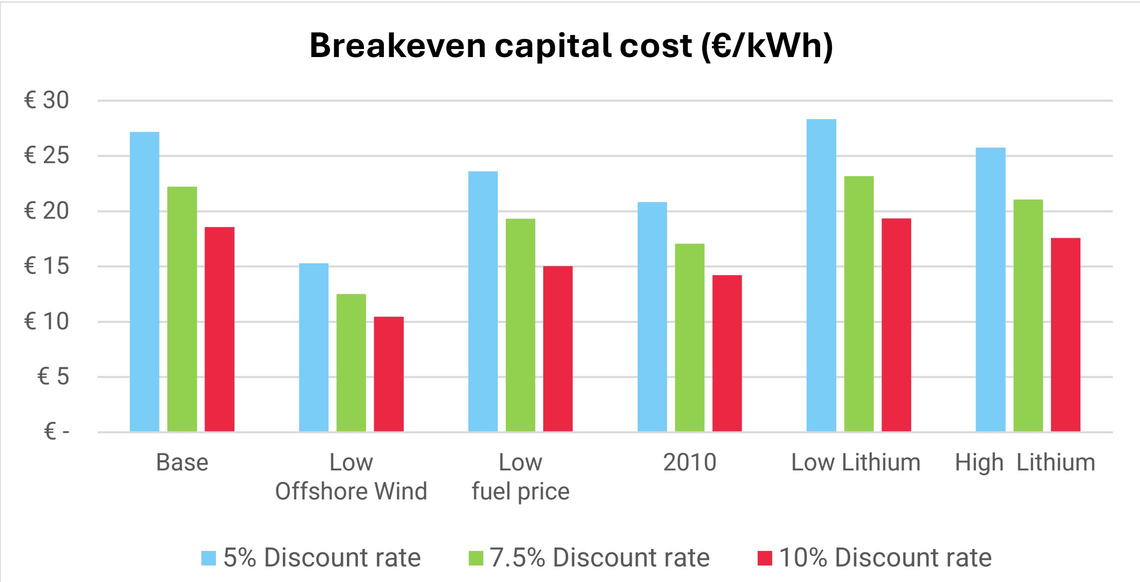

Figure 11: Breakeven capital costs per scenario

5.6) Capacity market payments

Since MDS would want to engage in "revenue stacking" to optimize its revenue (Ho & McNamara 2023), particularly in the capacity market as longer duration storage could provide reliable dispatchability (Albertus et al. 2019), this paper explores at what price would the capacity market need to clear in order for MDS to reach a certain internal rate of return. Furthermore, if assumed capital costs (Form Energy 2024b) are higher than profits, then the results could shed light on extra revenue the assets would need. The internal rates of return selected were 6%, 9% and 11%, which are a range of rates that reflect the energy industry (DESNZ 2023c). Using capped or uncapped negative pricing, gives similar results, but results will be expressed with uncapped negative pricing. The capital cost chosen for this calculation comes from Form Energy's GB study, which shows capital costs in 2030 of £1,970/kW or 2,345€/kW (23.45€/kWh) (Form Energy 2024b). The two scenarios selected were the baseline scenario and the "low fuel price" scenario to represent varying profit scenarios.

To put this into the GB context, these results will be expressed in GBP using an exchange rate of 1 Euro to 0.84 GBP. In the baseline scenario, to reach a 6% IRR, no capacity payments are needed since the NPV is positive solely from arbitrage revenue. However, at a 9% and 11% IRR, the capacity market price would need to be £33/kW/year and £64/kW/year respectively. Whilst for the "low fuel price scenario", the capacity payments needed for a 6%, 9% and 11% IRR are £13/kW/year, £56/kW/year, £88/kW/year.

