Department for Energy Security & Net Zero

LCPDelta

regen transforming energy

Scenario Deployment Analysis for Long-Duration Electricity Storage

A study of the benefits of Long-Duration Electricity Storage technologies on the GB power system

DESNZ Research Paper Number 2023/047

January 2024

Any enquiries regarding this publication should be sent to us at: smartenergy@energysecurity.gov.uk

Contents

Executive Summary

LCP Delta and Regen were commissioned by the Department for Energy Security and Net Zero (DESNZ) to assess the role and impact of a range of Long-Duration Electricity Storage (LDES) technologies on the future GB power system.

To achieve decarbonisation targets whilst meeting significant increases in electricity demand, the GB power sector requires large levels of intermittent renewables on the system. To integrate these intermittent renewables, there is a corresponding need for low-carbon flexibility technologies to respond to the variation in renewable output. One of the low-carbon flexibility technologies available is Long-Duration Electricity Storage (LDES).

LDES provides flexibility by being able to store energy for prolonged periods. The definition of LDES is not well-defined in industry or in government, but for the purpose of this study, LDES technologies are defined as those that can continuously discharge at their maximum power output for at least 6 hours. It encompasses a group of conventional and novel technologies, storing and releasing energy through mechanical, thermal, electrochemical, and chemical means. Currently, there are several uncertainties around bringing LDES technologies onto the GB system. Revenue uncertainty, market design, large upfront capital investment and the early development stage of many LDES technologies, mean that developers may struggle to gain the required investment.

In this study, LCP Delta and Regen were commissioned by DESNZ to independently assess the role and impact of LDES technologies in delivering the flexibility needed for the electricity system. The impacts that these technologies have on the system were assessed using scenario analysis to find the 'optimal' level of LDES deployment across a range of power market scenarios. The Study builds on previous DESNZ-commissioned analysis[1] on LDES by analysing a wider array of long-duration archetypes[2] and a wider range of power sector scenarios. This will inform policy development to determine the case for government policy to de-risk investment in LDES technologies and feed into corresponding business cases and value for money assessments.

The project is split into three key stages: engagement with the LDES sector; scenario deployment analysis to understand the impact adding LDES can have on emissions and system costs; and locational analysis to understand the impact that locating LDES in different places has on locational balancing to deal with network constraints.

An engagement process was conducted with leading UK storage technology and project developers. Through this process insight was also gathered on the roles and challenges LDES developers see for their technologies.

In the first stage of the Study Regen conducted an engagement process with leading UK storage technology and project developers. The purpose of this engagement exercise was to

[1] Benefits of long-duration electricity storage - GOV.UK (www.gov.uk)

[2] Note that this study only includes technologies where their use is contained within the power sector meaning that hydrogen storage is out of scope.

verify, improve and road-test a number of modelling assumptions and technical characteristics to support the modelling and broader assessment of LDES technologies. It also provided useful qualitative information to better understand the market-based risks, technology development pathways and policy hurdles facing storage developers. Through one-on-one interviews and an online survey, 25 storage technology developers participated, covering 11 storage technologies. Key findings from the engagement exercise are summarised below.

- Developers see a need for reforms to existing markets to provide the right market and financial incentives.
- The business model for LDES will include stacking of a wide range of system services and associated revenue streams. In addition to mitigating wind generation curtailment and solar time-shifting and system balancing, developers highlighted that LDES technologies are also well-placed to provide balancing and stability services, such as inertia, reactive power and black start.
- There are a range of technical characteristics and capabilities across different technologies and even individual projects of the same technology owing to the importance of site-specifics factors such as their location and onsite resources.
- There is no clear consensus on the energy storage durations that should be developed or required with developers looking at a range of durations to support different system needs.
- LDES *system* CapEx costs are highly variable depending on the LDES technology mix and technology-readiness levels as well as the significant uncertainty around CapEx for LDES technologies due to scale, location and volatility of supply markets.
- Locational factors and opportunities for co-location (with other generation and storage assets) could be important with many interviewees highlighting the consideration of co-locating their storage technology with other assets or resources. Some also highlighted locational deployment constrictions due to geological resources, land classification and co-location opportunities.

The modelling shows that adding LDES to the system can have a positive impact on both emissions and system costs, with the duration of deployed LDES being the biggest factor in the size of that impact.

In the second stage of the project, LCP Delta conducted a modelling exercise to assess the scale of LDES required in GB up to 2050. This was done through scenario analysis to evaluate the impact that different capacity levels and types of LDES have on emissions and system costs. The analysis looks at the impact of LDES across a wide range of scenarios with over 1,000 total scenarios modelled. This includes a range of long-duration storage technologies from 6 to 32 hours in duration[3] and capacity levels from 1.5GW to 12GW in 2035 rising to 2.5GW to 20GW in 2050. Other key uncertainties around capital costs (CapEx) and lower deployment levels of gas with carbon capture and storage (CCS) and hydrogen power plants were also modelled. All key assumptions and scenarios were provided by DESNZ except for

[3] Here ‘duration’ refers to the amount of time an asset can continuously discharge at its maximum power output.

the assumptions used for characteristics and costs of LDES, which were developed between LCP Delta, Regen and DESNZ.

To first understand the extent to which LDES can reduce emissions, different levels of LDES capacity, replacing peaking generation capacity (unabated gas in DESNZ scenarios), were modelled for a DESNZ Core Scenario. This shows that adding LDES can have a positive impact on emissions reduction. Adding just 3GW of LDES in 2035 can reduce emissions intensity of the power system by 3-8% (0.3-0.8gCO_2e/kWh) whilst adding 12GW of LDES can reduce emissions intensity by 10-28% (1-2.5gCO_2e/kWh). In general, the higher the duration of the LDES deployed the larger the impact on emissions, with durations of 16-32 hours (the upper-end of modelled durations) having the largest impact on emissions. This highlights that adding LDES technologies can reduce emissions intensity and therefore help to achieve power sector decarbonisation targets set by government for Carbon Budget 6 (CB6) and Net Zero.

LDES enables existing wind capacity to be used more effectively and therefore government can achieve the same level of emissions reduction with less investment in wind capacity. To understand the impact LDES can have on system costs, additional modelling was undertaken where LDES displaces installed wind generation capacity in addition to peaking capacity. This allows for an assessment of LDES impacts on the system cost required to reach CB6 and Net Zero. Here the Study finds that LDES can bring net benefits to the system with longer durations and larger capacities having larger impacts.

At medium CapEx levels for LDES, most LDES technologies tested bring net benefits to the system except for some low-efficiency and lower-duration technologies. The ‘optimal’ deployment level depends on the type of LDES technology, with the benefits of different technologies peaking at different points. Those with the longest modelled durations (16-32hr) and slightly lower CapEx costs, primarily representing pumped storage hydro, provide increasing system benefits with every additional GW added with benefits peaking at the maximum level of capacity modelled at £24bn (Net Present Value (NPV), 2030-2050). This equates to a 3.5% reduction in total system costs. Those with lower durations and slightly higher CapEx costs, representing more nascent technologies such as liquid air, compressed air and longer-duration batteries, show lower benefit levels of £1-3bn (0.2-0.5% reduction in total system costs) at capacities between 2.5-10GW (in 2050). This shows that while LDES can reduce system costs, the type of LDES technology and the duration of LDES deployed are important in determining the scale of system cost reduction and the ‘optimal’ level of LDES capacity.

The capital costs of LDES technologies are critical in determining the net benefits of these technologies. Reducing the capital costs of these technologies increases system benefits.

Given the level of technology readiness of many LDES technologies, there is significant uncertainty as to the capital cost of future LDES projects. As a result, the analysis considers three different CapEx cost levels (low, medium, and high) to understand the impact changes in CapEx can have on the system benefits across the different LDES scenarios. The Study finds that the capital costs of LDES technologies are critical in determining whether their deployment results in a net system cost or saving (where the LDES replaces peaking and wind capacity).

In comparison to the medium CapEx levels, at low CapEx levels every LDES technology provides benefits to the system at every capacity level tested with the reduction in system costs increasing with more capacity added. The maximum benefit across the different CapEx levels for those technologies with the longest modelled duration (16-32hr) increases from £24bn (3.5%) to £27bn (4%) while a mix of different LDES types with varying durations increases from £4bn (0.5%) to £13bn (2%). However, at high CapEx levels the system benefits decrease significantly with LDES technologies below 12 hours in duration at all levels of capacity imposing a cost rather than a benefit to the system and only those with the longest durations continuing to a show a net system benefit.

The CapEx required for LDES technologies significantly influences the benefits these technologies can impart to the system. As such, the government should consider ways to help reduce capital costs or the cost of capital, when implementing any policy.

LDES can act as a risk mitigation for reduced delivery of other technologies. With lower levels of gas CCS and hydrogen deployment, the Study finds that there are greater emissions and system cost benefits when LDES is added to the system.

Gas CCS and hydrogen to power are expected to play similar roles to LDES (when it is discharging) in the future GB electricity system. However, there is uncertainty around the speed and scale of their future deployment. Therefore, it is prudent to assess LDES benefits under additional market scenarios with lower gas CCS and hydrogen to power deployment levels. The Study finds that the benefits of adding LDES to the system are increased in scenarios with less gas CCS and/or hydrogen to power.

Compared to the Core counterfactual where LDES replaces peaking capacity only, the emissions reduction can be up to 1gCO2e/kWh higher with lower gas CCS/hydrogen deployment as in this scenario the additional wind generation offsets more unabated gas. With LDES replacing both wind and peaking capacity, the impact of adding LDES can be significantly higher in scenarios with lower gas CCS and/or hydrogen deployment as more wind capacity needs to be added in this scenario to reach the same level of emissions as the baseline scenario.

This is most pronounced in a low hydrogen scenario where at medium LDES CapEx levels, adding any LDES shows a system benefit with system cost savings increasing significantly compared to the Core Scenario across all technologies tested. With lower levels of gas CCS and hydrogen the overall system costs across both the counterfactual and scenarios with LDES are higher. However by adding 2.5GW of LDES of varying durations, the system costs in these situations are estimated to be reduced by £3-6bn (0.5-1%) and adding 20GW can reduce system costs by £12-31bn (2-4%). This shows that adding LDES to the system can help to mitigate the potential delivery risks for gas CCS and hydrogen deployment.

The location of LDES is not a significant driver of LDES benefits to the system. The benefits of locating LDES in the right place are significantly smaller than the overall benefits of adding LDES to the system.

To understand the locational benefits that LDES can bring to the system, a subset of the LDES scenarios used in the scenario deployment analysis have been modelled in LCP Delta's

Locational Dispatch Model. In these scenarios, the LDES is deployed in different locations to understand the impact that this could have on the system costs associated with locational constraints. This analysis indicates that locating more LDES in England and Wales is likely to bring more benefits to the locational elements of the system than locating LDES in Scotland.

Through the modelled scenarios the system costs of locational constraints decrease by up to £1.7bn if 10GW of LDES are located in England. Conversely, with 10GW of LDES located in Scotland, locational balancing system costs could increase by up to £0.7bn. Note that LDES located in Scotland can still provide a substantial overall benefit, with 10GW of LDES providing a net system benefit of up to £14bn in our Core Scenario (regardless of location).

The primary reason for LDES slightly increasing locational balancing costs in the case of Scotland, is that in the wholesale market, the LDES is operated to often discharge at times of locational constraints over the B2 and/or B6 boundaries. This is due to times of high demand, and hence high prices, in the wholesale market being correlated with times of high generation in Scotland looking to be exported to England. Conversely, during periods of low demand (& low prices), Scottish wind is already being curtailed at a national level, easing the constraints on the B2/B6 boundaries.

The same behaviour occurs when more LDES is located in England and Wales but does not lead to higher system costs. LDES discharges in the wholesale market during times of Scottish network constraints but the additional generation from these LDES assets can be used closer to demand centres. Therefore, this reduces the need for locational balancing actions by the system operator and hence the system costs of locational balancing.

However, these findings do not necessarily indicate that all LDES should be placed in England and Wales or that government policy should restrict LDES in Scotland. The scale of benefits excluding locational balancing that LDES brings to the system as outlined above are much higher than the change in system costs due to locational balancing, with variations in CapEx, type, duration, and deployment of competing technologies being significantly more important. This shows that in general the other benefits that LDES can bring to the system outweigh any locational benefits/costs. Additional LDES is likely to bring benefits to the system regardless of where it is located. As such, the Study finds that where the LDES is built is significantly less important than getting optimal levels of capacity onto the system.

Overall, Long-Duration Electricity Storage technologies could have a significant impact on providing the flexibility the future GB power system will need, driving reduction of both emissions and system costs.

Overall, the Study shows that LDES can play an important role in providing the flexibility that the GB system requires in future. The Study should provide government with the key evidence base it needs to design successful policy and/or change in market design to support the deployment of LDES technologies. Adding LDES can reduce both emissions and system costs as it allows intermittent renewable power to be used more efficiently. Longer durations of LDES (up to 32 hours tested) can have larger impacts but LDES technologies of all types still have a positive impact and can bring benefits to the system in the right circumstances. Capital costs for LDES technologies are an important driver of the extent of system benefits so reduction of these costs should be a key focus and will help bring these technologies to market.

1. Introduction

In this study, LCP Delta and Regen were commissioned by DESNZ to independently assess the role of long-duration electricity storage (LDES) technologies in delivering the flexibility needed for the electricity system and the impact that these technologies have on the system.

This chapter of the report provides an overview of the project including an introduction to the energy system and the role of flexibility in the power sector. Chapter 2 gives an introduction to LDES, describe the types of LDES available and provides of an overview of the different revenue streams available to them. In Chapter 3 we describe the approach taken for the technology developer engagement exercise and its outcomes. In Chapter 4 we describe the LDES archetypes used in LCP Delta's modelling and the modelling approach taken. Chapters 6 and 7 outline the results from our modelling across a Core Scenario and scenarios exploring varying levels of gas CCS and hydrogen deployment. Chapter 8 examines the locational benefits that LDES can bring to the system. Chapter 9 summarises the overall conclusions from the Study.

1.1. Background and context

The energy system in GB is set for fundamental change over the coming years. The UK has committed to reaching Net Zero by 2050 and to reduce emissions over the Carbon Budget 6 Period (CB6) of 2033-37 by 78% compared to 1990 levels. Achieving these targets whilst maintaining energy security and affordability is a significant challenge and requires a major transition across the entire energy sector.

The power sector will play a major role in the decarbonisation of the economy with the latest government energy strategy, 'Powering up Britain'[4], outlining that 'a secure, reliable, cost-effective, decarbonised power sector is critical for a modern industrial economy'. In the Net Zero Strategy,[5] the government committed to a fully low-carbon power sector by 2035, subject to security of supply, meaning that nearly all generation will need to come from low-carbon sources. Demand in the electricity sector will also increase significantly as other parts of the energy sector such as heat, and transport electrify. DESNZ project that electricity demand will increase by 40-60% by 2035 from 2019 levels.

This creates a twin challenge for the power sector to 2035: the need to decarbonise whilst meeting a significant increase in demand. Future electricity demand on the energy system will predominantly be met by renewables (mainly wind and solar) but renewables cannot meet this demand alone as there are times when the wind is not blowing, and the sun is not shining. Renewables need to be supported by other low-carbon technologies. The Net Zero strategy highlights that 'to ensure the system is reliable, intermittent renewables need to be

[4] Powering up Britain - GOV.UK (www.gov.uk)
[5] Net Zero Strategy: Build Back Greener - GOV.UK (www.gov.uk)

complemented by known technologies such as nuclear and power CCUS, and flexible technologies such as interconnectors, electricity storage, and demand-side response'.

1.2. The role of flexibility

Flexible technologies that can adjust their supply or demand quickly are crucial to the operation of the electricity system as they help balance demand and supply which vary depending on a number of factors. The need for these technologies is set to increase as the system decarbonises. Demand will vary based on consumers' needs, such as heating their homes, while supply will vary based on fuel availability or the weather. Currently flexible technologies largely respond to increases in peak demand, but in the future they will be needed more and more to balance the system when there are highs or lows in wind and solar output.

The government's 2021 Smart System and Flexibility Plan concluded that 'around 30GW of short-term storage, demand side response and interconnection flexible capacity in 2030, may be needed to cost-effectively integrate high levels of renewable generation'. Since then, the British Energy Security Strategy[6] has outlined plans to significantly increase renewable capacity with an ambition for offshore wind to reach 50GW by 2030 and solar to reach 70GW by 2035. To integrate these large volumes of intermittent renewables (3-4x increase by 2035), the system will also require high levels of flexible technologies to ensure system balance. The case for change used in the government's Review of Electricity Market Arrangements (REMA) consultation produced by LCP Delta 'identified a significant, increasing need for low-carbon flexibility technologies (including low-carbon flexible generation, storage, interconnection to other countries, and devices and technologies which shift or reduce demand) to respond to the variation in renewable output'.

Regen worked with National Grid ESO on a project examining a 'Day in the Life' of a 2035 net zero electricity system,[7] in coordination with the ESO's Bridging the Gap programme. This involved working with the ESO and incorporating views from ESO's Future Energy Scenarios team, future markets team, control room and other key players within the ESO. The output was a detailed narrative around how the demands of a challenging winter day may be met in 2035 through the use of new technologies, markets, digitalisation and roles for system actors. This analysis highlighted that both shorter-duration and longer-duration electricity storage could be called upon to manage intra-day balancing on the electricity system. The analysis revealed that up to 5GW of long-duration electricity storage would potentially be charging and discharging across both a calm, cloudy winter's day with high demand and low renewables, and a warm, windy and sunny summer's day with low demand and high renewable energy output.

[6] British Energy Security Strategy - GOV.UK (www.gov.uk)
[7] A day in the life 2035 - Regen (www.Regen.co.uk)

1.3. What is long-duration electricity storage?

Storage technologies will be one of the main technologies in providing the flexibility the system needs in future. Flexibility will be needed across a range of time horizons and not all technologies are equally suited to providing longer sustained periods of flexibility. The definition of LDES is not well defined in industry but for the purpose of this study, LDES technologies are defined as those that have the ability to continuously discharge at their maximum power output for at least 6 hours. They can be deployed to store energy for prolonged periods, charging when prices are low/renewable generation is high and discharging when there are low periods of electricity supply or high prices.

LDES encompasses a group of conventional and novel technologies, storing and releasing energy through mechanical, thermal, electrochemical, and chemical means. Most LDES technologies are still in their infancy in terms of development and deployment with pumped storage hydro (PSH) currently the only mature technology with 2.9GW currently deployed on the GB energy system. There are many research projects underway to develop more nascent technologies that can provide stored electricity at a useful capacity for long periods of time, such as compressed air, liquid air, gravitational storage, hydrogen and flow batteries. More detail on the different types of LDES can be found in Chapter 2.

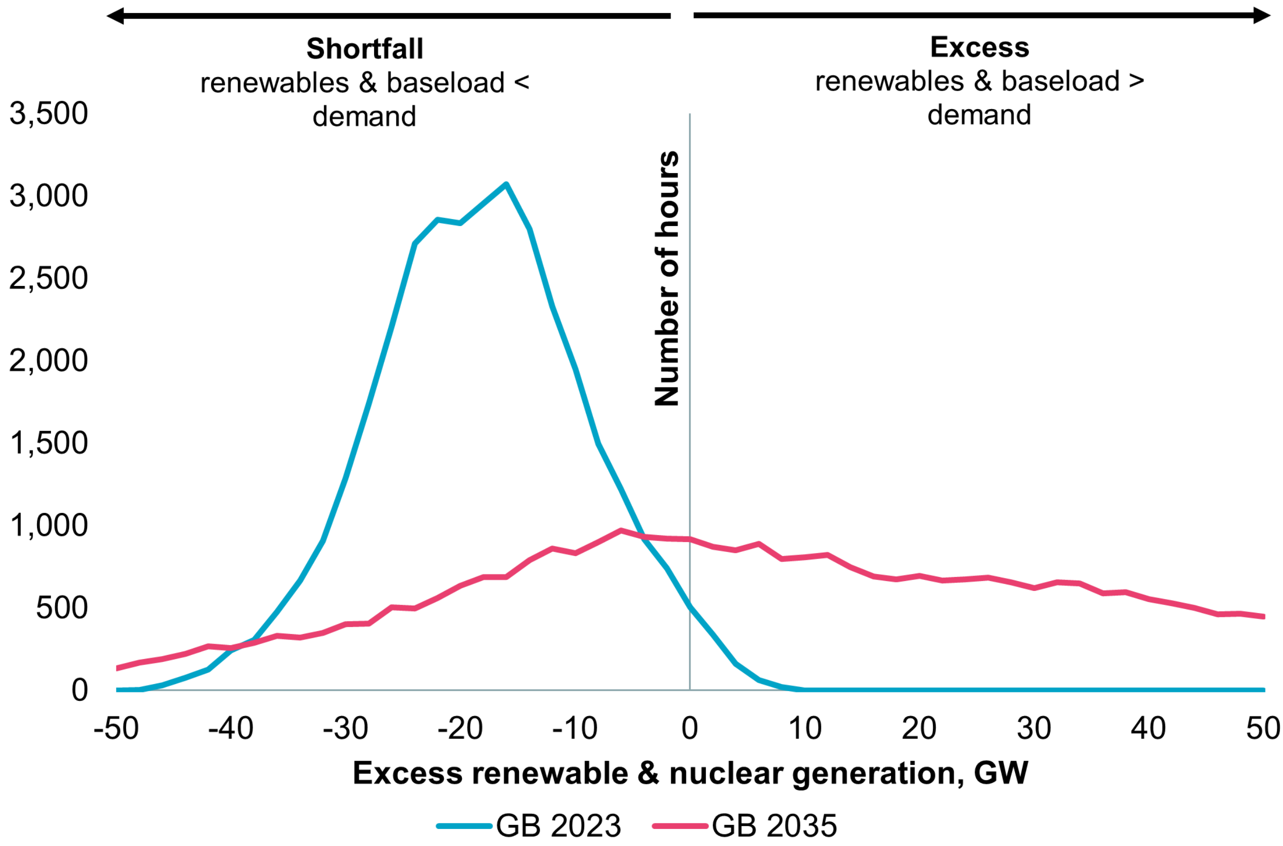
1.4. The need for flexibility and longer-duration electricity storage

Previous LCP Delta analysis[8] showed that if the government meet their 2030 targets (as outlined in the British Energy Security Strategy) for renewables there will be oversupply of power for more than half of all hours across the year by 2030 and that up to 72TWh of renewable power could be wasted. This analysis estimated that to keep balancing and constraint costs down, and to mitigate falling revenues for renewable generators, over 50GW of flexibility from energy storage, demand side response (DSR), electrolysers and interconnectors is needed.

This analysis has been updated for this Study using the DESNZ Net Zero Higher Demand scenario for future demand and capacity levels (scenario assumptions outlined in more detail in chapter 5). The below charts show the amount of time in which there will either be too much or too little generation from nuclear and renewables relative to demand. This shows that in 2023, before any flexibility is used only 14% of hours across the year have excess renewables and nuclear. By 2035, renewable capacity has increased significantly with the system now being dominated by intermittent renewables, particularly offshore wind. This will increase the volatility of supply across different timescales within notable excesses of renewable generation when demand is low and wind/solar output is high. This significantly increases the number of hours across the year where there are excess renewables from 14% in 2023 to 64% in 2035.

[8] British Energy Security Strategy: Homegrown clean power, but at what cost? (lcp.uk.com)

Figure 1: *Excess renewables and baseload generation in 2023 and 2035 for the DESNZ Higher Demand scenario*



This increase in excess renewable hours highlights the need for flexibility to help manage volatility in supply. To avoid curtailing high levels of renewable power, renewable generation could be moved from hours where there is too much renewable generation to hours where there is too little renewable generation, or, used elsewhere such as through export abroad and in electrolysers to produce green hydrogen. Additionally, other technologies alongside renewables that can turn-up and turn-down quickly, such as thermal technologies, will be needed when renewable generation cannot be shifted and there is still a shortfall.

In addition to the increased need for flexibility, there is also a need to move away from the current sources of flexibility. Most flexibility is currently provided by unabated gas plants adjusting their output to manage changes in demand/renewable generation across the day and providing more consistent output during longer periods of too little renewables. However, as the system decarbonises this will need to be provided by zero-carbon sources of flexibility. This will diversify the number of technologies that will provide flexibility as summarised below.

- **Short-duration energy storage** – Battery energy storage systems are already playing an increasingly important role on the system as they are able to store energy during trough periods and discharge during peak periods. However, as the name suggests they are limited in their duration.
- **Long-duration energy storage** – Storage technologies with longer durations, such as pumped storage hydro, are also likely to increase in future. These can act within day to respond to intraday volatility but can also act over longer time periods to provide

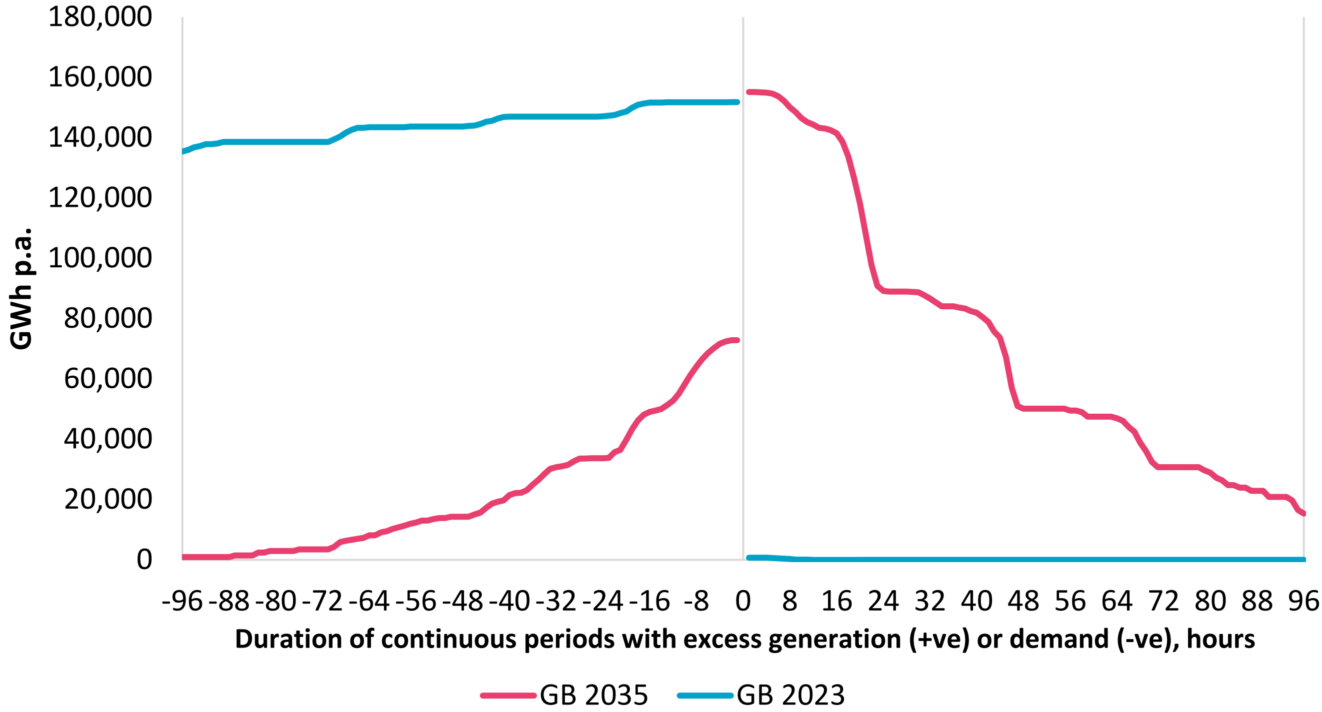
flexibility for adequacy over a weekly or monthly timescale. These technologies are the focus of this study.

- **Demand side response (DSR)** – DSR encompasses a range of technologies and consumer behaviours. One key differentiator is whether the DSR represents demand turn-down (i.e., reduction in overall demand, in response to system need), or demand shifting, where demand from peaks is shifted to periods of lower demand. Demand shifting will often have limitations on how long it can be delayed or brought forward by. For example, heat pump demand may only be able to be shifted forward a couple of hours while EV charging may only be able to be pushed back a few hours as it is charged overnight.
- **Demand side flexibility** – Flexible demand-side assets can turn-up in response to periods of low demand or high inflexible supply. For example, electrolysers can make use of excess renewable generation to produce green hydrogen which may be stored and later used in other parts of the economy such as in industry or heating or in the power sector in dispatchable hydrogen power plants.
- **Vehicle to Grid (V2G)** – Technology that enables energy to be pushed back into the power grid from the battery of electric vehicles (EVs) essentially allowing EVs to act in a similar way to battery storage, but with certain restrictions around the required state of charge of the EV at certain points in the day as defined by the owner.
- **Dispatchable thermal power plants** – This includes unabated combined cycle and open cycle gas turbines (CCGTs and OCGTs) and reciprocating engines, as well as abated variants of these technologies running on low-carbon fuel such as hydrogen or fitted with CCUS technology. Load factors required from the thermal fleet are likely to decrease over time, but they will still play an important role in a Net Zero consistent power system, particularly during periods of very high demand and low renewables.
- **Interconnectors** – Interconnectors to other countries allow GB to import and export power to foreign countries based on the price differential between countries' power markets. During times of excess renewables, the wholesale price in GB is likely to be relatively low meaning some electricity can be exported abroad. Conversely, during times of too little renewables, the wholesale price is likely to be higher in GB than interconnected European countries meaning that GB can import electricity from its neighbours.

As shown above, the increase in intermittent renewables will increase the volatility of the GB electricity supply with the number of periods across the year where renewables are in excess of demand increasing significantly to 2035. While wind and solar output will vary across the day, wind in particular can also exhibit significant volatility at a weekly/monthly scale where relatively less windy days are more likely than not to be followed by relatively less windy days – and vice versa. This means we can expect consecutive days where renewables are sufficient to meet demand and there is excess supply followed by days where baseload and renewable generation fall significantly short.

This can be seen in the chart below which illustrates how much energy shortfall/excess from renewable and nuclear generation versus demand is incurred in continuous periods of shortfall/excess of increasing length. The chart is cumulative, showing the energy shortfall/excess associated with continuous periods of a certain duration or longer. For example, in 2023 144TWh of energy shortfall comes in periods where renewables and nuclear are short of demand for at least 48 hours or longer versus a figure of 14TWh in 2035.

Figure 2: *Energy in continuous periods of excess or shortfall of renewable and nuclear generation*



The chart demonstrates that, unlike in 2023, in 2035 renewable and nuclear output will exceed demand continuously for periods that last up to 100 hours. However, though less so than in 2023, there will still be considerable amounts of energy shortfall incurred in longer-duration spells. Of GB's total energy shortfalls/excess in 2035, over 50% of TWhs occur in shortfall/excess events lasting more than 24 hours, and over 25% in periods lasting more than 48 hours. A high-wind electricity system, such as GB, would be expected to have larger tails of longer-duration excess/shortfall events relative to a high solar system (e.g. Spain) which is expected to have most of its excess/shortfall in periods lasting less than 24 hours. This is because shortfall/excess events will be driven by the intraday/daily variation in solar rather than the multi-day/weekly variation of wind patterns.

While technologies that can respond to intraday volatility such as short-duration (<6-hour) storage, DSR and V2G, these are not equipped to address volatility at the longer timescales of excess and shortfall in renewables that we are likely to see in the GB energy system. For instance, even though the charge itself could be stored for longer periods with some degradation, a 2-hour battery cannot provide full coverage for shortfalls greater than 2 hours.

In comparison, longer-duration storage technologies are well-suited to managing volatility at a weekly or monthly scale. As outlined in Section 1.3 above, these types of assets can store larger amounts of energy for prolonged periods and as a result, they are in a better place to manage these longer periods of excess/shortfall renewables. GB will have an acute need for longer-duration storage in the future due to having a wind-dominated generation mix.

1.5. Project overview

As shown above, to integrate the large volumes of intermittent renewables required to decarbonise the power sector, corresponding levels of flexibility are needed with the need for longer-duration storage being particularly acute in GB. A critical requirement for the sector at this point in its development is to ensure there is a clear route to market for this flexibility. This Study is key to the evidence base that will underpin the market and support mechanisms required to enable the LDES sector to develop.

The overall aim of this Study is to independently assess the role of LDES in delivering the flexibility the GB electricity system needs and the optimal level of LDES deployment in a range of electricity market scenarios. This will inform policy development to determine an optimal approach to de risking investment in LDES technologies and feed into corresponding business cases and value for money assessments.

This study builds on previous DESNZ commissioned analysis on long-duration electricity storage[9]. DESNZ have commissioned this additional analysis to further understand the specific role of long-duration electricity storage in a wider range of deployment scenarios with a variety of different storage characteristics. This analysis also expands the understanding of LDES impacts on locational network constraints. This study also only includes technologies that are contained within the power sector meaning that hydrogen storage is out of scope of this analysis.

The focus of the analysis is on assessing the scale of impacts of adding LDES in GB up to 2050 by evaluating the impact that different levels and types of LDES have on the system. This includes impacts on system costs and the contribution these technologies can make in balancing the system, reducing emissions and ensuring security of supply. The analysis will look at the impact of LDES across a range of scenarios covering both variations in the LDES technologies themselves (characteristics, costs, capacity and location) and the environment in which they operate, such as changes to deployment levels for hydrogen to power plants and gas CCS.

Taken together, this will give DESNZ and Ofgem a strong evidence base for the policy development for LDES technologies and give an understanding of the scale of LDES that can be supported at a low-regret level.

1.6. Project approach

To estimate the benefits that LDES can bring to the system, the project is split into three key stages as below.

[9] Benefits of long-duration electricity storage - GOV.UK (www.gov.uk)

1. We have engaged with leading players in the sector through Regen's management of the Electricity Storage Network, to ensure we have the latest insights on the characteristics and costs of LDES through a survey and interviews.
2. LCP Delta has used scenario deployment analysis to assess the scale of LDES required in GB up to 2050 by evaluating the impact that different levels of 5 defined LDES archetypes have on emissions and system costs. The analysis looks at the impact of LDES across a wide range of scenarios with over 1,000 total scenarios modelled. This includes variations across key LDES characteristics, costs and capacity combined with various wider deployment scenarios for different technologies, such as lower levels of gas CCS and hydrogen.
3. The final stage of the analysis looks at the impacts of deploying LDES in different locations. To test this, modelling was undertaken to understand the impact on the system of locating LDES in different parts of the country by looking at 18 different scenarios where the location and type of LDES is varied.

The technology developer engagement in stage 1 has been conducted through Regen's management of the Electricity Storage Network; the only industry membership organisation dedicated to supporting the electricity storage sector. We interviewed leading players in the sector as well as carrying out a survey to ensure we have the latest insight on technology characteristics and costs. We carried out five interviews covering the main types of LDES (mechanical, chemical, electrochemical & thermal), including reference to the winners of the Longer Duration Energy Storage Demonstration competition fund rounds. In addition, a survey was sent out to LDES developers. Given limited public data on long-duration technical characteristics and costs, this provides a useful evidence base to use in the modelling as well as a useful understanding of the role that developers see for long-duration storage on the system. The intent for the interviews was to also gain additional understanding on market-based risks and possibility of sub optimal operational behaviour. Findings from the engagement are outlined in Chapter 3.

The modelling in stage 2 of the project has been conducted with LCP Delta's Envision Framework. Various future systems with and without LDES have been modelled to understand the likely impact of adding these technologies to the system and understand what an 'optimal' level of LDES technologies could be. A set of LDES archetypes each spanning multiple LDES technologies is used during modelling to reduce the modelling requirements to a tractable scale. These are outlined in Chapter 4. Within the modelling we assess the impact these LDES archetypes have on key outputs such as system costs, generation, curtailment and emissions. The modelling has considered the impacts of four key LDES factors: technology type, capacity, cost, and location. Deployment of long-duration electricity storage is also considered under a wide range of electricity market scenarios that incorporate the risks for the deployment of alternative technologies. Analysis completed on the Core Scenario (based on DESNZ's own power sector scenario) has then been repeated for alternative counterfactuals with lower levels of gas CCS and hydrogen deployment levels to understand the impact of LDES if these technologies do not deliver to their full potential. Results from this modelling can be found in Chapters 6 and 7.

Finally in stage 3, the location of LDES has been considered as optimising location of LDES deployment can enhance benefits to the system. Network constraints mean that renewables are more likely to be curtailed in certain locations and LDES can help alleviate this issue and reduce future network reinforcement costs. As such where LDES is deployed could be an important consideration for any future policy design. To test this, modelling has been undertaken to understand the impact on the system of locating LDES in different parts of the country. This is covered in more detail in Chapter 8.

All analysis for this Study was carried out between January and May 2023 with engagement of developers and survey taking place in January to February 2023.

2. Long-Duration Storage Technologies

2.1. Types of long-duration electricity storage

There is a wide range of LDES technologies that have the potential to be deployed onto the GB energy system. These are all have different characteristics, costs and are at different stages of technology readiness. The main technologies considered in this report are outlined in *Table 1* below with a brief description of the technology and their likely duration range reflecting the near-term feasible GB capabilities of this technology:

Table 1: *Overview of LDES technologies considered for this Study*[10]

Name	Description	Likely duration
Lithium-ion Batteries	Lithium-ion battery storage stores electrical energy as chemical potential energy using lithium and carbon-based electrodes and is widespread in the consumer electronic sector as well as in the electric vehicle sector.	1-8hr
Pumped Storage	Pumped Hydro uses the upstream hydraulic potential of a water reservoir as a store of energy. The water is held back until the pressurised pipe linked to the downstream area is opened, allowing the water to flow downwards, decreasing in potential energy and increasing in pressure as the column increases in vertical height. It then goes through a turbine which produces electrical energy.	8-32hr
Compressed Air	Compressed Air Energy Storage (CAES) is based on the principle of pressurised air being used as an energy storage medium. It comprises a pressurised reservoir (typically subsurface geological formation such as a salt cavern) being used to hold a pressurised medium, typically air, with the air whose flow out of or into the reservoir is the basis on generating or storing electrical energy to/from the grid.	4-8hr
Liquid Air	Liquid Air Energy Storage (LAES) stores electricity by liquefying air into tanks and generates electricity by expanding the liquefied air in a turbine. It is a form of thermo-mechanical energy storage.	4-12hr
Flow Batteries	Flow batteries are an alternative form of electrochemical storage, using alternative chemistries such as vanadium or manganese. The energy capacity of the battery is a function of the volume of electrolyte, therefore, by changing the size of the tanks the energy capacity of the system can be increased or decreased.	4-8hr

[10] All technology descriptions are taken from the 2018 BEIS Storage cost and technical assumptions for electricity storage technologies report or the NG ESO Storage for Constraint Management publication

Gravity Energy Storage	Gravity energy storage is a form of mechanical energy storage which stores energy in the form of potential energy. The basic principle is that electricity is used to raise large masses to a certain height over the charge cycle.	6-10hr
Zinc Batteries	Zinc Battery storage is based on storing energy in an electrochemical cell based on a zinc chemistry. There are different types, primarily Zinc air and Zinc Copper. Zinc battery work in a similar way to Lithium Ion with Zinc based ions replacing Lithium Ions	1-6hr
Sodium Sulphur	Sodium Sulphur (NaS) Battery storage is a high temperature rechargeable battery and is based on storing energy in an electrochemical cell using a molten electrolyte	1-6hr
Iron-air battery	Using a principle called “reverse rusting,” the cells “breathe” in air, which transforms the iron into iron oxide (aka rust) and produces energy. To charge it back up, a current reverses the oxidation and turns the cells back into iron.	Up to 100 hours

Hydrogen storage is considered to be out of scope of this analysis as the focus of this study is technologies contained within the power sector. Hydrogen storage is not a power sector only technology with much of the hydrogen stored from electrolysis likely to be used in sectors other than power. Hydrogen storage was also covered extensively in the previous LDES study commissioned by DESNZ.

2.2. Roles of long-duration electricity storage

As illustrated in section 1.4, GB has an acute need for long-duration storage as the system decarbonises. The primary role of long-duration storage within the power sector will be to provide the flexibility that the system needs, mainly though increasing utilisation of low-carbon generation by charging during periods of high renewable output and lower demand, then discharging during periods of higher demand and low renewable output. However, through our research we have identified that LDES can play a number of different roles on the system in addition to this main purpose, some of which are dependent on the location of the LDES. The following use cases for LDES have been identified:

- **Wind curtailment support –** LDES could be co-located with wind generation or at a system nodal/Grid Supply Point (GSP) level to mitigate the impact of generation curtailments, by charging during curtailment events (potentially multiple hours) and discharging when wind drops.

- **Solar PV time-shifting –** LDES could be co-located with solar generation to smooth solar generation profiles and reduce midday generation peaks, by charging multi-hour energy storage and discharging when solar yield reduces in the evening.
- **Demand management –** LDES could assist with the management of demand and supply, responding to longer 'turn-up' or 'turn-down' service calls. LDES technologies could also co-locate with major energy users to mitigate the impacts of high-cost electricity periods.
- **Reserve services –** LDES technologies are well placed to participate in established and future network reserve services, such as Slow Reserve and Fast Reserve procured by National Grid ESO. These commercial balancing services could become part of the LDES revenue stack.
- **Wider system balancing –** LDES can act within Balancing Mechanism to ensure the system is balanced at any one time. This could be during times of energy demand imbalance or locational balancing.
- **Stability and power quality services –** Alongside longer-duration services, many of the LDES technologies being developed, and their grid-facing equipment, could be well placed to provide inertia, voltage support and reactive power services to the network.
- **Capacity market/system stress –** LDES technologies could be a key participant in the Capacity Market, discharging energy to help avoid or plug the gap during multi-hour system stress events.
- **Black start –** Some LDES technologies and their grid-facing plant could potentially be well placed to provide system restoration services, including black start. This could be specific to technologies that can be started without mains import, or potentially LDES developers that might consider co-locating companion technologies like shunt reactors.

2.3. Deployment of long-duration electricity storage

As well as there being various use cases for LDES, there are also a number of factors that will affect the deployment of LDES and what the 'optimal' level of LDES will be. These can split into two key categories: variation in the LDES costs and characteristics and variations in the wider environment for LDES.

LDES costs and characteristics

As outlined above there are many different types of LDES. Each of these will have different costs and characteristics that will affect its deployment and the impact it will have on the system. This will also vary for each individual storage project and archetype. Some of these factors are summarised below.

- **Storage type** – Different storage types will have different characteristics such as round-trip efficiency, availability, size in MW terms, different degradation rates and depth of discharge which will affect the revenues of the plant and how it operates within the system.

- **Storage duration** – Different storage types have different durations. For example, longer durations can continuously dispatch their stored energy across longer periods enabling them to contribute during prolonged periods of low wind known as 'Dunkelflaute'.
- **Costs –** The capital and operational costs will have a big impact on the investment decisions for an LDES project, as projects will need to reach a certain level of internal rate of return (IRR) for investors to consider investing in them. Their capital costs, including the CapEx costs and the cost of capital (hurdle rate) can have a big impact on overall system costs as well.
- **Investment risks –** To get to a certain level of IRR for investors there will be an assessment of project risks more generally in addition to costs. This is to establish whether the risk taken warrants the potential return that is being offered. Theses risk would include the level of technology readiness, whether there is international finance or domestic, the extent of currency risks for construction imports as well as the wider market and political stability. Assessment of these risks is out of scope of this Study.
- **Location –** The location of the LDES projects will affect how the asset participates in the locational Balancing Mechanism. For example, a project located behind a locational constraint can help alleviate that constraint by charging during a constrained period and discharging during an unconstrained period. Projects located in certain areas may also have access to specific locational markets such as stability services. Some LDES archetypes may also be restricted in where they can locate – for example pumped storage hydro needs a certain type of topography to build which is more likely to be found in Scotland.

Variations in wider environment

Other drivers across the power sector will also impact the deployment of LDES technologies. These include:

- **Capacity of alternate technologies** – The amount of other flexibility technologies that are also on the system will affect the system need for LDES and whether the LDES is viable. This includes gas CCS, hydrogen, short duration storage, DSR and interconnectors.
- **Capacity of LDES** – LDES includes different techs that will also compete with each other, and greater storage deployment could cannibalise revenue streams for LDES.
- **Demand levels and renewable deployment – T**he make-up of the underlying system in terms of demand levels (both total and peak) and renewable capacity will impact LDES deployment. A higher demand (in terms of total or variation in peaks and troughs) and/or renewables system will mean more variation across generation and more volatile prices meaning higher price spreads for storage in wholesale and Balancing Mechanisms.
- **Commodity prices –** Fuel and carbon prices drive electricity prices so changes in these will affect the revenue for LDES projects and how much can deploy. These plus the

hydrogen price and GB electricity price will also affect the dispatch of competing technologies.

- **Network build –** Network reinforcement levels will impact the locational revenues that a LDES project can achieve and more broadly how the assets could be utilised to alleviate locational constraints. They may also impact overall deployment as LDES can be deployed to help solve network issues.
- **Government policy –** One of the fundamental drivers of LDES deployment will be government policy and support for LDES. The higher the support level, the more LDES that will be able to build. Government support can be provided at different stages of LDES technologies. Research and development (R&D) funding has already been provided to some developers through the Net Zero innovation fund, which helps to develop technology demonstrators. Further policy changes to support new LDES projects could help LDES to build at a larger scale. Additionally, changes to the market, such as possible changes through the REMA programme, may also have a large impact on viability of projects by providing additional or easier routes to market for LDES.

2.4. Revenue streams

The different roles that LDES technologies can play on the system mean that there are various markets and revenue streams that LDES plants are likely to participate in. For LDES plants, there are 5 key revenue streams.

- **Wholesale market –** This represents price arbitrage opportunities within the day ahead market. This can be within-day and between days or even weeks for LDES. This price arbitrage means that LDES is charging at lower prices often during times of excess renewables and discharging at times of a renewable's shortfall and high demand, thus fulfilling the roles of wind curtailment support, solar PV time shifting and demand management.
- **Balancing Mechanism** – Price arbitrage within day for energy imbalance at the national level. Similar to the wholesale market, price arbitrage opportunities often occur when wind or solar outputs and in particular is inaccurately forecast. This gives opportunities to LDES to charge if wind/solar output is high and/or higher than expected, and discharge if wind/solar output is low and/or lower than expected. This fulfils the role of wider system balancing as well as helping with wind curtailment and demand management.
- **Locational constraints** – System actions in the balancing mechanism to ease network constraints. LDES can act during times of locational imbalance helping to manage constraints. In particular, LDES can charge if wind would otherwise be curtailed due to constraints on the network and then discharge that energy when that area of the network is less constrained. This helps with wind curtailment and wider system balancing.
- **System services –** Revenues through ancillary markets providing services such as reserve, system inertia, reactive power and black start services. As outlined above,

some LDES technologies can provide these system services through parts of the balancing mechanism. Some longer-term contracts, such as the Stability Pathfinder contracts offered by NG ESO[11], may also be available.

- **Capacity Market –** Payments for derated capacity through Capacity Market (CM) auctions with revenues based on the CM auction clearing price multiplied by the derating factor. LDES technologies can bid into CM auctions as they are able to provide energy during system stress events if required. Charging before a system stress event allows them to discharge during such events to ensure that the lights do not go out. Derating factors for storage vary by duration of the storage.

2.5. Risks and opportunities of different revenue streams

Each revenue stream presents different levels of opportunity and risk for LDES. These are outlined for each revenue stream below. This is presented qualitatively as while the revenues for LDES can be modelled, they are often very project specific and as such can vary significantly across different types, with different LDES archetypes and durations targeting different elements of the revenue stack.

Wholesale market

The key advantage of the wholesale market for LDES plants is that it is a deep and liquid market meaning there are significant opportunities for LDES plants. LDES plants make money in this market through arbitraging price spreads, charging when price is low and discharging when price is high. As more and more renewables are added to the system and the carbon price rises, price spreads will increase with many zero price periods with renewables at the margin and high prices when thermal generators are at the margin. As more wind is deployed on the system, the time between these periods is likely to increase with longer periods of low/high wind giving LDES an advantage over short duration storage in this market, as they will be able to capitalise on larger price spreads.

Competition from other flexible plants, such as short-duration storage, DSR, hydrogen and interconnection, are the main risk in this market with the risk that these competing technologies cannibalise revenues for the LDES. In addition, peak prices may not be as high in the future as they are now due to gas prices falling, reducing the price that can be achieved when the LDES discharges. The wholesale market is also subject to longer term uncertainties such as changes in commodity prices and level of renewable deployment but overall is likely to be relatively stable in comparison to other revenue sources.

Wholesale market revenues will likely make up the largest part of the revenue stack for most LDES technologies, particularly for those with longer durations. The scale of these revenues will vary by LDES type with longer duration plants obtaining higher revenues as they are better able to capture price spreads over prolonged intervals. Those with longer durations will also likely have a larger proportion of their revenue stack from the wholesale market.

[11] NOA Stability Pathfinder | ESO (nationalgrideso.com)

Balancing Mechanism

Opportunities in the Balancing Mechanism are similar to the wholesale market in that LDES makes money in this market through price spreads, charging when the price is low and discharging when the price is high. Again, as more and more renewables are added to the system, this is likely to create more greater opportunities, increasing the Net Imbalance Volumes (NIV) and increasing price spreads, due to the frequency of zero or negative price periods. The advantage here over the wholesale market is that the Balancing Mechanism tends to have more volatile prices and therefore likely higher price spreads and more frequent fluctuations.

Unlike the wholesale market, this is a relatively shallow market meaning competition from other flexible plants such as short-duration storage, DSR, hydrogen and interconnection – along with other LDES – is even more likely to cannibalise revenues. It is also more volatile and challenging in terms of the ability to capture value meaning revenues in this market are more uncertain than in the wholesale market.

After the wholesale market, revenues from the Balancing Mechanism will likely make up the next largest portion for most LDES archetypes, with wholesale and balancing revenues likely making up the bulk of the revenue stack for most LDES technologies. As with the wholesale market revenues, the scale of these revenues will vary by LDES type with longer duration and higher efficiency plants able to obtain higher revenues. Those with shorter durations are likely to have a higher proportion of their revenue stack in the balancing market.

Locational constraints

As outlined in Section 2.2, LDES can act to alleviate locational constraints. The way in which the LDES can make revenues in this market will depend on where they are located with respect to network constraints. By locating behind constraints, the LDES can charge during times of constraint and discharge during times of no constraint easing issues around renewable curtailment due to network constraints. However, if they locate in front of constraints, they can turn-up/discharge during times of constraint and therefore reduce use of unabated gas or other more expensive thermal assets being turned up to deal with constraints.

Opportunities in this market are likely to increase with constraints expected to grow in coming years and low prices (for charging) often common in constrained areas. However, this market is quite shallow as its location specific. It is also uncertain given it is dependent on so many variables such as the location of future generation/demand, network build and possible wholesale market reform. The implications of location on LDES system impacts are explored further in section 8.

Recent regulatory oversight in this area will also likely limit the revenues available. LDES is unlikely to be able to submit negative bids to charge or reduce their output during times of network constraints. This is shown through Ofgem's recent fines for Drax Pumped Storage Limited[12] and SSE Generation Limited[13] for breaching their Transmission Constraint Licence

[12] Ofgem closes its compliance engagement with Drax Pumped Storage Limited in relation to a breach of the Transmission Constraint Licence Condition (TCLC) | Ofgem
[13] Investigation into SSE Generation Limited | Ofgem

Condition (TCLC) for 'submitting excessively expensive bid prices to curtail its generation during times of transmission constraint' for their pumped storage hydro plants. Since then, both plants in question more often bid at £0/MWh to reduce the output from their pumped storage hydro plants rather than submitting negative bids. This shows that is it will be unlikely that LDES plants will be able to make significant revenue through decreasing their output during times of locational constraint.

Given the changes in regulatory oversight and likely increases in network capacity, at a qualitative level this indicates that locational constraint revenues are likely to make up a small part of the LDES revenue stack. The scale and proportion of these revenues will vary by both the type of LDES and where it is located.

System services

Some LDES technologies are suited to providing system services, such as inertia, reactive power, reserve and black start. For example, liquid air plants and pumped storage hydro can both provide inertia and reactive power.

Pathfinder contracts from NG ESO can provide long-term contracts for these services providing guaranteed revenue such as those for inertia and to a more limited extent reactive power. Additional opportunities or markets could be designed which would provide additional opportunities to LDES. However, gaining long-term contacts is uncertain given that the market for most ancillary services is shallow, with many potential suppliers for relatively low requirements, meaning limited opportunities. NG ESO have released a recommended market design for a future stability market[14] which could provide a more enduring solution to future stability issues and provide opportunities for participants in this market, such as LDES. However, there is still uncertainty in market design and the level of requirement and competition from other sources for these services, could limit opportunities for LDES.

Given this, it is likely that system services will make up a small part of the revenue stack, although this will vary by LDES type depending on the system services they can provide. A new stability market and delays around development of competing technologies such as Nuclear, CCS and hydrogen could increase opportunities for LDES but regardless, revenues from these services are likely to be small in comparison to those from all other sources listed here. Those LDES technologies that can provide more system services will likely see a slightly higher proportion of their revenues coming from system services but still significantly lower than revenues from wholesale or balancing.

Capacity Market

The Capacity Market (CM) provides a long-term stable revenue for LDES plants with 15-year contracts available for new build. CM prices have recently trended upward and these high prices could continue as demand increases and existing capacity retires.

LDES have higher derating factors than shorter duration storage with anything over 9.5 hours in duration currently getting a derating factor of 95% in the 2026/27 T-4 capacity auction while

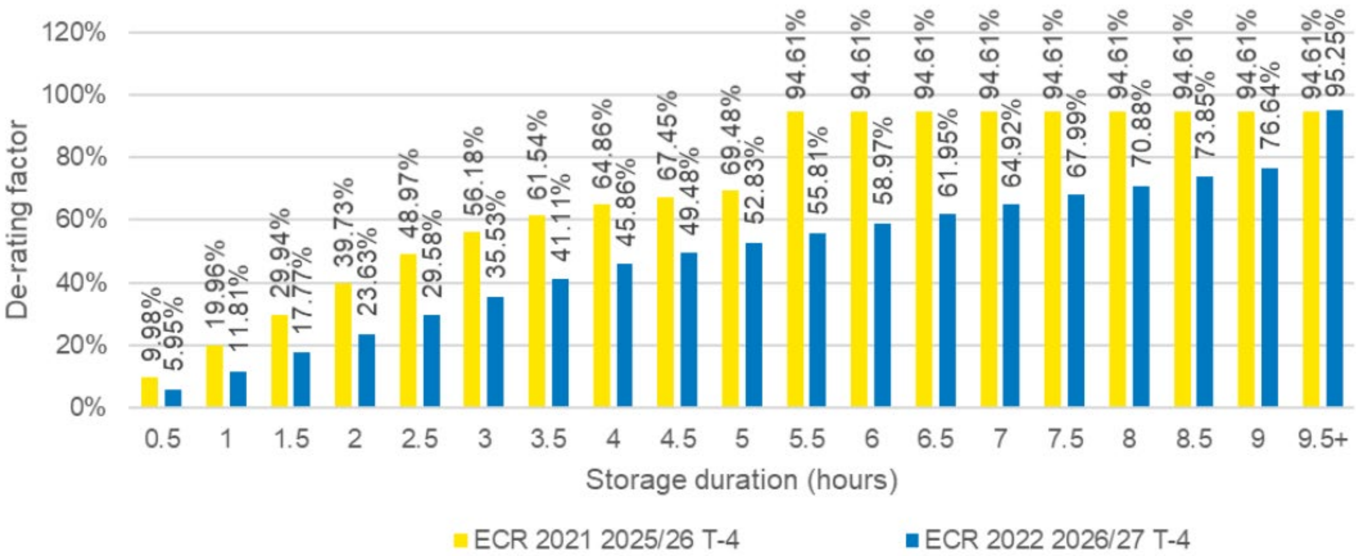
[14] Stability Market Design | ESO (nationalgrideso.com)

a 4-hour storage system receives a derating factor of 50%. This could change in the longer term as the length of potential system stress events could increase over time (due to more renewables and short duration storage on the system), meaning derating factors decrease.

But currently LDES can receive relatively high revenues through the CM. The CM also provides 15-year contracts to new plants in the T-4 auctions which provides a high degree of certainty on these revenues for developers and investors.

There is uncertainty around changes to derating factors in future years. Derating factors for LDES less than 9.5hrs fell significantly for the last auction and this may continue (incl. for higher durations). For example, the derating for a 6-hour storage system fell from 95% in the 2025/26 T-4 CM auction to 59% in the 2026/27 T-4 CM auction as can be seen in the chart below from National Grid ESO's 2022 Electricity Capacity (ECR)[15].

Figure 3: *Derating factors for storage of different durations for the 2025/26 T-4 auction and the 2026/27 T-4 auction, as published by NG ESO in the ECR 2022*



Revenues from the CM are likely to make up a small part of the revenue stack for LDES plants but can be an important stream given this provides a stable income for a long period . The level of this revenue will vary by the duration of the LDES as illustrated above.

The construction times for LDES (e.g. 5 – 8 years for Pumped Storage) are longer than the <4 year lead time in the capacity framework. This has meant that the CM has not been able to provide investors with secure long term income streams to support investments in LDES. The October 2023 Capacity Market Consultation[16] aims to overcome this barrier for LDES by proposing that low carbon technologies, such as LDES, can declare a 12-month or 24-month delay at the time of pre-qualification. This will allow LDES developers to account for their longer construction times when bidding into capacity market T-4 auctions and thus allow them to access this important long term stable revenue stream more easily.

[15] Electricity Capacity Report 2022.pdf (emrdeliverybody.com)
[16] Capacity Market 2023: Phase 2 proposals and 10 year review - GOV.UK (www.gov.uk)

3. Engagement with LDES developers

3.1. Background and the Electricity Storage Network

To support the modelling and broader assessment of long-duration electricity storage (LDES) technologies, Regen conducted an engagement process with leading UK storage technology and project developers. The purpose of this engagement exercise was to verify, improve and road-test a number of the modelling assumptions and technical characteristics that LCP used as inputs to their system and market scenario modelling.

The engagement process tapped into the sector expertise and market insight of the Electricity Storage Network (ESN),[17] an industry membership organisation dedicated to developing the electricity storage sector in the UK. Established in 2008, and now managed by Regen, the ESN has c.60 member organisations[18] representing different aspects of the storage sector and a broad range of storage technologies. The ESN run working groups on markets and revenues, safety, sustainability and the supply chain, a regular coordination working group with the System Operator, and a working group dedicated to innovation and technology. These working groups have been an excellent starting point to explore the role and benefits of LDES.

3.2. Engagement overview

To ensure the latest industry information and insights were included, analysts from Regen interviewed long-duration and short-duration technology developers. Alongside this, Regen developed and issued an online survey, seeking quantitative data from LDES technology developers, including some of the winners of the LDES funding competition.[19]

Through both 1:1 interviews and via the online survey, the project team were, overall, able to engage **25 storage technology developers**, covering **11 storage technologies**, and representing all of the LDES categories defined in LCP's modelling. These organisations were selected through contacts engaged in the NZIP long-duration storage competition fund programme and through other professional contacts in the project team. The survey was not publicly advertised for open participation / call for input.

Given the limited public data on LDES technical characteristics and costs, this survey provided a useful quantitative evidence base to support LCP's modelling, as well as qualitative information to enable the team to better understand the market-based risks, technology development pathways and policy hurdles facing storage developers.

[17] Electricity Storage Network
[18] ESN member organisations
[19] Longer Duration Energy Storage Demonstration Programme: successful projects - GOV.UK (www.gov.uk)

This report section summarises the interviews and survey responses received that have been used to inform LCP's modelling. The 1:1 interviews with nine organisations sought broader developer views on:

- The role of LDES in a net zero electricity system
- Specific technical characteristics
- Existing and potential future technology and project costs
- Operating behaviour and market participation
- Use cases, services and LDES functions
- Asset classification and definition

The online survey was designed to obtain quantitative views around LDES technology characteristics, with questions categorised by:

- **Technology development information:** Technology type, tech readiness level, development phase and timescales.
- **Technology characteristics:** Power vs duration, depth of discharge, cycle efficiency, lifetime, retrofit/repowering, degradation and annual availability.
- **Technology costs:** CapEx, OpEx, hurdle rate, future cost reduction.
- **Site requirements:** Network voltage tiers, locational factors, exploration of co-location, types of network services targeted.
- **Other evidence:** Respondents were also given the opportunity to share other commentary and upload supporting documentation.

3.3. Summary findings from engagement interviews

Interviews with storage technology and project developers were conducted across December 2022 and January 2023. Those interviewed included a mix of longer-duration technology providers and three lithium-Ion battery storage developers as shown in .

Prior to the interviews, the Regen team provided a background to the Study and previous analysis undertaken by DESNZ, Afry and LCP. The interviewees were advised that the modelling sought to identify and understand:

- The scale of LDES deployment that contribute to system balancing in 2050
- The mix and characteristics of LDES that could be deployed, including technology type, capacity, durations, locational factors, operating behaviour and market interactions.

The interviewees were asked for their views on the role of LDES in a net zero electricity system, as well as the technical and cost assumptions LCP were to use as inputs to the system modelling. See Annex A for a full list of survey questions. Some of the characteristics discussed and verified included asset scale (power capacity and hours), cycle efficiency, annual availability, degradation, construction/commissioning time, CapEx, OpEx, hurdle rates, future cost reduction potential and potential revenue sources/business models.

Table 2 below outlines some of the key takeaways from the engagement interviews. The sections that follow also describe some of the considerations and technology-specific factors for each of the organisations interviewed and the LDES technologies they are developing.

Table 2: *Key takeaways for modelling from LDES engagement interviews*

LDES modelling area	Key takeaway
Markets and financial incentives	**There is a need for reforms to existing markets, such as tailoring the Capacity Market (CM) to directly support LDES technologies.** This should be a key inclusion in the Review of Electricity Market Arrangements (REMA) process. Developers also highlighted the need to create new, specific, incentivised system services or markets that value the functions that LDES technologies can provide. This was already explored in the UK Government's LDES call for evidence, but a market that incentivises a range of different LDES technologies of different scales and capabilities will be crucial to a thriving sector. Some developers highlighted that new market signals are required to effectively integrate new/emerging LDES technologies into the UK electricity grid, including how LDES could be considered as part of future constraint management pathfinders. Some developers highlighted that they are aiming for LDES technologies to achieve cost parity with legacy power plants.
System operability	**The business model for LDES will include stacking of a wide range of system services and associated revenue streams.** A number of the interviewees were aligned on the operational services that LDES technologies will be targeting, such as mitigating wind generation curtailment, solar time-shifting and system balancing. LDES technologies are also well-placed to provide power quality services such as voltage management, reactive power, system inertia and potentially even frequency support. Alongside charging and discharging energy for longer periods of time, the nature of the assets being developed and their grid-facing technologies could enable LDES sites to provide power quality and stability services. Some organisations fed back that they are specifically targeting power stability pinch points in the system (e.g. voltage support, system inertia, reactive power) as part of the basis of their site finding and project development pipelines.

Asset categorisation	**There is a range of technical characteristics and capabilities across different technologies and individual projects of the same technology.** Even for established LDES technologies like pumped hydro, there could be a significant range of power and duration scales, project costs and availabilities etc. This variation is partially down to the individual sites being developed, their location and onsite resources. Other technologies are more consistent and modularly scalable. However, defined sets of characteristics for individual technologies or technology categories should not be too prescriptive or narrow.
Duration	**There is no clear consensus on the energy storage durations that could be developed or required moving forward.** Some interviewees fed back that you can provide a range of system services (response, reserve, inertia, outage support, curtailment management, constraint support etc.) with 8 hours, whereas other organisations are specifically aiming to develop 24, 48 or even 100-hour assets. This links closely to the points around tailored LDES market design and system services areas. There is the potential for duration stacking, where durations could theoretically be stacked and dispatched in a synchronised way to target longer durations. The durations shown in section 3.4.2 demonstrate the range of hours being targeted by LDES technologies, each potentially able to meet different system challenges. This diversity of durations and asset capability is potentially very valuable. Future policy should consider how to encourage LDES technologies of varying durations to come forward so that the future energy system has a range of assets that could be called upon to meet a range of system events. Some developers highlighted that there is strong potential for modular extension and replicability in multiple locations. Allowing for portfolios of LDES technologies with different storage durations.
Cost reduction	**LDES system CapEx costs are highly variable depending on the LDES technology, its technology readiness level, scale and location, as well as volatile supply markets.** A number of developers (including those of well-established technologies such as pumped hydro and lithium-ion batteries) highlighted the nature of the current supply chain and material costs as having an adverse impact on CapEx. These issues will likely affect almost all of the LDES technologies featured in the modelling. Global supply pressures, economic turbulence, Brexit and the conflict in Ukraine are having material impacts on many energy technology costs, including storage.[20] An example of material cost increases is cement/concrete

[20] See Department for Business & Trade, *Monthly Bulletin of Building Materials and Components - May 2023*: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1163671/Construction_Building_Materials_-_Tables_May_2023.xlsx

	products. This consideration should be reflected in the modelling, including for established LDES technologies.
Location and co-location	**Locational factors and opportunities for co-location could be important for the development of LDES projects.** Many of the interviewees highlighted the consideration of co-locating their storage technology with other assets or resources. Whether co-locating with wind power, hybridisation with short and long-duration storage at the same connection point, or co-location with geological resources, the potential for standalone LDES assets located nominally anywhere is limited and could be very dependent on the LDES technology. Locational factors are a feature of the modelling and whilst very specific considerations will likely be subsumed in a broader ‘system node’ approach to locational modelling, consideration should be given to technologies with the following locational limitations: 1) Geological resources – i.e. pumped hydro, salt caverns for hydrogen 2) Co-location opportunities – i.e. Grid Supply Points with wind or solar farms 3) Land classification – i.e. physical space and industrial areas for batteries or LAES 4) Coastal locations – i.e. compressed air pipelines or offshore wind farms Feedback from some developers suggested that LDES projects could feasibly connect at multiple voltage tiers; 11Kv, 33Kv, 132Kv and through to transmission level (400Kv) connections. Some developers mentioned the potential for LDES projects to be located at electricity system boundary points, such as the B8 boundary between North Wales/Northern England and the Midlands, and the B6 boundary between South Scotland (SPT transmission) and North England (NGET transmission). Representatives from some LDES technologies highlighted less of a locational restriction and the potential to deploy their technology in multiple locations, wherever the system need is.

3.4. Summary findings from online engagement survey

Across February 2023, Regen developed and ran an online survey, asking for quantitative values and supplementary comments to further support the assumptions that underpinned LCP's modelling of LDES. This survey was circulated to the LDES developers interviewed in the first phase of the engagement, to enable these organisations to provide specific technical characteristic figures, alongside the broader views and comments shared in the interview. It was also shared, via representatives from DESNZ, with the organisations engaged in the DESNZ long-duration energy storage competition funding programme, other relevant members of the Electricity Storage Network, and contacts held in the Regen team.

Figure 4: *Regen online LDES survey, hosted on TypeForm*[21]

> **Informing Long-duration Electricity Storage modelling for BEIS**
>
> THE ELECTRICITY STORAGE NETWORK
>
> regen transforming energy
>
> BEIS have commissioned the electricity storage network, managed by Regen, and LCP Delta to seek stakeholder feedback to inform a modelling study, looking at the role of Long-duration Energy Storage (LDES) in the future energy system.
>
> BEIS have asked to independently assess the optimal level of LDES deployment and the role LDES could play in delivering flexibility requirements in a range of electricity market and system scenarios. Your feedback will inform BEIS and Ofgem's policy approach to de-risking investment in LDES technologies.
>
> The aim of this survey is to make sure the most up-to-date information on LDES technology is included in this modelling. By taking 10 minutes to provide your feedback, you will not only be informing this modelling but the subsequent LDES policy decisions that arise from it.

The survey received 22 responses[22], covering 11 different storage technologies and LDES technology categories used in LCP's modelling, as outlined in *Table* 3. Some technologies and organisations had more than one response, with average values taken and applied. We recognise the response is a representatively small sample size for the storage sector. This section of the report provides a statistical summary of the responses received. The next section of this report then explores some of the specifics that were taken from this initial stakeholder engagement to help inform the modelling.

***Table* 3** *List of technologies that responded to Regen long-duration storage online survey*

Storage technology	Respondents
Pumped hydro energy storage (PHES)	7
High-density pumped hydropower	1
Copper-Zinc batteries	1

[21] At the time the survey was issued, DESNZ was the Department of Business, Energy and Industrial Strategy (BEIS)
[22] Note not all respondents answered every question. The summaries included show the responses received for each question.

Liquid air energy storage (LAES)	1
Gravitational storage	1
Compressed Air Energy Storage (CAES)	2
Lithium-ion batteries	1
Hydro-Pneumatic Energy Storage	1
Hydrogen electrolysis	1
Iron-Air batteries	1
Flow batteries (Vanadium)	1
Flow batteries (Alkaline Sulphur)	1
Flow batteries (Organic)	1

3.4.1. Technology development and construction

There was a range of technologies covered in the survey, across a wide range of technology readiness levels (TRLs).[23] Pumped hydro and lithium-ion are very mature technologies, with all developers classifying themselves as TRL 9, reflecting that there are large commercial projects already operating in the UK. Technologies such as LAES, flow batteries, CAES and hydrogen electrolysis[24] were also classified as very mature, with respondents classifying as TRL 8. Less mature technologies such as iron-air, copper-zinc, gravitational storage and high-density pumped hydro were classified as TRL 4-6. Respondents highlighted that construction timeframes were more project/developer-specific than technology-specific, with a large range of construction times from 6-60 months. Commissioning timescales also varied moderately, between 1-18 months.

Figure 5: *Technology readiness level results from Regen LDES online survey*

Technology	TRL Level
Pumped hydro	TRL 9
Li-Ion Battery	TRL 9
Liquid Air Energy Storage	TRL 8
Flow Battery	TRL 8 / 5
Hydrogen electrolysis	TRL 8
Compressed Air Energy Storage	TRL 7 / 4
Hydro-Pneumatic Energy Storage	TRL 7
Gravitational storage	TRL 6
High Density Pumped Hydro	TRL 5
Iron-Air Battery	TRL 5
Copper-Zinc	TRL 4

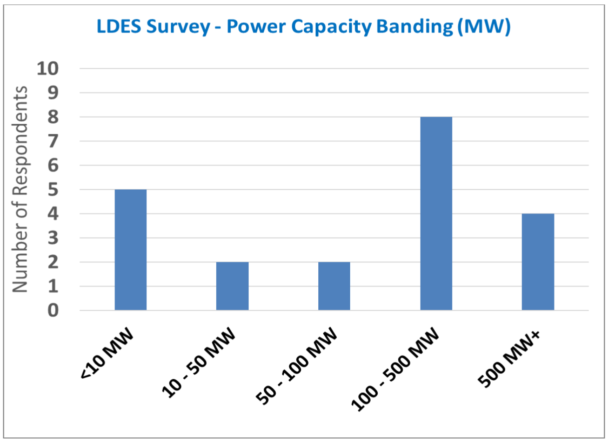
[23] See UKRI definition for TRL levels 1-9: https://www.ukri.org/councils/stfc/guidance-for-applicants/check-if-youre-eligible-for-funding/eligibility-of-technology-readiness-levels-trl/

[24] Note we recognise that electrolysis is nominally different to other LDES technologies, meaning that it is not as easily comparable in terms of technical metrics and cost benchmarking. But we have included it as part of the scope of the report and analysis, as it still has a role in providing electricity storage services to the system.

3.4.2. Technology characteristics – power and duration

Power capacities (MW) and storage durations (hours) varied significantly across the respondents. Again, this was partly related to the technology and partly due to the individual developer and project. A notable number of developers are targeting >100 MW scales, but some are also pursuing much smaller (<10 MW) assets. Smaller projects related to less mature TRL technologies pursuing pre-commercial scale projects, as well as developers aiming to bring forward multiple smaller assets rather than one central strategic site. The majority of the respondents advised that their import (i.e. storage charge-up) to export (i.e. storage discharge) ratio was 1:1, though some developers highlighted that this was slightly different or adjustable for some technologies, such as flow batteries, liquid air energy storage and hydro-pneumatic energy storage.

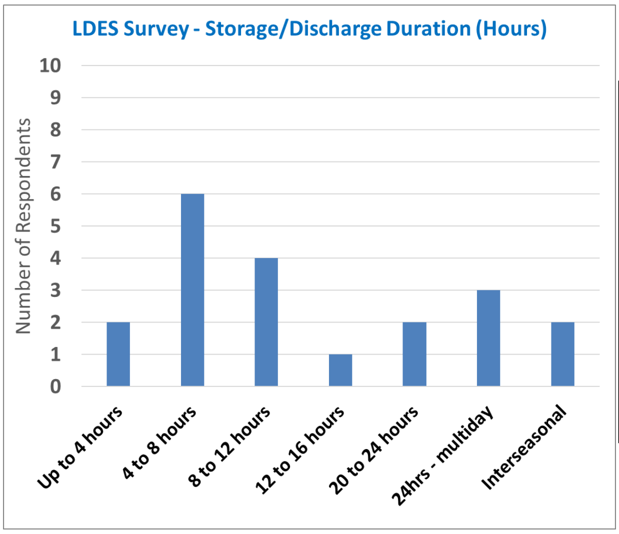
Figure 6: *Technology power capacity results from Regen LDES online survey*



Technology	Power Capacity Range (MW)
Pumped hydro	100 MW to 500 MW+
Li-Ion Battery	50 - 100 MW
Liquid Air Energy Storage	100 - 500 MW
Compressed Air Energy Storage	100 - 500 MW
Gravitational storage	<10 MW
Flow Battery	10 MW to 100 MW
High Density Pumped hydro	10 MW to 100 MW
Hydro-Pneumatic Energy Storage	100 - 500 MW
Copper-Zinc Battery	500 MW+
Hydrogen	<10 MW to 500 MW

There was a significant range in energy storage durations, with a number of developers targeting 4 to 8 hours and 8 to 12 hours, but also some technologies are targeting 24 hour, multi-day and even interseasonal storage durations[25].

Figure 7: *Technology storage duration results from Regen LDES online survey*



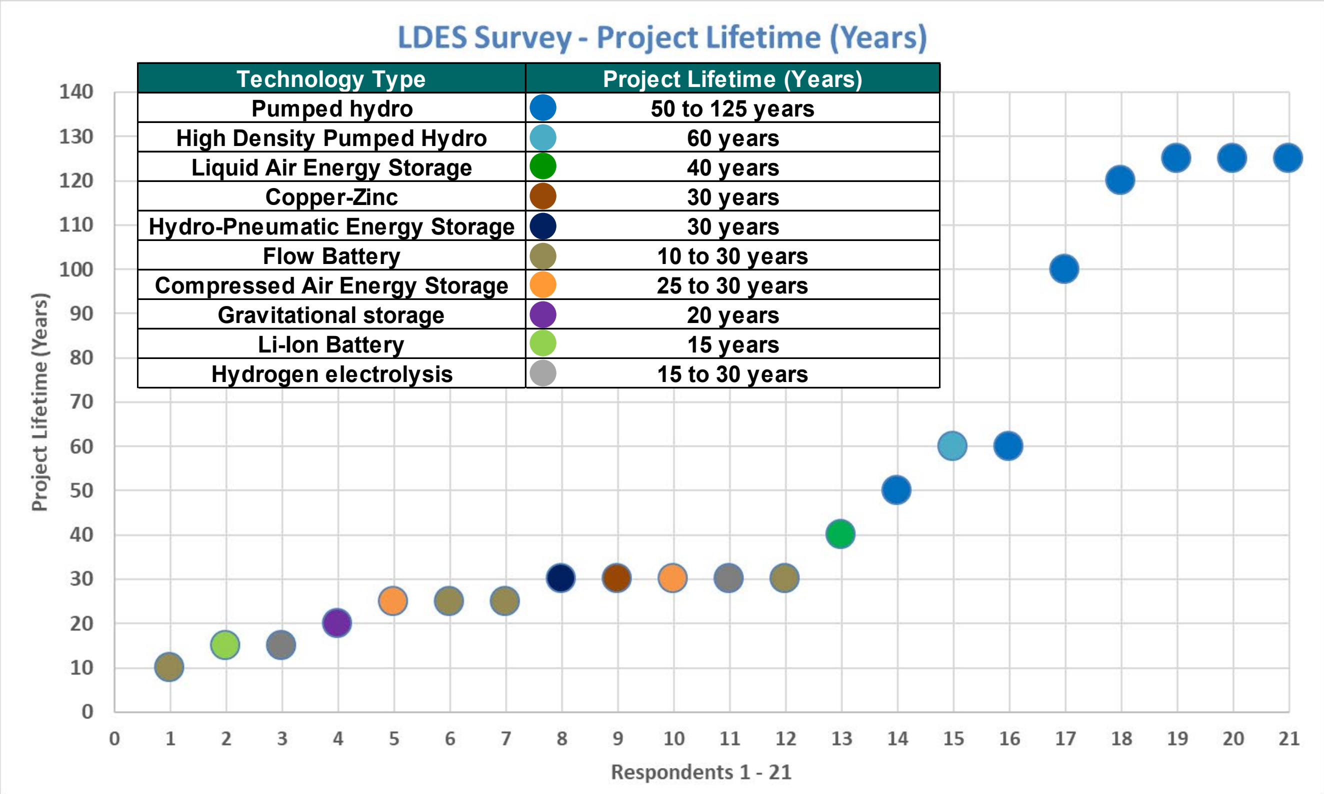
Technology	Storage/Discharge Duration (Hrs)
Pumped hydro	4 hours to Multiday
Li-Ion Battery	Up to 4 hours
Liquid Air Energy Storage	12 - 16 hours
Compressed Air Energy Storage	4 - 8 hours
Gravitational storage	Up to 4 hours
Flow Battery	4 - 20 hours
High Density Pumped hydro	4 to 16 hours
Hydro-Pneumatic Energy Storage	4 - 8 hours
Copper-Zinc Battery	8 - 12 hours
Iron-Air Battery	24hrs - multiday
Hydrogen	Interseasonal

[25] Note this is the duration of continuous charge at maximum power. For interseasonal storage this is used to refer to a continuous sustained response.

3.4.3. Technology characteristics – lifetime, availability and cycle efficiency

The asset lifetime varied significantly by technology, with lithium-ion and hydrogen electrolysis estimating 15 years and some pumped hydro sites stating up to 125 years. Many respondents highlighted the strong potential for future repowering, especially for pumped hydro systems, compressed air energy storage systems and battery systems of various chemistries.

Figure 8: *Technology asset lifetime results from Regen LDES online survey*



The annual availability of technologies being developed by respondents was all shown to be >95%, suggesting minimal operational downtime for these technologies. The roundtrip cycle efficiencies also ranged significantly depending on the technology, with hydrogen (electrolysis plus generation) at 30% and lithium-ion batteries targeting 85% (see figures below).

Figure 9: *Annual availability results from Regen LDES online survey*

Technology Type	Annual Availability (%)
Pumped hydro	100%
Pumped hydro	99%
Pumped hydro	99%
Pumped hydro	97%
Pumped hydro	95%
Pumped hydro	95%
Pumped hydro	90%
High Density Pumped Hydro	99%
Hydrogen electrolysis	100%
Hydrogen electrolysis	97%
Copper-Zinc	97%
Li-Ion Battery	95%
Flow Battery	100%
Flow Battery	98%
Flow Battery	95%
Flow Battery	90%
Compressed Air Energy Storage	95%
Compressed Air Energy Storage	95%
Gravitational storage	95%
Liquid Air Energy Storage	95%
Hydro-Pneumatic Energy Storage	95%

Figure 10: *Cycle efficiency results from Regen LDES online survey*

Technology Type	Round Trip Efficiency Per Cycle (%)
Li-Ion Battery	85%
Pumped hydro	85%
Pumped hydro	81%
Pumped hydro	80%
Pumped hydro	80%
Pumped hydro	80%
Pumped hydro	80%
Pumped hydro	78%
High Density Pumped Hydro	80%
Copper-Zinc	80%
Gravitational storage	80%
Flow Battery	96%
Flow Battery	81%
Flow Battery	70%
Hydro-Pneumatic Energy Storage	72%
Compressed Air Energy Storage	60%
Compressed Air Energy Storage	55%
Liquid Air Energy Storage	55%
Iron-Air Battery	45%
Hydrogen electrolysis	70%
Hydrogen electrolysis	30%

3.4.4. Locational factors

The potential location of LDES technologies is variable, with some technologies being driven by resources necessary for their technology to operate. For example, pumped hydro being driven by geography and topography, and both compressed air energy storage and hydrogen electrolysis having linkages to salt cavern storage.

The business models for some technology developers look beyond geographical constraints and look to locate their assets to target market and revenue opportunities. For example, some technologies are seeking to deliver reactive power or system stability services in specific locations or seeking to be nearby (in terms of system node) to wind power, to mitigate curtailment. Some respondents highlighted that their technology could deploy anywhere where there is a system need, and that location is fairly unrestricted.

Figure 11: *Technology locational factor results from Regen LDES online survey*

Technology Type	Locational Factors	Co-location	
Pumped hydro	Hydro topography	Yes	Lithium-Ion Batteries
Pumped hydro	Hydro topography	No	-
Pumped hydro	Hydro topography	No	-
Pumped hydro	Hydro topography	Yes	Wind and Solar PV
Pumped hydro	Hydro topography	No	-
Pumped hydro	Hydro topography	No	-
Pumped hydro	Hydro topography	No	-
High Density Pumped Hydro	Hydro topography	Yes	Solar PV
Li-Ion Battery	Reactive power needs	Yes	Solar PV
Liquid Air Energy Storage	No restrictions	No	-
Compressed Air Energy Storage	Salt cavern geology	Yes	Wind and Solar PV
Compressed Air Energy Storage	Must be coastal, near offshore pipelines reaching shore	Yes	Not specific
Iron-Air Battery	No restrictions	Yes	Not specific
Hydro-Pneumatic Energy Storage	Offshore wind	Yes	Offshore wind
Hydrogen electrolysis	Hydrogen storage	Yes	Not specific
Hydrogen electrolysis	Salt cavern geology	Yes	Not specific
Gravitational storage	No restrictions	Yes	Not specific
Copper-Zinc	Constrained wind farms	Yes	Wind and H2 electrolyser
Flow Battery	No restrictions	Yes	Not specific
Flow Battery	No restrictions - space	Yes	Wind and Solar PV
Flow Battery	No restrictions	No	-

3.4.5. System services and use cases

Alongside the wide range of target connection voltages highlighted (11 kV to 400 kV), many respondents indicated that LDES technologies will seek to offer multiple services, as outlined in section 2. As such, revenue stacking is likely to be common in LDES technologies (as it is for short-duration battery projects) to ensure a viable business case. A range of services are being targeted across the technologies. Constraint management and mitigation of wind or solar curtailment were highlighted as a beneficial LDES service, potentially with reduced grid connection costs if physical co-location is explored. Demand management, reserve services and system stress support were also highlighted as services that are likely to be pursued by a range of technologies. Alongside these core services, system stability and quality services such as system inertia (absolute and synthetic), reactive power, voltage support and frequency response services were also highlighted as opportunities for some LDES technologies.

See also section 2.5 – Risks and opportunities of different revenue streams.

Figure 12: *System services and use case results from Regen LDES online survey*

Technology Type	Wind curtailment support	Solar PV time shifting	Demand management	Reserve services	Wider system balancing	Stability & power quality services	Capacity market - system stress	Black start
Pumped hydro	Y	N	Y	Y	Y	Y	Y	Y
Pumped hydro	Y	Y	N	Y	Y	Y	Y	Y
Pumped hydro	Y	Y	Y	Y	Y	Y	Y	Y
Pumped hydro	Y	Y	Y	Y	Y	N	Y	Y
Pumped hydro	Y	N	N	Y	Y	Y	Y	Y
Pumped hydro	Y	Y	Y	Y	Y	N	N	N
Pumped hydro	Y	Y	Y	Y	Y	Y	Y	Y
High Density Pumped hydro	Y	Y	Y	Y	Y	Y	Y	Y
Gravitational storage	Y	Y	Y	Y	Y	Y	Y	Y
Liquid Air Energy Storage	Y	Y	Y	Y	Y	Y	Y	Y
Copper-Zinc Battery	Y	Y	Y	Y	Y	Y	Y	Y
Li-Ion Battery	N	N	N	Y	Y	Y	Y	Y
Flow Battery	Y	Y	Y	Y	Y	Y	Y	N
Flow Battery	N	Y	Y	N	N	N	Y	N
Flow Battery	Y	Y	Y	Y	Y	Y	Y	Y
Compressed Air Energy Storage	Y	N	Y	Y	N	N	Y	N
Compressed Air Energy Storage	Y	Y	Y	Y	Y	N	Y	N
Hydro-Pneumatic Energy Storage	Y	Y	N	Y	Y	Y	Y	Y
Iron-Air Battery	Y	Y	Y	Y	Y	Y	Y	Y
Hydrogen electrolysis	Y	N	N	Y	Y	N	N	N
Hydrogen electrolysis	Y	Y	Y	N	Y	Y	Y	N

3.4.6. Technology costs

Arguably the most significant factor affecting the viability of LDES technologies, as well as the overall system cost assumptions considered in the modelling, technology costs were a key area of the stakeholder engagement. Respondents were asked about technology CapEx cost benchmarks (referenced as £/cyclable-MWh), fixed OpEx costs (referenced as £/MW/year) and variable OpEx costs (as £/MWh).

Unsurprisingly, CapEx costs vary significantly across the different technology types and, to some extent, by the individual project. This is partially related to the capacity/size of the projects being developed (i.e. economies of scale) but also related to the technology readiness level (i.e. established vs novel technologies).

CapEx values for established technologies like pumped hydro can still vary but were in the range of £200,000-300,000 per MWh. Flow batteries and compressed air technologies typically have higher CapEx costs than lithium-ion batteries, at £500,000-700,000 per MWh. Hydrogen electrolysis is difficult to compare to other LDES technologies that responded to this engagement, as technology CapEx includes costs for the electrolyser, compressor and hydrogen turbine generator. Similarly, OpEx costs are also different due to the input electricity and water costs, as well as service and maintenance. The CapEx and OpEx ranges for each technology are detailed in *Table* 4.

***Table* 4:** *Technology cost results from Regen LDES online survey*

Technology	CAPEX (£/MWh)	OPEX (£/MW/Yr)
Pumped hydro	**£200k-1500k / MWh**	**£15k-25k / MW / Year**
Li-Ion Battery	**£400k / MWh**	**£26k / MW / Year**
CAES	**£500k / MWh**	**--**
Flow Battery	**£100k-700k / MWh**	**£6.5-22k / MW / Year**

CapEx costs for some LDES technologies are projected to reduce in the medium term, but the current financial climate means these reductions may not be as significant as originally thought. More novel technologies have a larger headroom for cost reductions than more commercially established technologies.

Flow battery developers suggested a range of potential cost reductions, in the region of 30-35% in the near term (up to 2035) and up to 70-80% in the longer term (out to 2050). Some pumped hydro developers suggested that very little cost reduction could be seen due to it being an established technology sector, but some respondents highlighted that not all pumped hydro sites are the same and some cost reductions could be achieved, depending on future sites and their scale. The UK supply chain was advised to be developing to enable costs to come down further for pumped hydro.

Copper-zinc battery developers highlighted an experience curve which could result in a 19% unit cost reduction per doubling of cumulative production. By 2035, depending on the technology growth rate, there could be a further reduction to 76%. Estimating beyond 2035 is difficult, but it was highlighted that the experience curve could potentially continue.

Respondents indicated that the technology costs for hydrogen electrolysis plants could see a reduction of 40-60% in the long-term and a 50% reduction could be seen in the long term for hydro-pneumatic energy storage.

A range of financial hurdle rates were provided by a small sub-group of respondents, as detailed in *Table* 5 below.

Table 5: Financial hurdle rate results from Regen LDES online survey

Technology	Hurdle Rate (%)
Pumped hydro	7%
Pumped hydro	10%
Pumped hydro	10%
Pumped hydro	10%
High Density Pumped Hydro	8%
Hydro-Pneumatic Energy Storage	5%
Copper-Zinc	15%
Compressed Air Energy Storage	8%
Hydrogen electrolysis	20%
Flow Battery	20%
Flow Battery	10%

4. Defining LDES Archetypes

4.1. Why archetypes?

LDES archetypes have been defined for use in the analysis. This has reduced the range of LDES variables we have tested, allowing us to focus on key LDES variables around duration, efficiency, costs, and location. A more detailed assessment of the nuances of every technology available would have provided too many scenarios to practically analyse. Each archetype is characterized by a standardised set of attributes which are then used in the modelling outlined in Chapters 6-8. The attributes are described in *Table 6* below.

***Table* 6:** *A description of archetype attributes*

Attribute	Description
Round Trip Efficiency (%)	Defined as energy out/energy in at the point of connection to the grid. This is AC power to AC power.
Variable Operating and Maintenance Costs (£/MWh)	Operating costs incurred as a result for charging/discharging. For most storage technologies these are near zero with the exception of pumped storage hydro.
Construction period (Years)	Length of time to construct the project. The capacity of the LDES asset is assumed to be phased in through the duration of the construction period.
Lifetime (Years)	Lifetime of the plant. With some technologies, this could potentially be expanded with some repowering/refurbishment in their lifetime
Average availability (%)	This is the percentage of time during a year that plant is available. This will account for failures (unplanned) and normal maintenance (planned).
Duration (hrs)	The number of hours the storage can continually discharge for, at maximum capacity.
Depth of Discharge (%)	Percentage of electricity storage useable (some technologies will not allow all stored energy to be discharged).
Degradation – Capacity (%)	The percentage decrease in discharge duration each year. This primarily applies to batteries.
CapEx (£/Kw)	CapEx costs include the costs incurred by the project after appointment of the EPC contractor / financial close. These include design costs, capital costs and installation costs. These are provided as a range for each technology and change over time due to learning rates.
Fixed OpEx (£/Kw)	Operational costs are the fixed costs incurred on an annual basis. These include operation, inspection, insurance etc. These are provided as a range for each technology and change over time due to learning rates.
Hurdle Rate (%)	Hurdle rates are defined as the minimum financial return that a project developer would require over a project's lifetime on a pre-tax real basis.

4.2. Methodology

To arrive at the chosen LDES archetypes and associated assumptions, we have used various sources, including DESNZ[26] [27] and NG ESO[28] reports and supplemented this with the findings from the engagement with LDES developers outlined in chapter 3 above. For this Study a detailed literature review of current sources has not been carried out. As such the information provided here should not be considered to constitute a review of storage assumptions used by DESNZ or industry.

Initially, the key attributes as outlined above were summarised for the technologies available across the reports referenced above. These attributes were then reviewed based on the engagement with storage developers and updated where needed. This resulted in a summarised list of assumptions for each LDES technology listed in *Table 1* in Section 2.1. Note that not all variables were available for every technology with some of the more nascent technologies having data missing. Similar technologies were grouped based on where available characteristics were similar. This primarily focused on variables that would have the largest impact on modelling results – storage duration, efficiency and costs. These were grouped into 5 LDES archetypes. This was compared against the results from the engagement with developers to ensure that all LDES technologies were covered. Given some technologies (for example Iron Air) did not have data for every variable available, these were agreed to be out of scope for the analysis.

4.3. Chosen archetypes

The five archetypes for use in the modelling have been defined as follows:

1. **Longer-duration batteries** – including all longer duration batteries between 6 and 8 hours that degrade over time such as Lithium-ion and Flow batteries.
2. **Longer-duration, low-efficiency (6hr)** – this includes compressed air and liquid air technologies that have duration of approximately 6 hours with lower efficiencies but do not degrade over time.
3. **Longer-duration, low-efficiency (12 hr**) – spanning the same or similar technologies to the previous archetype, but with longer duration of 12 hours.
4. **Established longer-duration storage (medium**) – pumped storage hydro with duration ranging from 8 to 12 hours.
5. **Established longer-duration storage (long)** – the same technologies as the previous archetype with durations of 16 to 32 hours.

For each technology archetype, a set of technical characteristics and cost assumptions have been defined, as shown in *Table 7* below. For archetypes with storage of two durations, the

[26] Storage Cost and technical assumptions for DESNZ Report, Mott McDonald
[27] Cost of Capital Update for Electricity Generation, Storage and Demand Side Response Technologies
[28] Energy Storage Technical Feasibility Assessment, NG ESO

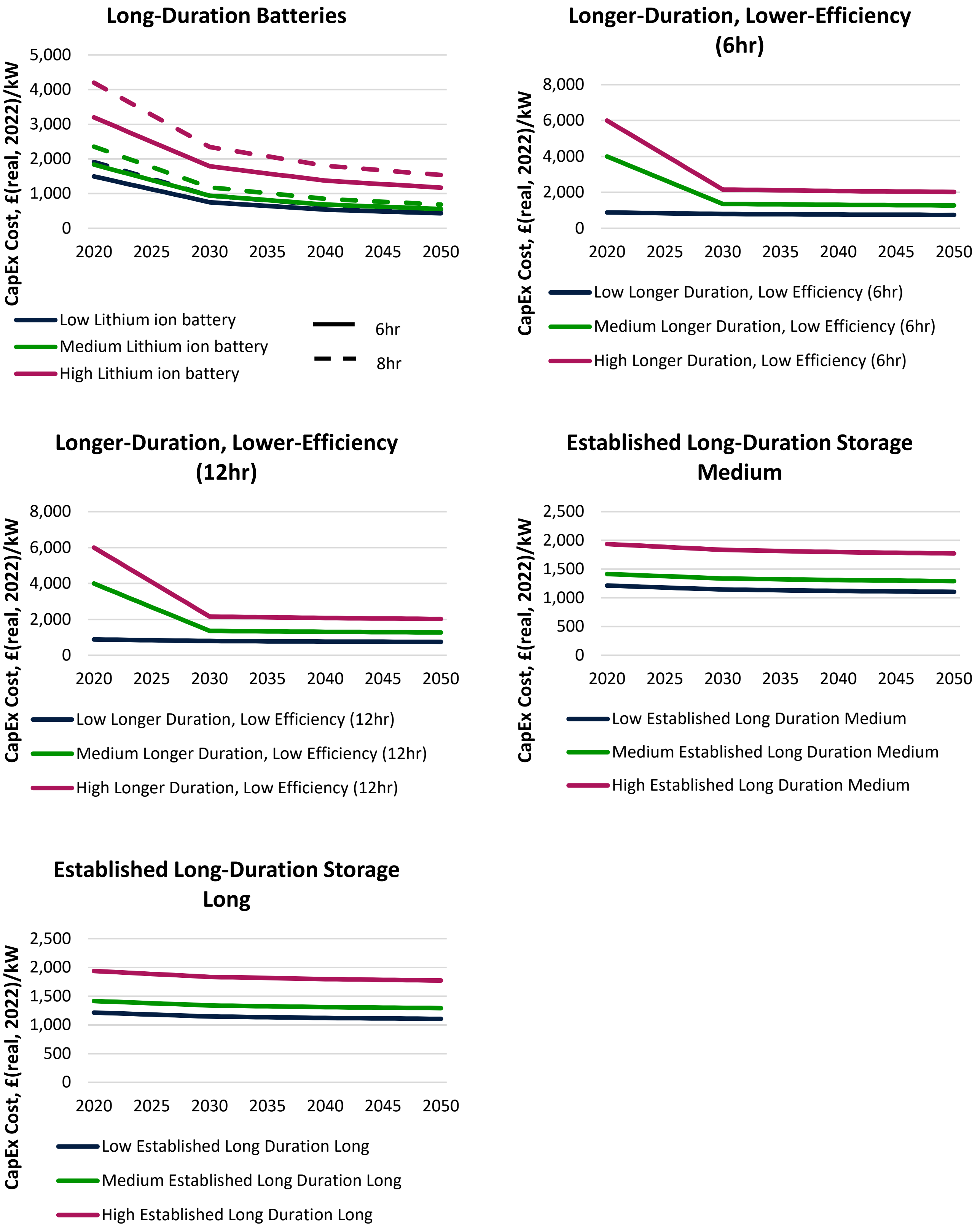
cost assumptions are specific to each duration. In the modelling where a single archetype has range of storage durations, this has been modelled as a 50/50 split between storage with the lowest duration and storage with the highest duration of the range.

Table 7: *The attributes assigned to each LDES archetype for modelling*

Attribute	Longer-duration batteries	Longer-duration, lower-efficiency (6hr)	Longer-duration, lower-efficiency (12hr)	Established longer-duration storage (medium)	Established longer-duration storage (long)
Round Trip Efficiency (%)	85%	60%	55%	80%	80%
Variable Operating and Maintenance Costs (£/MWh)	0	0	0	2	2
Construction period (Years)	1	1.5	2	4	4
Lifetime (Years)	20	30	40	50	50
Average availability (%)	96%	95%	95%	96%	96%
Duration (hrs)	6, 8 (50/50 Mix)	6	12	8, 12 (50/50 Mix)	16, 32 (50/50 Mix)
Depth of Discharge (%)	90%	100%	100%	100%	100%
Degradation – Capacity (%)	-2.5%	N/A	N/A	N/A	N/A
CapEx 2020 (£/Kw)	£1500-3200	£880-6000	£880-6000	£1200-1900	£1200-1900
CapEx 2050 (£/Kw)	£430-1500	£750-2000	£750-2000	£1,100-1800	£1,100-1800
Fixed OpEx (£/Kw)	£5	£10	£10	£15	£15
Hurdle rate	7.3%	7.3%	7.3%	6.2-7.3%	6.2-7.3%

Feedback from the engagement with developers and data from the report showed that there was a large variation in capital cost within the different archetypes. Given the significant uncertainty identified around capital costs, three CapEx cost levels were defined for each LDES archetype. These, along with hurdle rates, were not updated based on the engagement with developers. One reason for this is that the capital costs of other technologies are based on the DESNZ generation costs report from 2020, updating LDES CapEx costs only based on latest available data would disadvantage LDES compared to other technologies. It is likely that costs have increased for all technologies which would not be captured. The CapEx used for each archetype are outlined in the charts below:

Figure 13: *Capital Cost levels for LDES Archetypes*



The capital costs for the modelled archetypes displayed above show varying levels of alignment with the costs identified in the survey of LDES developers.

- For longer-duration batteries, the CapEx cost from the survey shows costs at around £1000/kW, similar to the lower-end of the range used. However, it should be noted costs in the survey are based on durations of up to 4 hours rather than the 6 or 8 hours used for the LDES archetypes.
- Longer-duration, lower-efficiency at 6 hours, most closely aligns with compressed air from the survey. The survey shows CapEx costs for this technology at £833.33/kW – again aligning with the lower-end of the range identified.
- Longer-duration, lower-efficiency at 12 hours, most closely aligns with liquid air from the survey. CapEx costs for this technology are not available from the survey so it is not possible to do a comparison.
- The two Established LDES archetypes most closely align with pumped storage in the survey. Given the wide range of durations in the survey for this technology (4 hours to multiday) and CapEx being provided on a £/MWh basis, a comparison between the survey and the costs used for the archetypes is extremely difficult. However, assuming a 4-hour duration to align with the duration used in the BEIS storage cost report (no other CapEx estimate for higher duration is available in either of the two reports used for CapEx assumptions) then the CapEx cost range is £500-3750/kW from the survey. With this simplification we see that the lower-end of the survey CapEx is below the range for the LDES archetype assumptions, but the higher-end of the survey CapEx is above the higher level for the LDES archetype assumptions.

In terms of hurdle rates, most of the hurdle rate estimates are higher in the survey compared to those published by DESNZ with a range of 8-20% compared to the 7.3% for most technologies in the DESNZ report. The only exception is one estimate for pumped storage hydro at 7% which aligns with the DESNZ estimate.

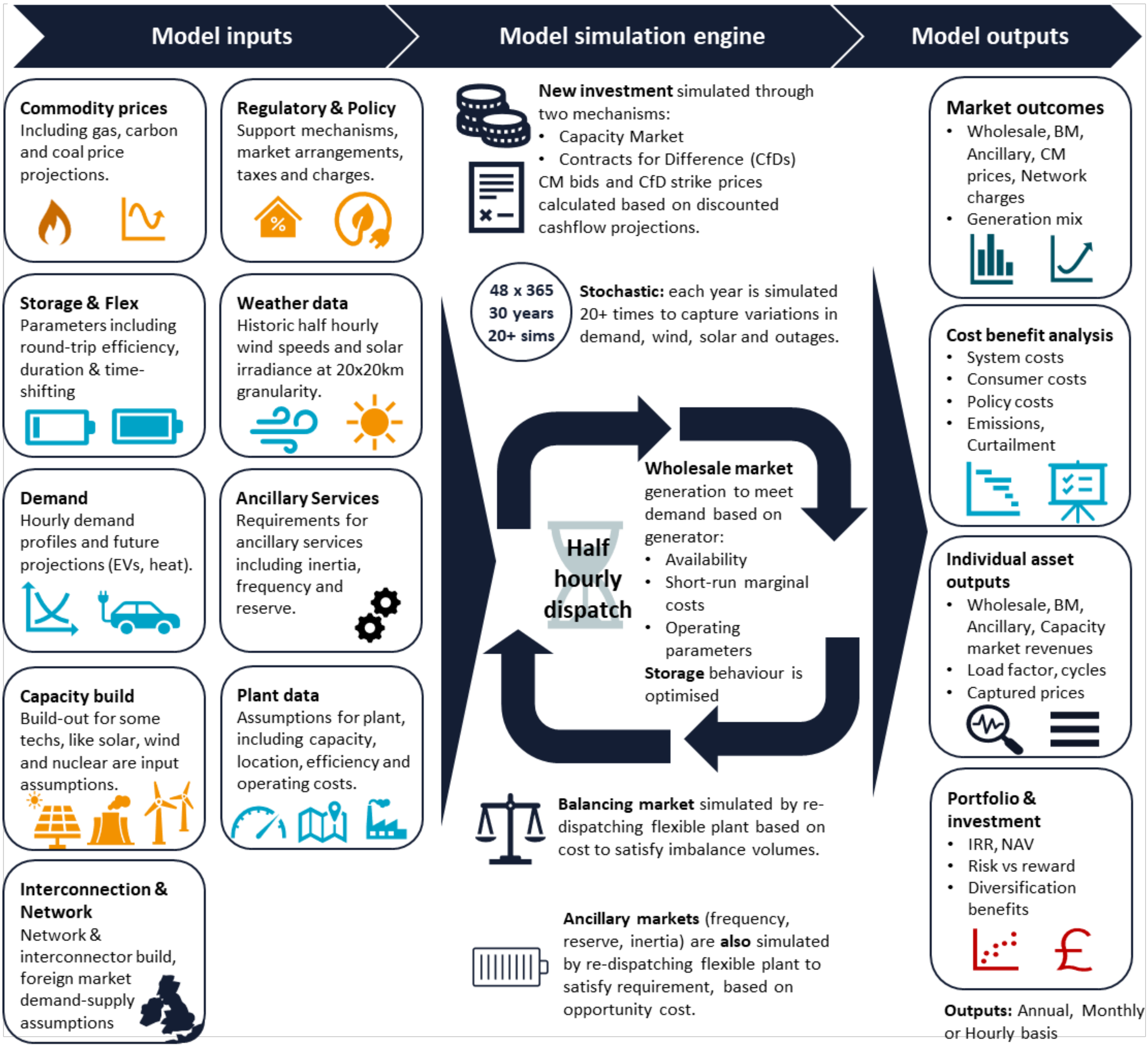
Note this information is provided as a high-level comparison only to give the reader an idea of the difference in the CapEx levels found in the survey compared to those in the published reports used to get estimates for the archetypes. A more detailed study on costs would need to be undertaken by DESNZ to fully understand how costs have changed since their published report on storage costs from 2018.

5. Modelling Approach

5.1. LCP Envision

The LCP Envision modelling framework is the primary tool used for this Study. Developed in-house at LCP Delta over the past ten years, the EnVision modelling framework is used by DESNZ, National Grid ESO, Ofgem and Low-Carbon Contracts Company (CfD counterparty). It can be used to model the wholesale market, Balancing Mechanism, locational balancing, ancillary services, network charges and the Capacity Market. A schematic is shown below.

Figure 14: *LCP Delta's Envision model framework*



Using the LCP Envision modelling framework has a number of features that makes it an appropriate tool for this Study.

- Our long-duration storage algorithm optimises the operation of the LDES assets across longer time periods (e.g. multiple days or weeks), rather than just within day (as is done for shorter-duration storage), to maximise their revenues. This approach allows us to model how LDES technologies will operate within the system. As this approach maximises revenues for the LDES assets, it better replicates how they will operate whilst also taking into account how its operation affects the operation of other assets on the system including other flexible assets. As the model simulates at half-hourly granularity for all 365 days across the year, we can also see exactly how the LDES is operating giving further insight into the impact that these technologies can have on the system.
- Within the model, the technical characteristics, operational behaviour and costs of LDES plants can be easily varied. This allows for testing a range of LDES characteristics to investigate the system impacts of LDES characteristics and costs.
- A stochastic approach is utilised to model the wholesale, balancing and locational Balancing Mechanisms. Many simulations of each year are run utilising differing demand and renewable generation profiles. This allows us to capture variations in weather and therefore renewable generation which are important for the operation of LDES. Weather data uses historical wind speed and solar irradiation data which is sampled from the NASA MERRA-2 dataset. This dataset includes weather data back to 1980 at 50km granularity covering the globe and is updated annually, and the raw weather data is converted into load factors using power curves for different technology types. Sampling historic weather data for the locations of the future fleet allows our model to capture how correlations across the wind fleet will change in the future. Importantly, this allows us to capture extreme events, such as periods of very low renewable output, which can provide a significant challenge to the system, while not under- or over-estimating their likelihood.
- A sequential approach is used, modelling a full 365 days for each year in each stochastic simulation at a half-hourly level[29]. This means we capture a full range of intermittency profiles and the resulting running profiles from the generation fleet. This is particularly important for LDES, whose running profiles and revenues will vary considerably under different renewable conditions and allows us to accurately model their operation across longer periods than just intra-day.
- Our modelling of balancing services (national energy imbalance and reserves) uses a fundamentals-driven approach. The requirement for each service is determined based on the underlying system drivers, and then the value available to flexible providers in satisfying these requirements is set by a market price.
- Our modelling accounts for security of supply requirements. The derating factors for specific technologies such as limited-duration storage, wind and solar are calculated

[29] Weather data is not available on a half-hourly basis so this is averaged based on the hourly data. For other assumptions, such as demand, inputs are on half-hourly basis.

based on the market scenario using the same modelling tools as those used by NG ESO. This allows us to understand the impact that LDES deployment can have on security of supply. This approach combined with scenarios which change levels of interconnection will enable us to understand how LDES can reduce reliance on electricity imports.

- The modelling framework includes outputs that will enable assessment of the impact of LDES both in terms of system cost (as outlined in 5.3 below) and market outputs that allow for insight into how LDES is operating within the system.
- The Envision modelling framework has been used for a number of projects that look at system benefits of technologies and policy changes to the system. This includes modelling provided to National Grid ESO and DESNZ on the case for change which informed the Review of Electricity Market Arrangements (REMA) consultation[30] and analysis for DESNZ to evaluate the success of the Contracts for Difference Scheme.[31]

For the locational modelling, LCP Delta's Locational Dispatch Model is used, this is covered in more detail in Chapter 8.

5.2. Modelling approach to assessing the impact of LDES

The analysis has been conducted in three key stages. Across all stages, a range of scenarios allowing LDES capacity and archetype to vary has been modelled to gather an understanding of how these two variables impact system cost and emissions intensity. These variables are outlined in Chapter 4 above with the scenarios modelled outlined in Section 5.4 below. With the exception of the archetype assumptions outlined above, all assumptions and scenarios have been provided by DESNZ unless otherwise stated.