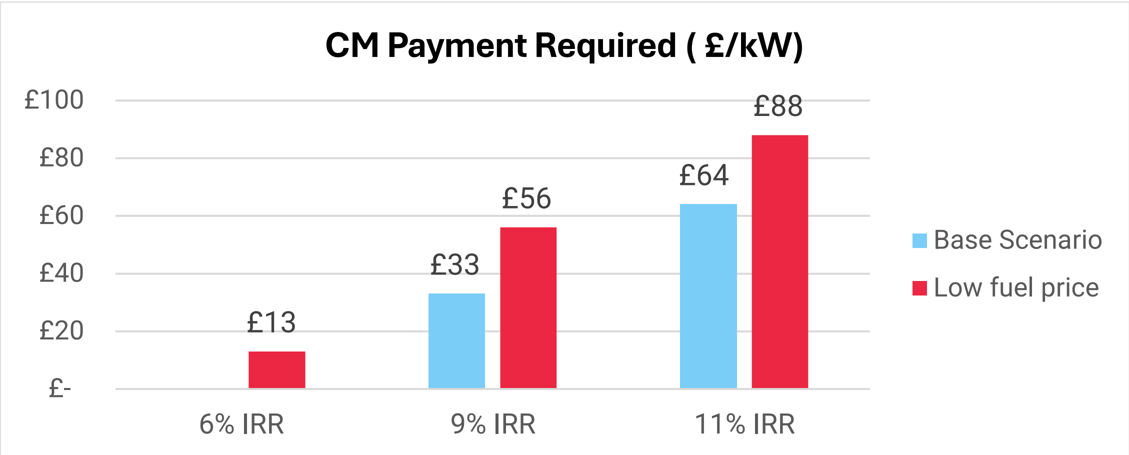

Figure 12: Extra capacity market payments required

Capacity market payment prices in the T-4 auction reached a historical high £65/kW/year (EMR 2024). Therefore, at this price and with a high de-rating factor, this capacity payment price would be enough to reach the selected IRRs for both scenarios and every IRR, except for the 11% IRR within the "low fuel price" scenario. However, arbitrage revenue could slightly decrease when participating in other services to "revenue stack", but this depends on the operational schedule of the asset (Schmidt & Staffell 2023).

6. Discussion

This section will consider the results' wider significance and limitations and set MDS in the broader GB context.

Discussions: results implications

Firstly, the research shows the importance of coupling renewables and MDS to increase its emission reduction potential, as it can capture high levels of curtailed wind to supply in peak periods and displace fossil fuels. Although there are fewer periods of significant wind curtailment as durations increase, the levels of curtailment volume are significantly higher as the length/duration of curtailment increases (Drax 2022), which is why MDS can be effective at reducing total curtailment. In line with previous research from Form Energy, this paper shows that multi-day energy storage reduces curtailment significantly as VRE increases (Form Energy 2024b). Moreover, curtailment from wind farms in 2023 caused constraint payments to reach £300 million, adding £4/MWh of wind generation (Drax 2024). Thus, if we take a bigger system picture, MDS can reduce constraint payments and reduce some system costs when it comes to curtailment and balancing costs (National Grid ESO 2024b). These results are supported by Pudjianto & Strbac (2022), who also find that multi-day energy storage increases system value as renewables are better utilised.

Furthermore, high variability and curtailment leads to an increase in negative pricing. This research shows further evidence of the increase in negative pricing and how it affects storage revenue. The results show high levels of negative pricing as renewable capacity increases, which can constitute a large share of storage's revenue. This is especially the case for longer duration storage as it can capture negative prices for longer periods. Therefore, renewables and MDS act as complements, with MDS further reducing emissions as renewables increase, and renewables increasing MDS profitability.

However, this paper does not focus on total system costs which can show a different picture. Indeed, more VRE penetration increases the market opportunity for LDES, but it also reduces LDES's relative capacity substitution value, which is a key segment of the value LDES brings to the system (Sepulveda et al. 2021). Future research could use a capacity expansion model to explore this, as total system costs could be lower when implementing more MDS and less renewables, but this could affect the financial viability of MDS.