How the LDES is added to the system has been varied to account for the different impacts it could have. Firstly, the LDES capacity is added to displace gas peaking capacity only. With the DESNZ scenarios having over 50GW of gas peaking capacity by 2050, this allows for an understanding of the impacts on emissions from adding LDES to the system. The LDES replaces gas peaking capacity to ensure that the overall derated capacity on the system required for security of supply stays the same. This varies across the different LDES archetypes as different storage durations have different deratings. For example, in the last T-4 capacity market auction for 2026/27[32] the derating factor for 6-hour storage plant was 59% but the derating factor for 9.5+ hour storage plant was 95%.

Secondly, the LDES capacity displaces installed wind generation capacity in addition to peaking capacity. This represents a reduced requirement to invest less in wind capacity in order to achieve the same level of emissions. Wind was chosen here over other technologies given the relationship between wind and LDES as highlighted in section 1.3 with deployment of LDES allowing for the wind to be used more effectively. Other technologies such as nuclear,

[30] Review of electricity market arrangements - GOV.UK (www.gov.uk)
[31] Evaluation of the Contracts for Difference scheme - GOV.UK (www.gov.uk)
[32] Electricity Capacity Report 2022.pdf (emrdeliverybody.com)

gas CCS or hydrogen could have been chosen to see an alternative impact. For example, LDES replacing nuclear would have shown significant CapEx impacts due to the high cost of nuclear. However, replacing wind (both onshore and offshore) with LDES capacity allows for an assessment on both impacts on costs and how renewables can be better utilised through LDES deployment.

The amount of wind capacity to be displaced is decided based on ensuring that the level of emissions remains at a similar level to the counterfactual. This effectively allows for a comparison across scenarios of the best way to achieve emissions ambitions within the power sector for different levels of LDES. Some peaking capacity is still replaced to ensure that the overall derated capacity on the system required for security of supply in maintained.

Finally, across all scenarios, given the significant uncertainty variations around CapEx costs are applied to understand the impact of LDES CapEx assumptions and how this changes the system cost. In addition, a breakeven CapEx point for a given hurdle rate for each archetype has been calculated with results from this analysis outlined in Annex B.

This modelling has been repeated for several counterfactuals, a Core Scenario based on DESNZ's own Net Zero Higher Demand scenario (Chapter 6) and then for various alternative counterfactual scenarios (Chapter 7). The alternative counterfactuals are based on reducing the installed capacity of gas with Carbon Capture and Storage (CCS) and hydrogen power plants, based on assumptions provided by DESNZ. These were chosen due to uncertainty around the deployment of these technologies and due to gas CCS and hydrogen to power being alternative providers of flexibility. This allows for an evaluation of how LDES can mitigate for the risk of these technologies not being able to deliver to the extent outlined in the DESNZ scenarios.

For the locational modelling, a small number of the modelled scenarios in the first stage have been further modelled within LCP Delta's Locational Dispatch Model to determine the impact that the location of LDES can have on locational balancing costs. This is explored in Chapter 8.

5.3. Assessing impacts

To assess the system impacts of adding LDES to the GB power system, the analysis measures the system costs across a range of different scenarios. This approach aligns with government value for money (VfM) guidance as set out in the Green Book.

The approach to system costs uses the framework for Whole System Costs that was developed in 2015 between LCP Delta, Frontier Economics and the UK government, and incorporated into the Dynamic Dispatch Model for use in government power sector impact assessments and VfM assessments. System costs represents the costs of building, operating and maintaining the system reflecting the overall cost of the power system and are split into the following components.

- **Generation costs –** Fuel and variable operating costs (VOM) costs associated with meeting electricity demand hour to hour, i.e. wholesale market dispatch.

- **Carbon costs** – Carbon costs based on carbon emissions (in MTCO2e) priced at social cost of carbon (DESNZ central appraisal price). The carbon cost can be split into two parts, carbon costs at the market price (carbon price plants pay) and unpriced carbon costs (additional carbon costs valued at appraisal price)
- **Balancing costs –** The fuel, VOM and carbon costs associated with balancing.
- **CapEx costs –** Capital costs include pre-development, construction and infrastructure costs (all £/kW). For the CapEx component of system cost, these costs represent the construction cost plus the cost of financing these investments. Costs are spread over the economic lifetime of the plant based on the assumed hurdle rate for the technology.
- **Fixed OpEx costs** – Fixed operating costs, any operating costs that do not vary with output, and represented in £/kW terms.
- **Interconnection costs –** Costs associated importing and exporting power over the interconnectors (the cost of building and maintaining interconnection is included in the CapEx and fixed OpEx categories). Costs are a 50:50 split between assuming interconnectors are part of the GB system and part of the connected market system.[33]
- **Network costs** – Cost of maintaining, reinforcing and extending the transmission network, including the costs of managing constraints. Note that distribution network costs are not out of scope of this report as these would need to be modelled separately. Impact on distribution network will be significantly smaller than impacts on the transmission network.

System cost impacts presented in the modelling sections represent a Net Present Value (NPV) of costs from 2025-50. Future costs are discounted at a rate of 3.5% per year (from 2025) as per green book guidance. All costs are provided on a real 2022 basis.

5.4. Scenarios and uncertainty

As outlined above, the modelling has been performed for both LDES scenarios and counterfactual scenarios. The LDES scenarios span a matrix of the LDES archetypes and LDES capacity. The LDES types are the LDES archetypes described above, with the addition of an ‘Even Mix’ type, which models an equal mixture of all LDES archetypes. Capacity levels have been defined levels for 2035 and 2050 with linear interpolation between these two points with capacity ramping up from an assumed start date of 2030. Capacities level are chosen to provide a representative view of the overall impact, the achievability of capacity levels for each archetype is out of scope of this study. Note that the modelling is conducted for every 5 years

[33] Interconnector (IC) costs can be calculated in two different ways with a 50:50 split between the two methods used in our system cost approach:

1. The domestic coast method is where the IC is treated as being part of the connected market. The CapEx and OpEx costs associated with the IC do not represent GB system costs, but the CM payments to the IC do. The GB system incurs the cost of imports (or receives revenues from exports) at the GB market price (rather than the foreign market price).
2. The foreign coast method is where the IC is treated as part of the GB system. The CapEx and OpEx costs associated with the IC represent GB system costs (but CM payments do not). The GB system incurs the cost of imports (or receives revenues from exports) at the foreign market price.

from 2030 in order to allow for modelling of more scenarios. The LDES scenarios based on different types and capacities used are displayed in *Table 8*. Combined this gives 84 different scenarios modelled.

Table 8: *LDES capacity and type scenarios. Every LDES type is modelled with every capacity scenario.*

Additional LDES Capacity scenarios
0GW (counterfactual)[34]
1.5GW in 2035 rising to 2.5GW by 2050
3GW in 2035 rising to 5GW by 2050
4.5GW in 2035 rising to 7.5GW by 2050
6GW in 2035 rising to 10GW by 2050
7.5GW in 2035 rising to 12.5GW by 2050
9GW in 2035 rising to 15GW by 2050
12GW 2035 rising to 20GW by 2050

LDES Types
Longer duration batteries (half 6 and half 8 hour)
Longer duration, lower efficiency (6 hour)
Longer duration, lower efficiency (12 hour)
Established longer duration medium (half 8 and half 12 hour)
Established longer duration long (half 16 and half 32 hour)
Even mix across all of the above

To account for the considerable uncertainty in LDES CapEx, low, medium and high CapEx scenarios are modelled for each LDES type and capacity scenario. The CapEx costs used are outlined in section 4.3. This increases the number of scenarios by 3x to 252 scenarios. To account for uncertainty around gas CCS and hydrogen to power deployment, 3 alternative gas CCS and hydrogen deployment levels have been defined. These are outlined in more detail in section 6. A further counterfactual with low capacity for both hydrogen and gas CCS is outlined in Annex B.

In total, this means 1,152 scenarios have been modelled for this Study accounting for a wide range of factors that change the impact that LDES can have on the power system. Overall, these scenarios allow for a robust analysis of the impact that LDES technologies could have on the system.

[34] In addition to any storage currently on the system

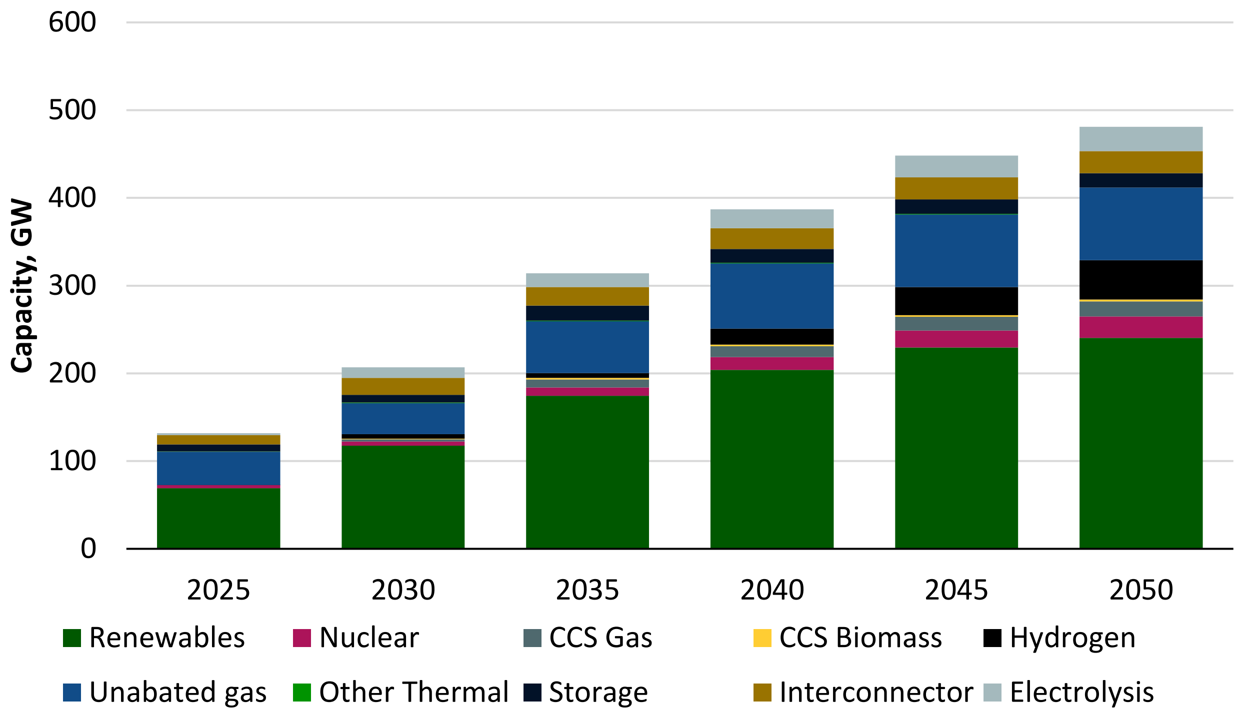
6. Modelling Results – Core Scenario

6.1. Key assumptions

Modelling the system benefits of adding LDES to the GB system requires a variety of assumptions on what the future power sector will look like. This includes power plant capacities, demand, network build-out, commodity prices, technology prices and policy inputs.

For this Study, these inputs are based on DESNZ's own Net Zero scenarios for the power sector as published in Annex O of the Energy and Emissions Projections.[35] The Core Scenario is based on the DESNZ Net Zero Higher Demand scenario. This represents a high electrification scenario for the future energy sector with total demand (excluding electrolysis) increasing by 50% to 2035 from 2022 levels and more than doubling by 2050. This requires large amounts of low-carbon capacity to be added to the system as shown below:

Figure 15: *Capacity (GW) by Technology – DESNZ Net Zero Higher Demand Scenario*



All other key input assumptions such as gas prices, carbon prices, peak demand, Contract for Difference (CfD) strike prices etc. also align with same inputs in the DESNZ Net Zero Higher Demand scenario from the Dynamic Dispatch model. Technology costs, including CapEx, hurdle rates, lifetimes etc. align with the 2020 DESNZ generation cost report.[36] LDES archetype costs and assumptions are defined separately as outlined in section 4.

[35] Energy and emissions projections: Net Zero Strategy baseline (partial interim update December 2021) - GOV.UK (www.gov.uk)
[36] DESNZ Electricity Generation Costs (2020) - GOV.UK (www.gov.uk)

Note that for the Core Scenario, locational impacts are considered to be out of scope with network reinforcement assumed to increase in line with capacity such that the impacts of network constraints are mitigated. The impacts of location of LDES are considered further in section 8.

6.2. Adding LDES to replace peaking capacity

6.2.1. Example scenario

As an illustration of the model outputs and to understand the impact that LDES has on the system, we outline the results from two example scenarios, before presenting the full analysis across multiple scenarios. The examples chosen are with 10GW of Established LDES Long and 10GW of 6-hour Low-Efficiency by 2050. These are an arbitrary choice and do not indicate a preferred scenario for LDES. In this scenario, LDES capacity replaces peaking capacity only, allowing for an understanding of the impacts on emissions from adding LDES to the system.

Change in capacity

In these example scenarios, some peaking unabated gas capacity is displaced by LDES. Adding LDES adds reliable capacity to the system meaning less capacity from elsewhere is needed to ensure security of supply. New peaking capacity (OCGT in DESNZ scenario), which is typically the marginal plant in the Capacity Market to maintain the same level of security. In earlier years, gas recip capacity is also replaced as there is not enough OCGT capacity to remove.

Figure 16: *Example Scenario 1 – change in capacity between factual with 10GW of LDES Low-Efficiency 6hr and counterfactual (DESNZ Net Zero higher demand) with no LDES*

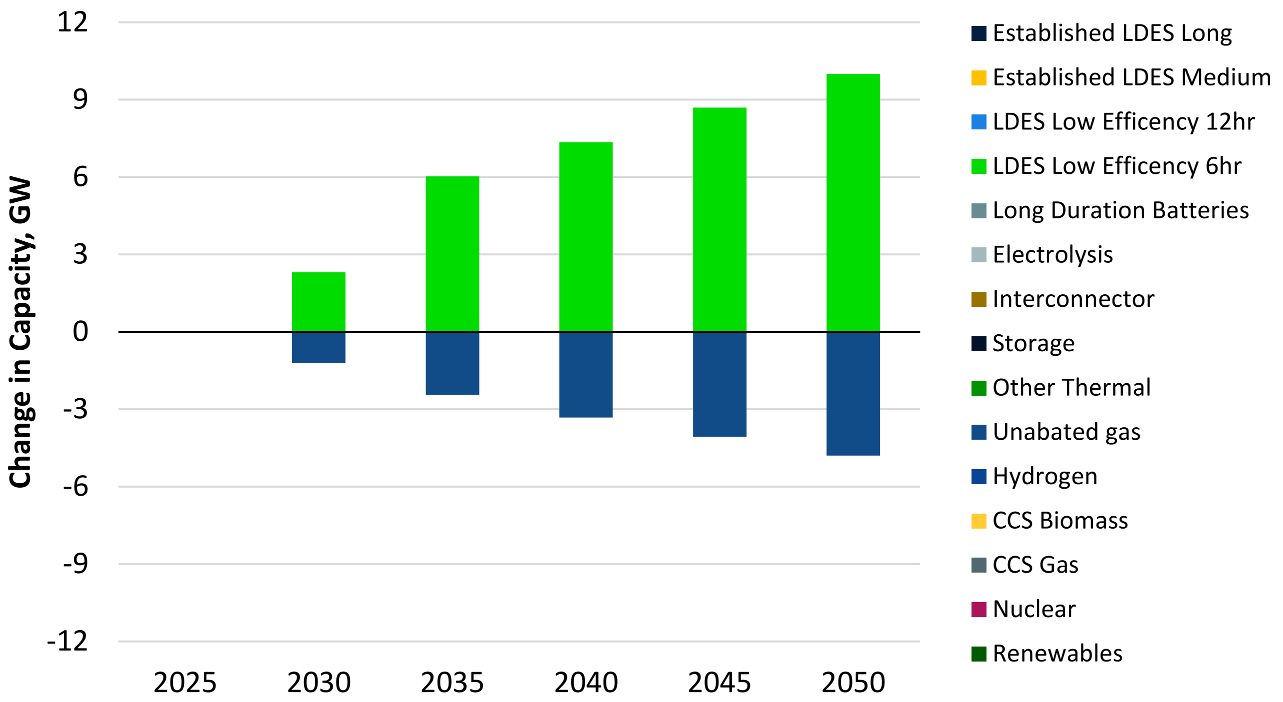
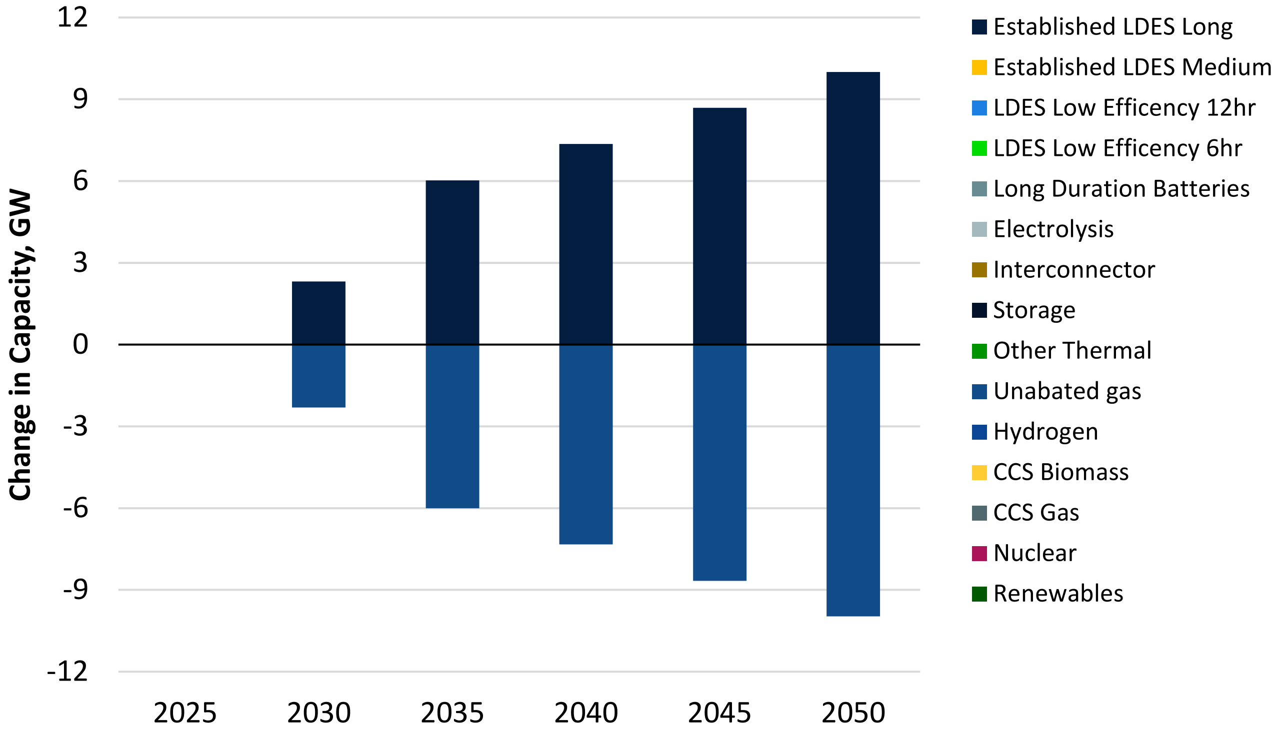


***Figure 17:** Example Scenario 2 – change in capacity between factual with 10GW of Established LDES Long and counterfactual (DESNZ Net Zero Higher Demand) with no LDES*



More unabated gas is removed in the Established LDES Long Scenario as this archetype would have a higher derating in the capacity market compared to the 6-hour low efficiency archetype, thus enabling more gas capacity to be replaced. LDES types with shorter durations have lower derating factors within the Capacity Market that are assumed to decline over time as the Effective Firm Capacity (EFC) of shorter duration storage declines over time as more renewables are added to the system. This is in line with published derating factors in the Electricity Capacity Report (ECR).[37] Future derating factors are modelled by LCP using the same model NG ESO use for the ECR. LDES above 9.5 hours are assumed to have a higher derating that does not change over time in the same way as shorter duration storage. This matches latest NG ESO assumptions, but this could change over time as stress events get longer meaning LDES above 9.5 hours may have a lower derating.

Change in generation and curtailment

Adding LDES to the system sees some significant changes in generation, despite only displacing peaking capacity. Renewable generation increases as the LDES allows excess generation from these plants to be stored and used more effectively, while generation from thermal assets (hydrogen to power, unabated gas and gas CCS) declines as it is displaced by LDES discharging. Interconnector net imports also decline as fewer imports are needed when the LDES is discharging, and exports decline as some renewable generation is used in storage rather than exported. LDES shows as net negative generation due to efficiency losses but generation from other sources increases (mainly renewables) to account for this.

[37] NG ESO Electricity Capacity Report - Electricity Capacity Report 2022.pdf (emrdeliverybody.com)

Figure 18: *Example Scenario 1 – change in generation between factual with 10GW of LDES Low-Efficiency 6hr and counterfactual (DESNZ Net Zero higher demand) with no LDES*

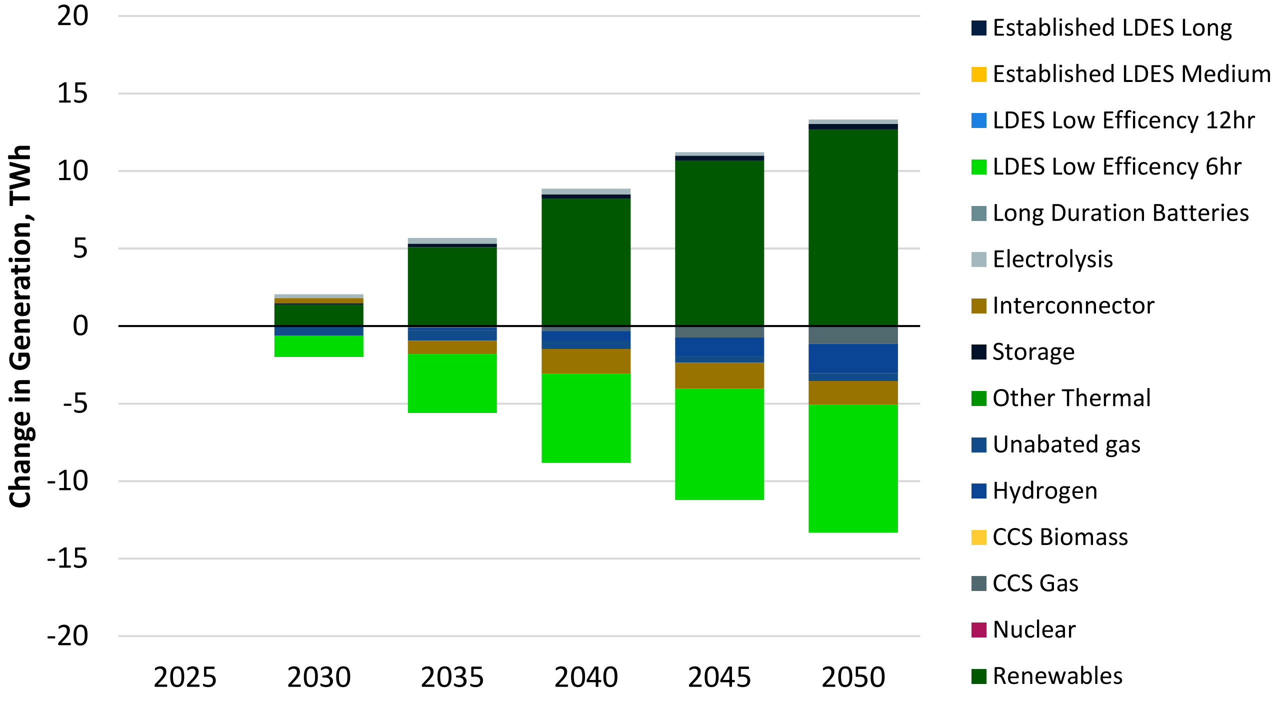
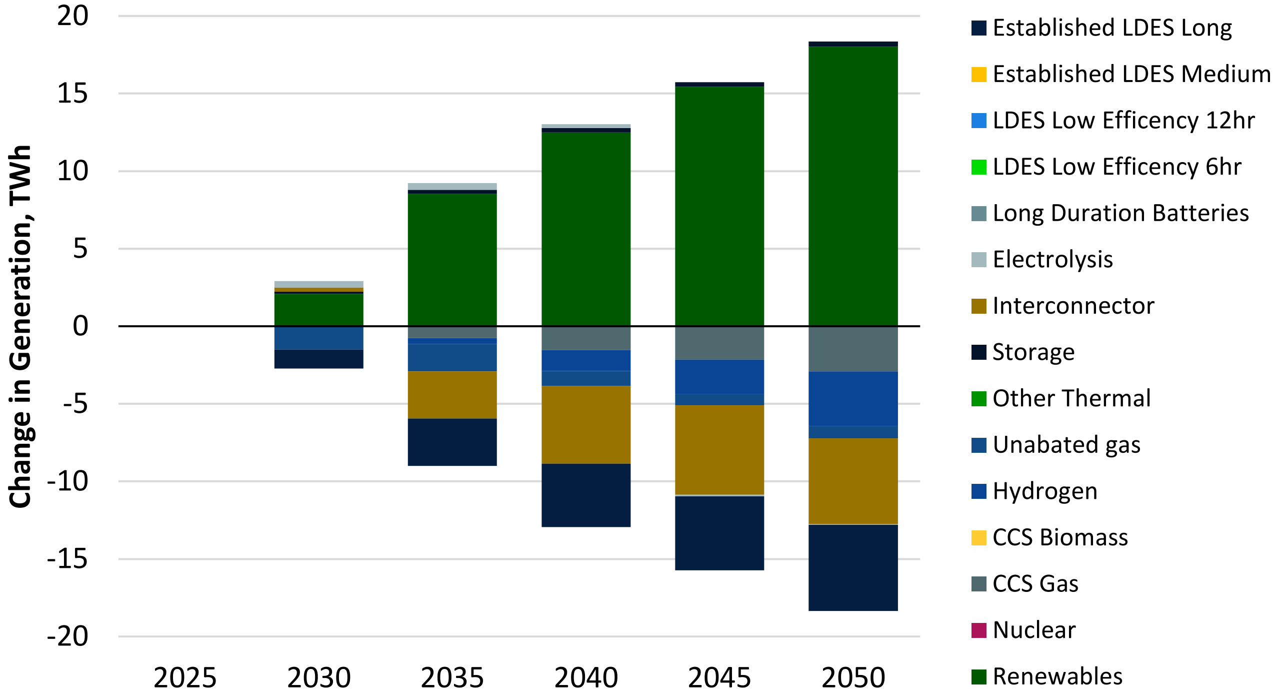


Figure 19: *Example Scenario 2 – change in generation between factual with 10GW of Established LDES Long counterfactual (DESNZ Net Zero higher demand) with no LDES*



Adding 10GW of the higher duration and more efficient Established LDES Long archetype allows for a larger increase in renewable generation compared to the Low-Efficiency (6hr). For example, renewable generation increases by 18TWh in 2050 with an additional 10GW of Established LDES long and 13TWh with an additional of 10GW of Low-Efficiency (6hr) LDES. This is due to longer duration of this archetype allowing for more renewable generation to be effectively moved from high wind, low demand to low wind, high demand periods and replace thermal generation or imports via the interconnectors. Additionally, the higher efficiency means there are fewer losses (net charge) when the LDES is used meaning the increase in renewable generation replaces more generation from unabated gas and hydrogen and imports via the interconnectors. This is shown by the net negative generation of the LDES in the Established LDES Long Scenario being 5.5TWh compared to 8TWh for the Low-Efficiency (6hr) LDES.

The increase in renewable generation is a result of less renewable curtailment meaning the renewable capacity on the system is being used more effectively. In both scenarios renewable curtailment decreases but the change is larger in the Established LDES Long Scenario. In this scenario renewable curtailment drops from 65TWh to 56TWh in 2035 and from 153TWh to 135TWh in 2050. This also means that the percentage of renewable generation that is curtailed drops from 14% to 11% in 2035 and 19% to 17% in 2050. In comparison in the Low-Efficiency (6hr) LDES Scenario, renewable curtailment drops from 65TWh (14% of renewable generation curtailed) to 60TWh (12%) in 2035 and from 153TWh (19%) to 141TWh (18%) in 2050.

Figure 20: *Example Scenario 1 – change in renewable curtailment between factual with 10GW of LDES Low-Efficiency 6hr and counterfactual (DESNZ Net Zero higher demand) with no LDES*

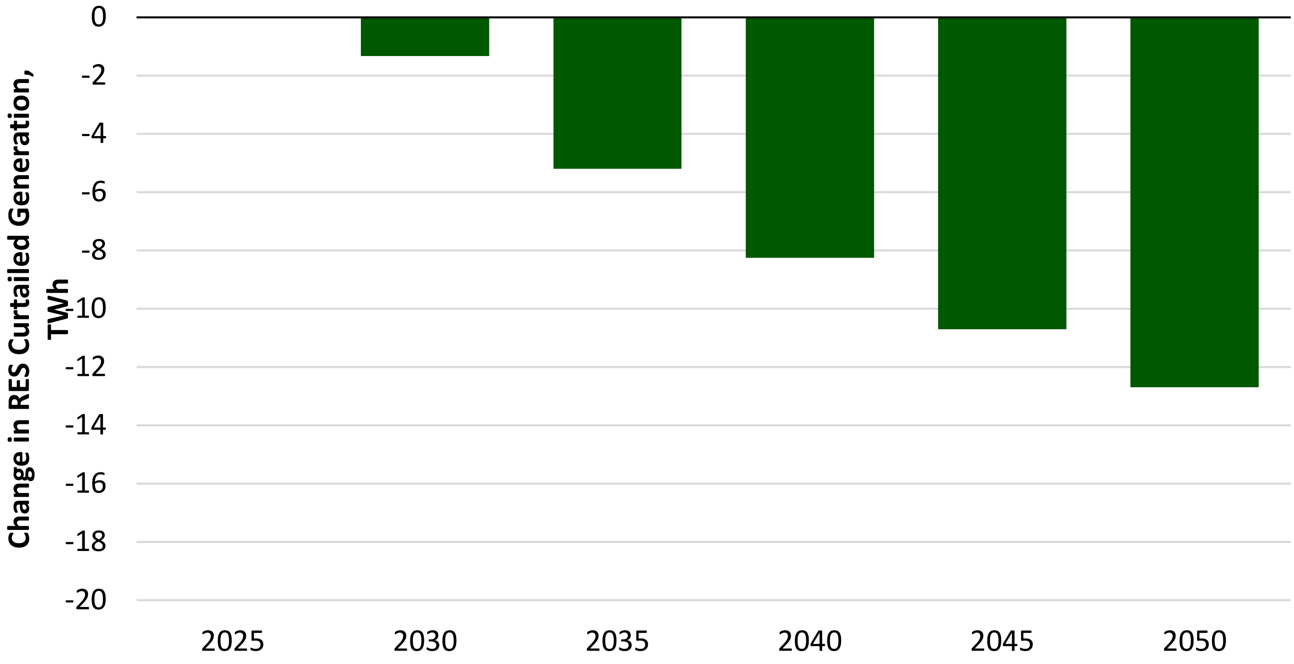
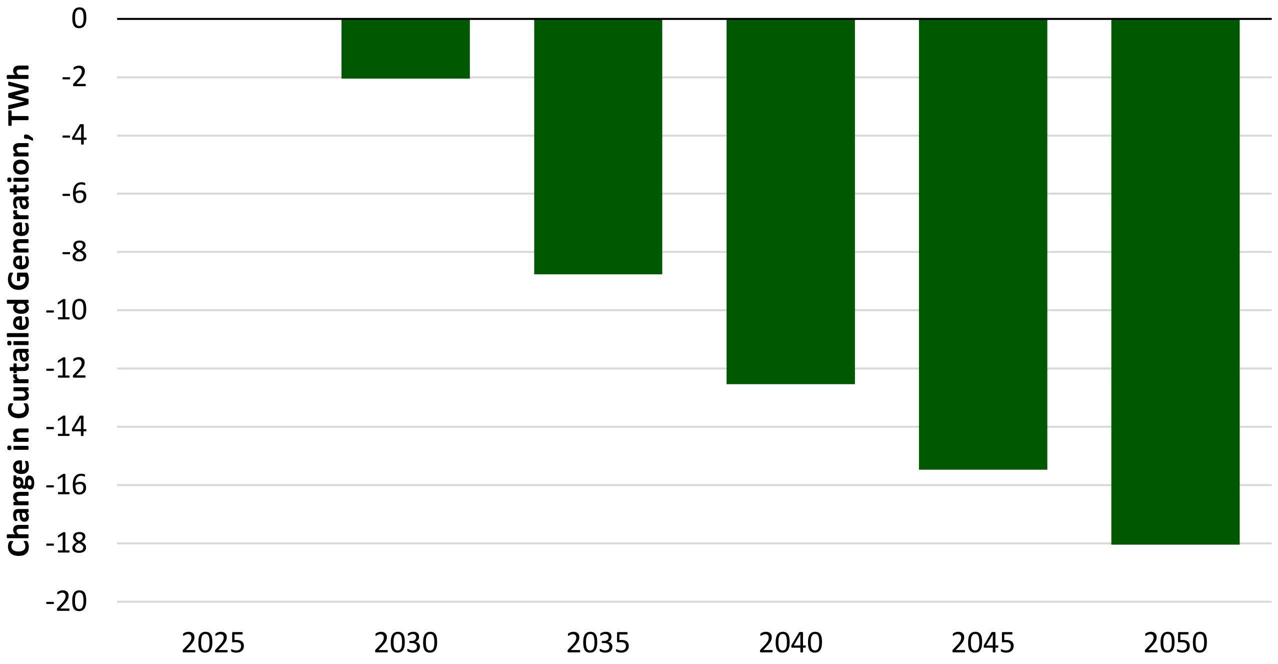


Figure 21: *Example Scenario 2 – change in renewable curtailment between factual with 10GW of Established LDES Long and counterfactual (DESNZ Net Zero higher demand) with no LDES*



Change in wholesale prices and emissions

Changes in generation lead to changes in wholesale prices. More generation from renewables and less from thermal assets, such as unabated gas, gas CCS and hydrogen leads to lower wholesale prices. This is a result of LDES being able to discharge at cheaper prices than the thermal assets and imports it is replacing when generating/discharging (this offsets the price increases during periods the LDES is charging).

Figure 22: *Example Scenario 1 – wholesale prices for factual with 10GW of LDES Low-Efficiency 6hr and counterfactual (DESNZ Net Zero higher demand) with no LDES*

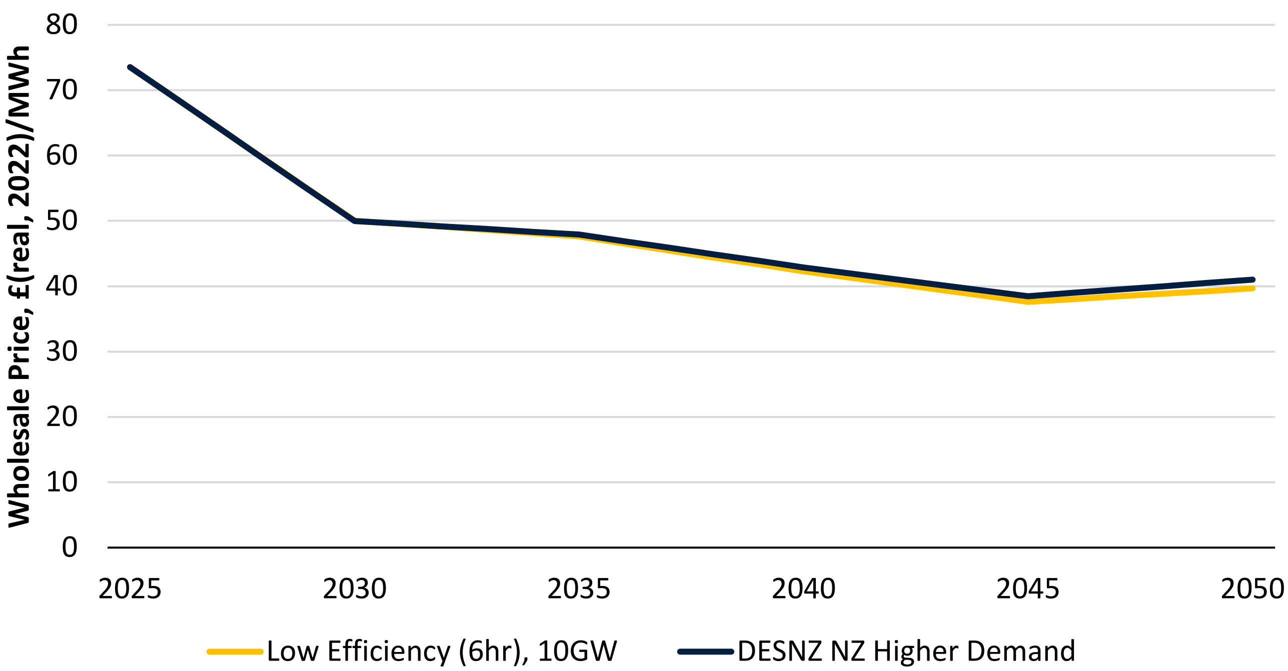
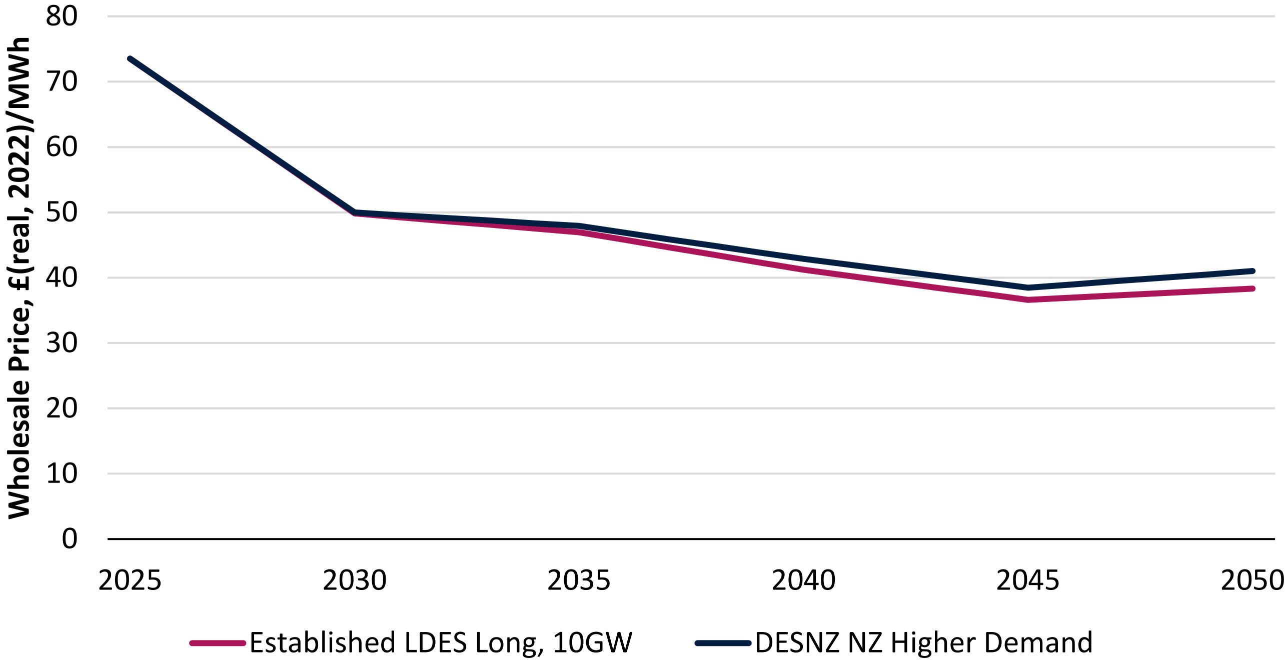


__Figure 23:__ Example Scenario 2 – wholesale prices for factual with 10GW of Established LDES Long and counterfactual (DESNZ Net Zero higher demand) with no LDES



Comparing across the two example scenarios, the Established LDES Long Scenario has a greater impact on reducing wholesale prices. This is a result of more renewable generation and less thermal generation in this scenario compared to the Low-Efficiency (6hr) LDES scenario.

Additional LDES also has an impact on emissions. Lower use of unabated gas and gas CCS with more LDES on the system causing emissions to decrease.

__Figure 24:__ Example Scenario 1 – emissions intensity for factual with 10GW of LDES Low-Efficiency 6hr and counterfactual (DESNZ Net Zero higher demand) with no LDES

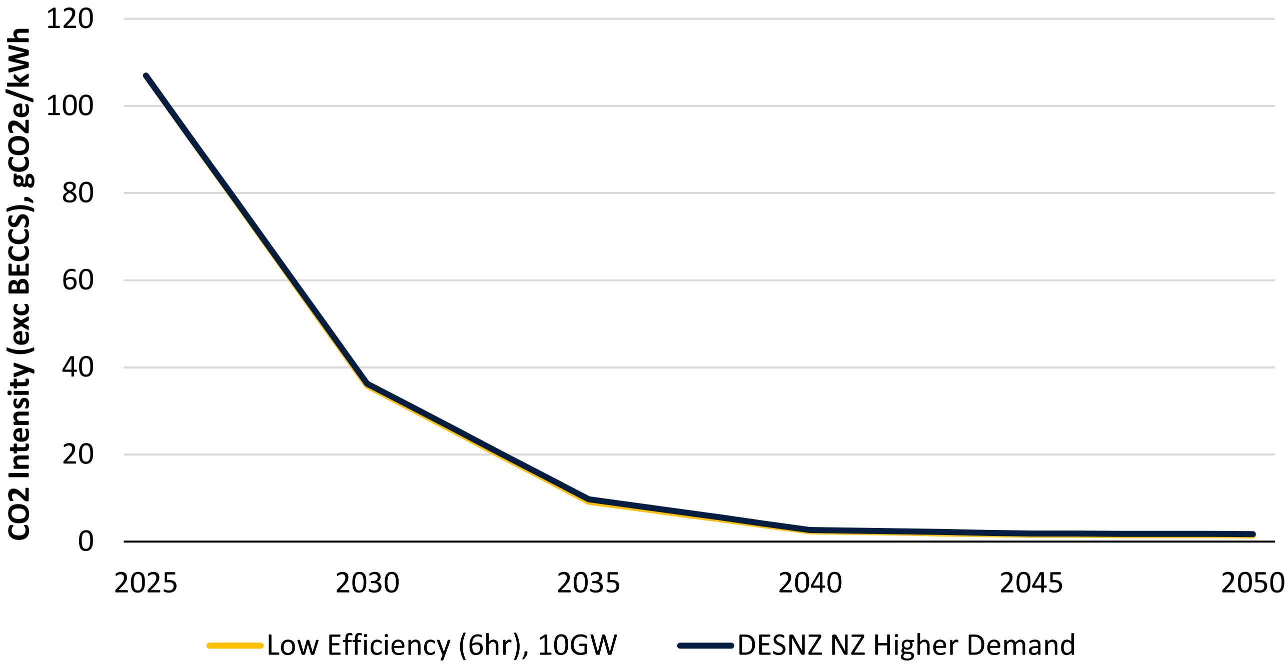
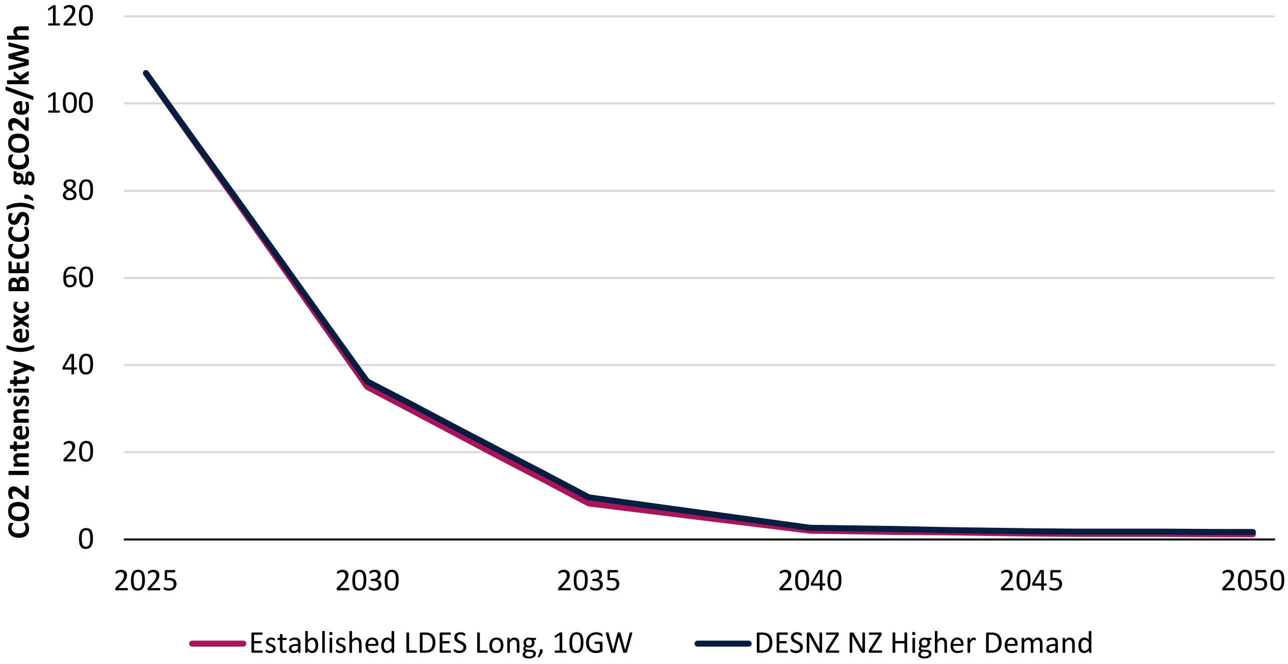


Figure 25: *Example Scenario 2 – emissions intensity for factual with 10GW of Established LDES Long and counterfactual (DESNZ Net Zero higher demand) with no LDES*



The impact on emissions is higher in the Established LDES Long Scenario with emissions intensity dropping by 8% (0.8gCO2e/kWh) in 2035 compared to 0.3gCO2e/kWh in the Low-Efficiency (6hr) LDES scenario.

Change in system costs

Adding LDES technologies has impacts on system costs but the extent of the impact depends on the type of LDES added. Comparing across the two example scenarios, adding Low-Efficiency (6hr) is a cost to the system with costs from 2025-50 at high (NPV £14.5bn cost) and medium CapEx (NPV £6.3bn cost) levels with a small benefit with low CapEx for the LDES (NPV £0.2bn benefit). In comparison the Established LDES reduces overall system costs if the CapEx costs of the LDES are at low (NPV £6bn benefit) but increases costs with medium (NPV £1.3bn cost) and high (NPV £6.9bn cost). These costs are broken down below into the different categories previously outlined in Section 5.3.

- **Interconnector costs** are reduced in both scenarios due to lower import costs as a result of the LDES discharge replacing these. This outweighs increases in net costs from the reduction in exports, due to LDES charging, which typically occur during lower cost periods. Impacts are higher in the Established LDES Long Scenario as the LDES enables more renewable generation to be used domestically decreasing use of interconnectors further.
- **Generation costs** also decrease in both example scenarios as LDES reduces fuel and carbon costs by displacing thermal generation costs with cheaper renewable generation as the LDES allows for renewable generation to be used more effectively. Again this impact is higher in the Established LDES Long Scenario as unabated gas, gas ccs and

hydrogen generation decreases by more in this scenario. Carbon costs are assessed at the carbon appraisal value.

- **Fixed OpEx** costs increases in both scenarios as the fixed OpEx of LDES technologies is higher than of the OCGT capacity it replaces. Fixed costs are assumed to be the same for both archetypes, so they see the same increase in costs.
- **Network costs** see a very small change in costs as connecting LDES technologies to the network is similar to connecting OCGTs.
- **Balancing costs** decrease slightly in both scenarios as LDES used in balancing is cheaper than using peaking plants such as OCGTs.
- **CapEx Costs** increase as the LDES has higher CapEx costs than the peaking capacity is replacing. The level of this rise is dependent on the CapEx cost of the LDES with the impact varying by archetype and CapEx level. CapEx costs are higher in the Low-Efficiency 6hr scenario due to higher hurdle rates, shorter lifetime and slightly higher CapEx costs than the Established LDES Long. The Establised LDES Long also replacing more OCGT capacity also has an impact here

Figure 26: *Example Scenario 1 – System Cost Comparison for factual with 10GW of LDES Low-Efficiency 6hr and counterfactual (DESNZ Net Zero higher demand) with no LDES at differing LDES CapEx levels*

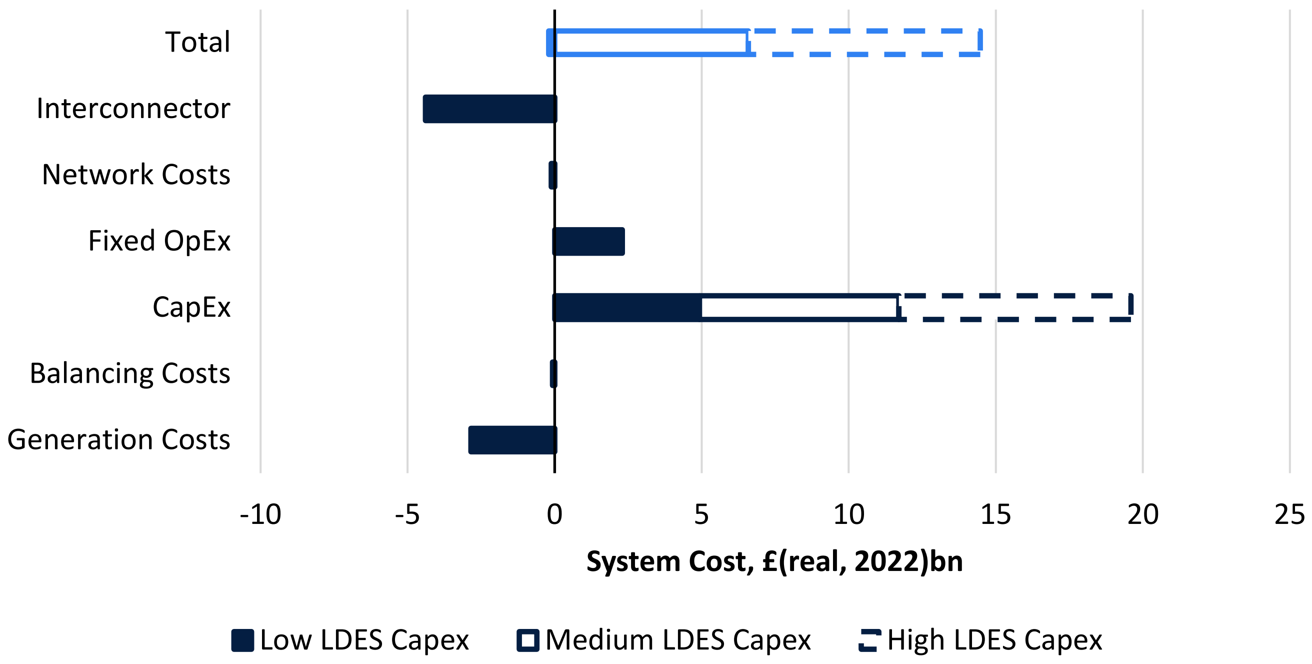
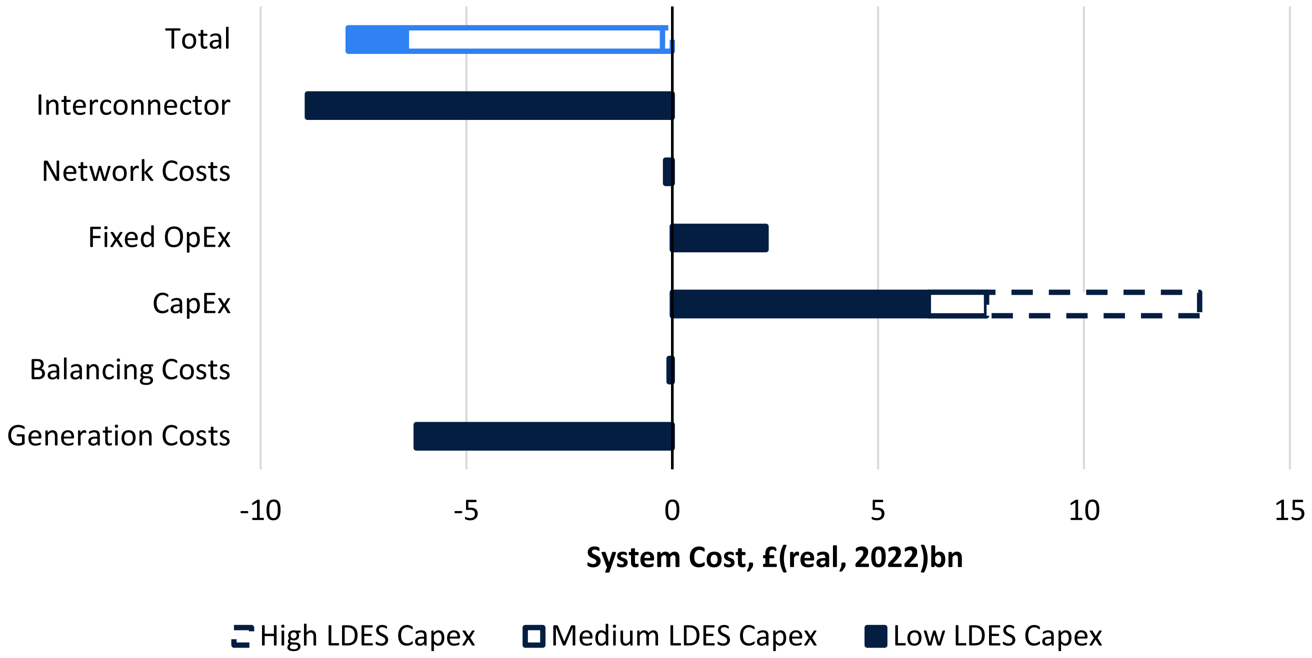


***Figure 27:** Example Scenario 2 – System Cost Comparison for factual with 10GW of Established LDES Long and counterfactual (DESNZ Net Zero higher demand) with no LDES at differing LDES CapEx levels*



The system costs can be broken down by the years modelled to show how the cost profile changes over time. This shows a relatively consistent change in system costs over time as more LDES is added to the system with interconnector and generation costs decreasing while CapEx and fixed OpEx costs increase. Note that costs in the chart below are undiscounted and for the medium LDES CapEx scenario.

Figure 28: *Example Scenario 1 – Change in yearly system costs (undiscounted) factual with 10GW of LDES Low-Efficiency 6hr with Medium LDES CapEx and counterfactual (DESNZ Net Zero higher demand) with no LDES*

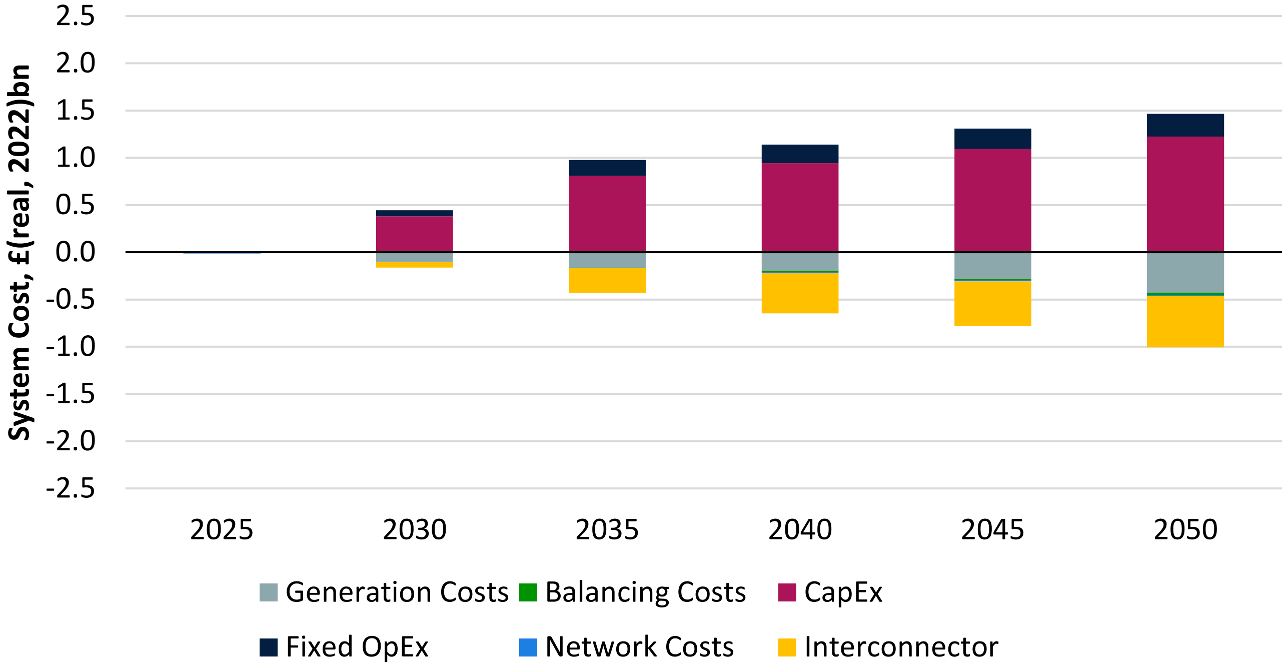
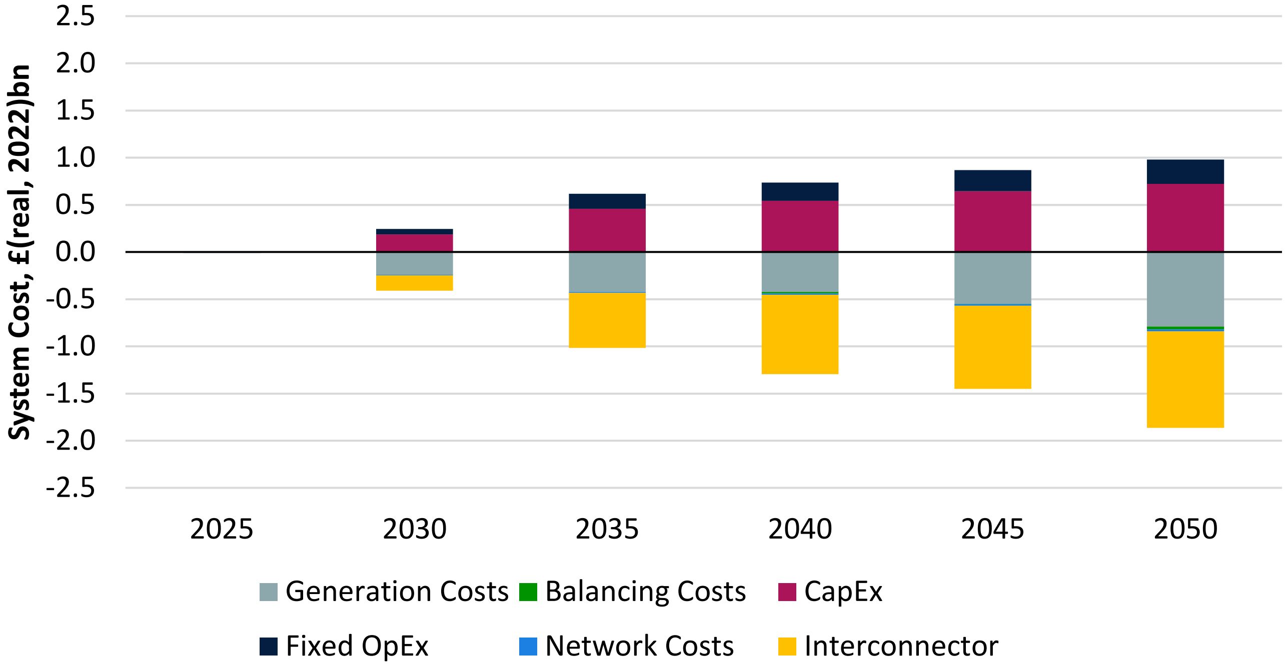


Figure 29: *Example Scenario 2 – Change in yearly system costs (undiscounted) factual with 10GW of Established LDES Long with Medium LDES CapEx and counterfactual (DESNZ Net Zero higher demand) with no LDES*



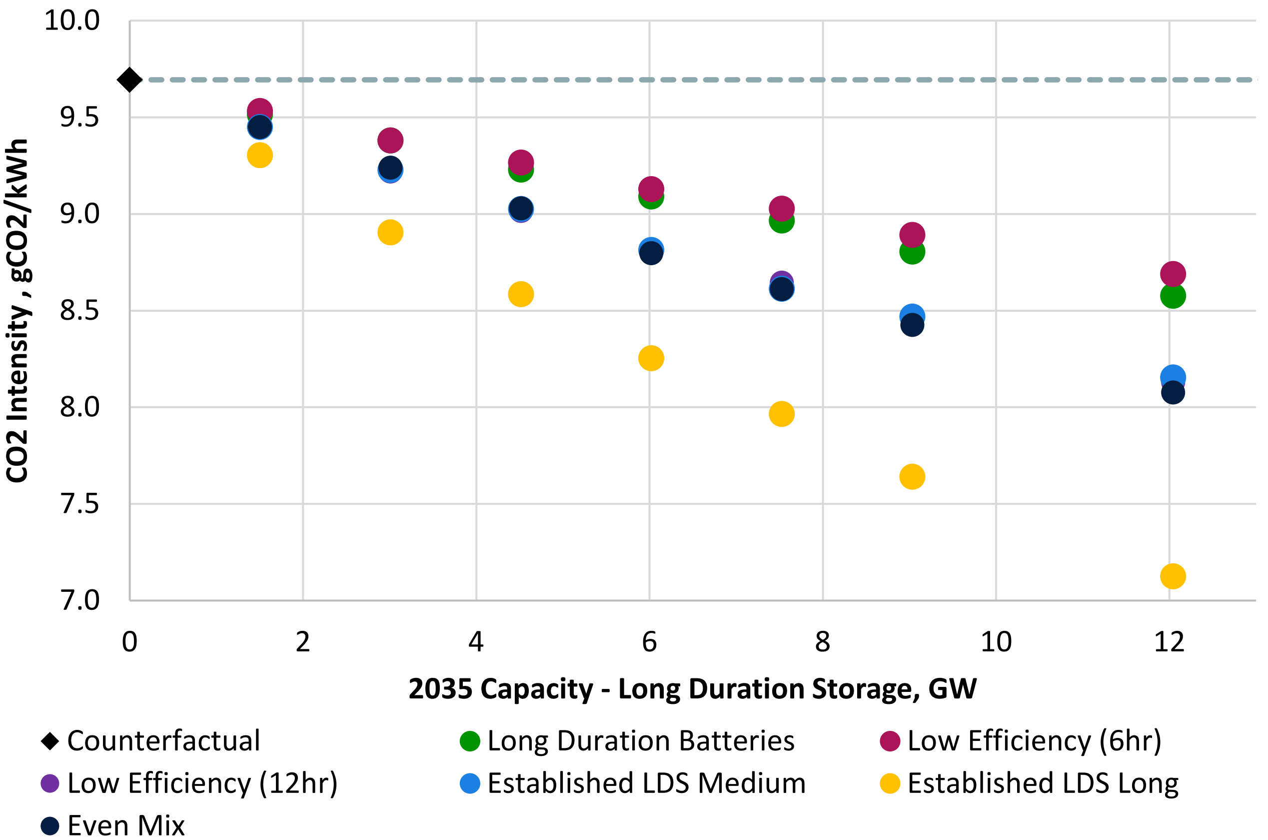
6.2.2. All LDES scenarios – adding LDES to replace peaking capacity

Emissions impact

The scatter plot below shows the 2035 emissions intensity against the LDES capacity for **all 42 scenarios** where LDES replaces peaking capacity against the DESNZ Net Zero higher demand counterfactual. Each dot on the graph represents a different LDES scenario with different LDES archetypes and capacities as outlined in section 4. The black diamond shows the DESNZ Net Zero higher demand counterfactual with no additional LDES added.

The plot below shows how adding LDES to the system at the expense of peaking capacity decreases emissions, with the CO2 intensity reducing by up to 26%. In general, the higher duration the larger the impact on emissions with the established long-duration storage long (16-32 hrs) having the largest impact on emissions.[38] This highlights that adding LDES technologies can help reduce emissions and therefore achieve emissions targets set by government for CB6 and Net Zero.

Figure 30: *Emissions intensity v LDES capacity in 2035 (coloured by LDES archetype) in the Core Scenario with LDES replacing peaking capacity only.*



The impact of different efficiency levels can also be seen as the low efficiency (12hr) archetype and Established LDS medium have a similar impact despite the established LDS medium

[38] Note that this does not necessarily mean that adding even longer durations would perpetually increase benefits further. Additional modelling would need to be undertaken to understand this.

having a lower duration on average but a higher charging efficiency.[39] This shows that higher efficiency levels in LDES can lead to lower emissions as well although the impact is not as significant as duration.

A mix across LDES archetypes could be beneficial to the system. The even mix scenarios have the second biggest impact on emissions across the different LDES archetypes, with only the Established LDES Long having a larger impact. This indicates that a mix of different types of storage could bring benefits to the system in terms of reducing emissions, especially as this is likely to be more realistic in terms of achievable deployment levels than just deploying large amount of Established LDES Long.

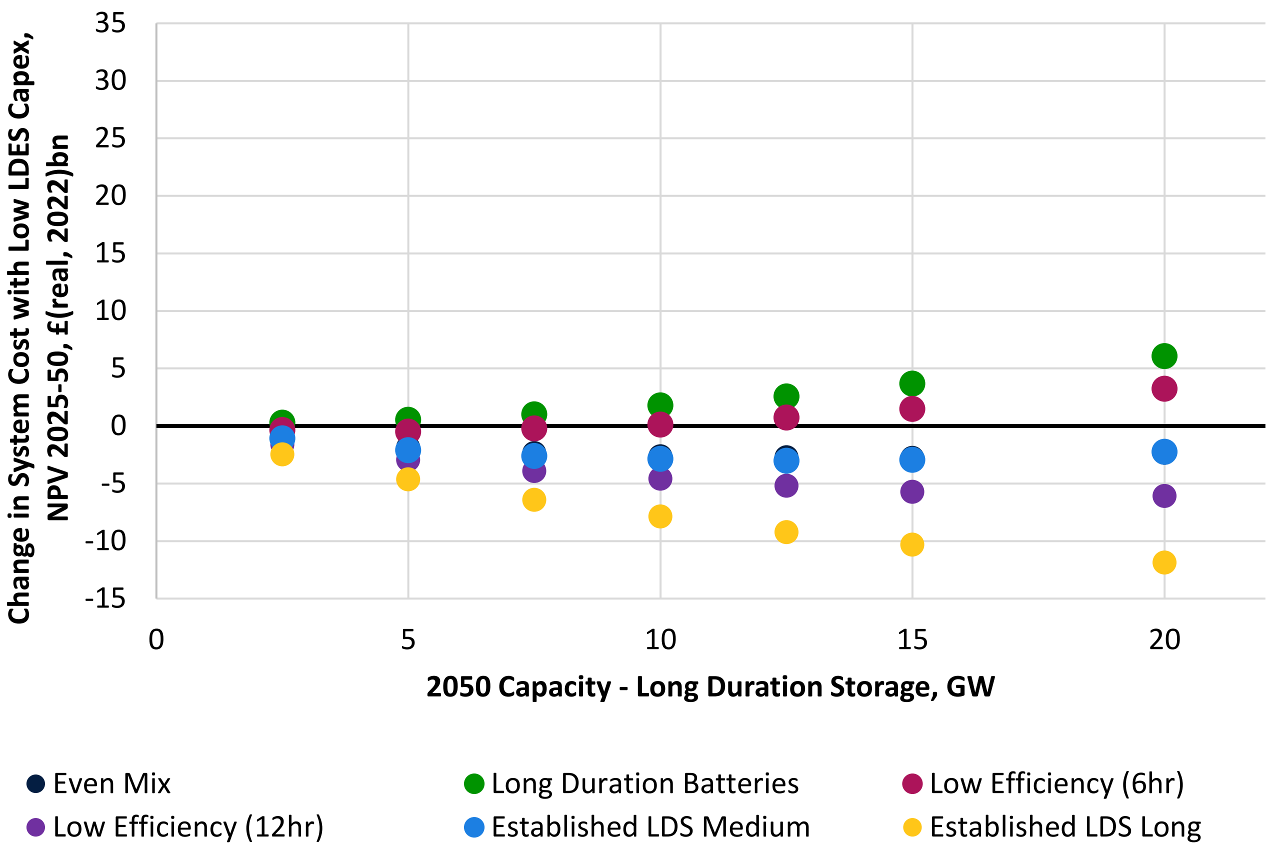
[39] Established LDS medium being a combination of 8- and 12-hour duration, with an efficiency assumed at 80% rather than the assumed 55% for the Low-Efficiency 12hr archetype.

Systems cost impact

In this Core Scenario, where only peaking capacity is replaced, all LDES technologies are found to reduce generation and interconnector costs (as illustrated in the example scenario above), however the total system cost can increase due to the CapEx, depending on the LDES archetype and CapEx assumptions. The scatter plots below show the total system costs (NPV 2025-50) against the LDES capacity for **all LDES scenarios with a DESNZ Net Zero higher demand counterfactual** where LDES replaces peaking capacity only with different levels of CapEx for the LDES archetype.

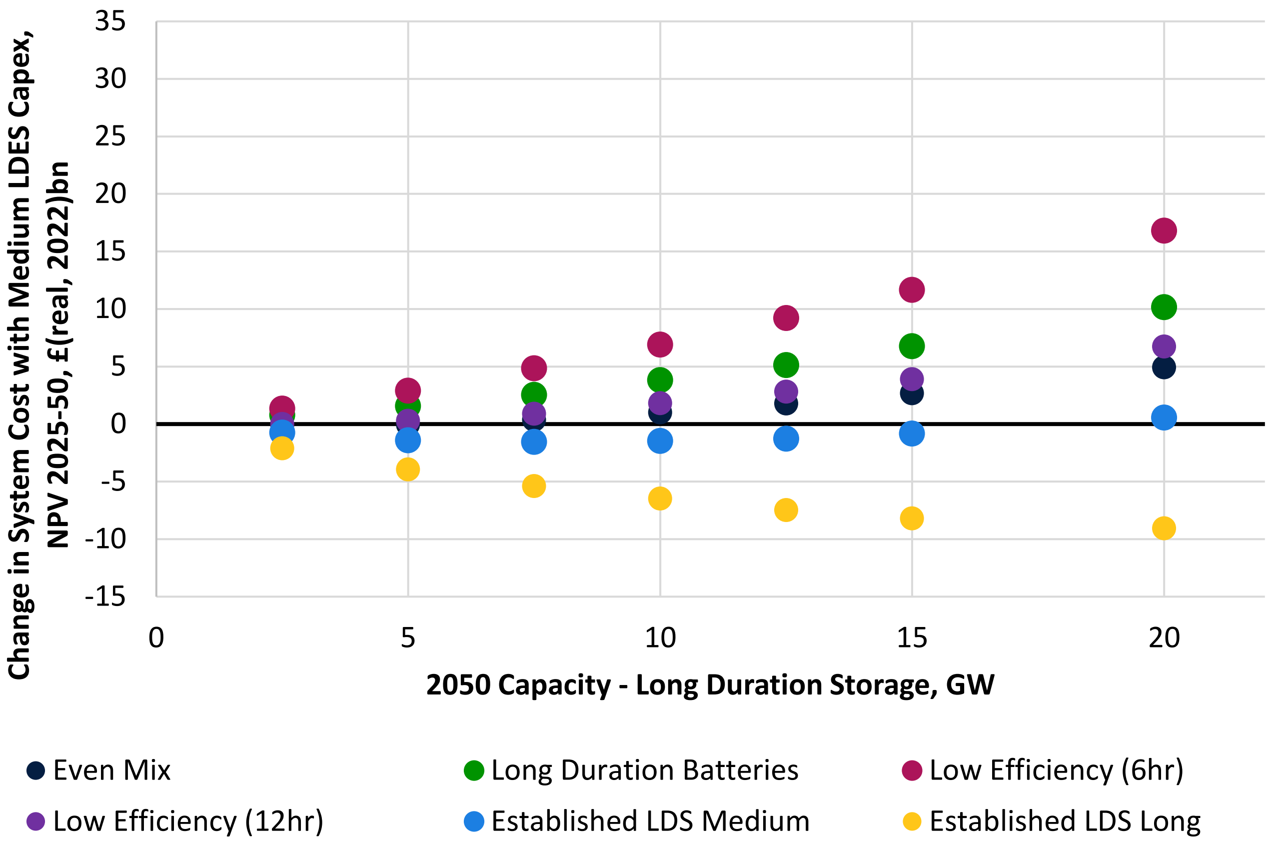
As with emissions, in general the higher the duration the larger the impact on costs with the Established LDES Long (16-32 hrs) showing the largest benefit in terms of reducing cost. With low CapEx assumptions, only the Long-Duration Batteries and Low Efficiency 6hr (at penetrations of 10GW or higher) archetypes increase system cost. This highlights that adding LDES technologies onto the system of higher durations (above 8 hours) can reduce both emissions and system costs simultaneously, provided the CapEx is low enough. The change across cost types for each LDES archetype largely follows the example scenarios outlined above with the biggest drivers being reduced generation and interconnection costs, offset by CapEx increases (which vary by CapEx level).

Figure 31: *System cost (NPV) with Low LDES CapEx v LDES capacity in 2050 (coloured by LDES archetype) in the Core Scenario with LDES replacing peaking capacity only.*



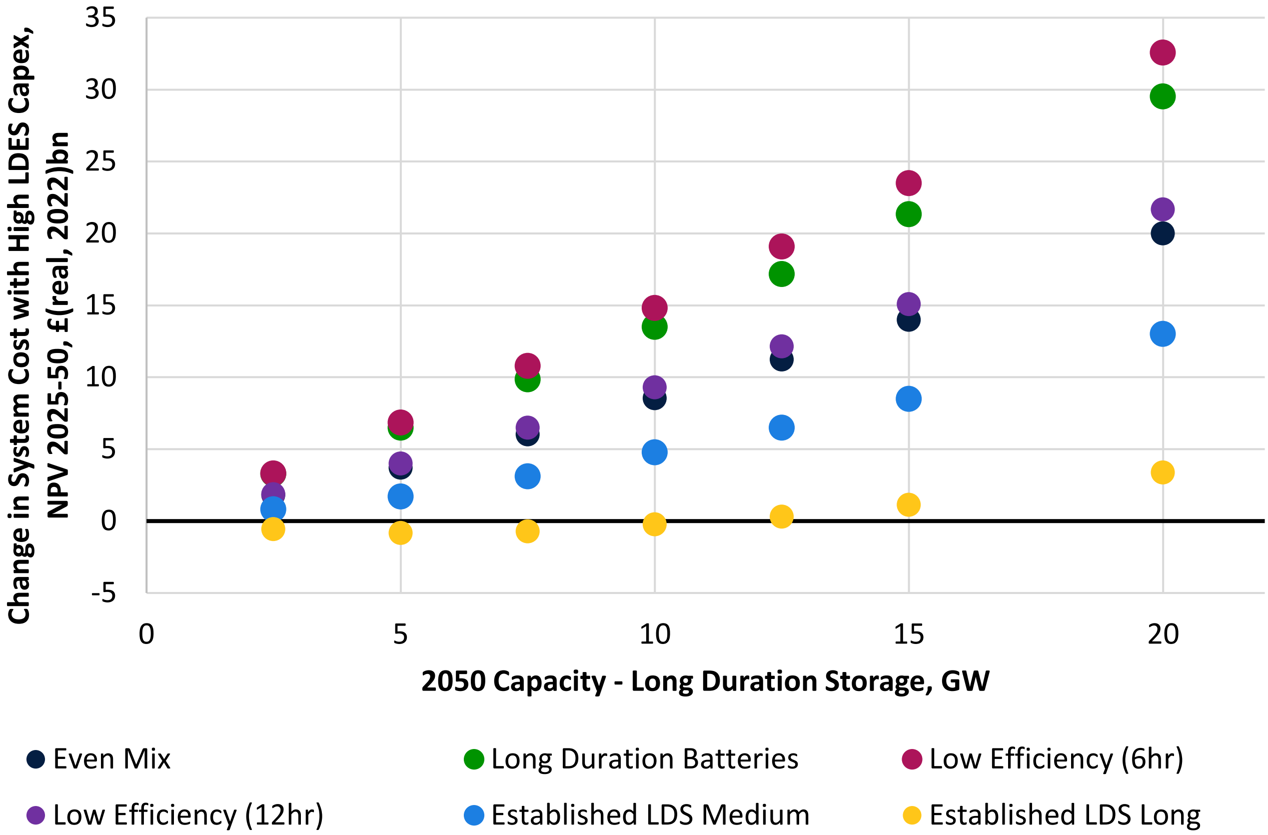
With medium CapEx assumptions (and replacing peaking capacity only), the Low Efficiency (12hr) archetype and the Even Mix across all archetypes adds costs to the system at all capacity levels (in addition to the Long-Duration Battery archetype and the Low-Efficiency (6hr) archetype). Only the Established LDES (Long) archetype continues to see benefits at all capacity levels tested, though Established LDES (Medium) sees benefits at capacity levels of 15GW or below.

Figure 32: *System cost (NPV) with Medium LDES CapEx v LDES capacity in 2050 (coloured by LDES archetype) in the Core Scenario with LDES replacing peaking capacity only.*



With High CapEx assumptions, only the Established LDES long archetype at 10GW or below shows a benefit. Adding all other archetypes now represent a net increase in system costs. These results highlight the importance of the CapEx of LDES and therefore shows that if LDES is to only replace peaking capacity (as modelled here), the primary benefit is in the reduction of the system's emissions intensity, rather than system cost reductions.

Figure 33: *System cost (NPV) with high LDES CapEx v LDES capacity in 2050 (coloured by LDES archetype) in the Core Scenario with LDES replacing peaking capacity only.*



To realise system cost savings with any confidence, installed capacity of renewables needs to be reduced relative to the counterfactual as LDES capacity is installed while maintaining the target emissions intensity. This is considered in the next section.

6.3. Adding LDES to replace peaking and renewable generation capacity

To achieve the same level of emissions as the counterfactual, scenarios are modelled where LDES replaces renewable capacity (in addition to peaking capacity). These represent a reduced need to invest in additional renewable capacity, as the LDES allows renewable capacity to be used more effectively. These scenarios allow for a comparison of the LDES contribution to reaching emissions targets at lowest system cost.

6.3.1. Example scenario

As with results in the previous section, as an illustration of the model outputs and to understand the impact that LDES has on the system, we outline the results from two example scenarios before presenting the full analysis across multiple scenarios. The same examples as before are chosen: 10GW of Established LDES Long and 10GW of 6-hour Low Efficiency in 2050. In this scenario, LDES capacity replaces wind capacity in addition to peaking capacity.

Change in capacity

In these example scenarios, wind capacity (in addition to peaking unabated gas capacity) is displaced by LDES. Adding LDES to the system allows for the wind capacity to be used more effectively, increasing generation from these plants, and meaning less capacity is needed to reach the same level of emissions. As the LDES also provides security of supply (more than the renewable capacity that is removed) it also still displaces peaking unabated gas capacity in the same way as the scenarios shown in 6.1 and 6.2.

***Figure 34:** Example Scenario 3 – change in capacity between factual with 10GW of LDES Low-Efficiency 6hr and counterfactual (DESNZ Net Zero higher demand) with no LDES*

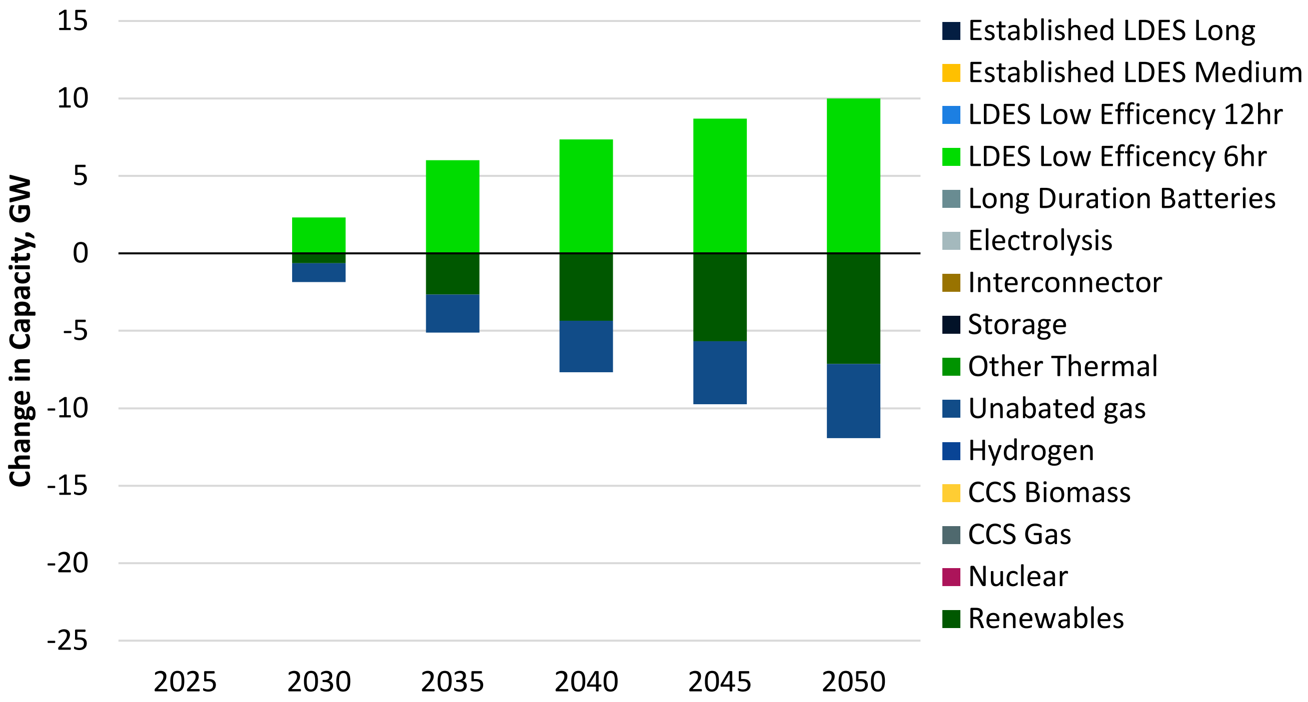
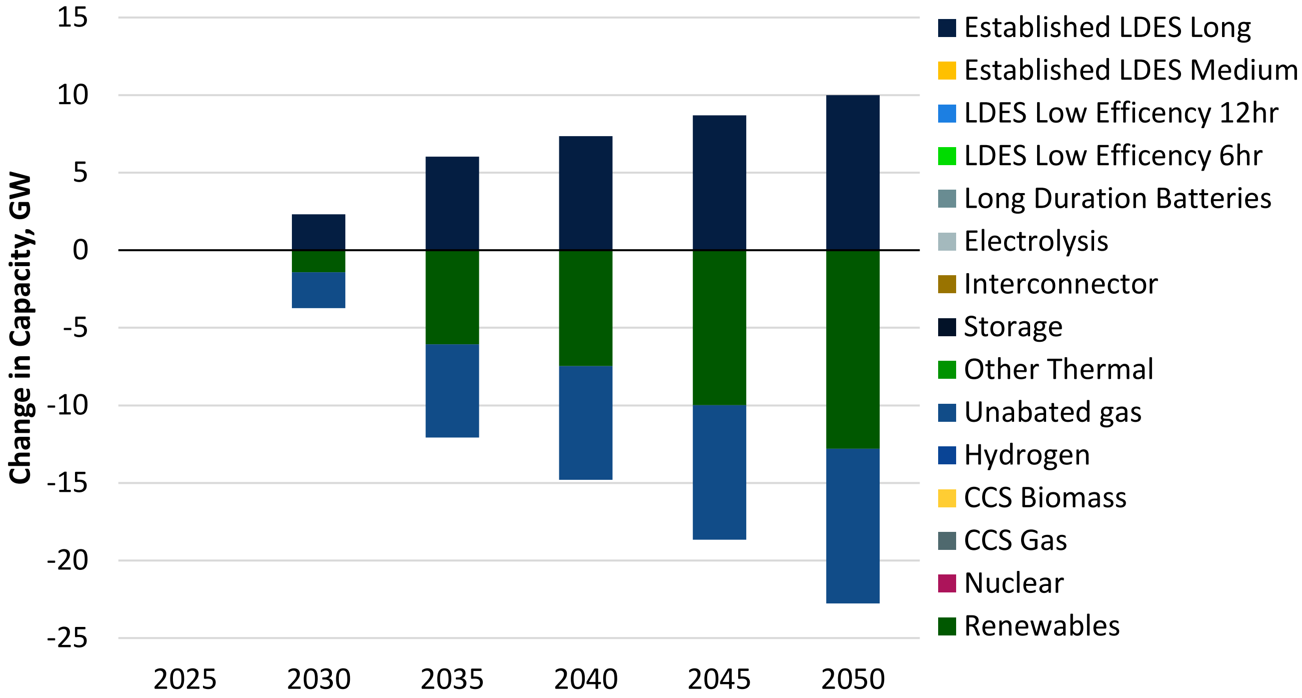


***Figure 35:** Example Scenario 4 – change in capacity between factual with 10GW of Established LDES Long and counterfactual (DESNZ Net Zero higher demand) with no LDES*



With 10GW of Low-Efficiency (6hr) LDES added to the system, this enables a reduction of 7GW of wind capacity for the same level of emissions, in addition to 5GW reduction in peaking capacity. Adding 10GW of Established LDES Long to the system allows for wind capacity to reduce further by 13GW for the same level of emissions, in addition to a 10GW reduction in peaking capacity. This is a result of the longer duration and higher efficiency of this archetype being able to increase renewable generation by more than the Low-Efficiency (6hr) archetype. Peaking capacity also reduces by a larger amount in the Established LDES Long Scenario owing to the higher derating in the capacity market of this archetype due to its longer duration.

Change in generation and curtailment

Adding LDES at the expense of peaking and renewable capacity sees some significant changes in generation. Renewable generation decreases compared to the counterfactual. This is due to the amount of capacity being removed in order to reach the same level of emissions meaning less wind generation is exported via the interconnectors and used in electrolysis. As expected, unabated gas and gas CCS generation sees very little change in order to maintain the same level of emissions.

The LDES results in changing behaviour on the interconnectors with net imports increasing meaning even with less renewable and unabated gas generation, emissions end up at a similar point to the counterfactual. The trend towards higher net imports is driven by lower exports. GB exports less, due to lower wind generation, and excess renewables being used to charge rather than exported. For similar reasons there is also reduced utilisation of electrolysers (i.e. lower electrolysis demand, shown as an increase in generation) as the LDES dispatches ahead of electrolysis. In some cases, this leads to more efficient use of wind within the power sector as the LDES will be displacing hydrogen generation in a more efficient way than the electrolysis to hydrogen to power generation cycle. However, this is dependent on assumptions around future hydrogen prices. It should be noted that this does not necessarily indicate that LDES is a better use of electricity than electrolysis from a whole economy perspective given the wider use for hydrogen across different sectors.

Figure 36: *Example Scenario 3 – change in generation between factual with 10GW of LDES Low-Efficiency 6hr and counterfactual (DESNZ Net Zero higher demand) with no LDES*

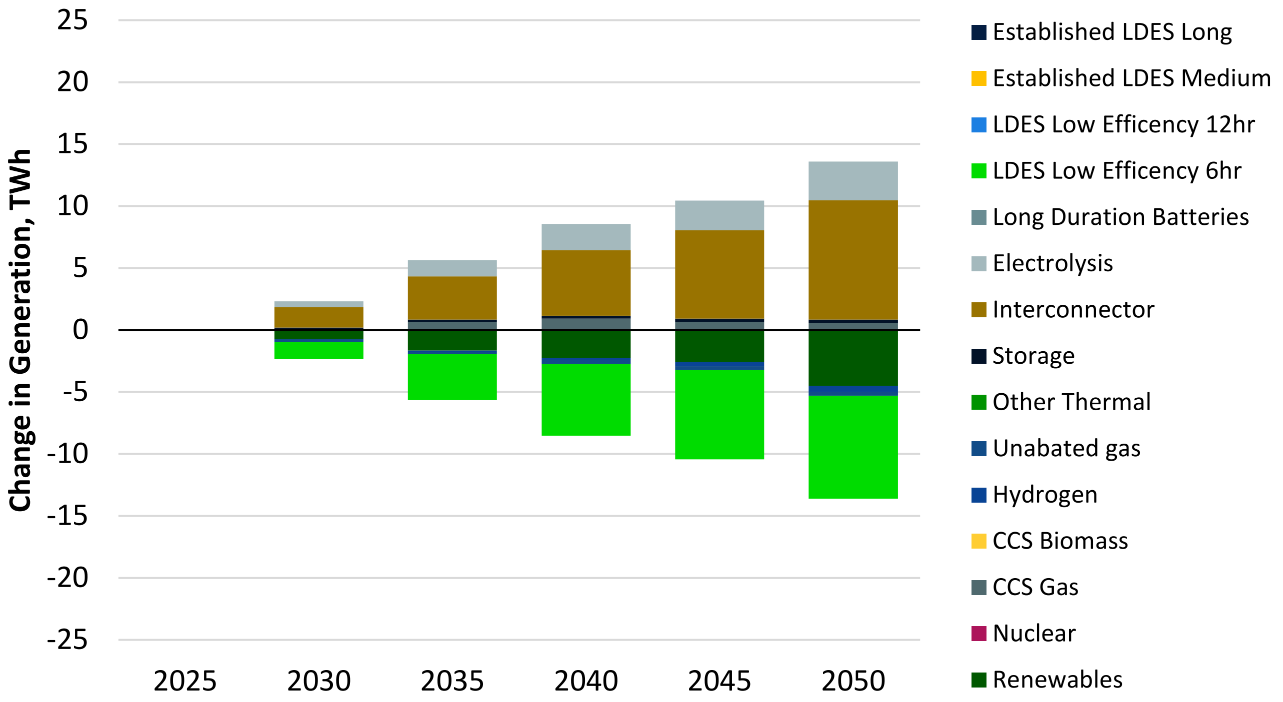
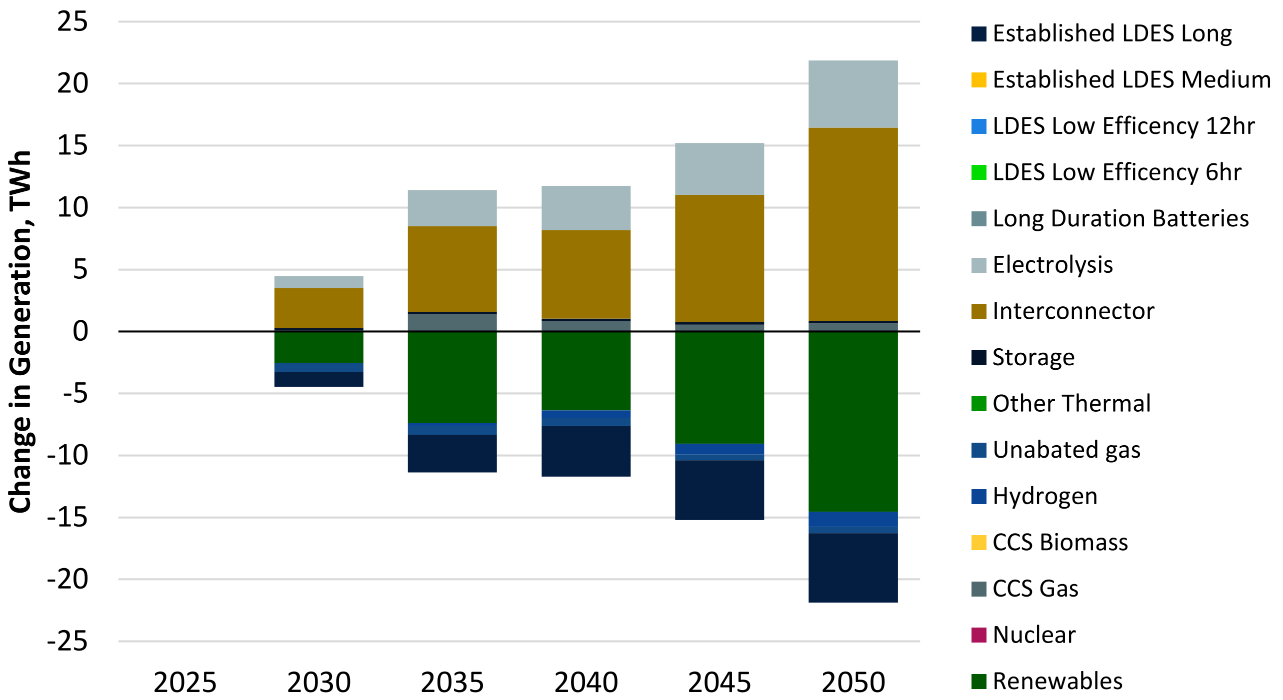


Figure 37: *Example Scenario 4 – change in generation between factual with 10GW of Established LDES Long and counterfactual (DESNZ Net Zero higher demand) with no LDES*



Comparing across the two example scenarios shows the greater impacts on renewable generation reduction (and increase in net interconnector imports) that adding the longer duration and higher efficiency Established LDES Long archetype has compared to the Low-Efficiency (6hr) LDES archetype. The step of removing the extra wind capacity leads to renewable generation decreasing and emissions increasing. This offsets the reduction in emissions due to LDES displacing peaking capacity, with the net impact that emissions are held steady relative to the counterfactual

The other impact that can be seen when looking at the change in generation is the impact on the net generation of the LDES assets themselves. The lower efficiency archetype has a larger net negative generation value as more electricity needs to be stored in this scenario for the same level of discharge.

Renewable curtailment decreases (in both absolute and percentage terms) due to less renewable capacity on the system and renewables that are on the system being used more effectively. Again, impacts are higher in the Established LDES Long Scenario as more renewable capacity is removed in this scenario and the longer duration and higher efficiency of this archetype allows for wind generation to be used more effectively. The percentage of potential renewable generation that is curtailed drops from 13% (65TWh) to 9% (43TWh) in 2035 and 19% (154TWh) to 14% (99TWh) in 2050 in the Established LDES Long Scenario. In comparison, the percentage of potential renewable generation that is curtailed drops from 13% (65TWh) to 11% (54TWh) in 2035 and 19% (154TWh) to 16% (120TWh) in 2050 in the Low-Efficiency (6hr) LDES scenario.

Figure 38: *Example Scenario 3 – change in renewable curtailment between factual with 10GW of LDES Low-Efficiency 6hr and counterfactual (DESNZ Net Zero higher demand) with no LDES*

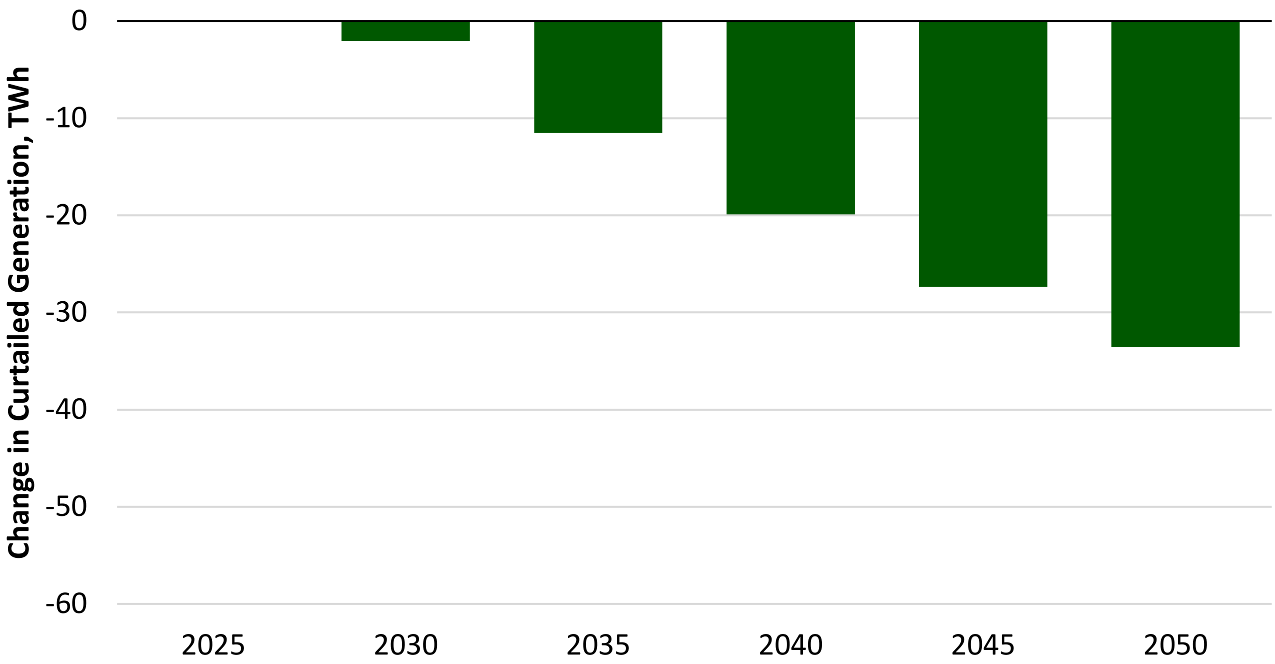
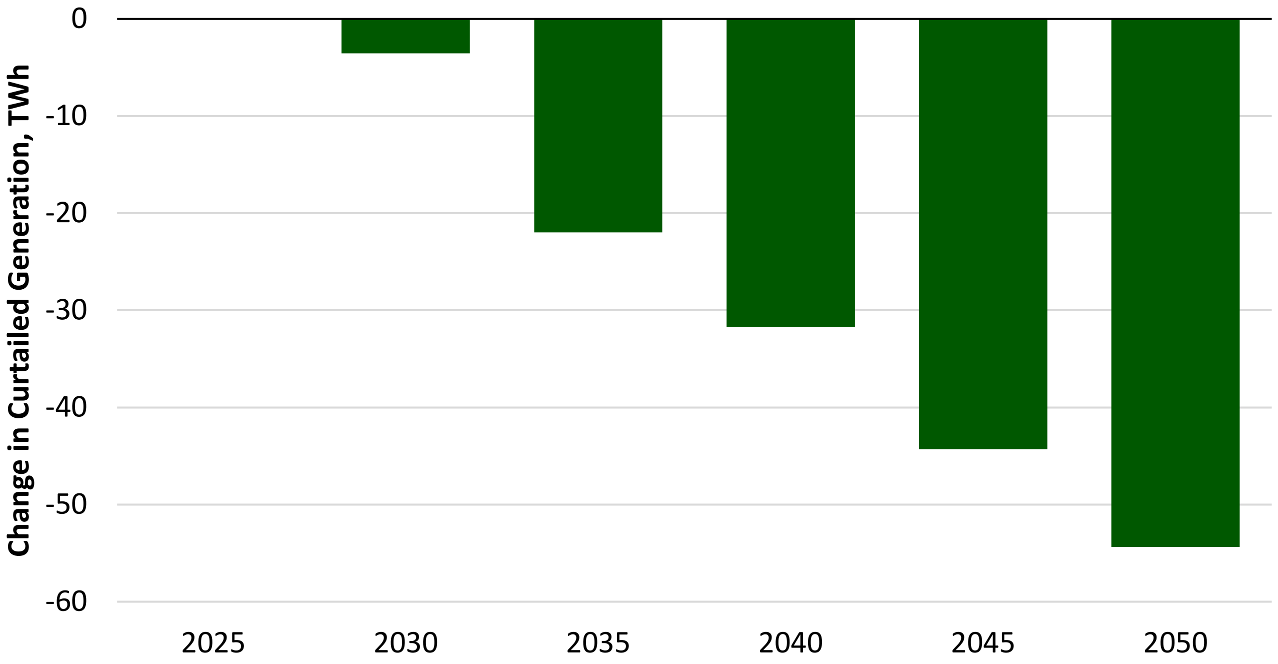


Figure 39: *Example Scenario 4 – change in renewable curtailment between factual with 10GW of Established LDES Long and counterfactual (DESNZ Net Zero higher demand) with no LDES*



Change in wholesale prices and emissions

By design, emissions are very similar to the counterfactual with a less than 0.5gCO2e/kWh[40] change in emissions intensity in 2035. For the Low-Efficiency (6hr) LDES scenario, the maximum difference in emissions intensity in any year is 0.1gCO2e/kWh while in the Established LDES Long Scenario, the maximum difference in any year is 0.3gCO2e/kWh.

LDES replacing both peaking and wind capacity sees wholesale prices increase slightly compared to the counterfactual. The changes in capacity lead to more expensive assets such interconnection and the LDES itself setting the price more regularly compared to the counterfactual causing a small increase to the average wholesale price. This would flow through as an impact on consumers but would be largely offset by a decrease in policy costs for consumers owing to lower CfD top up payments from less renewables on the system.

This impact is greater in the Established LDES Long Scenario with wholesale prices increasing by a maximum of £2.50/MWh compared to £1.30/MWh in the Low-Efficiency (6hr) LDES scenario. This reflects the impact seen in generation with larger decreases in renewable generation in this scenario.

[40] 0.5gCO2e/kWh is the assumed tolerance for difference in emissions across all of the core scenarios modelled. This is explained further in the next section.

Figure 40: *Example Scenario 3 – wholesale prices for factual with 10GW of LDES Low-Efficiency 6hr and counterfactual (DESNZ Net Zero higher demand) with no LDES*

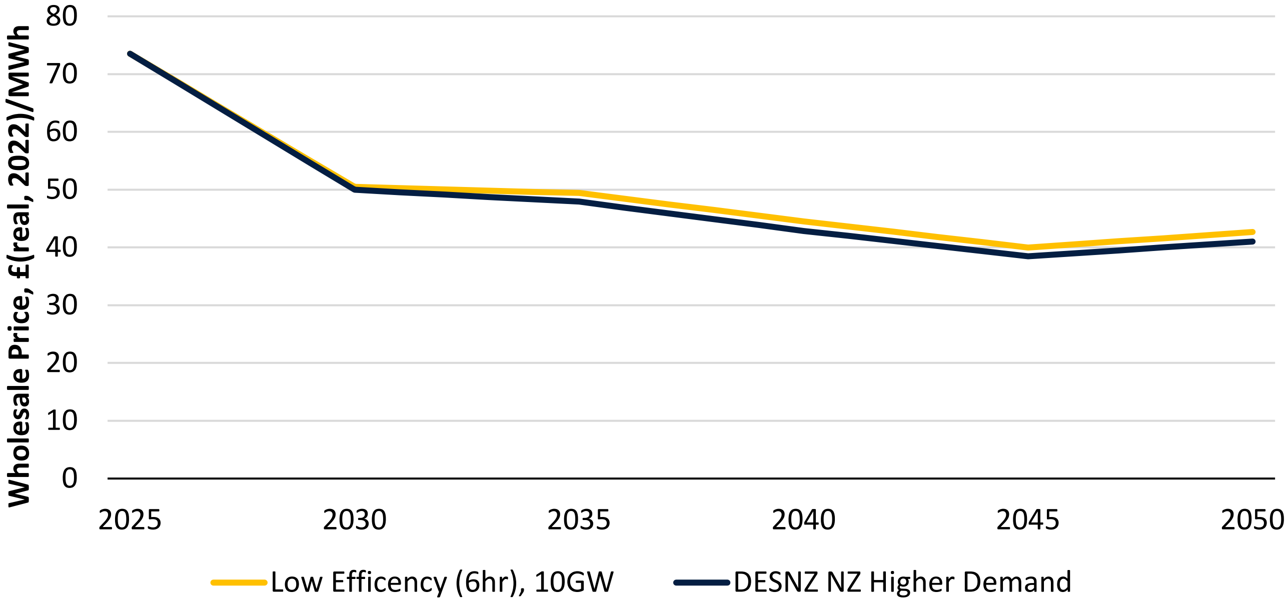
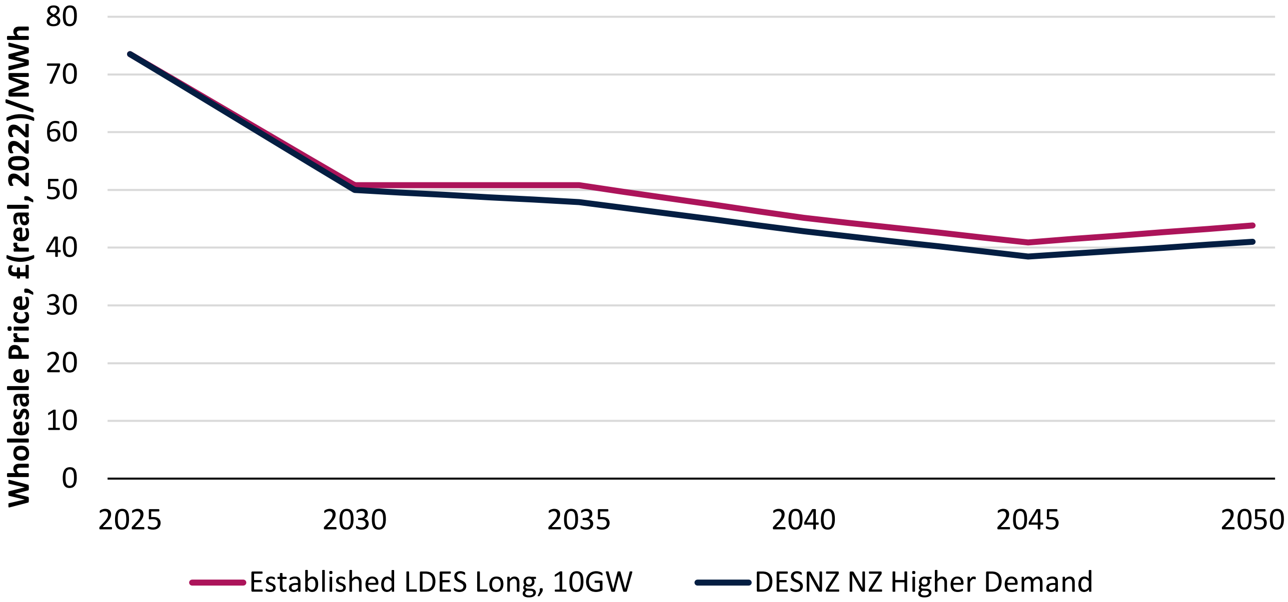


Figure 41: *Example Scenario 4 – wholesale prices for factual with 10GW of Established LDES Long and counterfactual (DESNZ Net Zero higher demand) with no LDES*



Change in system cost

Adding LDES technologies to replace wind and peaking capacity brings benefits to the system in different ways to just replacing peaking capacity. In general, this shows higher system cost benefits and net total system cost reductions. In the example scenarios, adding LDES now brings a benefit to the system across nearly all scenarios and LDES CapEx levels. For the Established LDES Long Scenario, system cost reductions range from £17.6bn to £25.2bn (NPV 2025-50) with impacts varying depending on the LDES CapEx level. For the Low-Efficiency (6hr) scenarios, adding 10GW of this archetype brings system benefits at the low LDES CapEx only with benefits of £6.1bn. At medium and high LDES CapEx levels, adding this archetype becomes a cost to the system of £2.5bn and £9.5bn respectively. These costs are broken down below into the different categories previously outlined in Section 5.3 and can be seen in the charts below.

- **Interconnector costs** are reduced (despite an increase in net imports) due to less imports as a result of displacement by LDES discharge. This offsets lost revenue due to a decrease in exports. Impacts are higher in the Established LDES Long Scenario as more imports are displaced by the LDES in this scenario.
- **Generation costs** decrease slightly in both scenarios. This is due the small changes in thermal generation as shown in the generation graphs. Differences in generation costs are much smaller than when the LDES replaces peaking capacity as in this scenario the LDES primarily displaces wind which has a very low short-run marginal cost the impact is minimal.
- **Fixed OpEx** costs decrease in the Established LDES Long Scenario as more wind and peaking capacity is removed. Costs changes are minimal in the Low-Efficiency (6hr) Scenario as the fixed OpEx costs of the LDES offset the reduction in fixed OpEx from lower wind and peaking capacity.
- **Network costs** decrease significantly as less wind capacity is being connected to the system, with offshore wind in particular incurring high network costs. Again, impacts are higher in the Established LDES Long Scenario as more wind capacity is removed compared to the counterfactual.
- **Balancing costs** decrease slightly, mainly due to less imbalance on the system as a result of less wind.
- **CapEx costs** decrease slightly with low LDES CapEx as it is cheaper to build the LDES than the peaking capacity and wind it replaces. With medium and high CapEx however, this becomes a cost increase. This highlights that CapEx is a key determining factor in whether adding LDES to the system is a benefit.