Additionally, the research highlights the impact of gas prices on MDS's revenue and benefits. Since gas sets the electricity price, lower gas prices reduce how much storage can sell their electricity for. It can also displace storage in the merit-order if gas prices are competitive at certain periods. Therefore, to reduce how much gas is dispatched which impacts MDS's ability to reduce emissions, it either needs to be less competitive through pricing (eg. carbon pricing), or some other policies or tools need to be imposed. MDS can become more valuable for the system with lower fractions of natural gas (Dowling et al. 2020).

Furthermore, the arbitrage revenues results are consistent with, albeit higher, other longer duration revenues in the literature and follow the logic that longer durations can earn more from arbitrage due to access to larger price spreads (Wilson et al. 2018) (Zhang et al. 2021) (Mercier et al. 2023) (Schmidt & Staffell 2023). Compared to Thatte et al. (2024), revenues from arbitrage are 2 to 4 times higher. However, it is unclear if this research can be compared as the paper focuses on the US ERCOT market and does not precise the LDES details. Furthermore, it does not take an 8760-hour temporal resolution which can lead to under-estimating value and revenues (Sanchez-Perez et al. 2021). However, none of these papers focus on MDS and GB. Therefore, the results found in this paper add to the literature when it comes to quantification of potential revenues for multi-day energy storage.

Finally, the results show how MDS can successfully provide energy for long periods of time during stress periods such as in the 2010 scenario, where MDS discharged for 32 out of 40 hours. The ability to provide power for periods that significantly exceed lithium batteries' capabilities, shows how valuable longer storage durations can be. However, the optimal amount of MDS to provide reliable power in GB was not studied in this paper, but it is a potential future consideration which Form Energy has modelled solely focusing on GB. Due to the paper using a dispatch model and not a capacity expansion model, answering the question of what the potential of MDS in 2030 GB is has been limited to certain benefits and costs. Including investment costs could show further benefits or shortcomings of MDS by optimising full system costs. For example, Dowling et al. (2020) and Form Energy (2023a) find that LDES reduces system costs and avoids certain renewable generation “overbuilding”, as well as land use savings. However, overbuilding renewables, facilitated by transmission, could still be cheaper in certain cases than storage (Dowling et al. 2020).

Discussions: Limitations

Firstly, the modelling in this paper does not account for within-country transmission constraints, which is a limiting assumption for the GB power sector as much of the wind capacity comes from the North, whilst the demand is more concentrated in the South (CCC 2023). Several notable transmission boundaries limit how much capacity can be transmitted which can increase curtailment, affect prices, and increase gas dispatching (Regen 2022). Therefore, this limitation can impact the potential revenues and benefits of MDS, as Dowling et al. (2020) and Form Energy (2021) show.

Although using quadratic programming with linear transformation on prices increases the accuracy of price variability and thus storage revenues, it still under-estimates arbitrage revenues for storage. Unmodified linear programming can under-estimate arbitrage revenues for storage by 99% (Mendes et al. 2024). With the programme used in this paper, profitability of storage for lithium batteries is under-estimated by approximately 60%, and 67% for sodium sulphur which is supposed to represent a slightly longer duration storage in Mendes et al. (2024). Thus, it is possible that for even longer durations such as MDS, EuroMod may under-estimate the arbitrage profits further. Future research could improve price variability by including transmission constraints and temporal constraints for unit commitment.

Although the model attempts to mimic imperfect behaviour, it still assumes decisions are made with perfect foresight of prices. In reality, decision-makers do not have complete information of what will happen in the future and rely on estimations (HydroTasmania 2019). With imperfect foresight revenues would not be optimised, which Guerra et al. (2024) discuss. HydroTasmania (2019) show that perfect foresight overestimates storage value and arbitrage revenue, however as storage durations increase, this overestimation decreases. Therefore, MDS revenues would be negatively affected by the perfect foresight assumption, but less than short duration storage. The impact on storage revenues could be between a 10-20% decrease (Schmidt & Staffell 2023), which is supported by results for storage with a 50 hour duration (HydroTasmania 2019). In summary, the revenues found when it comes to optimal behaviour, represent an upper limit, but the perfect foresight assumption shouldn't invalidate the results.