***Figure 42:** Example Scenario 3 – System Cost Comparison for factual with 10GW of LDES Low-Efficiency 6hr and counterfactual (DESNZ Net Zero higher demand) with no LDES at differing LDES CapEx levels*

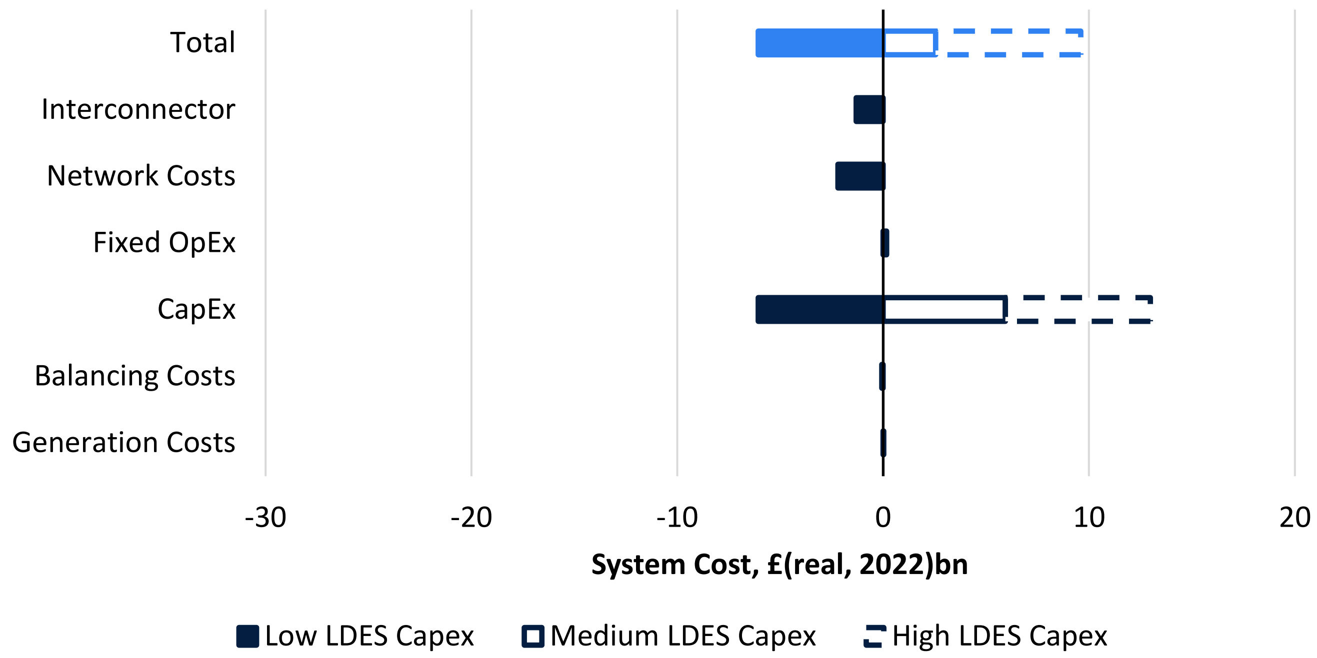
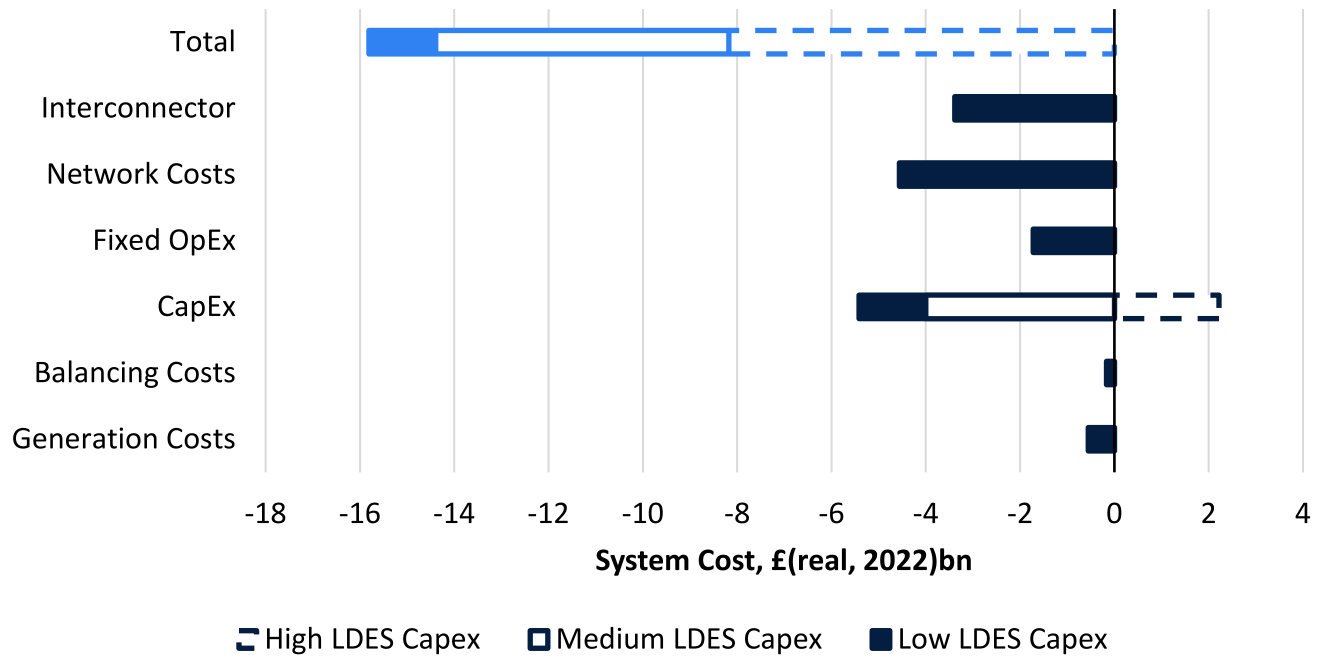


***Figure 43:** Example Scenario 4 – System Cost Comparison for factual with 10GW of Established LDES Long and counterfactual (DESNZ Net Zero higher demand) with no LDES at differing LDES CapEx levels*



The system cost (in undiscounted terms) can be broken down by the years modelled to show how the cost profile changes over time. Across both example scenarios, the cost decreases are higher in later years as more LDES capacity is added to the system. For the Established LDES Long archetype, the difference in costs decreases by less in each 5 years indicating that adding LDES capacity is likely to have higher benefits in earlier years. The same is true of the Low-Efficiency (6hr) archetype for most costs excluding CapEx. However, the increase in CapEx is higher in earlier years when the CapEx is at a higher level which leads to the increase in CapEx offsetting the benefits in generation, interconnector and network costs by a greater amount in 2030 and 2035.

Figure 44: *Example Scenario 3 – Change in yearly system cost (undiscounted) for factual with 10GW of LDES Low-Efficiency 6hr vs counterfactual (DESNZ Net Zero higher demand) with no LDES, at medium LDES CapEx levels*

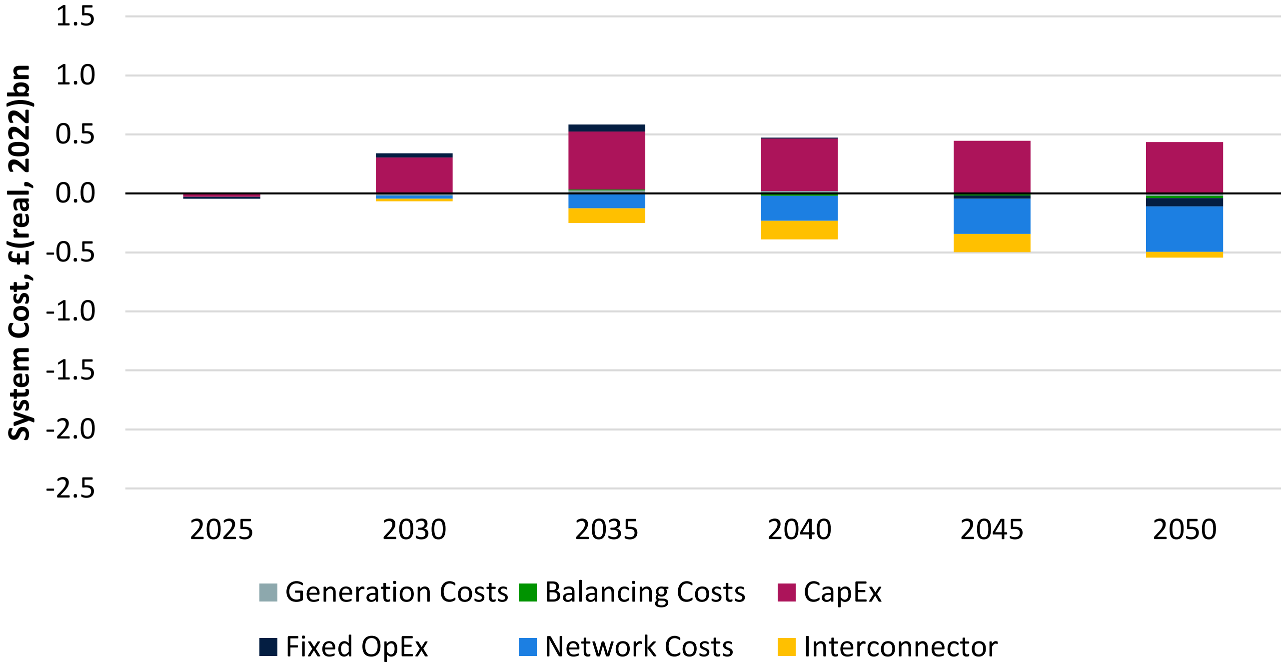
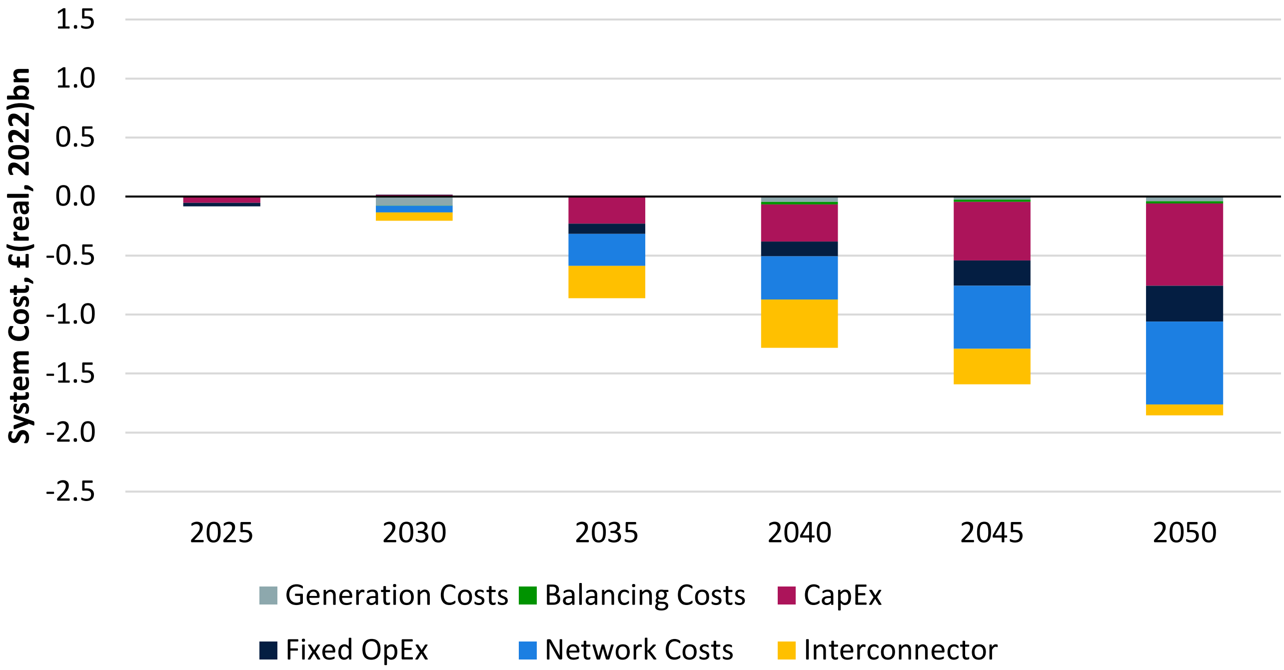


Figure 45*: Example Scenario 4 – Change in yearly system cost (undiscounted) for factual with 10GW of Established LDES Long vs counterfactual (DESNZ Net Zero higher demand) with no LDES, at medium LDES CapEx levels*

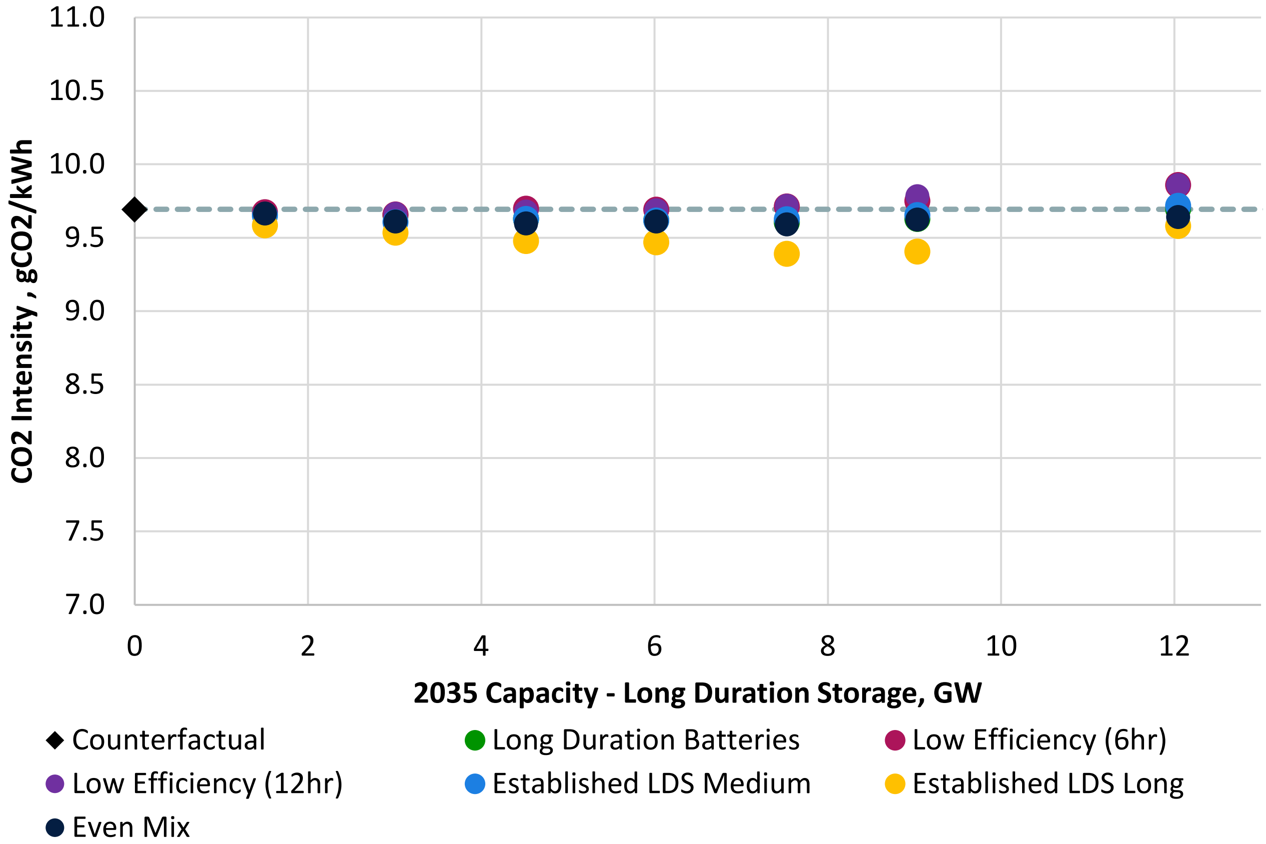


6.3.2. All LDES scenarios – Adding LDES to replace peaking and wind capacity

Emissions intensity

The scatter plot below shows the 2035 emissions against the LDES capacity for all scenarios where LDES replaces peaking and wind capacity. By design, emissions are at a similar level to the counterfactual to within 0.5gCO2e/kWh.[41]

Figure 46: *Emissions intensity v LDES capacity in 2035 (coloured by LDES archetype) in the Core Scenario with LDES replacing peaking and wind capacity*



Systems cost

The scatter plots below show the total system costs (NPV 2025-50) against the LDES capacity for all scenarios where LDES replaces peaking and wind capacity. Given the significant uncertainty in CapEx costs, a range of LDES CapEx scenarios (as defined in section 4) have been tested to give an understanding of how these impacts results. The change across cost types for each LDES archetypes largely follows the example scenarios outlined above with the

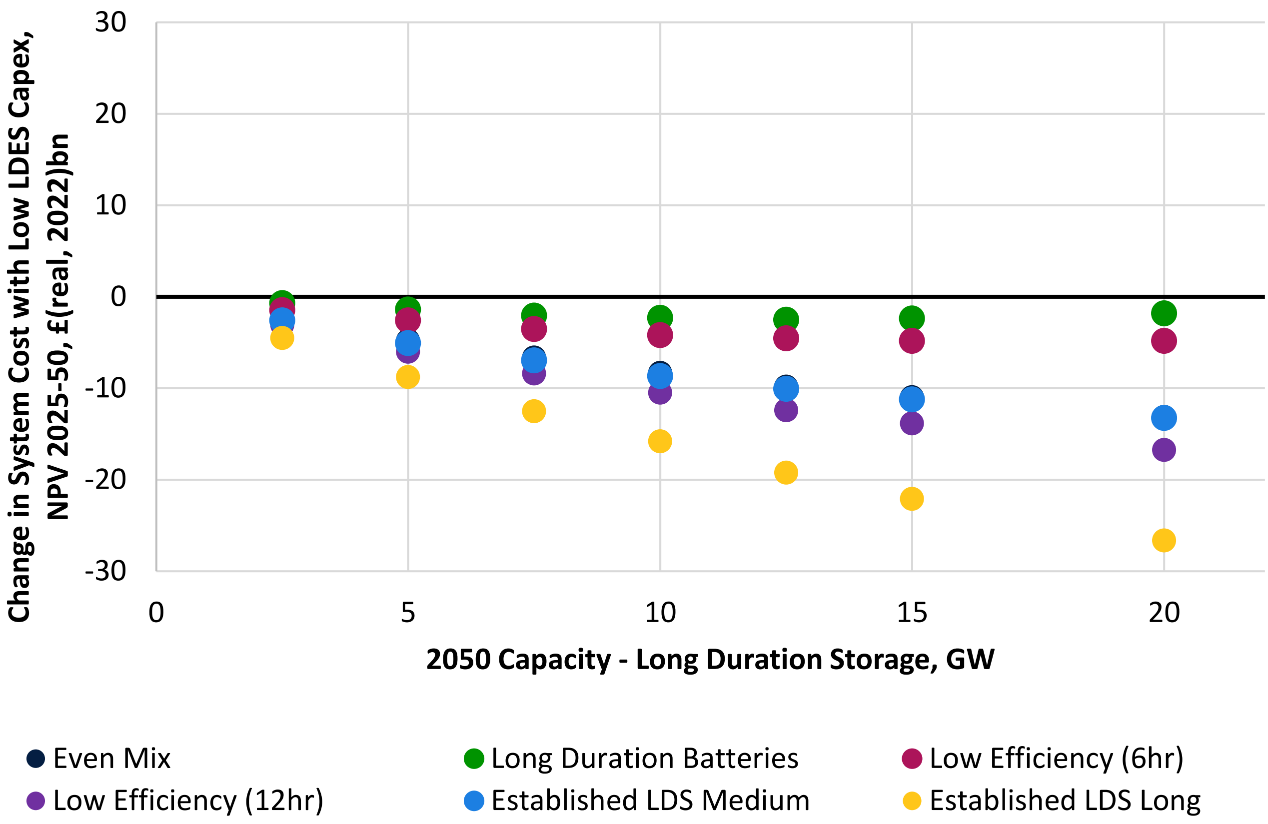
[41] Within the modelling, it is difficult to get emissions to precisely the same level as the counterfactual. To achieve this would require multiple iterations of each scenario, adjusting the level of wind capacity each time. Given the volume of scenarios being modelled, a tolerance of 0.5gCO2/kWh was used to ensure a close match in emissions without a large number of iterations. Precise alignment would cause some minor changes to system costs and carbon costs but we do not expect these to be significant.

biggest drivers in reduced network costs and interconnectors and the CapEx impact varying by CapEx level.

With **low LDES CapEx assumptions:**

- All LDES archetypes at all capacities bring benefits to the system with longer durations and larger capacities having larger impacts. The biggest benefits are from interconnector and network costs across all scenarios.
- Most scenarios see a decrease in CapEx costs as building LDES is cheaper than the larger amounts of wind and peaking capacity displaced.
- Established long-duration technologies have the biggest impact as these have long lifetimes and lower hurdle rates in addition to having the biggest impact on system cost (excluding CapEx). 10GW of established long-duration capacity on the system by 2050 could reduce system costs by around £16bn (2.3%), and 20GW could reduce system costs by around £26bn (3.7%). 10GW of an even mix across all archetypes reduces system costs by around £8bn (1.1%) and 20GW could reduce system costs by around £13bn (1.8%).
- Long-Duration Batteries have the smallest overall NPV impact despite having a larger impact on year-to-year costs (excluding CapEx) than Low-Efficiency LDES. This is because of the shorter assumed lifetime of batteries before refurbishment (20 years) meaning their CapEx costs are financed over shorter periods and refurbishment costs (40% of CapEx costs) are included after that 20-year period.

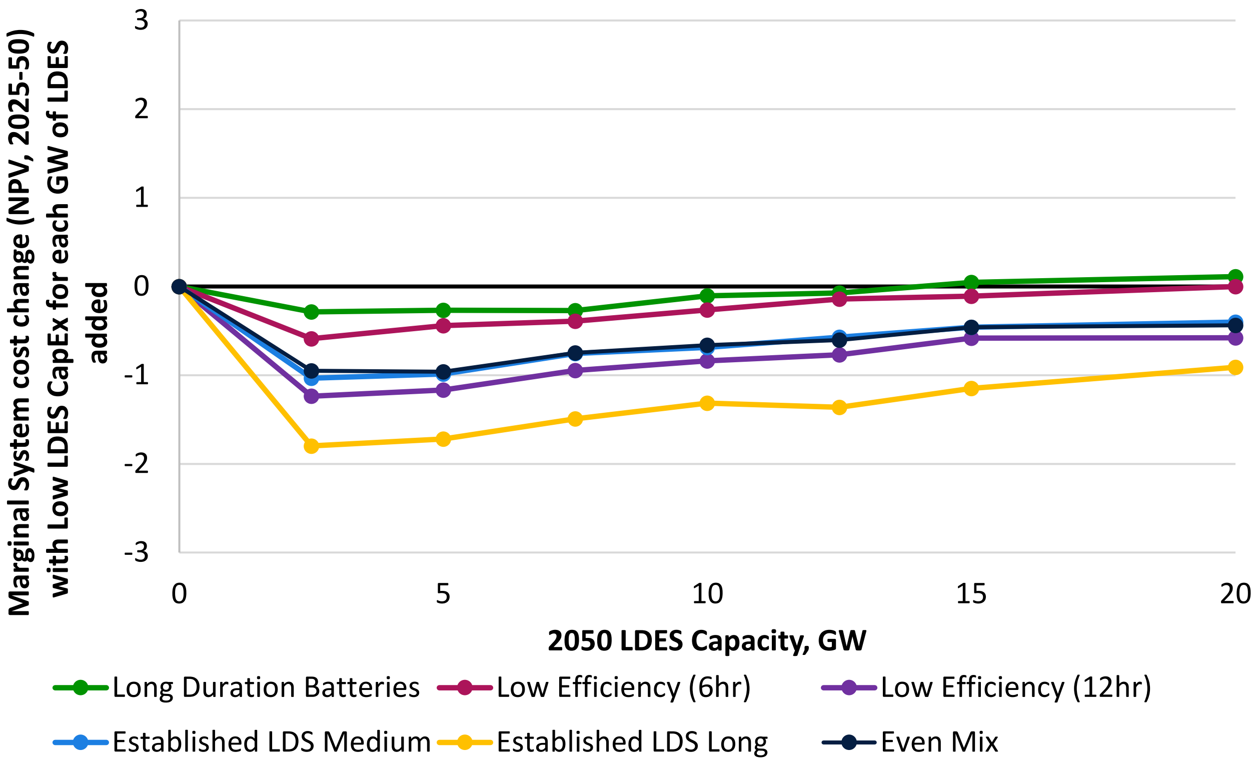
Figure 47: *System cost (NPV) with low LDES CapEx v LDES capacity in 2050 (coloured by LDES archetype) in the Core Scenario with LDES replacing peaking and wind capacity.*



To illustrate optimal levels of LDES deployment, the below graph shows the marginal change in system cost for each extra GW of LDES added at different LDES capacity levels. In general, this shows that the marginal benefit of LDES decreases with each GW of LDES added and for some archetypes, there is a point where adding additional LDES is no longer beneficial for the system. The situation for each archetype is summarised below.

- **Long-Duration Batteries** – The marginal benefits of adding additional Long-Duration Batteries are quite consistent until 7.5GW is reached, at which point benefits begin to tail off. There are still small benefits of adding additional LDES at 10GW and 12.5GW but at 15GW and 20GW adding additional Long-Duration Batteries will increase system cost.
- **Low-Efficiency 6hr** – The largest marginal benefit is at the first 2.5GW added with similar levels at 5 and 7.5GW. Like Long-Duration Batteries, the marginal benefit declines after this point around 10-15GW. At 20GW, adding additional LDES of Low-Efficiency 6hr will increase system costs.
- **Low-Efficiency 12hr, Established LDES Medium and Established LDES Long** – Adding more capacity up to 20GW always provides a marginal benefit to the system. However, the marginal benefit of adding LDES is around double when adding at 2.5GW or 5GW compared to 20GW.

Figure 48: *Marginal change in system cost (NPV) with low LDES CapEx for each GW of LDES added (in 2050) in the Core Scenario with LDES replacing peaking and wind capacity.*

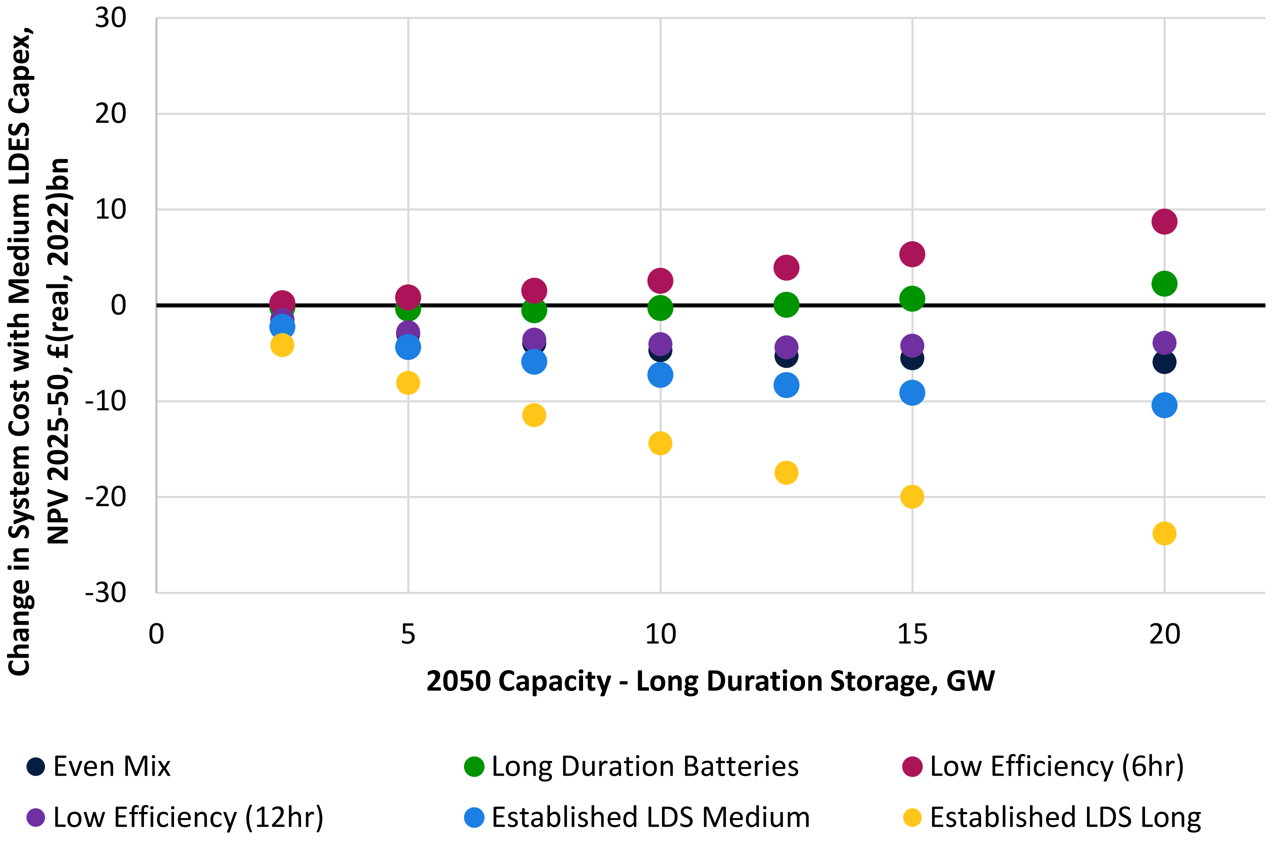


With **medium LDES CapEx assumptions**:

- Most LDES archetypes at different capacity levels still bring benefits to the system although these benefits are reduced compared to under low CapEx assumptions. Again, those modelled archetypes with higher duration have the largest system cost reductions with the largest reduction in system costs at £24bn (3.3%).

- Longer-Duration, Lower-Efficiency (6hr) now increases system cost with system cost rising with any additional GW. Long-Duration Batteries only show benefits at 12.5GW and below with 15GW and 20GW of this archetype being a cost to the system. This is due to the higher CapEx values more than offsetting the operational benefits that adding LDES brings to the system. In particular, the large rises in CapEx costs between low and medium see the Longer-Duration, Lower-Efficiency (6hr) now being more expensive than Long-Duration Batteries. The higher efficiency and lower fixed OpEx costs of the battery archetype compared to the 6hr low efficiency archetype also play a role here.
- The Longer-Duration, Lower-Efficiency (12hr) archetype sees benefits peak sees the highest system cost benefit to the system with 15GW of capacity in 2050 at £4.2bn. This then declines at 20GW to £3.9bn.
- The Established LDES archetypes and an even mix across all archetypes see benefits continue to increase as more capacity is added to the system.

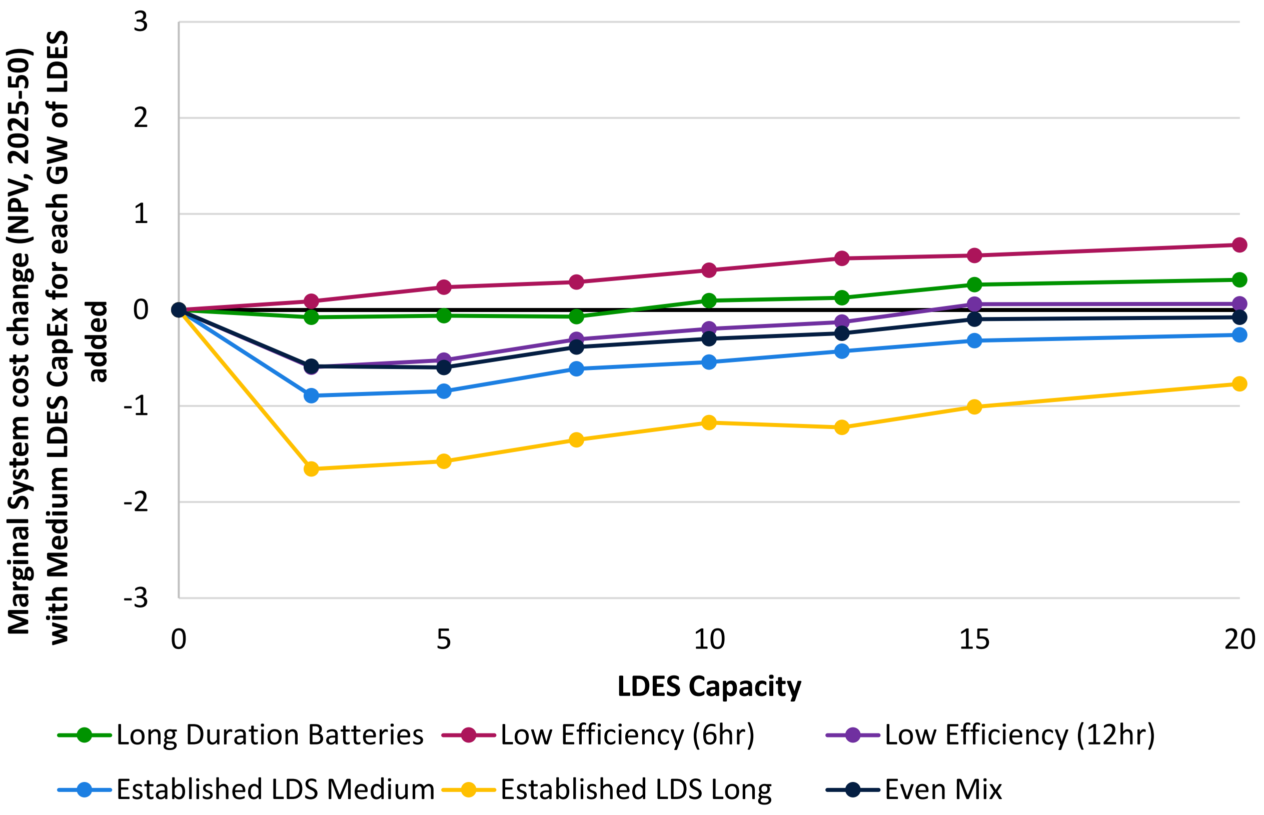
Figure 49: *System cost (NPV) with medium LDES CapEx v LDES capacity in 2050 (coloured by LDES archetype) in the Core Scenario with LDES replacing peaking and wind capacity.*



Again, to illustrate optimal levels of LDES deployment, the below graph shows the marginal Change in system cost for each GW of LDES added at different LDES capacity levels. For each archetype this shows:

- **Long-Duration Batteries** – The marginal benefit of adding additional Long-Duration Batteries are at very small levels up to 7.5GW but each additional GW is still providing system benefits. At capacities >10GW adding additional Long-Duration Batteries where their CapEx is at medium levels will be a marginal cost to the system,
- **Low-Efficiency 6hr** – Adding any level of Low-Efficiency 6hr with medium CapEx levels now increases marginal costs. This aligns with the system costs which showed any level of this archetype is a cost to the system due to the high CapEx of this archetype.
- **Low-Efficiency 12hr** – Adding more LDES of Low-Efficiency 12hr up to 15GW is a marginal benefit with the first 5GW having the biggest impact. At capacities of 15GW or higher, adding additional capacity of this archetype is a marginal cost to the system.
- **Established LDES Medium, Established LDES Long** – Adding additional capacity of these archetypes up to 20GW is always a marginal benefit to the system, though this marginal benefit reduces as more capacity is added.

Figure 50: *Marginal change in system cost (NPV) with medium LDES CapEx for each GW of LDES added (in 2050) in the Core Scenario with LDES replacing peaking and wind capacity.*

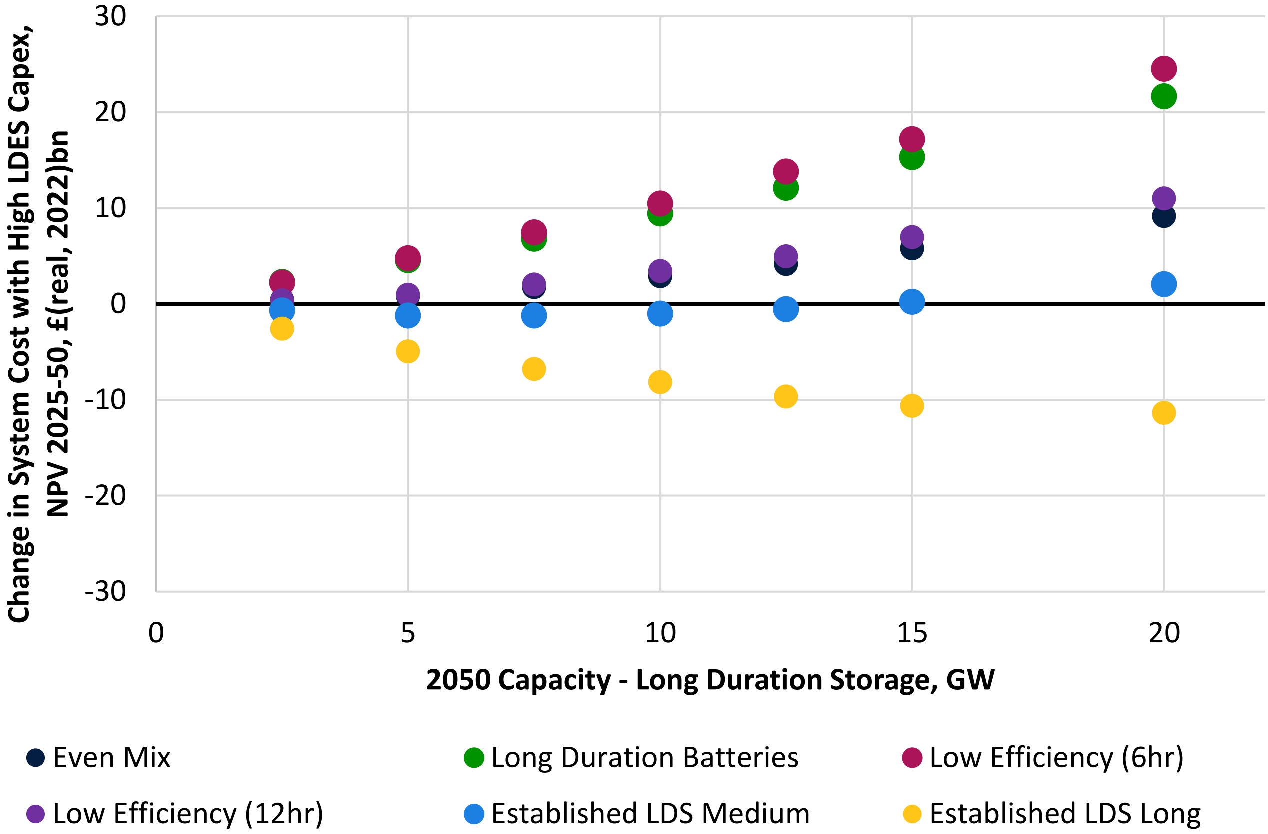


At **high CapEx levels**:

- Only the Established LDES Long archetype provide benefits across all capacity levels with the largest reduction in costs is £11.4bn (1.6%). All other archetypes becoming costs to the system especially at high-capacity levels.

- The Established LDES Medium archetype only brings benefits to the system at 12.5GW of capacity and below with benefits peaking at 7.5GW.
- The Low-Efficiency (12hr) archetype and an even mix across all archetypes are now costs to the system across all capacity levels.
- Long-Duration Batteries see a large increase in CapEx costs compared to medium as these are based on flow rather than lithium-ion batteries causing this archetype to be a large cost to the system across all capacities.

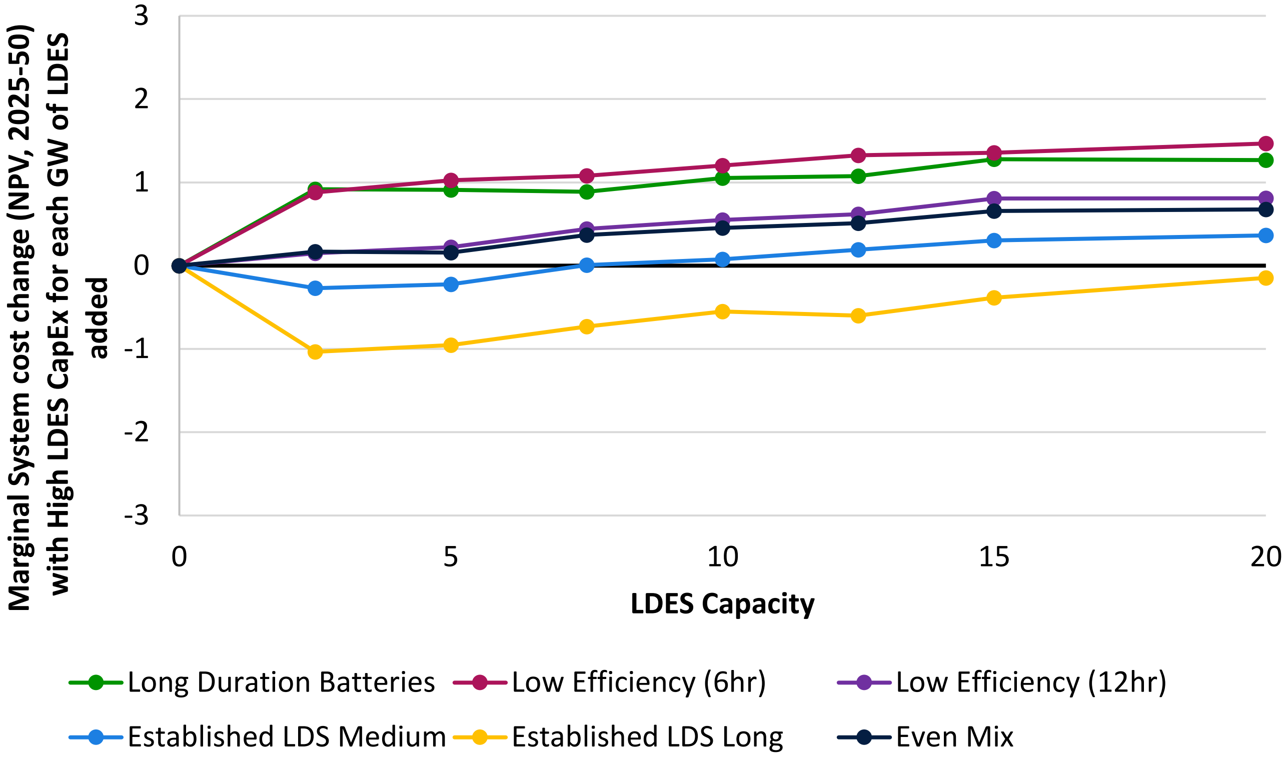
Figure 51: *System cost (NPV) with high LDES CapEx v LDES capacity in 2050 (coloured by LDES archetype) with DESNZ NZ higher counterfactual with LDES replacing peaking and wind capacity.*



Again, to see optimal levels of LDES deployment, the below graph shows the marginal change in system cost for each GW of LDES added at different LDES capacity levels. For each archetype this shows:

- **Long-Duration Batteries, Low-Efficiency 6hr, Low-Efficiency 12hr** – Adding any level of capacity with high CapEx levels increases marginal system costs.
- **Established LDES Medium** – Adding additional LDES of this archetype up to 5GW brings marginal benefits to the system. Additional capacity added beyond 7.5GW increases system costs.
- **Established LDES Long** – Adding any level of this archetype brings marginal benefits to the system. Marginal benefits reduce with more capacity on the system with benefits close to 0 at 20GW.

***Figure 52**: Marginal change in system cost (NPV) with high LDES CapEx for each GW of LDES added (in 2050) in the Core Scenario with LDES replacing peaking and wind capacity.*



As highlighted above, there is significant uncertainty around the capital costs of LDES and the different CapEx levels outlined here do not necessarily reflect the full range of capital cost possibilities for the given LDES archetypes. To explore this further, a breakeven CapEx point is calculated which shows the CapEx value that would result in a zero-system cost impact for each scenario, i.e. the point where the 2025-2050 system cost NPV in the factual LDES scenario is equal to the counterfactual system cost NPV. This analysis is explored in Annex B.

7. Modelling Results – Gas CCS and H2 Scenarios

Hydrogen and gas CCS are expected to play an important role in providing flexibility to the future electricity system. However, there are uncertainties around the scale of their deployment such as the development of the technologies themselves, delivery timelines of supporting infrastructure and investor uncertainty. There is currently no plant of either technology deployed within the power sector in GB. As such, it is currently unclear if these technologies will be able to deploy at the scale set out in the ambition of the DESNZ Net Zero High electricity demand scenario (5GW of hydrogen and 9GW of gas CCS in 2035, and 45GW of hydrogen and 17.5GW of CCS in 2050). In a future system, the primary role of gas CCS and hydrogen is likely to be to provide flexibility to the system and generate when wind is low and/or demand is high, fulfilling a role similar to LDES.

Given this uncertainty and the similar role these technologies will play to LDES, it is prudent to look at scenarios where less gas CCS and/or hydrogen capacity is available to understand how the impacts of LDES change in these scenarios. Three reduced gas CCS and hydrogen deployment levels are modelled: low gas CCS, low hydrogen, and medium gas CCS & hydrogen. Further scenarios looking at low gas CCS & hydrogen are also modelled but as this scenario uses a different methodology to those presented in this chapter, the results from this modelling is outlined in Annex D.

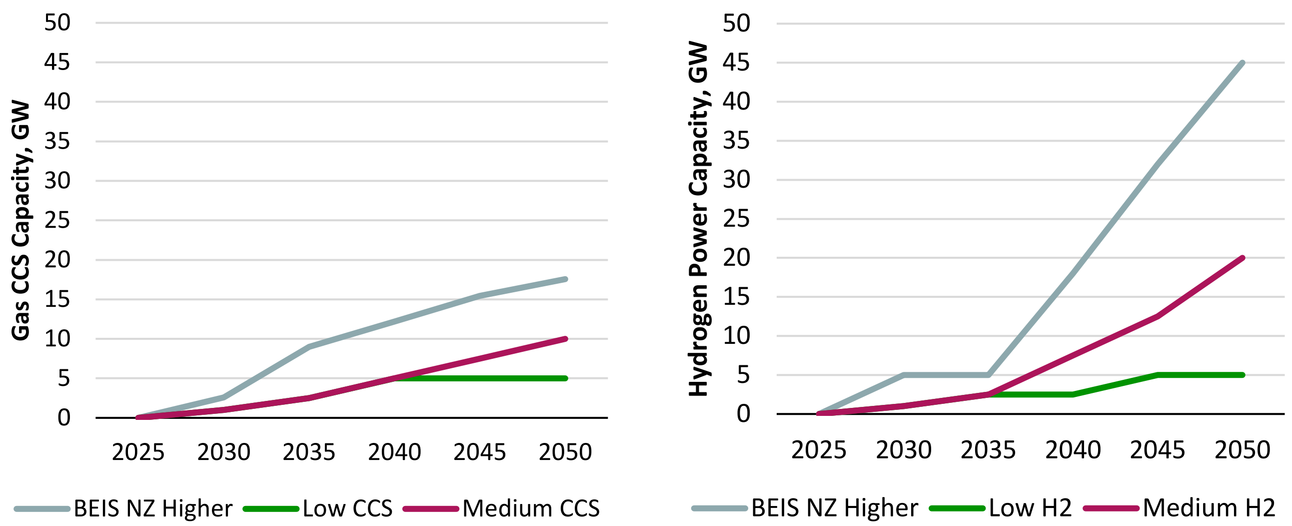
7.1. Defining new counterfactuals

New counterfactuals need to be defined with lower capacities of gas CCS and/or hydrogen to understand the impact that adding LDES can have with less gas CCS or hydrogen available. This ensures that when LDES is added to the system, comparisons between these scenarios and the low gas CCS or hydrogen counterfactuals are as equivalent as possible to the comparisons made in the Core Scenario. We model three counterfactual scenarios with reduced gas CCS and hydrogen deployment levels that capture different combinations and extremes of reduced gas CCS and hydrogen capacity. The three reduced CCS and hydrogen scenarios have been defined by DESNZ and represent hypothetical lower capacities of the technologies due to any potential deployment constraints. The descriptions are outlined in the table below and the capacities are presented in the subsequent figure.

***Table 9:** Gas CCS and hydrogen counterfactual description*

Name	Gas CCS deployment	Hydrogen in power deployment	Adjustment made to align emissions
Core	DESNZ Net Zero higher	DESNZ Net Zero higher	N/A
Low Gas CCS	Low	DESNZ Net Zero higher	Yes
Low Hydrogen	DESNZ Net Zero higher	Low	Yes
Medium Gas CCS and Hydrogen	Medium	Medium	Yes

***Figure 53:** Gas CCS and hydrogen deployment levels across different counterfactuals*



For the different gas CCS and hydrogen deployment levels, adjustments are made to wind capacity to align emissions to the Core Scenario. This ensures that these scenarios modelled still meet CB6 and are consistent with Net Zero. It also allows for easier comparison with the Core Scenario (outlined in section 6). An additional scenario where there is both low gas CCS and low hydrogen has also been looked at, but the same method could not be applied to this scenario as it would have resulted in a level of wind deployment which would not have been realistic. This scenario is covered in Annex D.

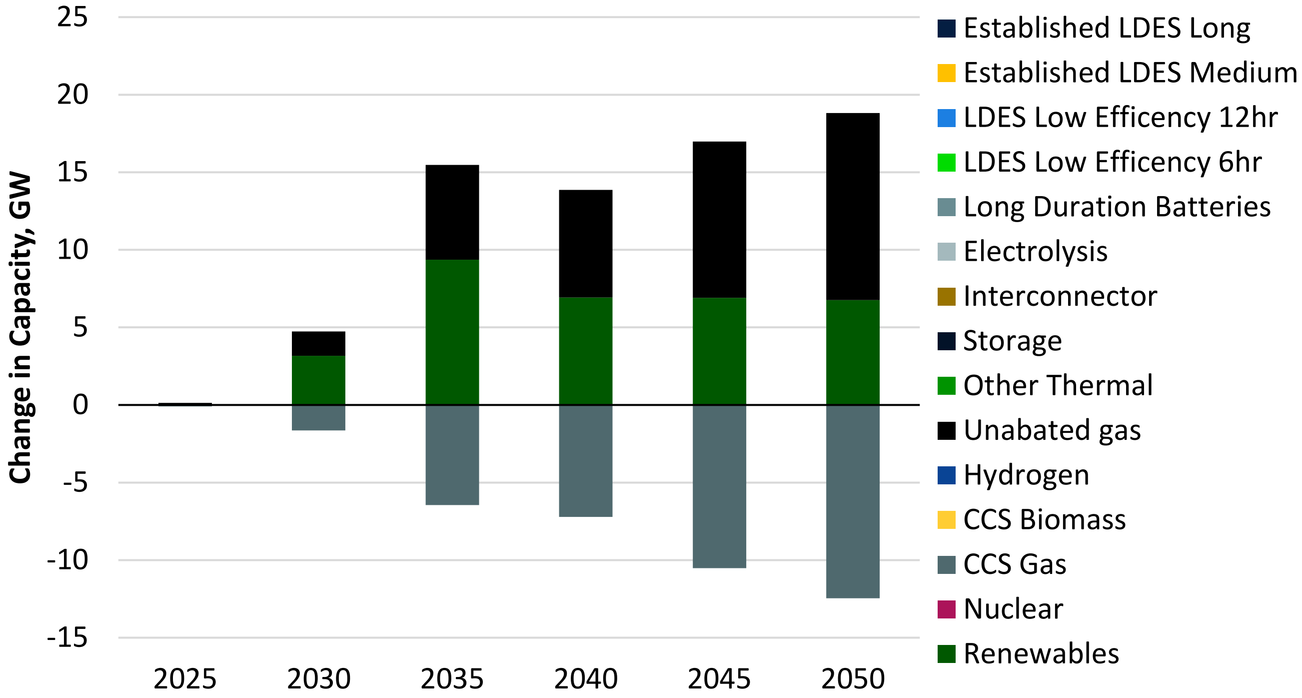
Below we compare each of the 3 redefined counterfactuals with lower gas CCS/hydrogen deployment to the Core counterfactual (DESNZ NZ higher) to highlight how we have implemented the reduction of the CCS and/or hydrogen capacity and the generation which has replaced it.

Low Gas CCS deployment

In the Low Gas CCS Scenario with no adjustments other than adding gas peaking capacity to ensure security of supply, overall emissions increase by up to 1MTCO2 a year as unabated gas generation increases. The biggest changes are in the early 2030s when hydrogen capacity is still low. However, the impact on emissions are generally low, particularly in later years, as hydrogen generation and imports via the interconnectors also increase to make up for the shortfall in gas CCS generation.

To reduce the emissions back to the same level as the Core counterfactual (DESNZ Net Zero higher), generation from renewable and low-carbon sources needs to be increased so that generation from unabated gas decreases. In the Low Gas CCS counterfactual, this has been achieved by increasing renewable capacity. While this may not be the optimal way to achieve this, it follows a similar approach to that taken when adding LDES and ensures consistency across the different scenarios looked at for this Study. Peaking capacity in the form of unabated gas also increases to ensure security of supply and to keep the overall derated capacity at the same level.

Figure 54: *Change in capacity (GW) between Low Gas CCS counterfactual and Core counterfactual (DESNZ NZ Higher demand)*



Low Hydrogen deployment

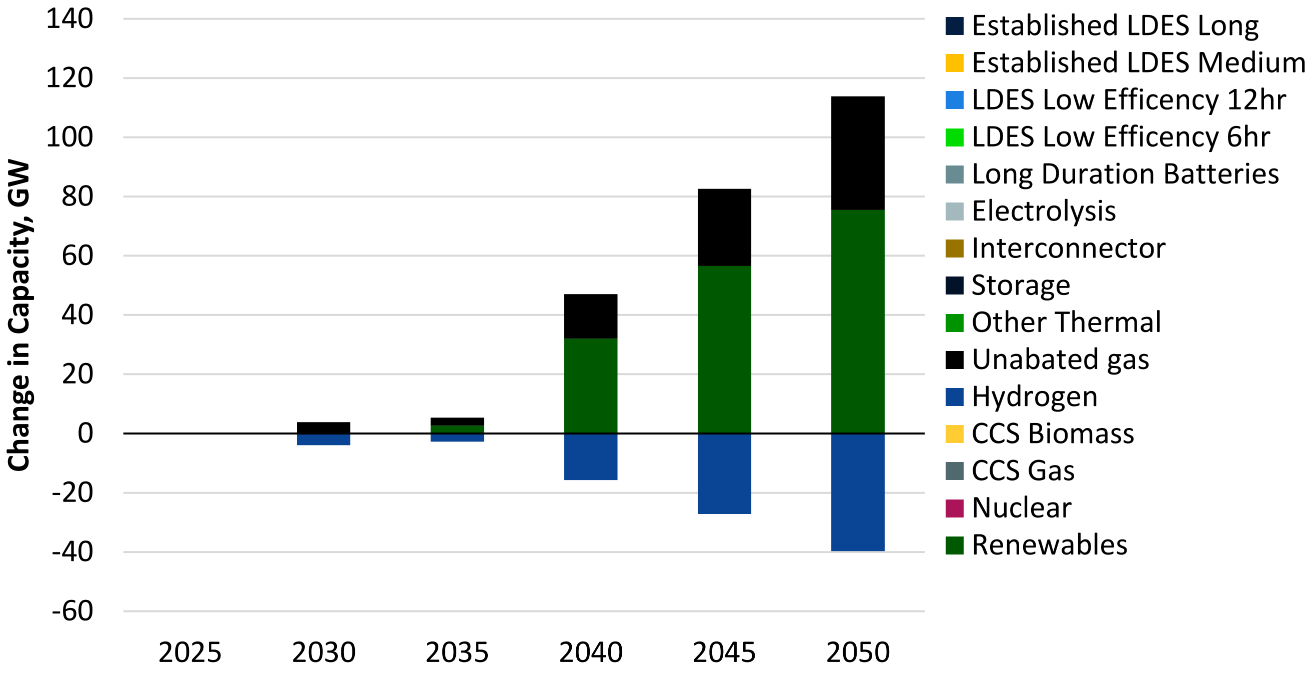
In the Low Hydrogen Scenario with no adjustments other than adding gas peaking capacity to ensure security of supply, overall emissions increase by up to 4MTCO2 in 2050 as unabated gas generation increases. Compared to the Low Gas CCS Scenario, increases in unabated gas generation are significantly higher. This is for two reasons outlined below.

- The level of hydrogen capacity removed is much higher than the CCS capacity removed: 40 GW by 2050, as opposed to 12.5 GW.
- Hydrogen is lower down the merit order than gas CCS and most imports via the interconnectors. This means that during periods where hydrogen is generating, CCS and imports are already at or near their maximum output. So, when the hydrogen generation is removed the only thing able to generate to replace it is unabated gas.

To reduce the emissions back to the same level as the Core Scenario, generation from renewable and low-carbon sources need to be increased so that generation from unabated gas decreases. As in the Low Gas CCS Scenario, this has been done by increasing renewable capacity. For the above reasons, significantly more renewable capacity is added to replace the hydrogen compared to replacing gas CCS.

It should be noted that this scenario results in high levels of wind generation curtailment – over 400TWh in 2050 alone, compared to approximately 150TWh for the Core Scenario. This calls into question how realistic this scenario is as it is unlikely other adjustments would not be made in order to reduce the level of curtailment, such as changes in other non-renewable capacity or increased electrolysers to produce hydrogen. However, for the purposes of this exercise we have kept to DESNZ assumptions regarding these capacities for consistency.

Figure 55: *Change in capacity (GW) between Low Hydrogen counterfactual and Core counterfactual (DESNZ NZ Higher demand)*

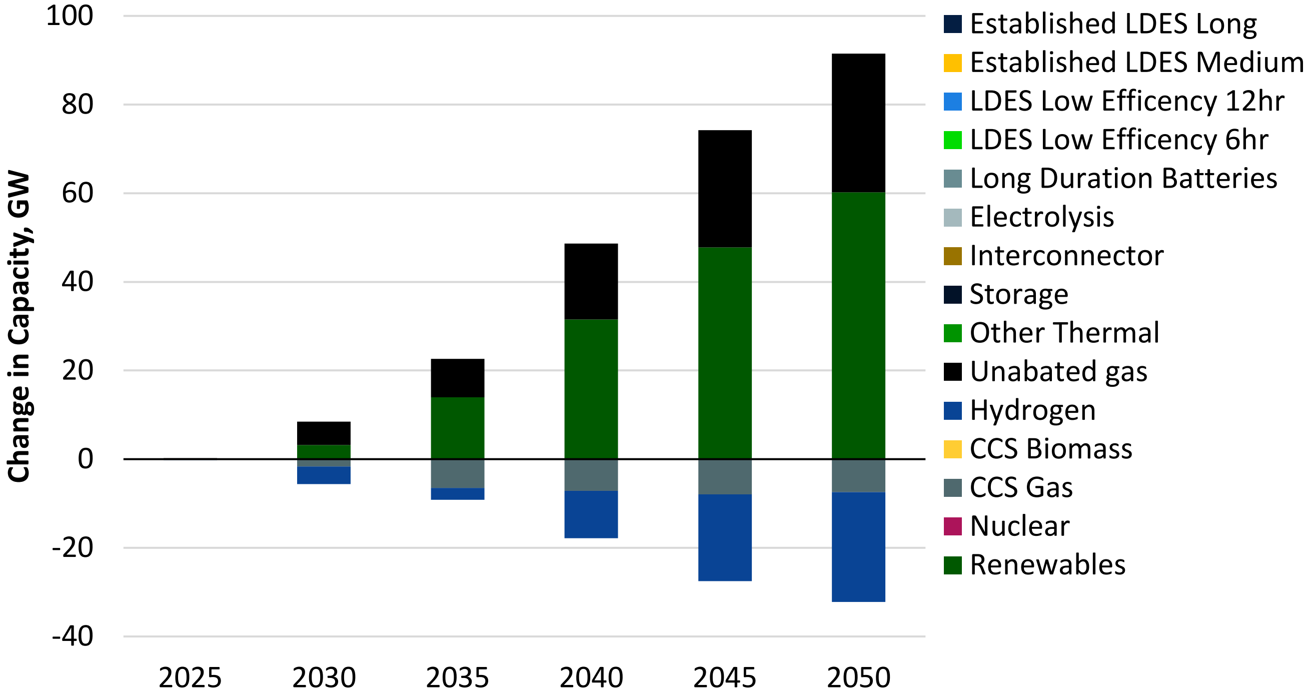


Medium CCS and Hydrogen deployment

In the Medium CCS and Hydrogen scenario, with no adjustments other than adding gas peaking capacity to ensure security of supply, overall emissions increase by up to 2.3MTCO2 in 2050 as unabated gas generation increases. As in the low scenarios, renewable generation is increased to bring overall emissions back to the same level as the DESNZ net zero higher scenario.

As shown in the chart below, by 2050 almost 60GW of additional renewable capacity is required to get emissions back to the levels in the Net Zero high baseline.

Figure 56: *Change in capacity (GW) between Medium CCS and H2 counterfactual and Core counterfactual (DESNZ NZ Higher demand)*



7.2. Adding LDES to replace peaking capacity

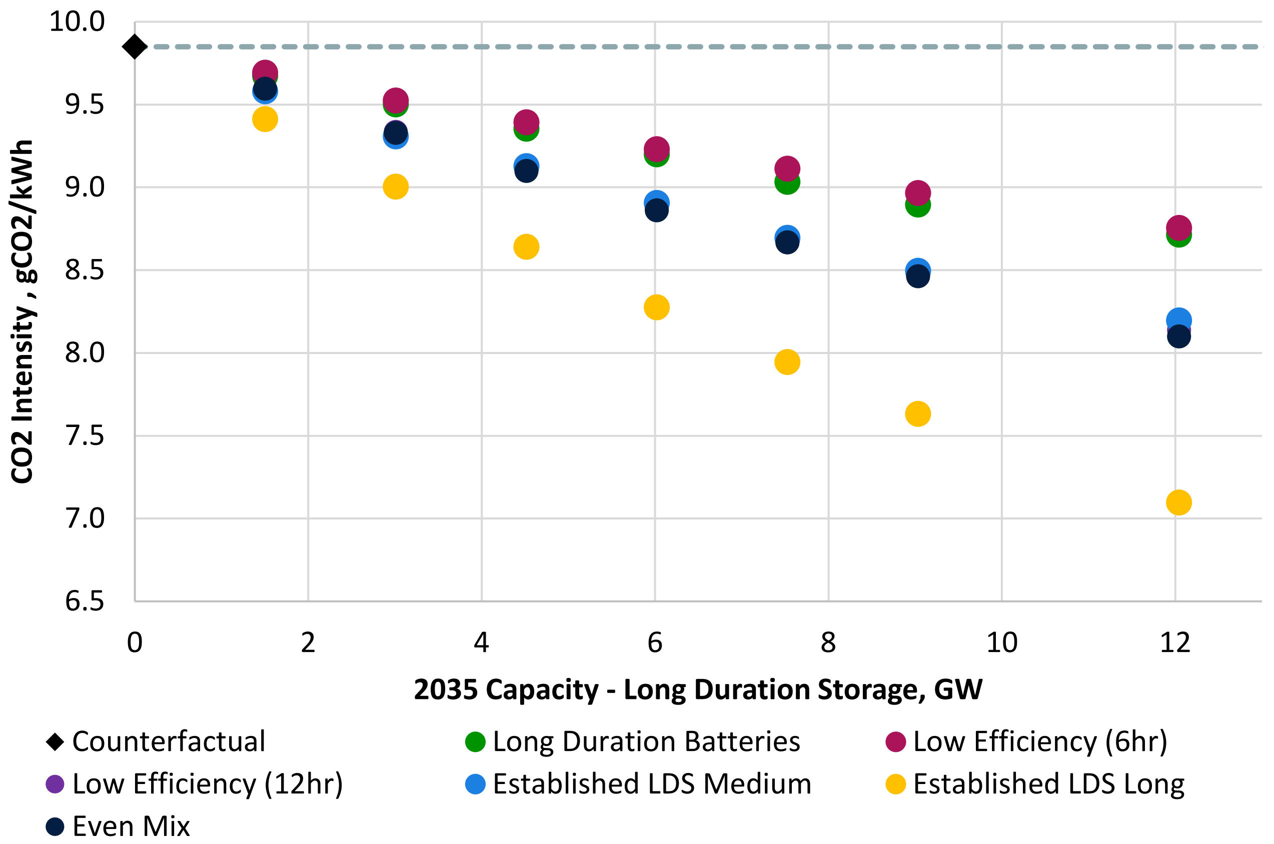
For the three gas CCS and hydrogen deployment levels where new counterfactuals are defined, the modelling of adding LDES has been completed in the same way as for the Core counterfactual. This section looks at results where LDES replaces peaking capacity only.

Emissions intensity

Adding LDES to the system at the expense of peaking capacity has a positive impact on emissions with emissions reducing across all LDES capacities and archetypes for all gas CCS and hydrogen deployment levels. As with the Core counterfactual, in general the higher duration and efficiency the larger the impact on emissions with the established long-duration storage long (16-32 hrs) having the largest impact on emissions. Findings are very similar across the Central, Low Gas CCS, and Low Hydrogen scenarios as the installed LDES capacity is an order of magnitude less than unabated gas in all counterfactual scenarios, so it can be utilised in the same way in each case.

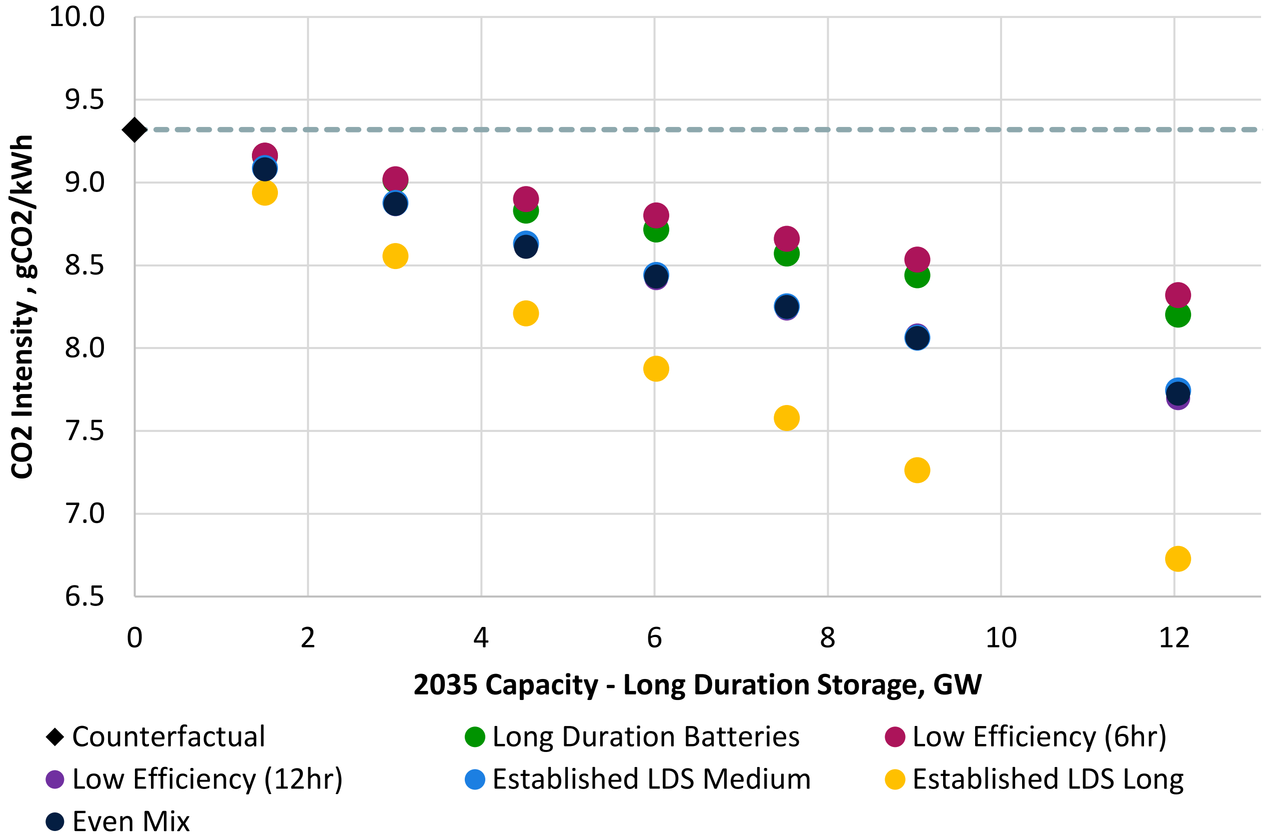
With the Low Gas CCS counterfactual, the impact on emissions from adding LDES to the system is similar to the Core Scenario with LDES. For example, emissions reduce by 1gCO2e/kWh in 2035 with 6GW of Established LDES Medium archetype on the system in 2035 (10GW in 2050) as they did with the Core counterfactual.

Figure 57: *Emissions intensity v LDES capacity in 2035 (coloured by LDES archetype) with the Low Gas CCS counterfactual and LDES replacing peaking capacity.*



With a Low Hydrogen counterfactual, the impact on emissions is slightly larger. For example, emissions drop by 1.5gCO2e/kWh in 2035 compared to the counterfactual with 6GW of Established LDES Medium archetype on the system in 2035 (10GW in 2050). This reflects the LDES being able to reduce unabated gas and gas CCS generation further with the Low Hydrogen counterfactual compared to the Core Scenario.

Figure 58: *Emissions intensity v LDES capacity in 2035 (coloured by LDES archetype) with the Low Hydrogen counterfactual and LDES replacing peaking capacity.*



System cost

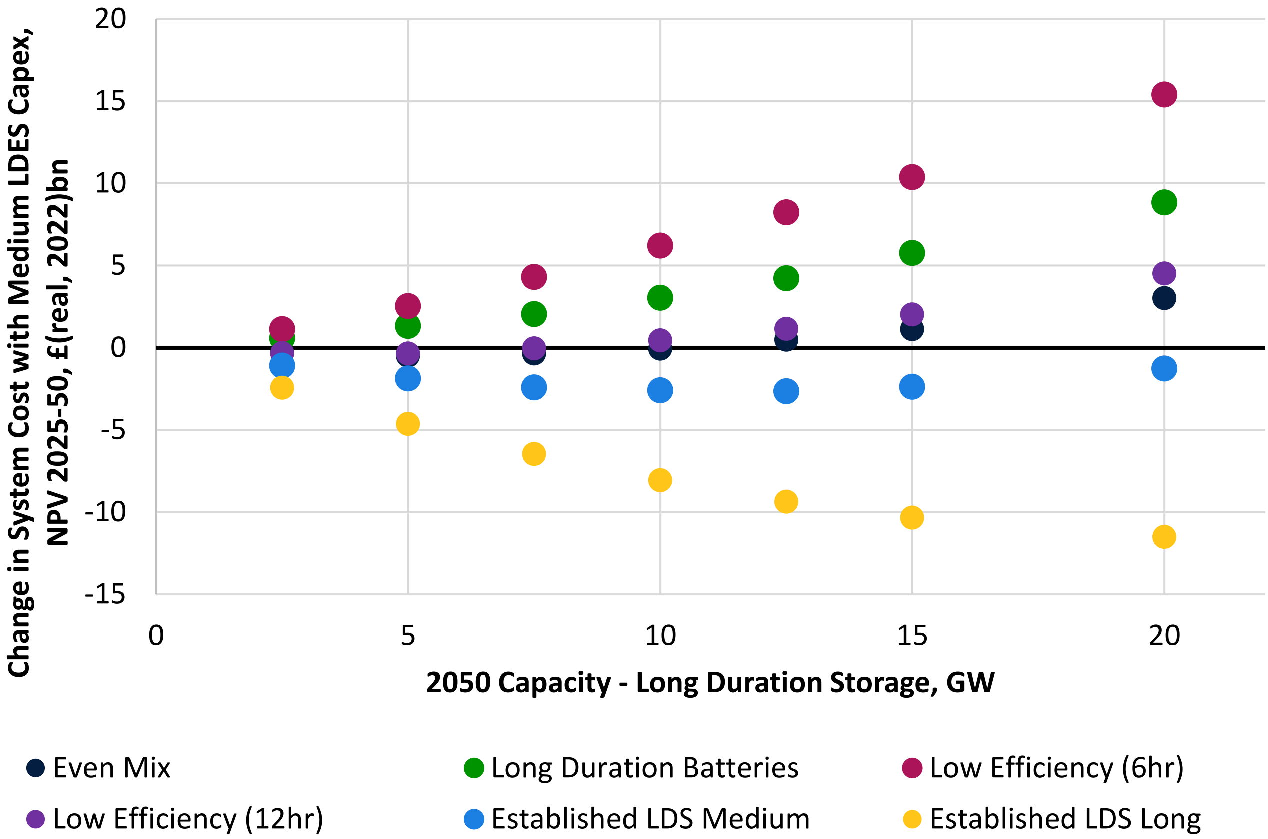
System cost impacts with medium LDES CapEx for each gas CCS/hydrogen deployment level with the LDES **replacing peaking capacity only** are shown below. Overall, the impacts of adding LDES to different gas CCS and hydrogen counterfactuals are similar to adding LDES to the Core counterfactual. Changes across the system cost types are similar to the Core Scenario with decreases in costs driven by reductions in generation and interconnector costs. This reflects similar changes to generation, curtailment, wholesale prices as seen in the Core Scenario but on slightly different scales. Cost increases are again driven by increases in CapEx and fixed OpEx as a result of adding the LDES onto the system and this being more expensive than the peaking capacity it replaces.

Adding any LDES to the system at the expense of peaking capacity decreases system costs, excluding CapEx, across all gas ccs and hydrogen deployment counterfactuals. However, with CapEx included, the overall impact depends on the LDES archetype and level of capacity. However, there are some differences across the different counterfactuals.

For the **Low Gas CCS counterfactual**:

- Overall system costs for the Low Gas CCS counterfactual are around £9bn (1.3%) higher compared to the Core counterfactual.
- The results for adding LDES show similar trends to the Core Scenario with only the Long-Duration Battery and Low-Efficiency 6hr archetype showing net increase in system costs across all capacity levels.
- Impacts are slightly larger with Low Gas CCS compared to the Core counterfactual. The maximum system benefit (20GW established LDES long) increases from £9bn to £11bn. This is due to the counterfactual having high levels of renewables and the LDES therefore being able to do more to reduce emissions and better utilise wind.

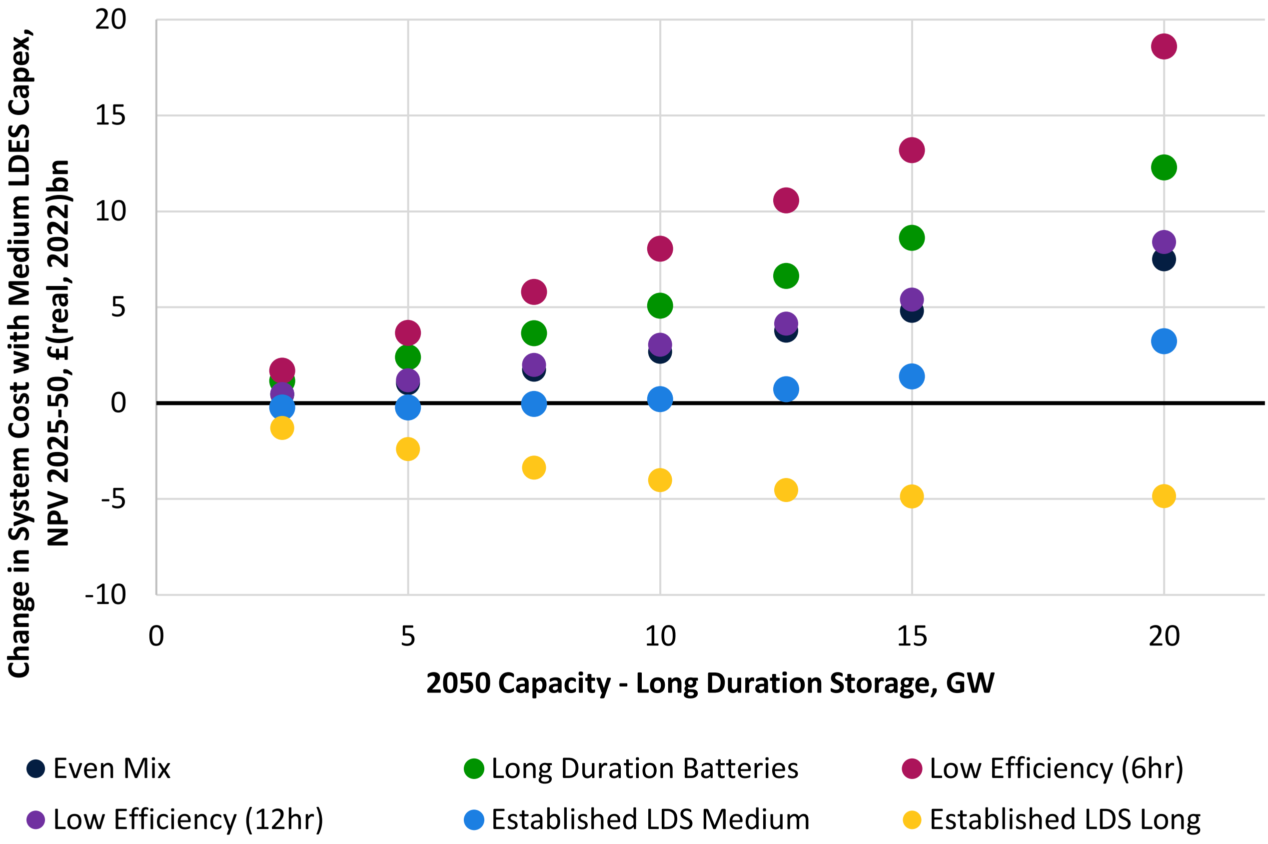
Figure 59: *Change in system cost (NPV) with medium LDES CapEx v LDES capacity in 2050 (coloured by LDES archetype) with Low Gas CCS counterfactual and LDES replacing peaking capacity only.*



For the **Low Hydrogen counterfactual**:

- Overall system costs for the Low Hydrogen counterfactual are a significant £39bn higher than the Core counterfactual and £30bn higher than the Low Gas CCS counterfactual. This is because of the large amount of wind capacity (that is often curtailed) that needs to be added to the system to reach the same level of emissions.
- In general, adding LDES in the Low Hydrogen counterfactual gives reduced benefits (or increased costs) compared to the Core and Low Gas CCS counterfactuals.
- As in the Core and Low Gas CCS counterfactuals, the Long-Duration Battery and Low-Efficiency 6hr archetypes show costs to the system across all capacity levels. However in the Low Hydrogen results this is also the case for the Low Efficiency 12hr and Even mix archetypes.
- Adding Established LDS Medium only provides benefits at levels of 7.5GW (in 2050) or below. Established LDS Long shows benefits to the system at all capacity levels but these benefits are reduced compared to the Core and Low Gas CCS counterfactuals. This is because there is so much additional wind generation across the year that the LDES is less effective in providing benefits from shifting this wind to new time periods.

Figure 60: *System cost (NPV) with medium LDES CapEx v LDES capacity in 2050 (coloured by LDES archetype) with Low Hydrogen counterfactual with LDES replacing peaking capacity only.*



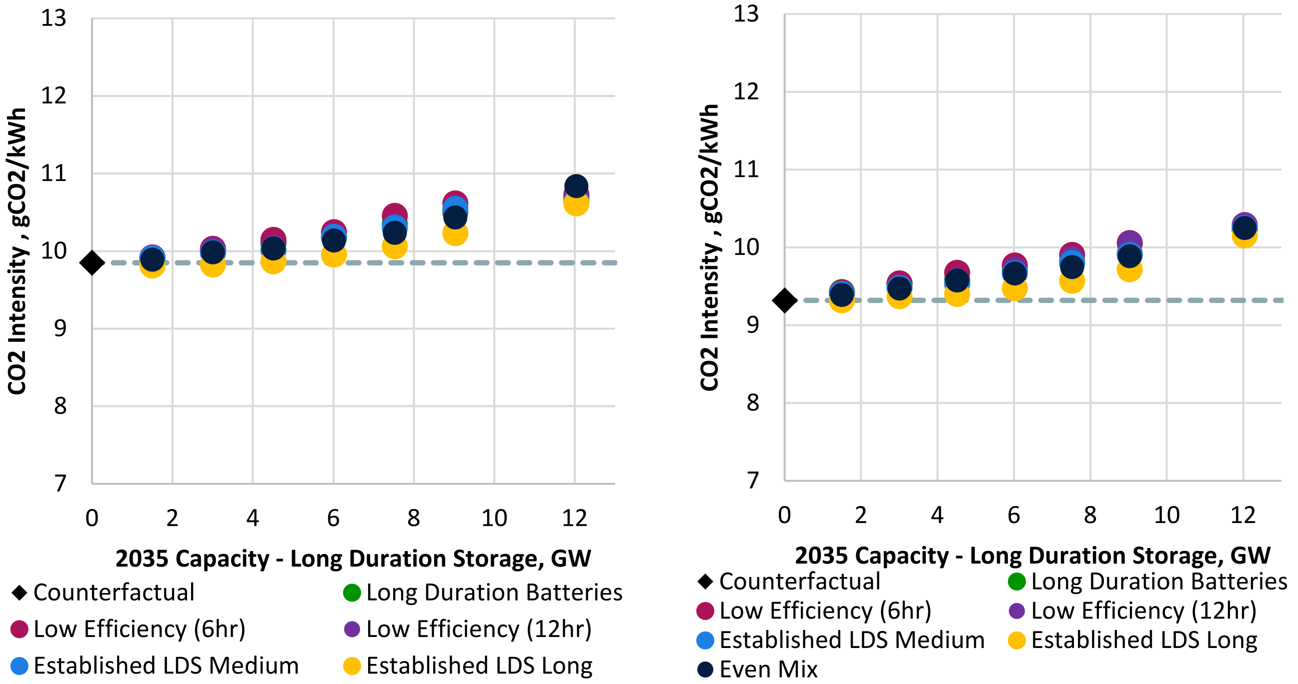
7.3. Adding LDES to replace peaking and renewable capacity

As with the Core counterfactual, for the second stage of the modelling peaking and wind capacity are replaced to reach a similar level of emissions in each LDES scenario as the counterfactual.

Emissions intensity

The scatter plots below show the 2035 emissions against the LDES capacity for all scenarios where LDES replaces peaking and renewable capacity. By design, emissions are at a similar level to the counterfactual to within 1gCO2e/kWh[42].

Figure 61: *Emissions intensity v LDES capacity in 2035 (coloured by LDES archetype) with LDES replacing peaking and wind capacity for Low Gas CCS counterfactual (left) and Low Hydrogen counterfactual (right)*



System costs

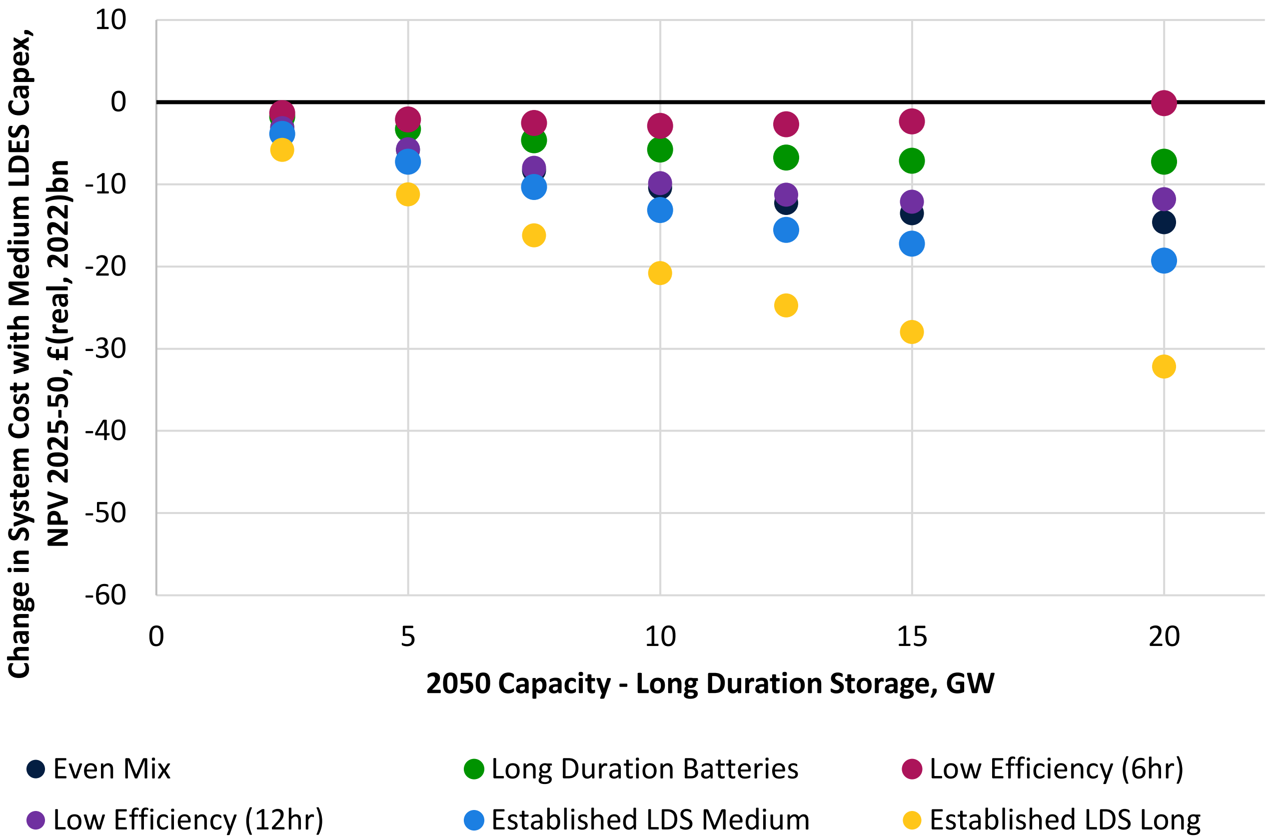
System cost impacts with medium LDES CapEx for each gas CCS or hydrogen deployment level with the LDES replacing peaking capacity and wind capacity are shown below. Overall, the impacts of adding LDES to the different counterfactuals are similar to adding LDES to the Core counterfactual. As with the Core counterfactual, the key system cost changes are in interconnector, network and CapEx costs. However, impacts tend to be larger as more renewable capacity is able to be replaced when adding the LDES, leading to a bigger reduction in network and CapEx costs.

[42] Within the modelling, it is difficult to get emissions to the exact same level as the counterfactual. To match exactly would require many iterations of each scenario changing the level of wind capacity each time. Given the volume of scenarios being modelled then a tolerance of 1gCO2e/kWh is used so emissions end up at similar level. This would cause some minor changes to CapEx and carbon costs but these will not be significant.

For the **Low Gas CCS counterfactual**:

- Overall system costs for the Low Gas CCS counterfactual are around £9bn (1.3%) higher compared to the Core counterfactual.
- Unlike the Core counterfactual, all 84 LDES scenarios now show a system benefit (under Medium LDES CapEx levels). In particular, adding any amount of Long-Duration Batteries and Low-Efficiency (6hr) are now benefits rather than costs to the system.
- Across all archetypes, system cost savings increase with a Low Gas CCS counterfactual with the maximum system cost saving now £32bn (4.4%) compared to £24bn (3.3%) with the Core counterfactual. This is a result of LDES replacing more renewable capacity in the Low Gas CCS counterfactual to reach the same level of emissions.
- The drivers of these system cost savings are the same as those outlined for the example scenarios in Chapter 6, however the magnitude of many of these costs is larger. In particular, impacts on network and CapEx costs are higher owing to the larger amount of renewable capacity that is able to be replaced when adding the LDES (as there is a larger amount in the counterfactual).
- Different LDES archetypes' system savings peak at different capacity levels; Low-Efficiency (6hr) peaks at 10GW and Low-Efficiency (12hr) at 15GW. All other archetypes continue to bring system benefits with more capacity, including an Even Mix across all archetypes.
- Adding the largest amounts of LDES with the highest duration brings system costs down to the same level or in most cases lower than the Core counterfactual (i.e. offsetting the £9bn increase between Core and Low Gas CCS before LDES is added). This shows that high levels of LDES could be deployed instead of gas CCS for a similar system cost, highlighting that LDES could be key in mitigating any deployment risk for gas CCS.

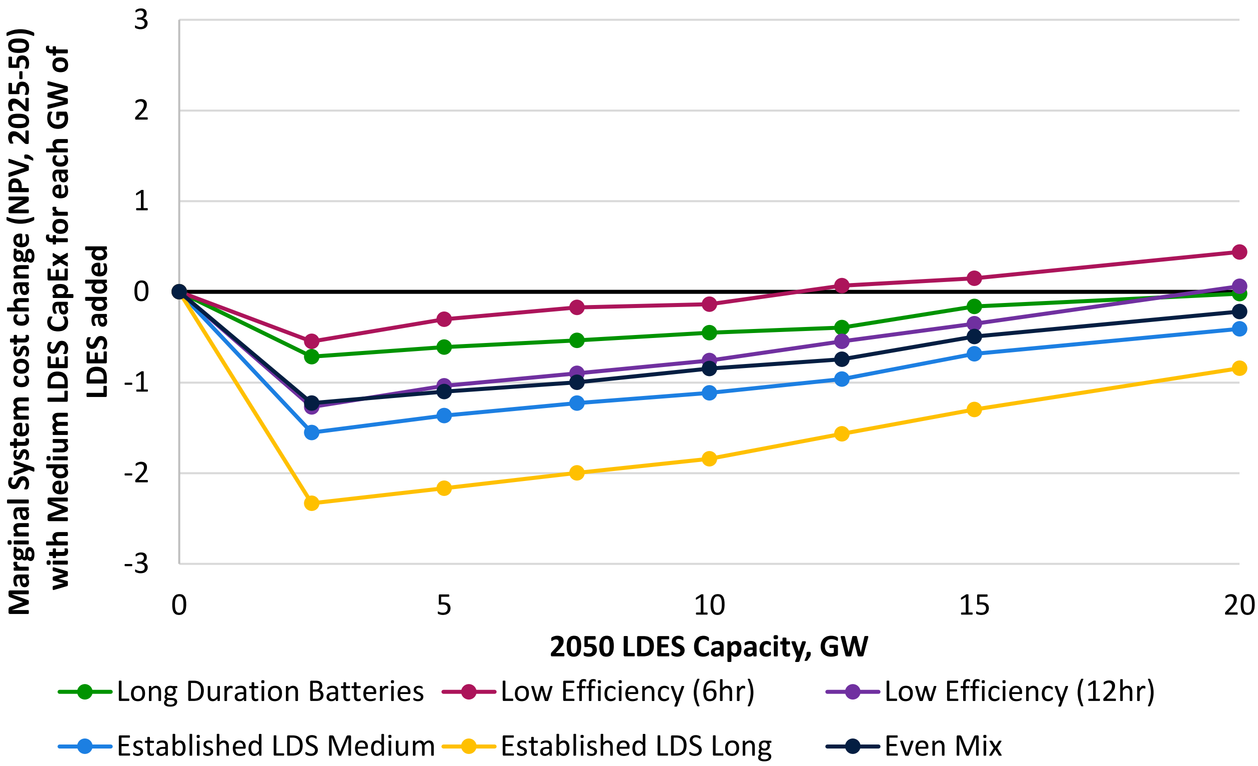
***Figure 62:** Change in system cost (NPV) with medium LDES CapEx v LDES capacity in 2050 (coloured by LDES archetype) with Low Gas CCS counterfactual and LDES replacing peaking and wind capacity*



As with the Core Scenario, in order to see optimal levels of LDES deployment, the below graph shows the marginal Change in system cost for each GW of LDES added at different LDES capacity levels. The situation for each archetype is summarised below.

- **Long-Duration Batteries –** Adding capacity of this archetype below 20GW brings benefits to the system. However, at 20GW adding additional capacity is close to zero.
- **Low-Efficiency 6hr** – Adding capacity beyond 12.5GW in 2050 with medium CapEx levels is no longer beneficial to the system. Adding the first 2.5GW has the largest marginal benefit to the system.
- **Low-Efficiency 12hr** – Adding capacity of this archetype below 20GW brings benefits to the system. However, at 20GW adding additional capacity is no longer beneficial.
- **Established LDES Medium, Established LDES Long** – Adding additional LDES of this archetype up to 20GW is always a marginal benefit to the system. However, as with all archetypes this marginal benefit begins to decrease as more LDES is added.

***Figure 63**: Marginal Change in system cost (NPV) with medium LDES CapEx for each GW of LDES added (in 2050) with a Low Gas CCS counterfactual and LDES replacing peaking and wind capacity.*

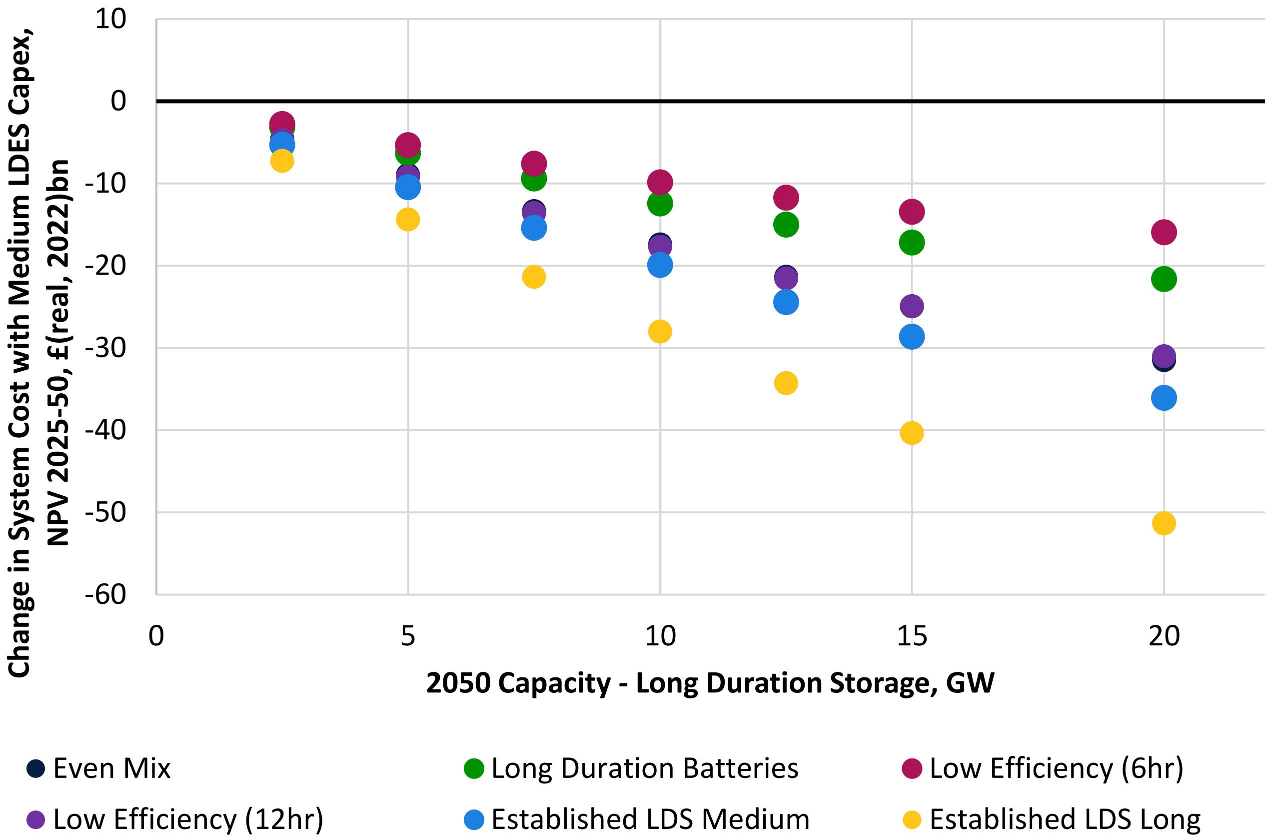


For the **Low Hydrogen counterfactual**:

- Overall system costs for the Low Hydrogen counterfactual are a significant £39bn higher than the Core counterfactual and £30bn higher than the Low Gas CCS counterfactual.
- Similar to the Low Gas CCS counterfactual all 84 LDES scenarios show a system benefit with fairly significant system cost savings across all archetypes (under Medium LDES CapEx levels).
- Across all archetypes, system cost savings increase as capacity increases. The overall drivers of these system cost savings are the same as outlined for the example scenarios in Chapter 6, however the magnitude of many of these costs is larger. In particular, impacts on network and CapEx costs are higher owing to the larger amount of renewable capacity that is able to be replaced when adding the LDES (as there is a larger amount in the counterfactual that is not being utilised as effectively)
- System cost savings can be very large. Adding only 2.5GW of LDES by 2050 can reduce system costs by £2.8-7bn (0.5-1%) while adding 20GW over the same time period can reduce system costs by £16-51bn (2-7%). Impacts are higher compared to the Low Gas CCS counterfactual due to the higher levels of renewable capacity displaced when adding the LDES. This is due to the Low Hydrogen counterfactual having more renewable capacity than the Low Gas CCS counterfactual, and more of this renewable capacity not being utilised effectively.

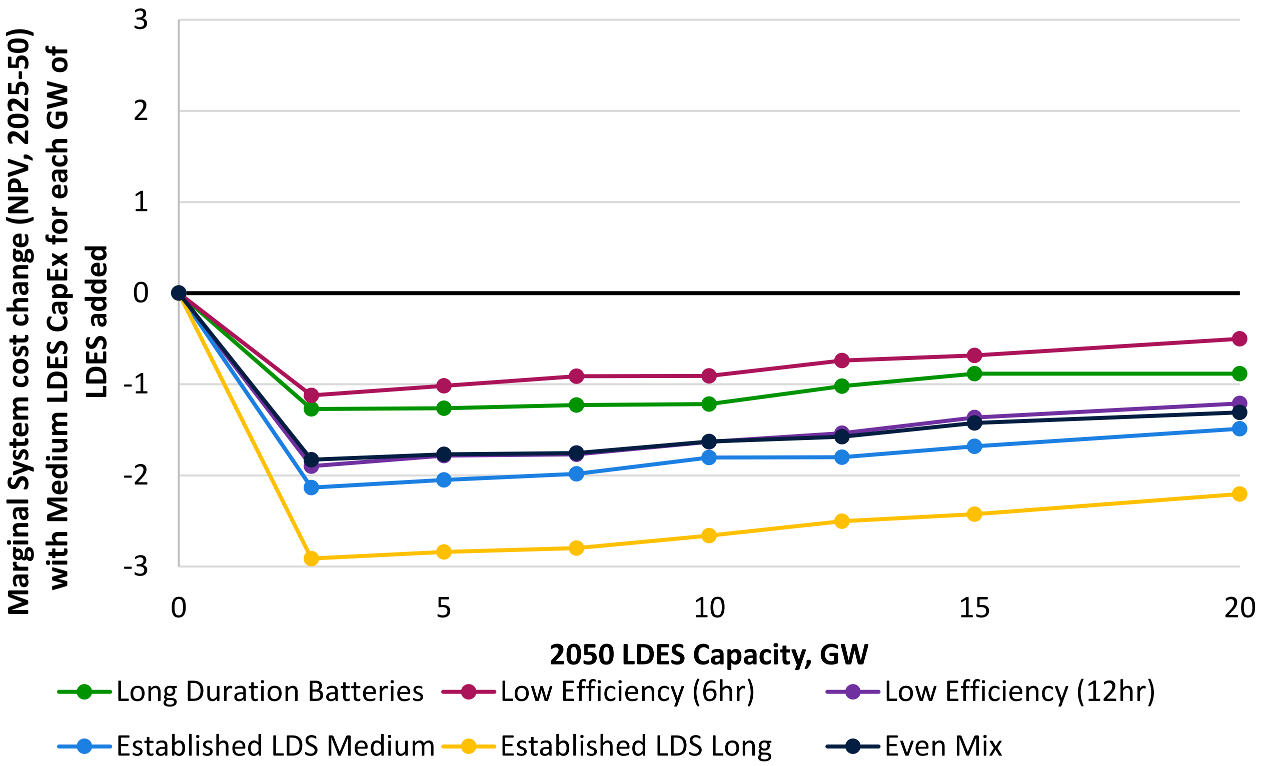
- Adding the largest amounts of LDES with the highest duration brings system costs down to the same level or lower than DESNZ NZ higher counterfactual (i.e. offsetting the £30bn increase between Core and Low Hydrogen before LDES is added). This shows that high levels of LDES could be deployed instead of hydrogen for a similar system cost, highlighting that LDES could be a key in mitigating any deployment risk for hydrogen to power technologies.

Figure 64: *Change System cost (NPV) with medium LDES CapEx v LDES capacity in 2050 (coloured by LDES archetype) with Low Hydrogen counterfactual and LDES replacing peaking and wind capacity.*



As with the Core Scenario, in order to see optimal levels of LDES deployment, the below graph shows the marginal change in system cost for each GW of LDES added at different LDES capacity levels. Across all archetypes this shows that adding additional LDES (at medium CapEx levels) capacity up to 20GW will continue to bring additional benefits to the system with a Low Hydrogen counterfactual. This is quite different to the Core Scenario which showed some archetypes having points after which adding additional capacity was no longer beneficial to the system. The marginal benefit still declines with each GW added for all archetypes suggesting that there would be a point at which building additional LDES will no longer be beneficial.

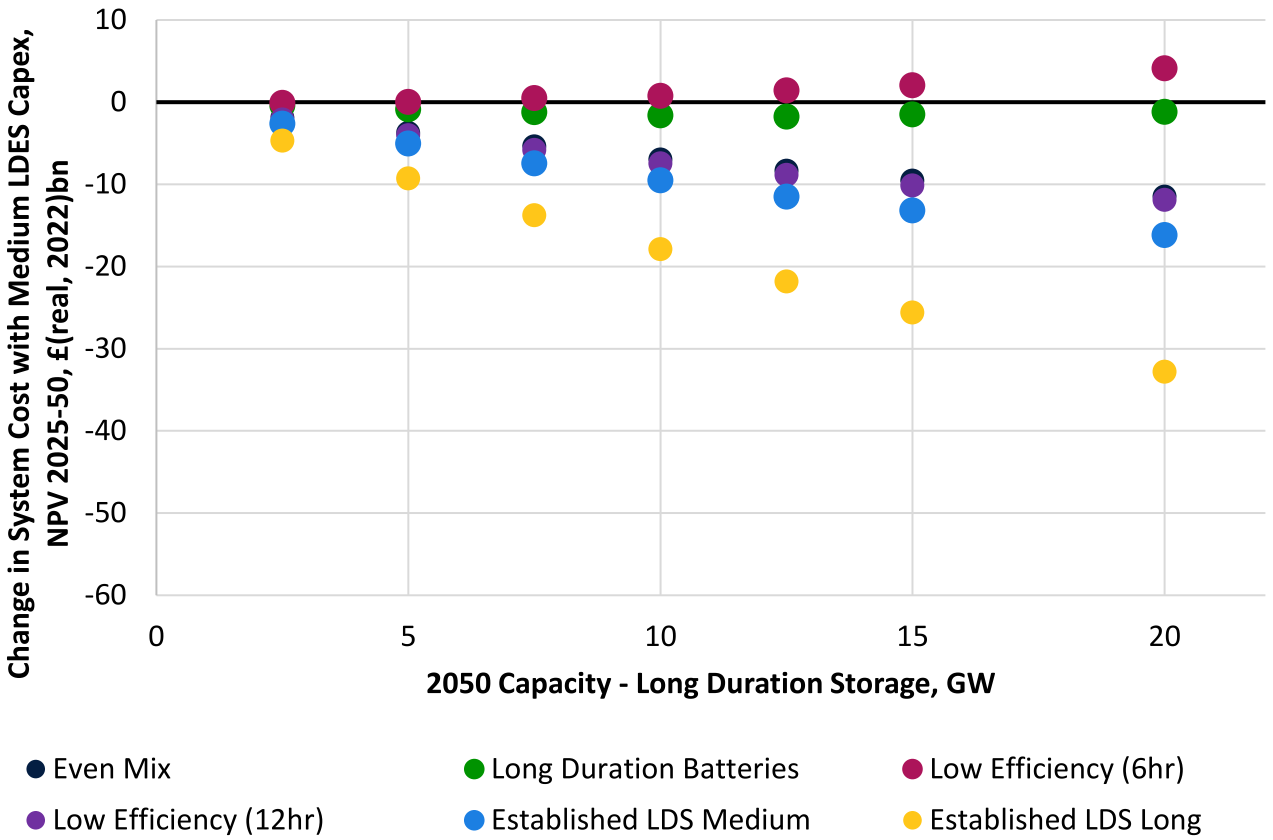
Figure 65: *Marginal change in system cost (NPV) with medium LDES CapEx for each GW of LDES added (in 2050) with a Low Hydrogen counterfactual and LDES replacing peaking and wind capacity.*



For the **Medium Gas CCS and Hydrogen counterfactual**:

- Overall system costs for the Medium Gas CCS and Hydrogen counterfactual are a significant £37bn higher than the Core counterfactual, £29bn higher than the Low Gas CCS counterfactual and £2bn lower than the Low Hydrogen counterfactual (all under Medium LDES CapEx levels). This is because of the large amount of renewable capacity (that is often curtailed) that needs to be added to the system to reach the same level of emissions, but the amount of capacity added is slightly less than in the Low Hydrogen counterfactual. Changes in network costs and CapEx costs are the largest drivers of these differences.
- Similar to the other gas CCS and hydrogen deployment levels, most LDES scenarios reduce system costs. Only the Low Efficiency (6hr) archetype results in increases to system costs.
- For all LDES archetypes, except Low Efficiency systems and Long-Duration Batteries, benefits increase with more capacity added. The maximum reduction in system costs is £33bn (4.3%) compared to £24bn (3.3%) in the Core counterfactual. In general, system cost savings are not as high as for the Low Hydrogen counterfactual, with savings more similar to Low Gas CCS counterfactual. This is a result of less wind capacity being replaced compared to the Low Hydrogen counterfactual.