Furthermore, small details could improve the accuracy of the MDS modelled, such as differentiating between charging and discharging efficiencies, energy capacity degradation, including self-discharge is which stands at 10% (Form Energy 2024b). This could have a small impact on the results (Guerra et al. 2024). Furthermore, storage starts at a 0% state of charge which means it would miss out on potential revenue in the month of January. Finally, a 20-year asset lifetime was chosen, yet other Form Energy papers project a 30 year lifetime (Form Energy 2024b) which would increase the total revenue of the asset and thus breakeven capital costs would be higher.

Additionally, single weather years were chosen. Revenues can highly differ between weather years which the results showed. However, this does not invalidate the results as many modelling exercises such as ENTSOE-E (2024) and AFRY (2023), also use single weather years. Furthermore, two different weather years were modelled to increase results' validity. Future research could include more weather years and a high wind year, as the weather years modelled were on average less windier years (AFRY 2023).

Including DSR and thus making demand flexible would make the results more accurate and has been shown to decrease the potential system benefits from storage compared to an inflexible demand scenario (Pudjianto & Strbac 2022). However, the effects of flexible demand are more pronounced on shorter duration storage than longer durations (ibid).

Discussions: Financial potential of MDS in GB 2030 grid

When it comes to the financial potential of MDS in GB, the results suggest energy capital costs need to be very low to be profitable. Discussions about "missing money" for longer duration storage occur in academia and industry (SONI 2023) as there may not be sufficient revenue available to justify building LDES and MDS, due to the decrease in revenue from fewer operating cycles (Schmidt & Staffell 2023). If iron-air batteries' capital costs exceed 26€/kWh in 2030 according to the results, then the question of missing money does arise for every scenario in this paper. Form Energy claim their all-in capital costs in 2030 can reach 20$/kWh (Form Energy 2023), which would make them profitable from arbitrage alone in only certain scenarios. The low capital costs for this type of long duration asset found in this paper, do fall in the price ranges for LDES in Ziegler et al. (2019). However, the results suggest the capital costs needed to breakeven are very low compared to other present long duration storage such as pumped hydro (Schmidt et al. 2019). Therefore, this paper also looked into capacity market payments in order to reach higher levels of return. The capacity payments needed are all below the historically high current capacity payments, except for one case (EMR 2024). Therefore, the results do show that MDS requires other sources of revenue than arbitrage, and that capacity payments at the current prices would be enough to reach the selected IRRs. One thing to note though, is that the capital costs used for the IRR calculations from Form Energy are higher than the figure commonly seen (26$/kWh vs 20$/kWh) (Form Energy 2024b).

However, a limitation to the results' general interpretability is that the model only considers arbitrage profits. Other sources of potential revenue for MDS include revenue from the balancing mechanism, capacity market payments and ancillary services (Aurora Energy Research 2022) (Carbonell & Moreira 2023). Whilst the wholesale market will contribute a large section of revenue for this type of storage (ibid), the capacity market and balancing mechanism together could make significant revenue (Aurora Energy Research 2022). Therefore, the results only show a fraction of the potential profits for MDS. However, arbitrage profits can be uncertain and vary year on year as the results show. Therefore, in order to attract investment and de-risk projects, more stable revenue streams such as capacity market payments will likely be needed (ibid).

Discussions: policy and market implications

Since the results show significant annual profits variation between scenarios and arbitrage alone cannot meet the projected capital costs for iron-air, it is probable that policies and market tools are needed to increase LDES profitability. Longer durations with higher de-rating factors could see themselves needing capacity market payments, especially if the number of discharges during a year are low, such as with iron-air. Capacity market revenues are likely to make a small share of LDES revenues, but it can represent an important stable source of revenues for these assets (LCP Delta 2024). However, many LDES assets with lower durations compared to MDS, do not provide the same level of reliability during very long periods of stress. Therefore, it is potentially even more important for assets such as iron-air batteries to receive compensation for providing even longer durations of reliability.