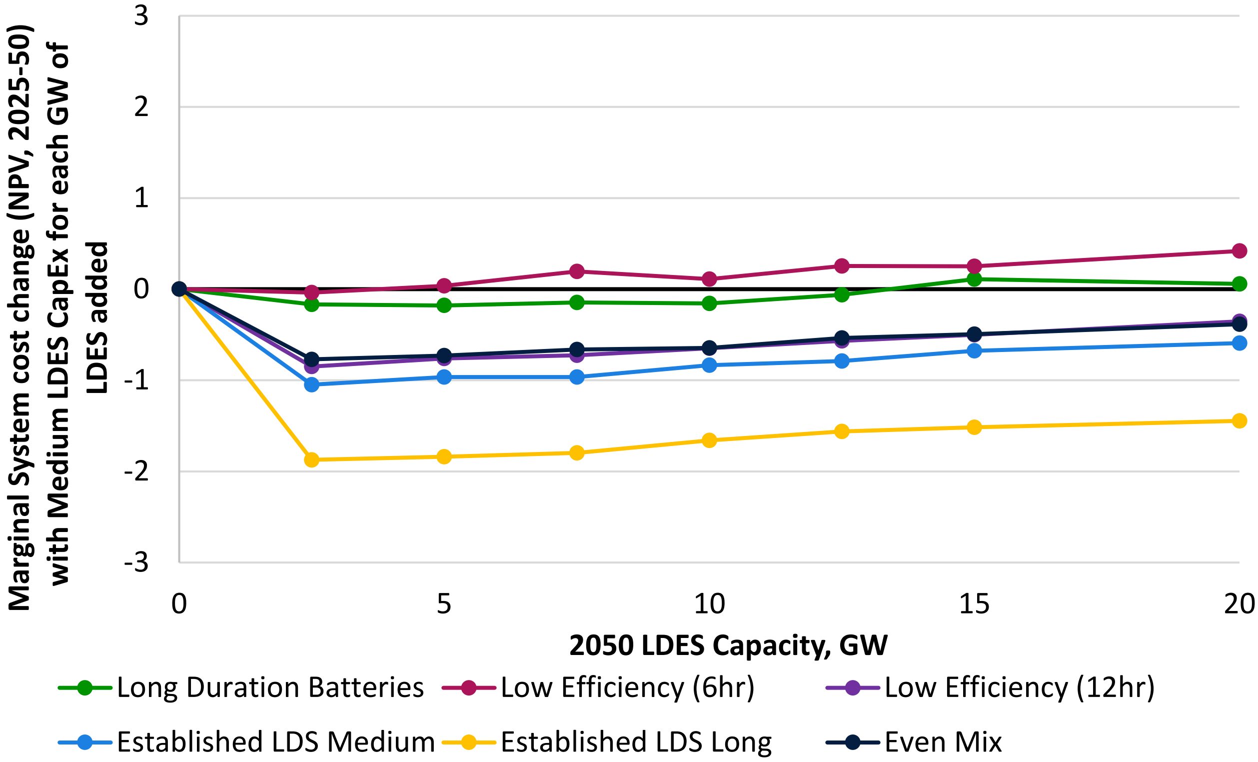
Figure 66: *System cost (NPV) with medium LDES CapEx v LDES capacity in 2050 (coloured by LDES archetype) with Medium Gas CCS and Hydrogen counterfactual and LDES replacing peaking and wind capacity.*



As with the Core Scenario, in order to see optimal levels of LDES deployment, the below graph shows the marginal Change in system cost for each GW of LDES added at different LDES capacity levels. For each archetype this shows:

- **Long-Duration Batteries –** Adding capacity beyond 12.5GW in 2050 with medium CapEx levels is no longer beneficial to the system.
- **Low-Efficiency 6hr** – Only adding capacity of this archetype below the 2.5GW levels brings benefits to the system with additional capacity beyond this point not bringing any additional benefits.
- **Low-Efficiency 12hr, Established LDES Medium, Established LDES Long** – Adding additional LDES of this archetype up to 20GW is always a marginal benefit to the system. However, as with all archetypes this marginal benefit begins to decrease as more LDES is added.

Figure 67: *Marginal change in system cost (NPV) with medium LDES CapEx for each GW of LDES added (in 2050) with a Medium Gas CCS and Hydrogen counterfactual and LDES replacing peaking and wind capacity.*



Results from the breakeven CapEx analysis plus results for the other CapEx scenarios (low and high) are shown in Annexes B and C respectively. Annex D contains results for a scenario with low gas CCS and hydrogen which uses a different methodology to the scenarios outlined in this chapter.

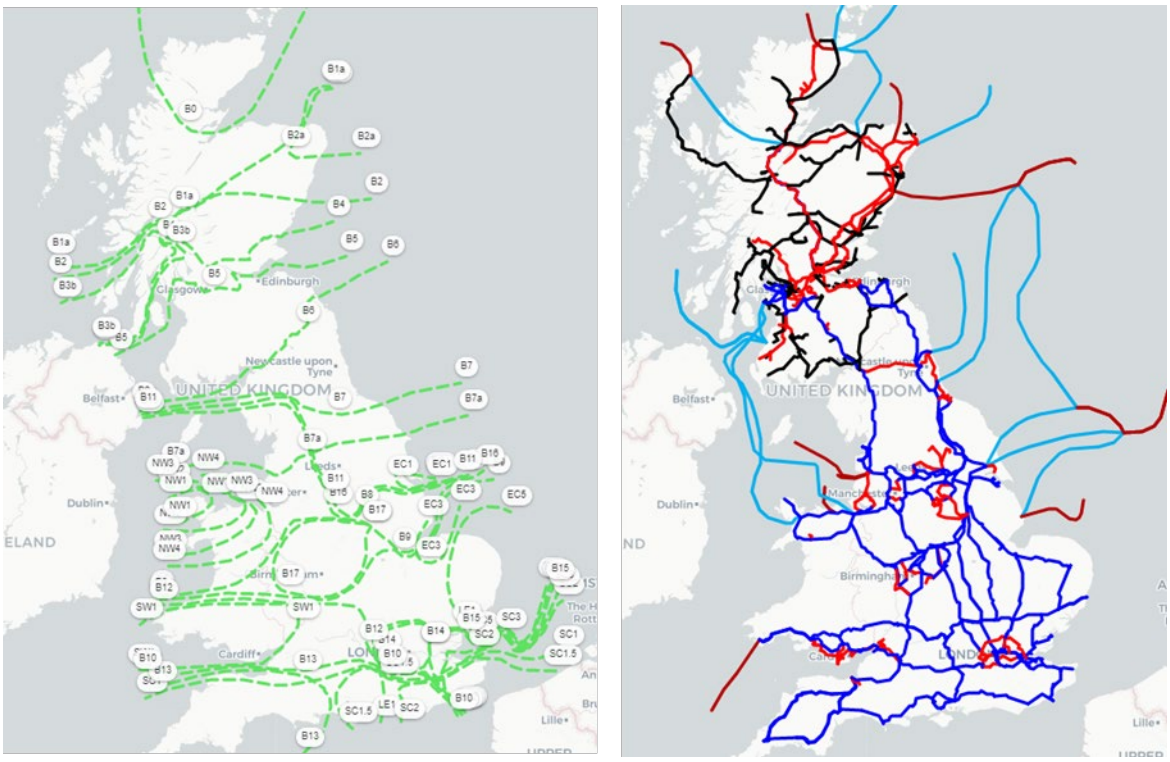
8. Modelling Results – Locational Impacts

8.1. Why is location important?

Moving electricity from its generation point to demand is a key challenge of any electricity system and the GB electricity system is no different. Generation assets are often located away from demand centres – for example most onshore wind generation is in Scotland, but south-east England has the highest level of demand. Moving electricity from generation point to demand centres is restricted by the capacity on the transmission network. For example, the B6 boundary is the key network boundary between Scotland and England and only has a certain amount of capacity (i.e. maximum power in MW that can be moved from Scotland to England at any one time).

As a result of these network restrictions, the TSO must often step in to turn-down generation in network constrained areas, such as Scotland, and turn-up generation near demand centres, such as south-east England, to ensure network restrictions are not breached and supply meets demand. This "locational balancing" can be a substantial cost to the system as generators are paid to turn-up and turn-down through the Balancing Mechanism.

Figure 68: *Map of GB boundaries and transmissions network lines*[43]



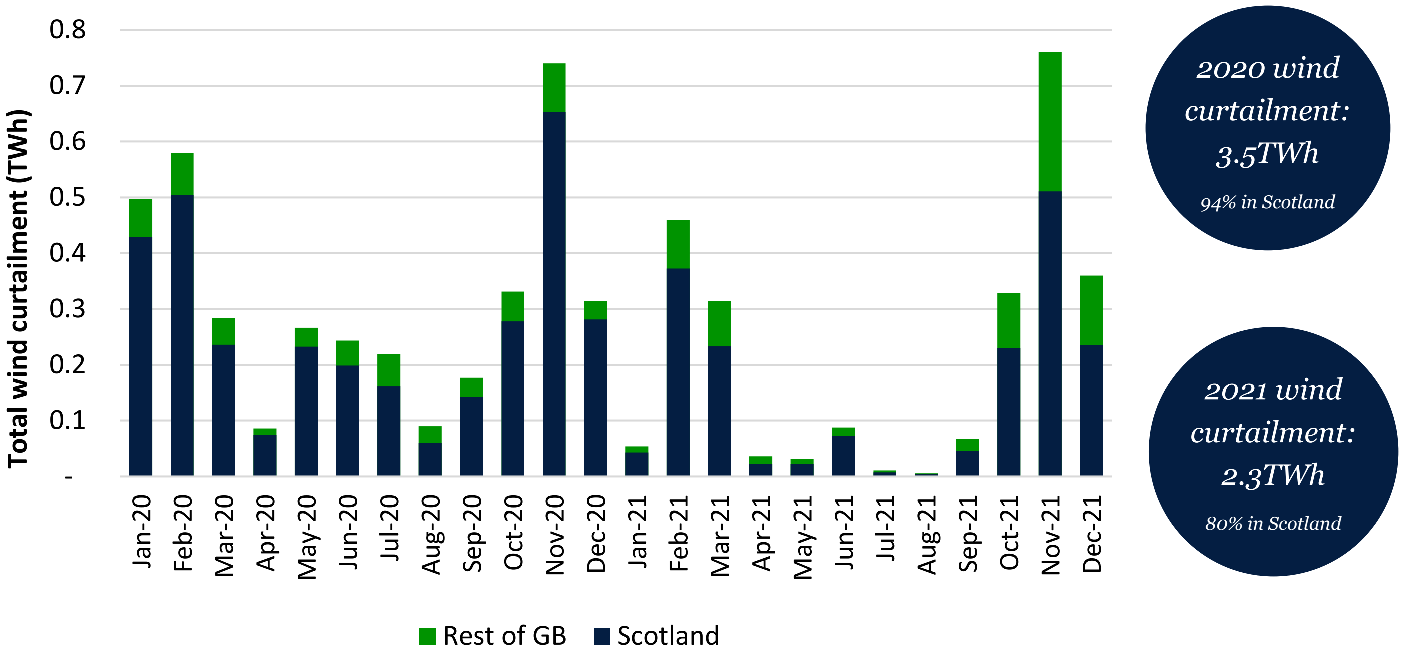
As more and more renewables are added to the system, the network is likely to become more constrained on a more regular basis unless the network capacity scales with this. National Grid

[43] Our Interactive Map | National Grid ESO

ESO predict that network constraints (via the locational Balancing Mechanism) could cost £2-3bn per year by the late 2020s before dropping to around £1bn per year in the 2030s as the network capacity increases.[44] While National Grid ESO and the government have plans to increase network capacity significantly in the coming years to cope with more renewables and higher demand on the system, there are still likely to be constraints on the network. This means generation being turned down in constrained areas and turned up in others. This could mean that other areas of the country in addition to the Scotland-England (B6) boundary becoming more constrained over time.

Deploying LDES in the right location can bring benefits to the system. Network constraints mean that renewables are more likely to be curtailed in certain locations and LDES can help alleviate this issue and avoid future network reinforcement costs. Locational renewable curtailment is already an issue as shown in LCP's Renewable curtailment and the role of long-duration storage report for Drax[45]. As a result of constraints in the transmission system, there have been many periods where significant levels of wind generation are being wasted costing consumers over £800m across 2020-21 and curtailing enough energy to supply around 800,000 households as outlined in the chart below.

Figure 69: *Total wind curtailment (TWh) across 2020/21 from LCP report for Drax*



LDES can help in these situations as it can be charged when the relevant network boundary is constrained and discharge when the boundary is no longer constrained. This reduces curtailment of renewables in constrained regions and can ultimately allow for a more efficient system.

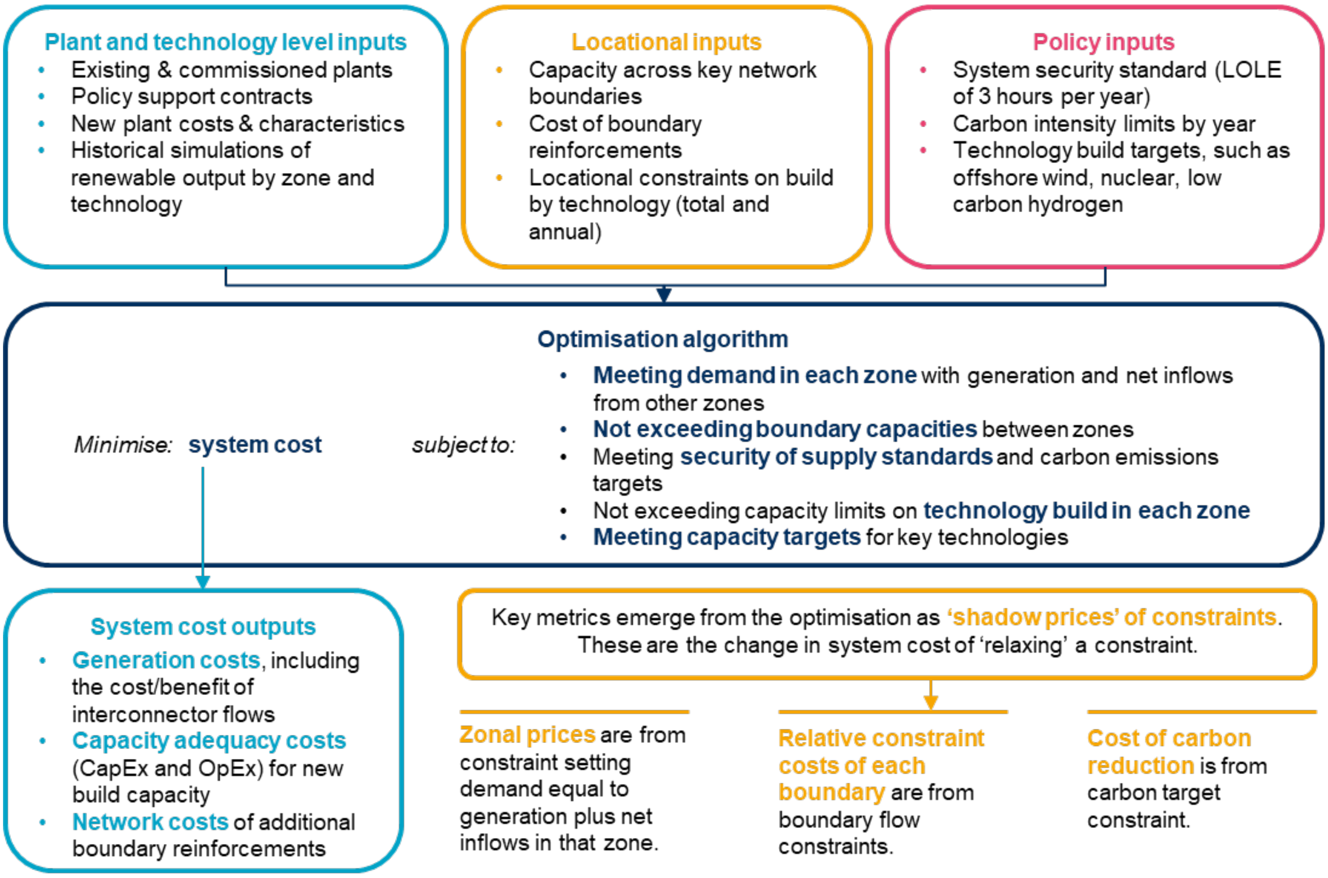
[44] download (nationalgrideso.com)
[45] Drax-LCP - Renewable curtailment report

8.2. Locational modelling approach

To understand the locational benefits that LDES can bring to the system, a subset of the scenarios outlined in previous chapters have been modelled in LCP Delta's Locational Dispatch Model. Using this model, the impact that adding LDES to the system can have on locational balancing is assessed, both in terms of the LDES archetype and where the LDES is located in the country.

LCP Delta's market dispatch algorithm simulates the supply demand in each hour by zone, based on market fundamentals using an optimisation algorithm. The model has options to run without and with boundary constraints to simulate national dispatch (current wholesale market arrangements with a single national price) followed by locational redispatch through the Balancing Mechanism. Comparing results between the two shows the changes due to locational balancing including on generation, emissions and system costs. An overview of the model can be seen in the diagram below:

Figure 70: *LCP Delta's Locational Dispatch Model*



The main algorithm of the LMPM model, optimises two days at a time and then records the data from the first day only. Most short duration batteries will not need any more foresight than this. However, LDES operators look at longer time scales to fully utilise their assets. To reflect this, LDES participate in a 'pre-optimisation' in the LMPM model. The idea of this pre-optimisation is to run a simplified version of the LMPM optimisation over a longer optimisation period with LDES able to fully participate. The 'pre-optimisation' gives us an idea of the state of charge we would expect from each long-duration battery at the end of each day. The charge of each long-duration battery at the end of each day is fixed in the standard optimisation afterwards. The standard optimisation is then run as normal.

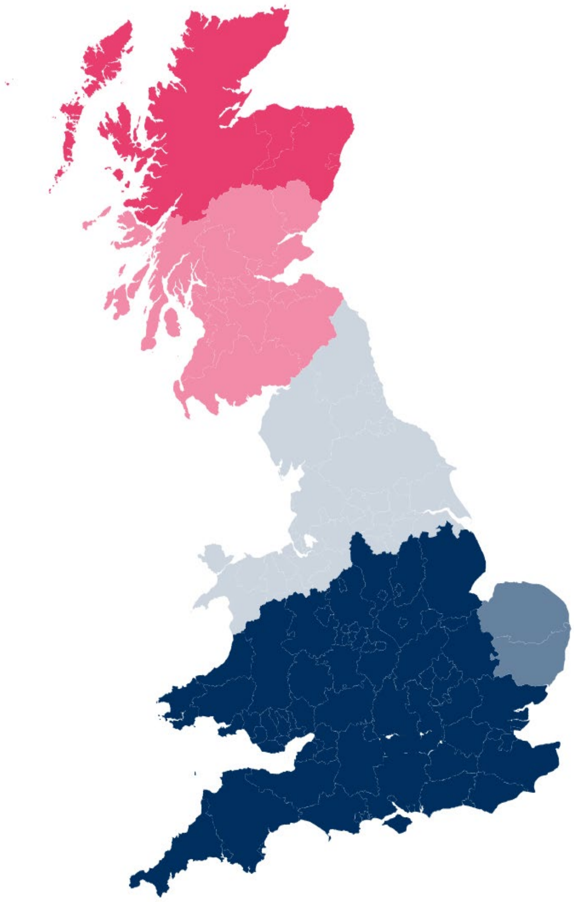
We do not model all storage assets over this longer optimization period as it gives unrealistic foresight. Wind and demand estimates are significantly worse the further in the future you get. This also allows us to accurately model the competition between long and short duration storage and their different operating strategies.

For this analysis, 5 zones are modelled: North Scotland, South Scotland, North England and Wales, South England and Wales, and East England. These reflecting 4 of the most constrained boundaries in the country: B2 (between North and South Scotland), B6 between Scotland and England, B8 (in middle of England and Wales) and EC5/SCD1 (separating East England). These can be seen in the map below:

Storage is modelled differently to other powerplants as storage needs to charge and generate, rather than just generate. The model optimises to reduce system cost over multiple periods, meaning storage plants buy energy when the price is low, and sell when it is high – generating instead of more expensive plants. Thus, storage plants decrease the difference between the two extreme prices.

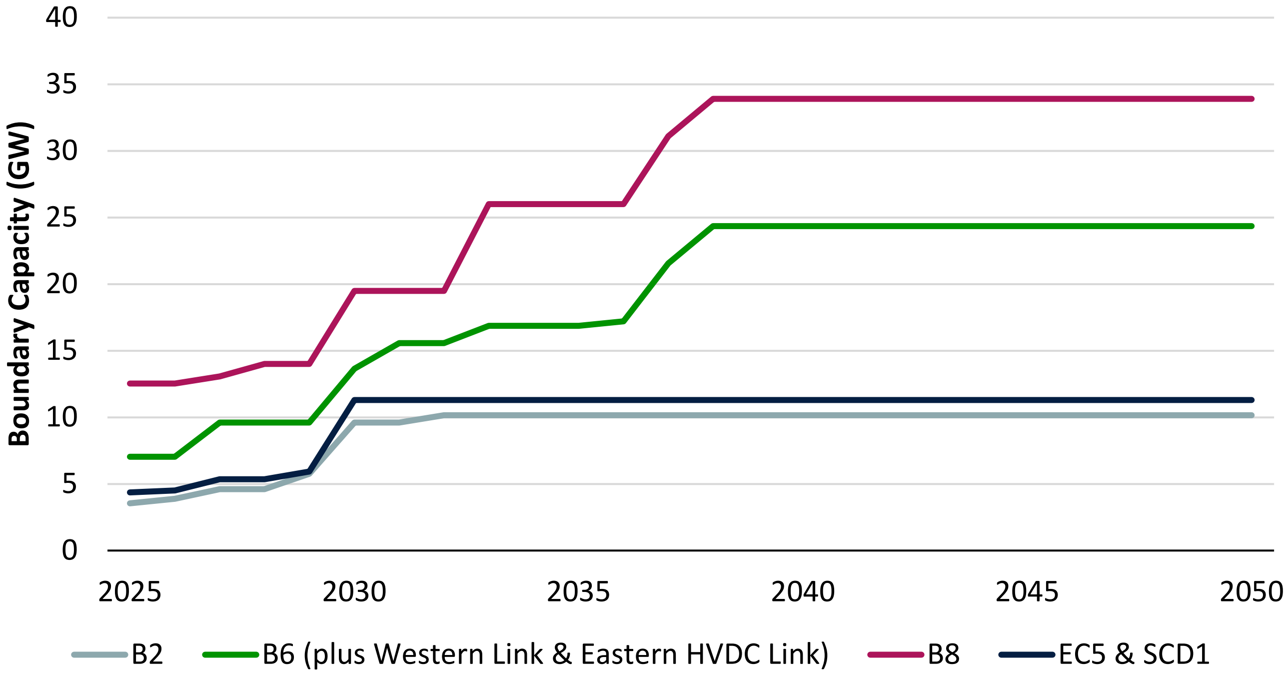
For long-duration storage, this optimisation needs to happen over a longer period to allow the long-duration storage flexibility to optimise its actions. Due to computing constraints and issues around capturing realistic levels of foresight, it's not always practical or desirable to run long optimisation periods. To combat this, the model performs a 'pre-optimisation' for long-duration storage. This works by running the same optimisation problem over a longer optimisation period with lower granularity. For this analysis, the pre-optimisation period is a rolling 4-day period with 6 hours equalling 1 period. As the periods are rolling then behaviour can be captured over a longer period than 4 days as well, however the 4-day foresight is designed to reflect how LDES plants may operate in the market given uncertainty in weather and demand over longer periods. Once the pre-optimisation has completed, the model records the charge of the LDES at the end of each day. The 'real' optimisation is then run with higher granularity, over a shorter optimisation period (i.e. running 1 day with hourly granularity). The LDES in the real optimisation have their charge fixed at the end of each day according to the pre-optimisation results. Their operation within day can be optimised but their shape over multiple days is fixed.

Figure 71: Map of modelled regions



It is assumed that the network capacity for these changes over time in line based on data available from NG ESO's Network Options Assessment 7 (NOA 7) refresh and Holistic Network Design (HND). How the capacity of these network boundaries changes over time can be seen below. This data was provided by DESNZ.

Figure 72: *Modelled boundary capacities over time*



All other assumptions used in this analysis are consistent with those outlined in previous chapters. Additional assumptions are used in the location of zones with all technologies located based on a combination of where existing and known planned capacity is located[46] and where plants of each type are expected to make the most revenue taking into account variations in load factor across the country and Transmission Use of System charges (TNUoS). There are also few restrictions, outlined below, on where certain technologies can build with these assumptions provided by DESNZ.

- As per current government policy, no new onshore wind builds in England.
- Seabed availability puts restrictions on where offshore wind can locate. This is reflected in the modelling with data provided by the crown estate giving overall restrictions as to how much offshore wind can build in each zone, but it should be noted that this is the most generous interpretation of availability, only based on seabed depth in certain areas.
- Nuclear plants are built in locations of already approved nuclear sites (for example, there is no nuclear build in Scotland even though some plants are currently located there).
- Gas CCS and hydrogen power plants cannot build in areas that do not contain industrial clusters.
- Electrolyser capacity is capped to a maximum of 50% in Scotland.

The 10GW scenarios for each LDES archetype (as outlined are above) plus the even mix scenario are modelled here to gain an understanding of the impacts on locational balancing that adding LDES to the system can have. In terms of locations, for the first set of scenarios,

[46] Taken from the Transmission Entry Capacity (TEC) Register

the LDES is deployed in places that are realistic for that archetype[47] with the below assumptions provided by DESNZ.

- **Longer-Duration Batteries** are able to locate anywhere as they are unlikely to have any specific locational requirements. As a result, they are split equally across all zones.
- **Low-Efficiency 6-hour LDES** mostly closely represents compressed air. As this technology requires salt caverns this limits locations. Based on the location of salt caverns, it is assumed 75% locate in North England and Wales and 25% in south England and Wales
- **Low-Efficiency 12-hour LDES** most closely represents liquid air technologies. This technology has no specific locational requirements, so capacity is split equally across all zones.
- **Established LDES Medium and Long** archetypes most closely resemble pumped storage hydro. These projects require sites with suitable topography and available water and as such are limited in GB. Based on the Transmission Entry Capacity (TEC) register[48] and the GIS Pumped storage map,[49] future projects are mostly located in Scotland with some in England and Wales. As such these are split 60% in the Northern Scotland, 30% in Southern Scotland, 5% in North England and Wales and 5% in South England and Wales.

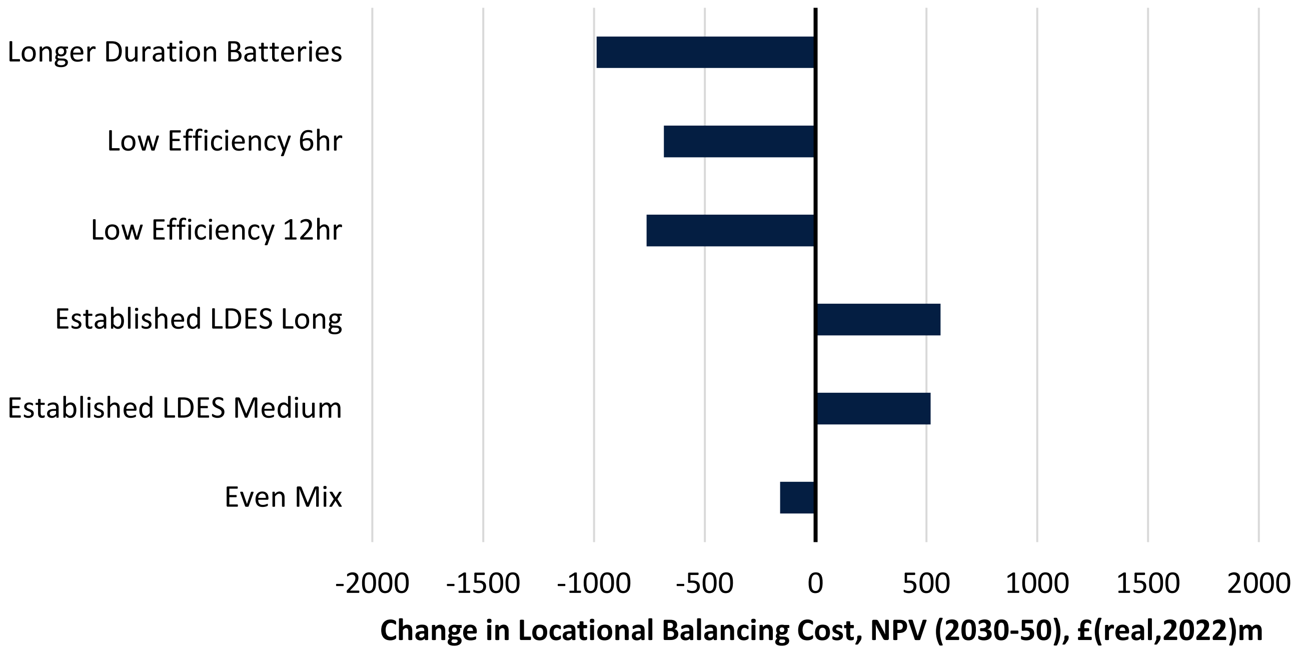
To test the importance of where the LDES is located on locational balancing, two additional sets of scenarios are run where the location of the LDES for every archetype is changed to all in Scotland (half in each zone) and all in England (a third in each zone). The results of this analysis are outlined below.

8.3. Locational modelling results

The chart below shows the impact that adding LDES to the system has on locational balancing costs from 2030 to 2050 (NPV). This shows the impact across the different archetypes, which is primarily driven by where the LDES is assumed to locate. This shows that LDES can bring benefits to locational balancing costs, depending on where it is located.

[47] Note these are assumptions are made based on the dominant technology with that archetype, other technology types could mean more diversity in location for some archetypes
[48] ESO Data Portal: Transmission Entry Capacity (TEC) Register - Dataset| National Grid Electricity System Operator (nationalgrideso.com)
[49] NationalMap

Figure 73: *Change in locational balancing system cost when adding 10GW of LDES (by archetype)*



The results by archetype are summarised below.

- **10GW of Longer-Duration Batteries** reduces locational balancing costs by £1bn (12%).
- **10GW of Low-Efficiency 6-hour LDES** reduces locational costs by £0.7bn (8%). This has the highest impact as it is the only archetype with no capacity in Scotland indicating that LDES capacity in England is more beneficial for locational balancing.
- **10GW of Low-Efficiency 12-hour LDES** reduces locational costs by £0.8bn (9%). This is lower than longer duration batteries despite these being located equally across the country and having higher duration. This indicates that for locational balancing, higher efficiency plants are better for the system.
- **10GW of Established LDES Medium** increases locational balancing costs by £0.5bn (6%). This appears to be mainly due to 90% of capacity located in Scotland. This is as a result of small increases in generation and interconnector due to increased exports and hydrogen production via electrolysis as a result of the LDES meaning slightly more hydrogen and gas CCS generation. This is explored below.
- **10GW of Established LDES Long** increases locational balancing costs by £0.6bn (7%) as well for the same reasons as established LDES medium.
- **10GW of even mix** across all archetypes sees locational balancing costs reduce by £0.2bn. This is a mix of all of the above with the decreases from Long-Duration Batteries and the low efficiency archetypes outweighing the decreases from the other archetypes.

Overall, these results indicate that where the LDES is located is a bigger driver of locational balancing costs rather than the type of LDES. To explore this further, we have modelled two additional sets of scenarios with all the LDES located in England/Wales and Scotland respectively.

Figure 74: *Change in locational balancing cost when adding 10GW of LDES (by archetype) all in England and Wales (split a third each across the zones)*

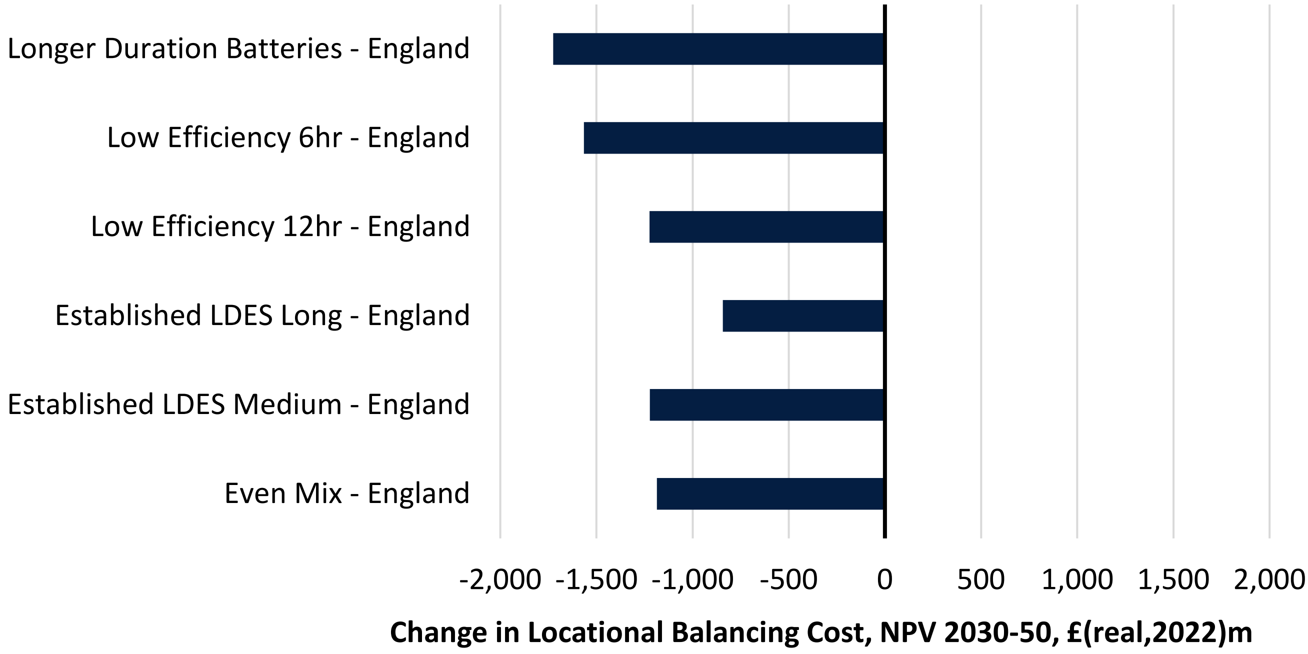
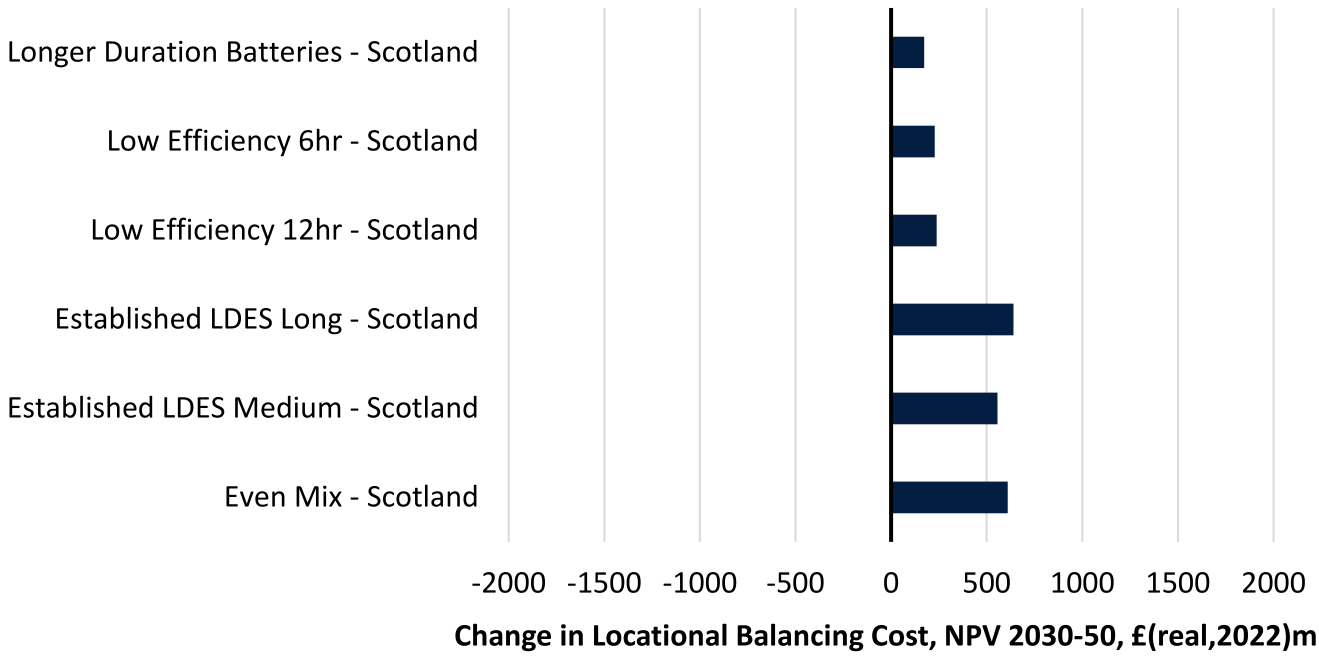


Figure 75: *Change in locational balancing cost when adding 10GW of LDES (by archetype) all in Scotland (split 50:50 across the zones)*



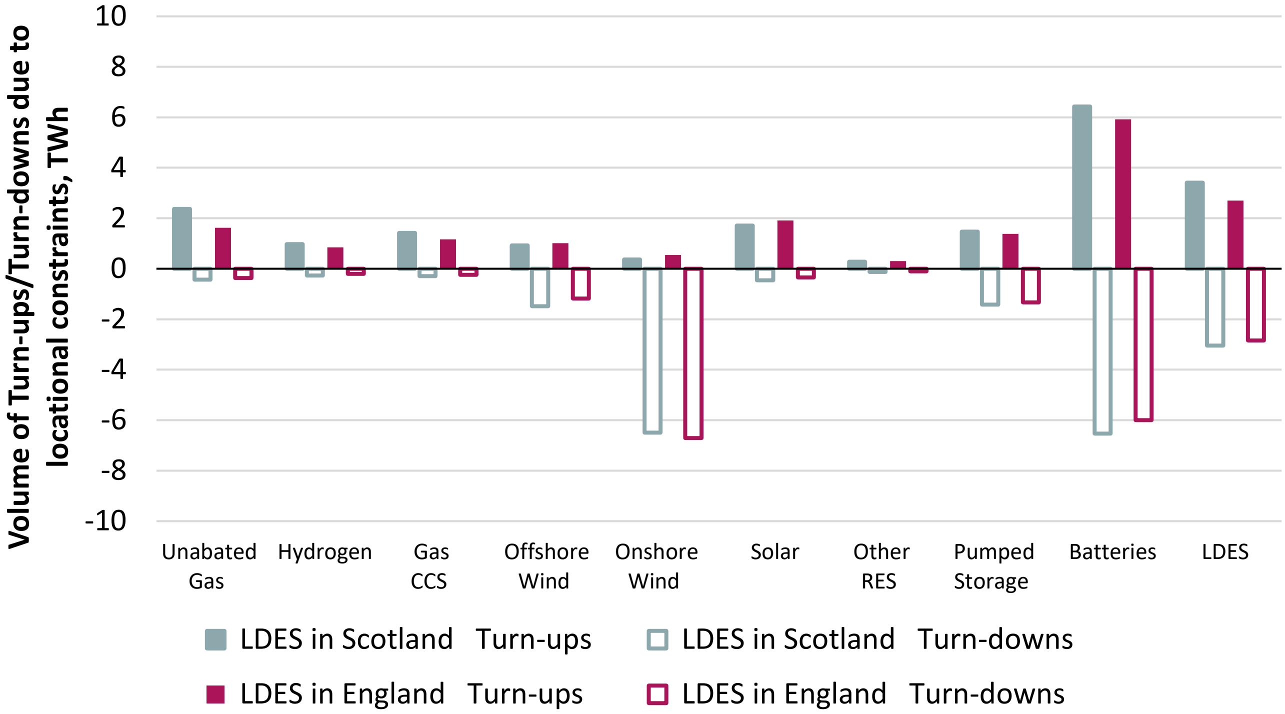
This shows that under the scenario modelled, locating LDES in England and Wales is likely to bring more locational benefits to the system than locating LDES in Scotland. Locational balancing system costs decrease by up to £1.7bn if 10GW of Long-Duration Batteries are located in England. Conversely, with 10GW of LDES located in Scotland, locational balancing system costs could increase by up to £0.7bn. Note that these system costs are the costs of locational balancing only and do not look at the other system costs covered in earlier sections.

The primary reason for LDES slightly increasing locational balancing costs in the case of Scotland, is that in the wholesale market, the LDES is operated to often discharge at times of locational constraints on the B2 and/or B6 boundaries. This is due to times of high demand, and hence high prices, in the wholesale market often correlated with high amounts of renewable generation from Scotland trying to be exported to England. Conversely, during periods of low demand (and low prices), Scottish wind is already being curtailed at a national level, easing the constraints on the B2/B6 boundaries. The high wholesale price periods are being driven by high demand in England rather than Scotland. As a result, the LDES discharges during these high price periods in the wholesale market and ultimately needs to be turned down in locational balancing. With more LDES in Scotland, more generation is trying to be exported over the B2 and B6 boundaries during these high demand periods, and therefore there are more turn-downs in Scotland and more turn-ups in England leading to increase in locational balancing costs.

When the LDES in located in England and Wales closer to demand centres the LDES is again discharging in the wholesale market during times of constraints in Scotland. As a result, then LDES is already discharging closer to demand centres meaning less generation is trying to being exported across the B2 and B6 boundaries and therefore there are less turn-up actions required, which reduces locational balancing system costs.

This effect can be seen by looking at the volume of turn-ups and turn-downs by technology in 2035 for two of the 10GW Even Mix scenarios where all the LDES is located in Scotland and all the LDES is located in England. As can be seen in the chart below, with the LDES in Scotland there are more turn-ups from thermal technologies (gas, gas CCS and hydrogen) and the LDES itself compared to all the LDES located in England. Total turn-ups also reduce from 19TWh to 17TWh leading to lower locational balancing costs. This shows that the LDES behaviour creates more constraints when located in Scotland as there are more total turn up & turn downs. This supports the above explanation that the reason for additional LDES in Scotland leading to an increase in locational balancing costs is to do with LDES discharging in wholesale market to create more constraint periods/cost.

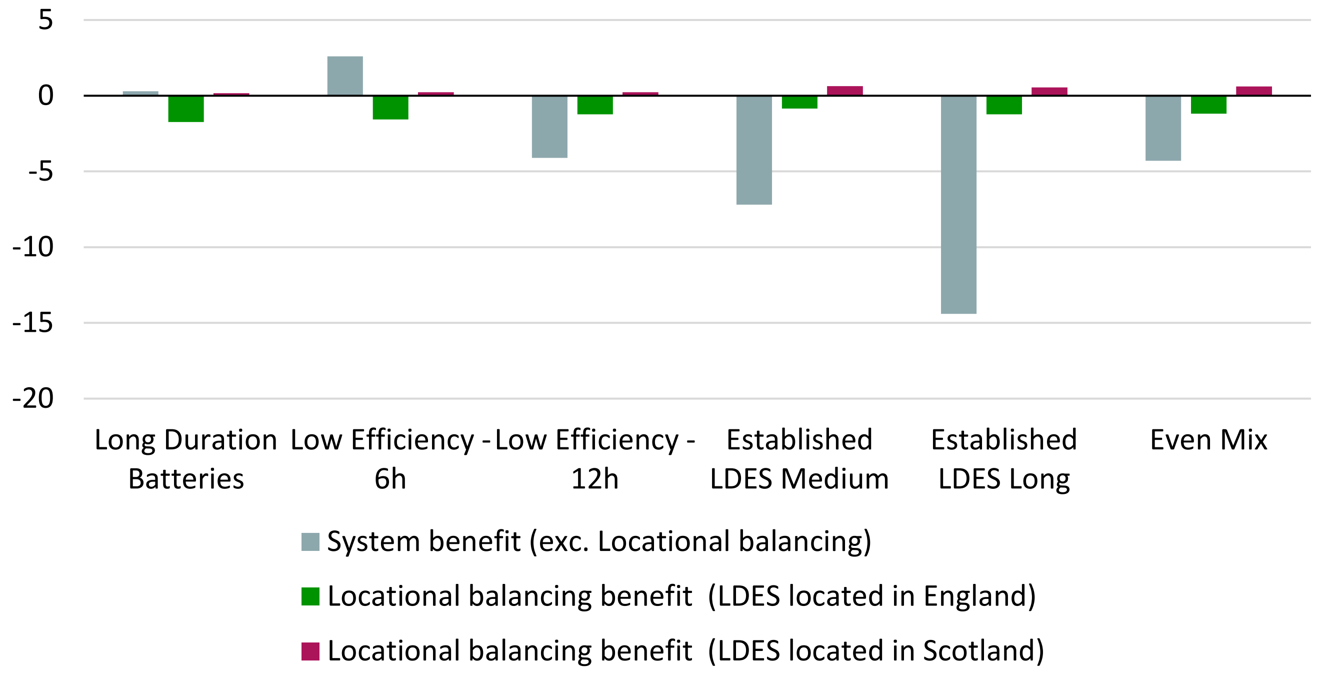
Figure 76: *Volume of turn-ups and turn-downs in 2035 in the 10GW Even Mix scenarios with all LDES locating in Scotland (grey) and all LDES located in England (red)*



The impact of adding LDES in different locations could change with alternative network scenarios. A smaller network could slightly exacerbate the issue outlined above. A small delay in network build, such as 1-3 years, is unlikely to have much impact on these results but a significant reduction in network capacity such as no building Holistic Network Design (HND) could have a larger impact. When the LDES is deployed could be important here – with constraints highest in earlier years, then deploying LDES in Scotland could exacerbate constraint costs as outlined in those years. But with network capacity forecast to increase by 3x to 2040 then by 2040, this will have less of an impact as constraint costs are reduced as a result.

Overall, these findings do not indicate that all LDES should only be placed in England and Wales or that government policy should restrict LDES in Scotland. The scale of the other benefits that LDES brings as outlined in previous chapters are much higher than the change in locational balancing costs with variations in CapEx, type, duration and deployment of competing technologies being significantly more important. This can be seen in the comparison chart below for the 10GW level. It should be noted that system impacts from the locational modelling cannot be added to the other modelling results as the scenarios are fundamentally different. Specifically, changes in network costs are key part of the dispatch modelling outlined in chapters 6 and 7 but in the locational modelling, the network is kept constant. Additionally, the locational modelling only sees LDES replace peaking capacity only whereas system cost results from chapters 6 and 7 have LDES replacing peaking and wind capacity.

Figure 77: *Change in cost when adding 10GW of LDES (by archetype) for all system costs excluding locational balancing (results from 6.3 with medium LDES CapEx) and change in locational balancing costs if LDES is located in England and Scotland respectively.*



For example, at the 10GW level, system cost reductions in an unconstrained network are at a max of £14bn compared to a £0.6bn increase in locational balancing costs if the LDES is all located in Scotland. This shows that in general the other benefits that LDES can bring to the system as outweighs any locational benefits/costs and additional LDES is likely to bring benefits to the system regardless of where it is located. Additionally, it should be noted that the LDES archetypes that brings the highest system benefit excluding locational balancing, as outlined in previous chapters, are the Established Medium and Established Long LDES. These represent pumped storage hydro technologies which will have the majority of their most suitable and lower cost sites in Scotland. As such the analysis shows that restricting build in Scotland for LDES technologies in any way is likely to reduce benefits that LDES can bring to the GB power system.

As such, the key findings from this locational analysis are that where the LDES is built is significantly less important than getting the right capacity onto the system so deployment of LDES generally should be prioritised over LDES location in any policy design.

9. Conclusion

LCP Delta and Regen were commissioned by DESNZ to independently assess the role of long-duration energy (LDES) storage technologies in delivering the flexibility needed for the electricity system and the impact that these technologies have on the system. The overall aim of this Study was to independently assess the role of LDES in delivering the flexibility needed and use scenario analysis to find the optimal level of LDES deployment across a range of electricity market scenarios.

Stakeholder engagement findings.

To support the modelling and broader assessment of long-duration electricity storage (LDES) technologies, Regen conducted an engagement process with leading UK storage technology and project developers. The purpose of this engagement exercise was to verify, improve and road-test a number of the modelling assumptions and technical characteristics that LCP Delta used as inputs to their system and market scenario modelling. It also providing useful qualitative information to better understand the market-based risks, technology development pathways and policy hurdles facing storage developers. Through both one-on-one interviews and via an online survey, 25 storage technology developers covering 11 storage technologies. Key findings from the engagement are summarised below.

- Developers see a need for reforms to existing markets to provide the right market and financial incentives.
- The business model for LDES will include stacking of a wide range of system services and associated revenue streams. In addition to mitigating wind generation curtailment and solar time-shifting and system balancing, developers highlighted that LDES technologies are also well-placed to provide balancing and stability services, such as inertia, reactive power and black start.
- There are a range of technical characteristics and capabilities across different technologies and even individual projects of the same technology owing to the importance of site-specifics factors such as their location and onsite resources.
- There is no clear consensus on the energy storage durations that should be developed or required with developers looking at a range of durations to support different system needs.
- LDES *system* CapEx costs are highly variable depending on the LDES technology mix and technology-readiness levels as well as the significant uncertainty around CapEx for LDES technologies due to scale, location and volatility of supply markets.
- Locational factors and opportunities for co-location (with other generation and storage assets) could be important with many interviewees highlighting the consideration of co-locating their storage technology with other assets or resources. Some also highlighted locational deployment constrictions due to geological resources, land classification and co-location opportunities.

Scenario Deployment Analysis

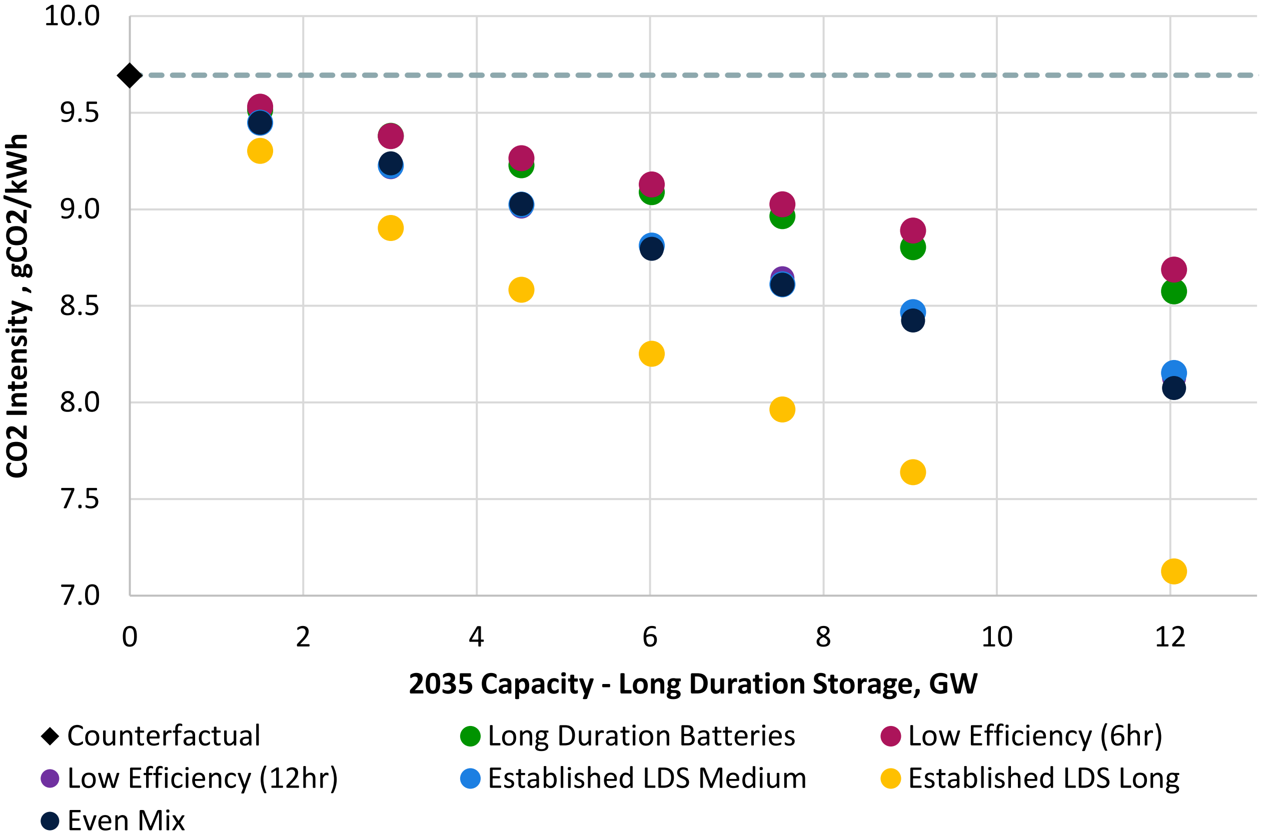
Based on findings from the stakeholder engagement and other publicly available data, five LDES archetypes were defined for use in the modelling, each with different technical and cost characteristics. The five archetypes for use in the modelling have been defined as follows:

1. **Longer-duration batteries** – including all longer duration batteries between 6 and 8 hours that degrade over time such as Lithium-ion and Flow batteries.
2. **Longer-duration, low-efficiency (6hr)** – this includes compressed air and liquid air technologies that have duration of approximately 6 hours with lower efficiencies but do not degrade over time.
3. **Longer-duration, low-efficiency (12 hr**) – spanning the same or similar technologies to the previous archetype, but with longer duration of 12 hours.
4. **Established longer-duration storage (medium**) – pumped storage hydro with duration ranging from 8 to 12 hours.
5. **Established longer-duration storage (long)** – the same technologies as the previous archetype with durations of 16 to 32 hours.

Each LDES archetype plus an even mix across all archetypes were modelled for 7 different capacity levels ranging from 1.5GW to 12GW in 2035 rising to 2.5GW to 20GW in 2050. The LDES scenarios span a matrix of the LDES archetypes and LDES capacity. Two key uncertainties were also accounted for in the analysis. To account for the considerable uncertainty in LDES CapEx, low, medium, and high CapEx scenarios are modelled for each LDES type and capacity scenario to understand if the cost of LDES changes the impact it can have on the system. And to account for uncertainty around gas CCS and hydrogen in power deployment, 3 alternative counterfactuals were modelled where gas CCS and hydrogen deployment counterfactual to understand if LDES can be used to mitigate delivery risks for these technologies.

For the first part of the scenario deployment analysis, LDES was added to the system at the expense of peaking generation capacity only. This allowed for an assessment of the impact LDES can have on reducing emissions as shown in the chart below.