When it comes to policies, a common policy suggestion is a cap and floor mechanism to minimize risk by providing a minimum certain revenue (Biggar Economics 2023) (House of Lords 2024). If revenues are above the cap, then the storage facility pay back the extra difference. If revenues fall below the floor, then the Government would pay the difference to the storage facility. The storage owners are incentivised to operate to reach the cap, whilst having a certain amount of revenue, which provides a certain flow of revenue (ibid), currently a problem with LDES projects. Interconnectors currently follow a similar mechanism too (ibid). Finally, discussions on how the capacity market could provide better remuneration for carbon-free assets are still being held, and could provide the needed "missing money" (DESNZ 2023c). Therefore, MDS could benefit from this type of stable and extra income.

7. Conclusions

Long duration energy storage is desirable and most likely necessary to minimise total system costs, reduce emissions and provide energy security (DESNZ 2024) (LCP Delta 2024) (Aurora Energy Research 2022). However, its financial viability can be an obstacle to rapid deployment. Thus, market and policy reforms are being discussed to better incentivise LDES.

This paper focused on the potential for multi-day energy storage which is a type of LDES. It reveals the benefits it can bring in terms of emissions reductions, curtailment, and supplying electricity during long periods of system stress. It does not answer if we need this type of long duration energy storage or the optimal amount, but explores how multi-day energy storage would fare in GB's 2030 power sector and if it can be a financially viable solution.

Furthermore, it suggests arbitrage revenue alone could in certain scenarios make the assets profitable at the capital costs that Form Energy aims to get to. It also suggests that other sources of revenue are most likely needed to reach higher financial returns or even breakeven in certain scenarios.

Different scenarios were modelled to acknowledge the uncertainties within the 2030 GB power sector, which have shown to have a relatively significant impact on results. Other key insights were discussed such as the role of gas prices on storage and negative pricing.

Future work could include extending to a capacity expansion model to integrate full system costs and consider other benefits and limitations with MDS that have not been modelled such as a lesser need to overbuild renewables (Dowling et al. 2020). Better modelling of the flexibility of thermal assets (unit commitment, shutdown constraints) would also increase the accuracy of the results and impact MDS as its goal is to provide flexibility. Modelling in transmission constraints could also be beneficial as MDS and storage as a whole is impacted by and can impact constraints (Guerra et al. 2024). Finally, other improvements could be made to the model such as including the capacity market and balancing mechanism to account for potential revenue stacking of storage assets.

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Appendix

A1. Total system costs equation:

$$COST \geq \sum_{p,t} avc_{p,t} \; Q_{p,t} + \sum_{w,t} c_w^{curtail} C_{w,t} + \sum_{n,t} c^{LostLoad} LL_{n,t} \forall p, w, t$$

First term: Sum of variable costs

Second term: Electricity curtailment costs

Third term: Lost Load costs

For more details see Mendes et al. (2024)

A2. Exchange rates used:

1. Euro/USD: 1/1.09; 2. Euro/GBP: 1/0.84

A3. Capacity assumptions: Baseline scenario

Technologies	In MW
Biomass	4220
Coal	0
Gas (CCGT)	33906
Gas (OCGT)	9956
Nuclear	5510
Oil	250
PS Closed	5428
RoR	2219
Solar	34425
Offshore wind	50000
Onshore wind	29733
Battery	19500
MDS	2000

A4. Gas costs assumptions in (€/MWh):

High	Low
40.3	22.6

A5. Carbon price assumption (€/ton):

CO2 price	113.4

A6. High and Low battery capacity assumptions in MW

High	Low
24600	15065

A7. OCGT assumptions:

Efficiency	Variable O&M costs (€/MWh)
35%	6

(Other cost and efficiency assumptions can be found at Mendes et al. (2024))

A8. MDS and Batteries increasing emissions in "low fuel price scenario":

In order to see if the small increase in emissions was due to MDS or not, the same scenario but with 2 GW extra of lithium batteries was run (19.5 GW vs 21.5 GW). The results show an increase in emissions larger than with MDS, so it seems all storage affects dispatch behaviour.