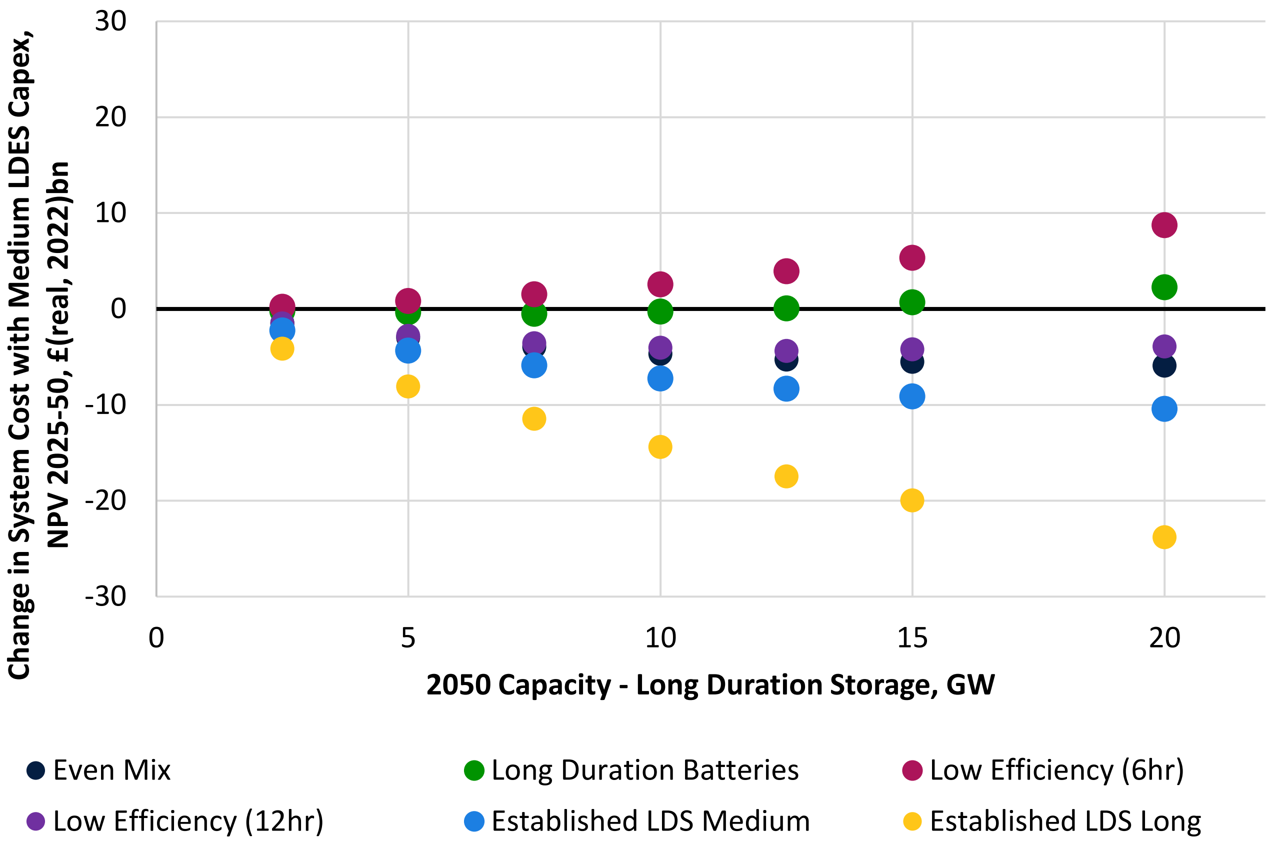
***Figure 78:** Emissions intensity v LDES capacity in 2050 (coloured by LDES archetype) in the Core Scenario with LDES replacing peaking capacity only.*



The plot shows how adding LDES to the system at the expense of peaking capacity has a positive impact on emissions with emissions intensity reducing by up to 26%. In general, the higher the duration the larger the impact on emissions with the established long-duration storage long (16-32 hrs) having the largest impact on emissions. This highlights that adding LDES technologies can help reduce emissions and therefore achieve emissions targets set by government for CB6 and Net Zero.

For the second stage of modelling, the LDES capacity displaces installed wind generation capacity in addition to peaking capacity. This represents government needing to invest less in wind capacity to achieve to the same level of emissions as the LDES enables the existing wind capacity to be used more effectively. This allows for an assessment of LDES impacts on the system cost required to reach to CB6 and Net Zero. The scatter plots below show the total system costs (NPV 2025-50) against the LDES capacity for all scenarios where LDES replaces peaking and wind capacity where the CapEx for LDES is at medium levels.

Figure 79: *System cost (NPV) with medium LDES CapEx v LDES capacity in 2050 (coloured by LDES archetype) in the Core Scenario with LDES replacing peaking and wind capacity.*

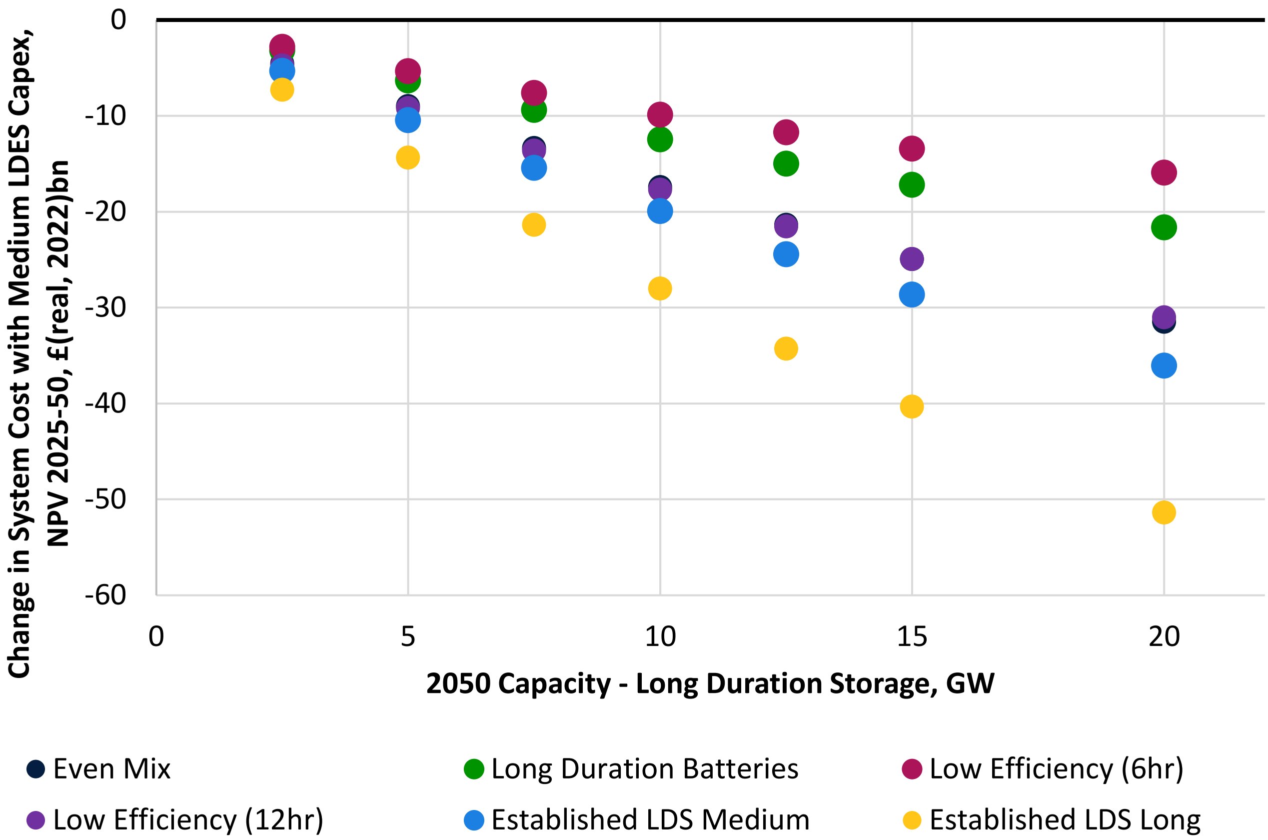


The analysis shows that LDES archetypes can bring net benefits to the system with longer durations and larger capacities having larger impacts. Most LDES archetypes bring net benefits to the system with the exception of the Low-Efficiency 6hr archetype. Each archetype peaks at different points with the Long-Duration Batteries peaking at 2.5GW, the Low-Efficiency 12hr at 10GW and the Established LDES archetypes providing benefit at every capacity tested.

However, the capital costs of LDES technologies are critical in the benefits of these technologies. At low CapEx costs every archetype provides benefits to the system at every capacity but at high CapEx, only the established LDES technologies with longer durations provide benefits across all capacity levels.

The same analysis that was completed for the Core Scenario was also performed for lower gas CCS and hydrogen deployment levels to understand this impact. This analysis finds that the benefits of adding LDES to the system are greatly increased in a world with less gas CCS and/or hydrogen. With the LDES replacing peaking capacity, the emissions reduction can be up to 1gCO2e/kWh higher with lower gas CCS/hydrogen deployment compared to the Core counterfactual.

Figure 80: *System cost (NPV) with medium LDES CapEx v LDES capacity in 2050 (coloured by LDES archetype) with Low Hydrogen counterfactual with LDES replacing peaking and wind capacity.*



With LDES replacing both wind and peaking capacity, the impact of adding LDES can be significantly higher with counterfactuals that have lower gas CCS and/or hydrogen deployment. This is most pronounced in the low hydrogen scenario where at medium LDES CapEx levels, adding any LDES shows a system benefit with significant system cost savings across all archetypes. System cost savings can be very large. Even adding 2.5GW of LDES can reduce system costs by £2.5-7bn while adding 20GW can reduce system costs by £16-51bn. This shows that adding LDES to the system that can be used to mitigate the delivery risk for gas CCS and hydrogen deployment.

Locational Analysis

To understand the locational benefits that LDES can bring to the system, a subset of the scenarios outlined in previous chapters have been modelled in LCP Delta's Locational Dispatch Model. The 10GW scenarios for each LDES archetype (as outlined are above) plus the even mix scenario are modelled here to gain an understanding of the impacts on locational balancing that adding LDES to the system can have. First scenarios based on the most likely locations of each archetype were tested followed by two additional sets of scenarios are run where the location of the LDES for every archetype is changed to all in Scotland (half in each zone) and all in England (a third in each zone).

Figure 81: *Change in locational balancing system cost when adding 10GW of LDES (by archetype) with the LDES locating in different places*

This shows that locating more LDES in England and Wales is likely to bring more benefits to the locational elements system than locating LDES in Scotland. Locational balancing system costs decrease by up to £1.7bn if 10GW of Long-Duration Batteries are located in England. Conversely, with 10GW of LDES located in Scotland, locational balancing system costs could increase by up to £0.7bn. Note that these system costs are the costs of locational balancing only and do not look at the other system costs covered in earlier sections.

However, these findings do not necessarily indicate that all LDES should be placed in England or that government policy should restrict LDES in Scotland. The scale of the other benefits that LDES brings as outlined above are much higher than the change in system balancing costs – a max of £23bn at medium-CapEx levels for overall system costs in an unconstrained network compared to a £0.6bn increase in locational balancing costs if plants locate in Scotland. This shows that in general the other benefits that LDES can bring to the system as outlined in previous chapters outweighs any locational benefits/costs and additional LDES is likely to bring benefits to the system regardless of where it is located. It should be noted that system impacts from the locational modelling cannot be added to the other modelling results as the scenarios are fundamentally different. Specifically, changes in network costs are key part of the dispatch modelling outlined in chapters 6 and 7 but in the locational modelling, the network is kept constant. Additionally, the locational modelling only sees LDES replace peaking capacity only whereas system cost results from chapters 6 and 7 have LDES replacing peaking and wind capacity.

Final conclusions

Overall, this study shows that LDES can play an important role in providing the flexibility that the GB system will need in the future. Adding LDES can reduce both reduce emissions and system costs as it allows wind to be used more efficiently. Longer durations of LDES (up to 32 hours tested) have larger effects on both of these but LDES technologies of all types still have an impact and can bring benefits to the system in the right circumstances. The capital costs of LDES will be important on the impact that they can have on the system so reduction of these costs should be a key focus in helping to get these technologies to market. LDES can act as a risk mitigation for reduced delivery of other technologies. With lower levels of gas CCS and hydrogen deployment, this Study finds that there are greater emissions and system cost benefits when LDES is added to the system. The Study should provide government with the key evidence base it needs to design a successful policy and/or market design to support the deployment of LDES technologies.

Annex A – Consultation Survey questions

Introduction:

Informing Long-duration Electricity Storage modelling for BEIS

BEIS have commissioned the Electricity Storage Network, managed by Regen, and LCP Delta to seek stakeholder feedback to inform a modelling study, looking at the role of Long-duration Energy Storage (LDES) in the future energy system.

BEIS have asked to independently assess the optimal level of LDES deployment and the role LDES could play in delivering flexibility requirements in a range of electricity market and system scenarios. Your feedback will inform BEIS and Ofgem's policy approach to de-risking investment in LDES technologies.

The aim of this survey is to make sure the most up-to-date information on LDES technology is included in this modelling. By taking 10 minutes to provide your feedback, you will not only be informing this modelling but the subsequent LDES policy decisions that arise from it.

A note on responses relating to multiple technologies

The questions in this survey have been tailored to gather input and information around one core technology type per respondent.

However, we are aware that some organisations may be developing multiple technologies or technology types that could have a range of technical characteristics.

Whilst this survey can be populated more than once, there is also a 'File Upload' function at the end of the survey. Respondents are free to use this question to upload any information relating to more than one technology, or ranges of technical characteristics / costs.

We appreciate any information shared in response to this survey.

1) Data acceptance statement

By responding to this survey you are giving permission for Regen and LCP Delta to use your response, to inform modelling on the role of long-duration electricity storage in the energy system on behalf of BEIS.

Your response will be processed, analysed and incorporated into the assumptions behind the modelling and summarised and issued to BEIS as part of a wider technical report that will inform UK energy policy. Your response will not be shared with any other parties.

[I accept] / [I don't accept]

2) About you:

2a) Contact information

- First name:
- Last name:
- Email:
- Company:

3) Technology development:

3a) What is your LDES technology type?

- [Pumped hydro]
- [Liquid Air Energy Storage]
- [Flow Battery]
- [Li-Ion Battery]
- [Gravitational storage]
- [Compressed Air Energy Storage]
- [Hydrogen]
- [Thermal]
- [Other]

3b) If you selected other, please tell us what your technology type is.

3c) How would you classify the current Technology Readiness Level (TRL) of this technology?

- [TRL 1: Basic principles observed and reported]
- [TRL 2: Technology concept or application formulated]
- [TRL 3: Analytical and experimental critical function or characteristic proof-of-concept]
- [TRL 4: Technology basic validation in a laboratory environment]
- [TRL 5: Technology basic validation in a relevant environment]
- [TRL 6: Technology model or prototype demonstration in a relevant environment]
- [TRL 7: Technology prototype demonstration in an operational environment]
- [TRL 8: Actual technology completed and qualified through test and demonstration]
- [TRL 9: Actual technology qualified through successful mission operations]

3d) Where are you in the development stage of your technology?

- [Pre-commercial demonstrators]
- [Pilot projects - small scale commercial]
- [Large scale commercial project(s)]

3e) When do you see your projects becoming operational?

- [Already operational]
- [Short term (0-5 years)]
- [Medium term (5-10 years)]
- [Long term (10+ years)]

3f) How long does it typically take to construct a facility using your technology type? (Unit = number of months)

3g) How long does it typically take to commission a facility using your technology type? (Unit = number of months)

4) Technology characteristics

4a) What power capacity scale are you targeting for your assets? (Unit = MW)

- [<10 MW]
- [10 - 50 MW]
- [50 – 100 MW]
- [100 – 500 MW]
- [500 MW+]

4b) What ratio of power capacity does your technology have on import (i.e. charge) vs export (i.e. discharge)? (Unit = Import to Export ratio "X:Y", e.g. 1:1 if import and export are the same, 1:1.5 if import is 100 MW and export is 150 MW)

4c) What storage charge/discharge duration are you targeting? (Unit = hours)

- [Up to 4 hours]
- [>4 to 8 hours]
- [>8 to 12 hours]
- [>12 to 16 hours]
- [>16 to 20 hours]
- [>20 to 24 hours]
- [>24hrs – multiday]
- [Interseasonal]

4d) What is the expected project lifetime? (Unit = years)

4e) Could retrofitting new equipment be considered at the end of asset life for your technology? If so, might this impact the costs compared to a new build project?

4f) What is the round-trip efficiency per full cycle? (Unit = %)

4g) What is the depth of discharge (i.e. the proportion of the charged capacity that can be removed/cycled) for your storage technology? (Unit = %)

4h) If applicable, what is the expected degradation rate per year of your technology? (Unit = percentage per year)

4i) Annual availability (Unit = % of year asset would be available)

5) Technology costs

5a) High level capital expenditure (CapEx) (Unit = £/MWh of storage capacity)

5b) Fixed operational expenditure (OpEx) (Unit = £/MW)

5c) Variable operating costs (OpEx) (Unit = £/MWh)

5d) Indicative hurdle rate (i.e. a minimum rate of return on a project) for your technology (Unit = %)

5e) What capital cost reduction potential do you foresee over time? (Percentage reduction of £/MWh by 2035 and 2050 (baseline – 2022)

5f) If available, please upload any documents that include you CapEx reduction projections [Upload function]

6) Site requirements and use cases

6a) What voltage tier(s) are you looking to connect at? (Unit = kV (e.g. 33kV, 132kV, 400kV – note can be a range))

6b) What locational factors are applicable to your technology?

6c) Are you exploring co-location/co-location with generation assets? If so, might this impact the potential costs or availability of your technology?

6d) What services do you foresee your technology providing? (You can select more than one)

- [Wind curtailment support]
- [Solar PV time shifting]
- [Demand management]
- [Reserve services]
- [Wider system balancing]
- [Stability & power quality services]
- [Capacity market - system stress]
- [Black start]
- [Other]

7) Is there any other evidence on your technology or other long-duration energy storage technologies you would like to highlight?

8) If you have any other documentation or data that you would be happy to share, please use the file upload function below.

Note: for any organisation seeking to provide information for multiple technologies, this file upload could be used to share information on alternate technologies, variances within your technology or ranges in values not captured by your responses to the main survey. Thankyou.

Thank you very much for your input and views. Your feedback will inform BEIS and Ofgem's policy approach to de-risking investment in LDES technologies.

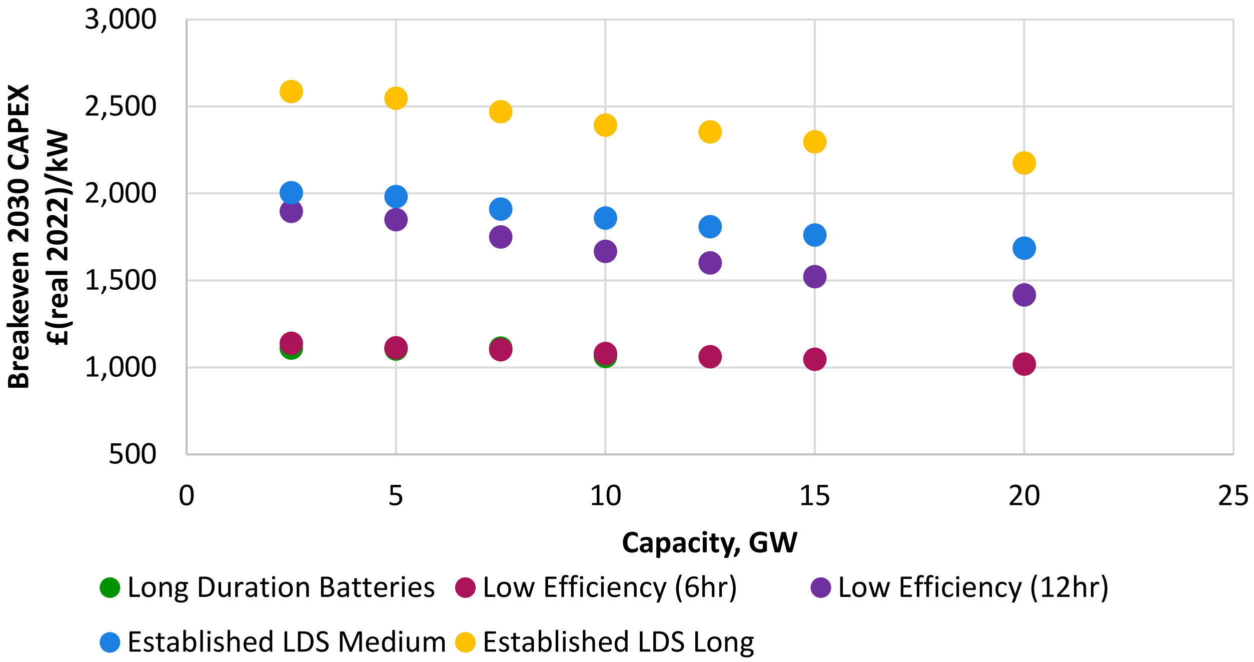
Annex B – Breakeven CapEx Analysis

Core Scenario

As outlined in the main report, there is significant uncertainty around the capital costs of LDES and the different CapEx levels (as shown in section 4) do not necessarily reflect the full range of capital cost possibilities for the given LDES archetypes. As defining additional ranges is difficult given the data availability, a breakeven CapEx point is calculated. This breakeven CapEx value shows the CapEx value that would result in a zero-system cost impact for each scenario, i.e.: the point where the 2025-2050 system cost NPV in the factual LDES scenario is equal to the counterfactual system cost NPV. This essentially shows that CapEx values below the breakeven CapEx point would bring benefits to the system while CapEx above this point would result in a cost to the system.

The below scatter plot shows the breakeven 2030 CapEx value for each of the LDES archetypes at each capacity level for the Core counterfactual. Other years could be shown but all CapEx values are scaled up or down by the same proportion to achieve breakeven for any year's CapEx.

Figure 82: *Breakeven CapEx values (£/kW) with the Core counterfactual and LDES replacing peaking and wind capacity. Note some of the long-duration battery values are behind the Low-Efficiency (6hr) values*



The results for the breakeven CapEx analysis show similar results to those outlined in 6.3 above:

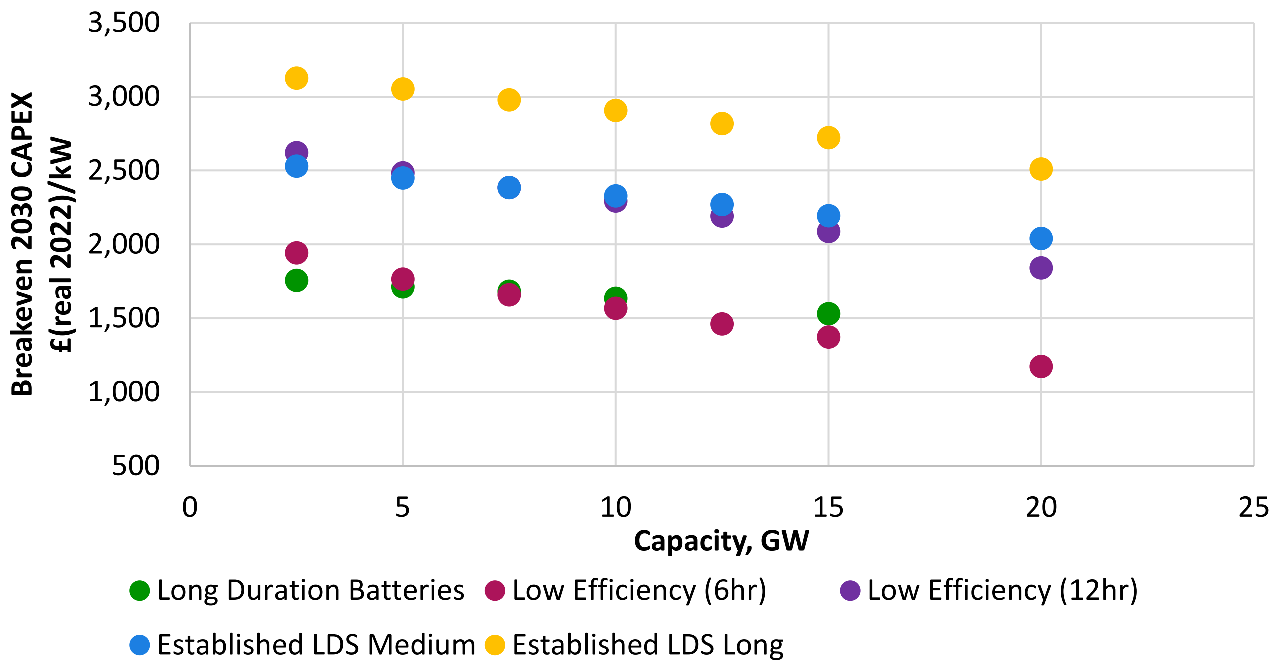
- The breakeven CapEx is approximately proportionate to the duration of the LDES technology with longer duration and higher efficiency technologies having a higher breakeven CapEx point.

- Established LDS Long technologies have the highest breakeven CapEx and so represent the greatest value to the system per kW capacity. However, they do not necessarily have the greatest margin between their forecast actual CapEx and breakeven CapEx, representing system cost savings. In our low CapEx scenario, they are one of the most expensive archetypes at £1,180/kW in 2025 and largely maintain their cost to 2050 while other technologies decrease in price. But in our high CapEx scenario they are on the lowest cost archetypes prior to 2040. Systems savings are best read from the data in the previous section.

Low Gas CCS counterfactual

The below scatter plot shows the breakeven 2030 CapEx value for each of the LDES archetypes at each capacity level for the Low Gas CCS counterfactual.

Figure 83: *Breakeven CapEx values (£/kW) vs LDES Capacity (GW) with the Low Gas CCS counterfactual and LDES replacing peaking and wind capacity.*



The results for these scenarios are similar to the Core counterfactual showing:

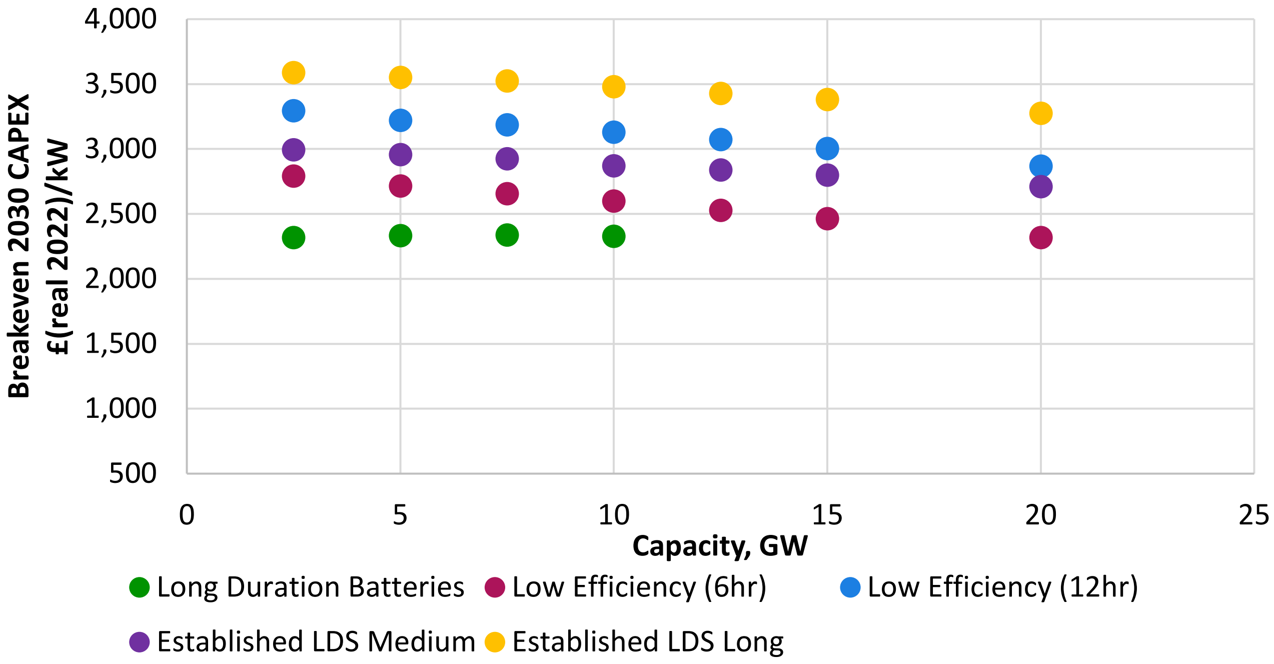
- Overall pattern shown is similar to the Core counterfactual. The breakeven CapEx is approximately proportionate to the duration of the LDS technology with longer duration and higher efficiency technologies having a higher breakeven CapEx point. As expected given the above results, the Established LDES Long archetype has the largest breakeven CapEx points across all capacity levels.
- The decreasing breakeven CapEx point as capacity increases across all archetypes illustrates that there is a slight diminishing value for each additional GW of storage added with low levels of gas CCS.
- Comparing longer duration, lower efficiency (12hr) to established LDES medium and longer duration, lower efficiency (6hr) to longer duration batteries shows crossover

points where the lower efficiency archetypes have a higher breakeven CapEx than their more efficient archetypes with longer durations. This shows that efficiency of LDES has a larger impact on results at higher capacity levels compared to lower capacity levels.

Low Hydrogen counterfactual

The below scatter plot shows the breakeven 2030 CapEx value for each of the LDES archetypes at each capacity level for the low gas hydrogen counterfactual.

Figure 84: *Breakeven CapEx values (£/kW) vs LDES Capacity (GW) with the Low Hydrogen counterfactual and LDES replacing peaking and wind capacity.*



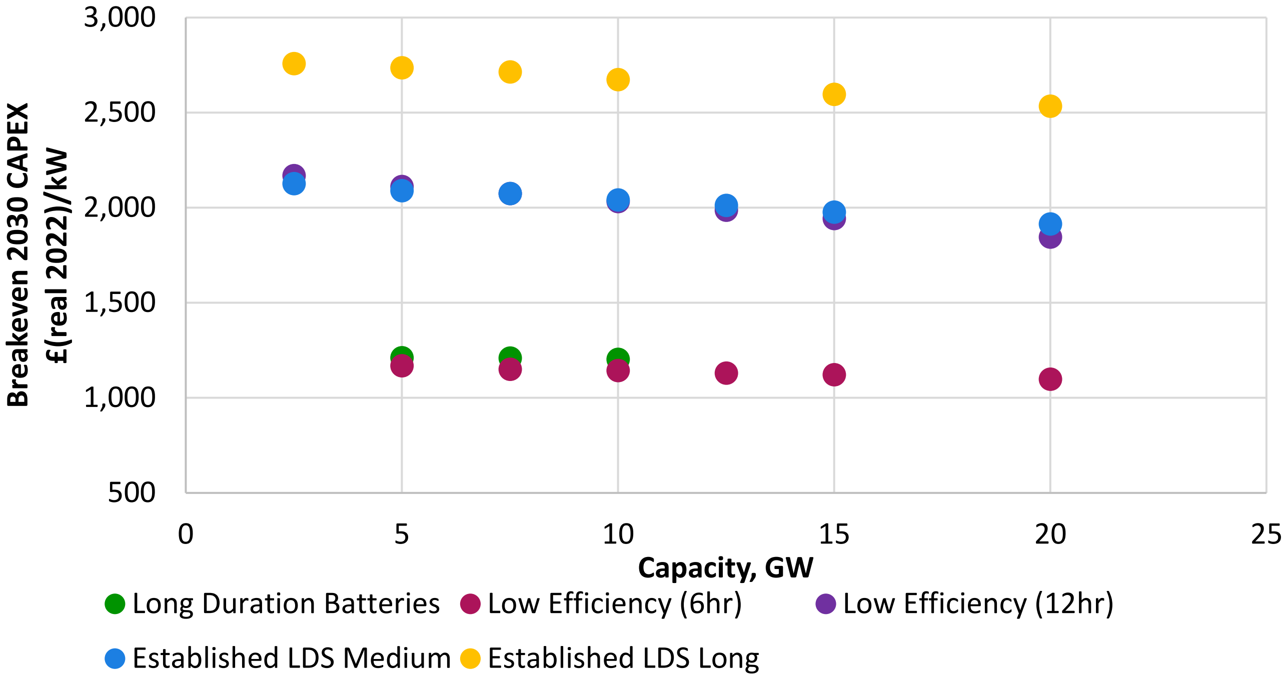
The results for these scenarios show:

- Overall pattern shown is similar to the central and Low Gas CCS counterfactual with the breakeven CapEx approximately proportionate to the duration of the LDS technology. Once again longer duration and higher efficiency technologies having a higher breakeven CapEx point.
- In general, however the impact is larger with higher breakeven CapEx points across all LDES archetypes and capacities compared to the Low Gas CCS and Core counterfactual. This mirrors the findings from the system cost analysis above.
- The downward trend as more LDES capacity is added to the system is also far less significant showing compared to the other counterfactuals. This shows that each extra GW of LDES added does not significantly diminish in value with low levels of hydrogen.

Medium Gas CCS and Hydrogen counterfactual

The below scatter plot shows the breakeven 2030 CapEx value for each of the LDES archetypes at each capacity level for the Medium Gas CCS and Hydrogen counterfactual:

Figure 85: *Breakeven CapEx values (£/kW) vs LDES Capacity (GW) with the Medium Gas CCS and Hydrogen counterfactual and LDES replacing peaking and wind capacity.*



The results for these scenarios show:

- Overall impact across archetypes shows similar results to the other counterfactuals with the breakeven CapEx approximately proportionate to the duration of the LDS technology. Once again longer duration and higher efficiency technologies having a higher breakeven CapEx point.
- The breakeven CapEx points are slightly lower than in Low Hydrogen counterfactual but higher than the Low Gas CCS counterfactual. This mirrors the findings from the system cost analysis and shows LDES has a larger impact than in the Core counterfactual with medium levels of gas CCS and hydrogen but that impact is less compared to the Low Hydrogen counterfactual.
- Similar to the Low Hydrogen counterfactual, the breakeven CapEx point stays relatively flat as CapEx increases. This shows that LDES has more of an impact at higher capacity levels in these scenarios, compared to the central and Low Gas CCS counterfactuals and the value of that LDES does not significantly decrease as more is added to the system.

Annex C – Gas CCS and H2 scenarios alternative CapEx results

This annex gives the results for the low and high CapEx scenarios where the LDES replaces peaking and wind for the gas CCS and hydrogen scenarios outlined in chapter 7.

Low Gas CCS counterfactual

Figure 86: *Change in system cost (NPV) with low LDES CapEx v LDES capacity in 2050 (coloured by LDES archetype) with Low Gas CCS counterfactual and LDES replacing peaking and wind capacity.*

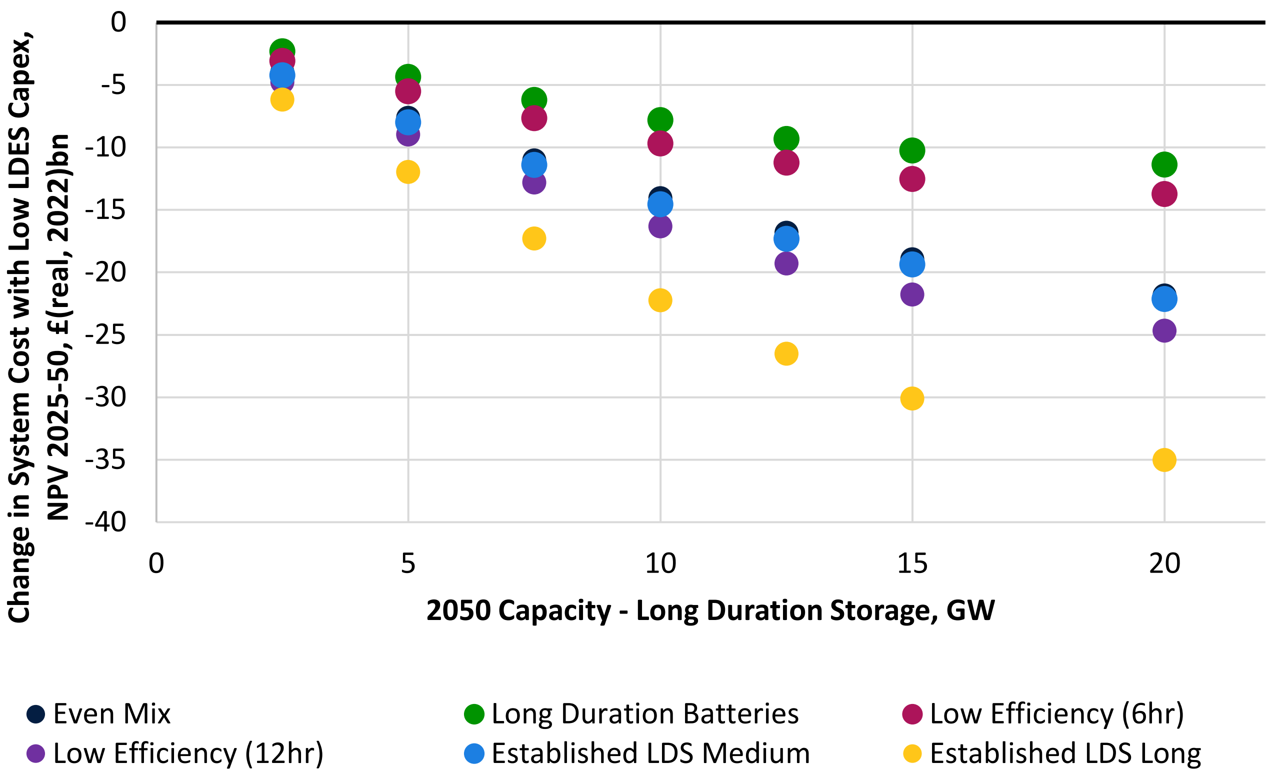


Figure 87: *Change in system cost (NPV) with medium LDES CapEx v LDES capacity in 2050 (coloured by LDES archetype) with Low Gas CCS counterfactual and LDES replacing peaking and wind capacity.*

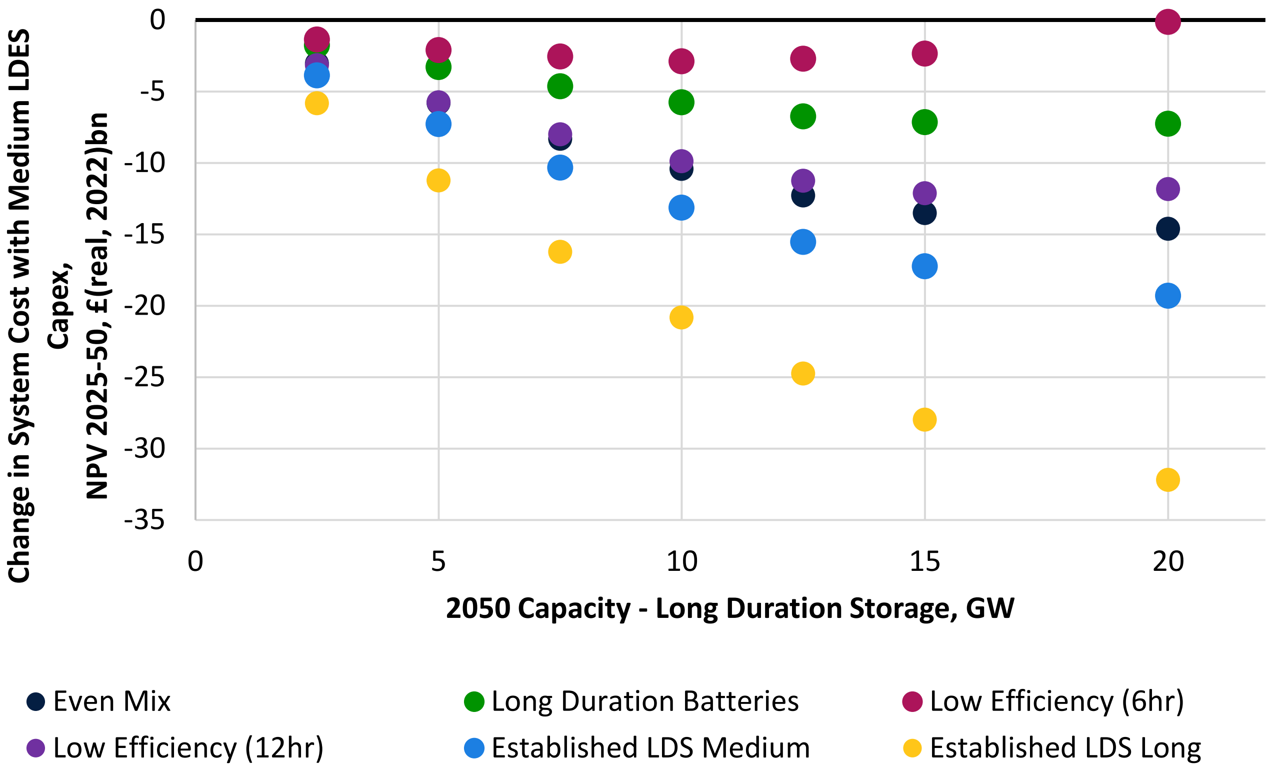
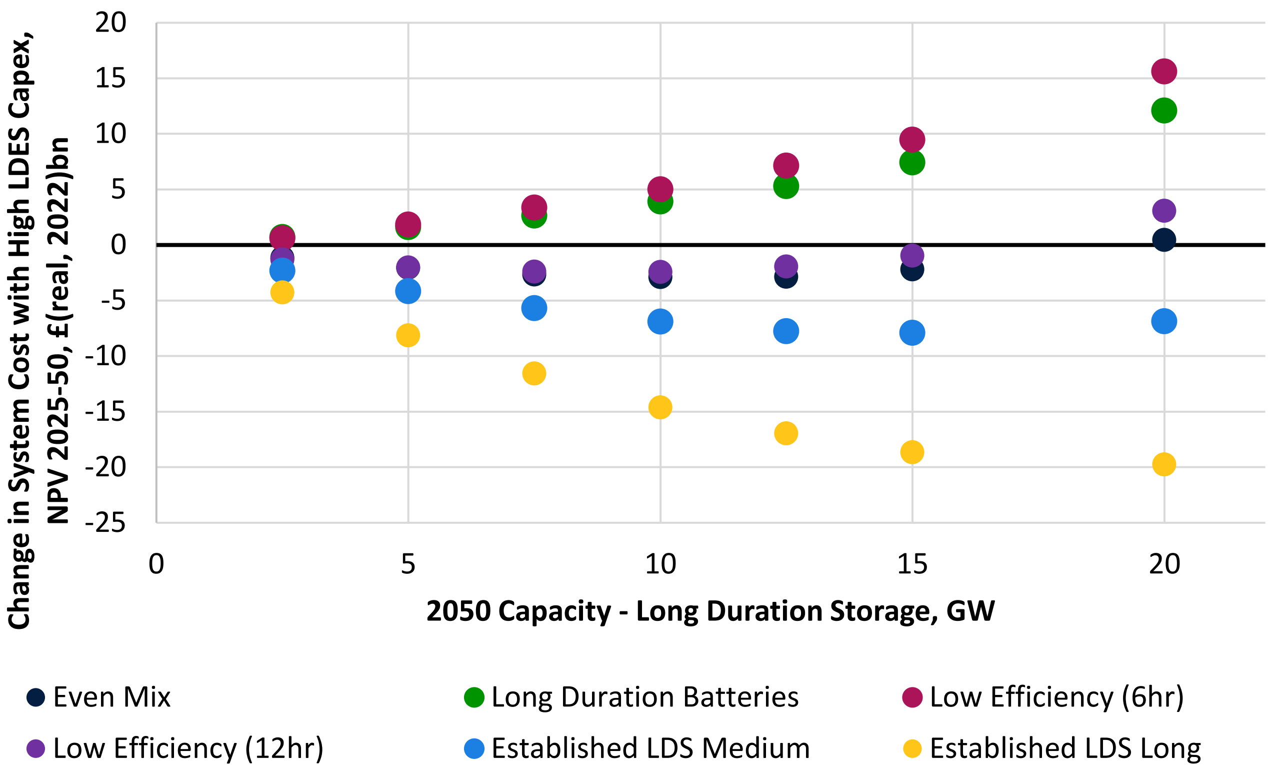


Figure 88: *Change in system cost (NPV) with high LDES CapEx v LDES capacity in 2050 (coloured by LDES archetype) with Low Gas CCS counterfactual and LDES replacing peaking and wind capacity.*



Low Hydrogen counterfactual

Figure 89: *Change System cost (NPV) with low LDES CapEx v LDES capacity in 2050 (coloured by LDES archetype) with Low Hydrogen counterfactual and LDES replacing peaking and wind capacity.*

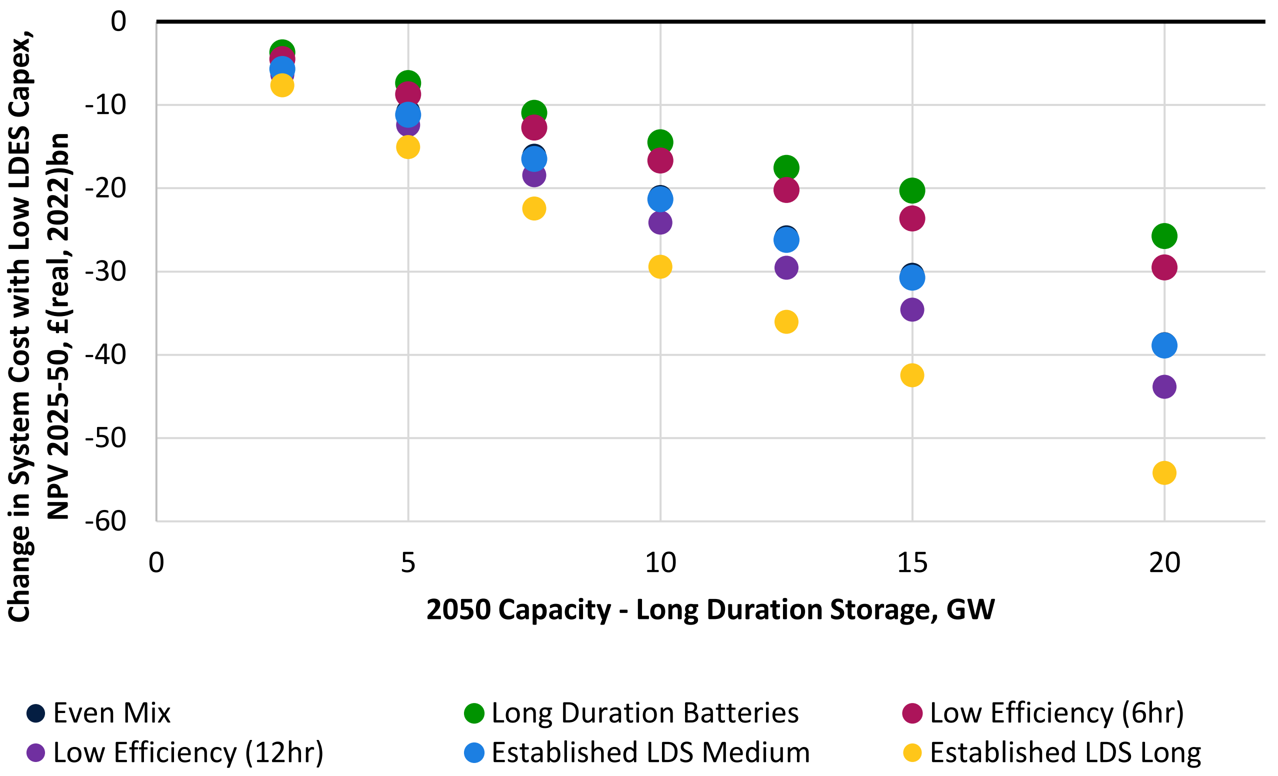


Figure 90: *Change System cost (NPV) with medium LDES CapEx v LDES capacity in 2050 (coloured by LDES archetype) with Low Hydrogen counterfactual and LDES replacing peaking and wind capacity.*

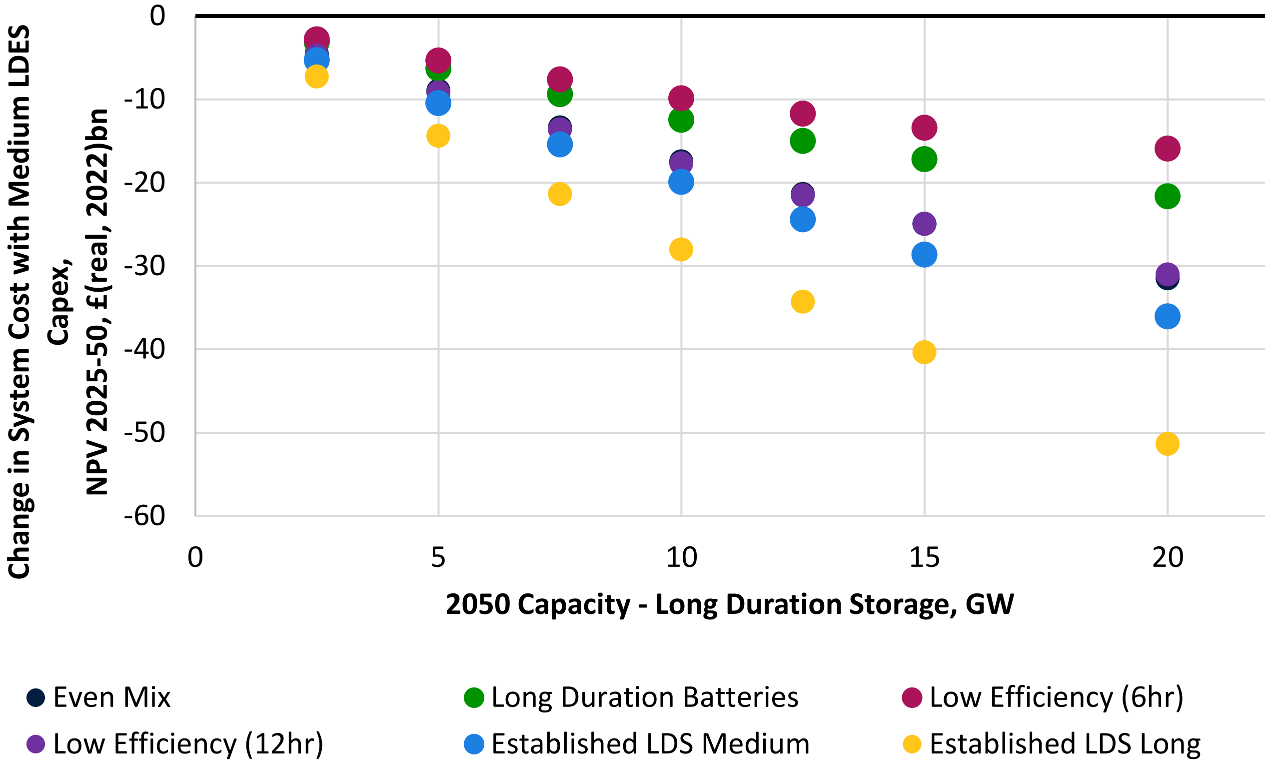
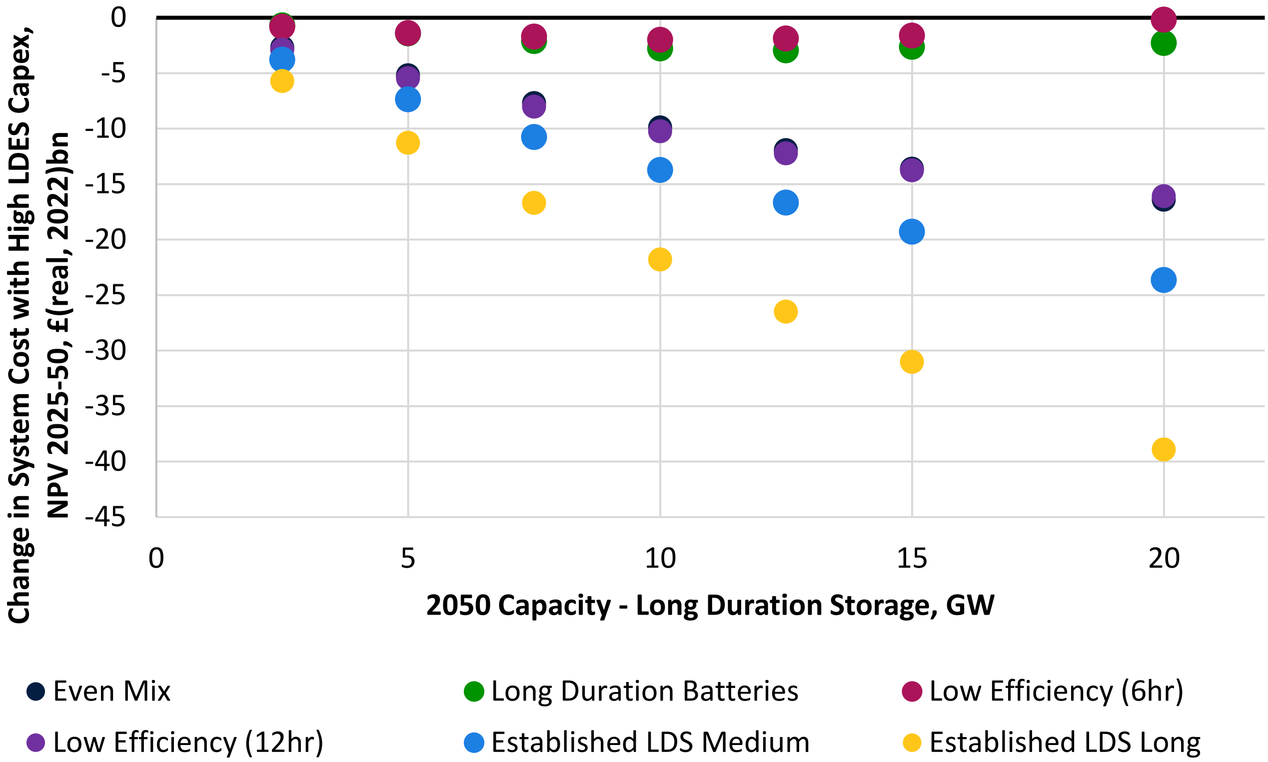


Figure 91: *Change System cost (NPV) with high LDES CapEx v LDES capacity in 2050 (coloured by LDES archetype) with Low Hydrogen counterfactual and LDES replacing peaking and wind capacity.*



Medium gas CCS and hydrogen counterfactual

Figure 92: *Change in System cost (NPV) with low LDES CapEx v LDES capacity in 2050 (coloured by LDES archetype) with Medium Gas CCS and Hydrogen counterfactual and LDES replacing peaking and wind capacity.*

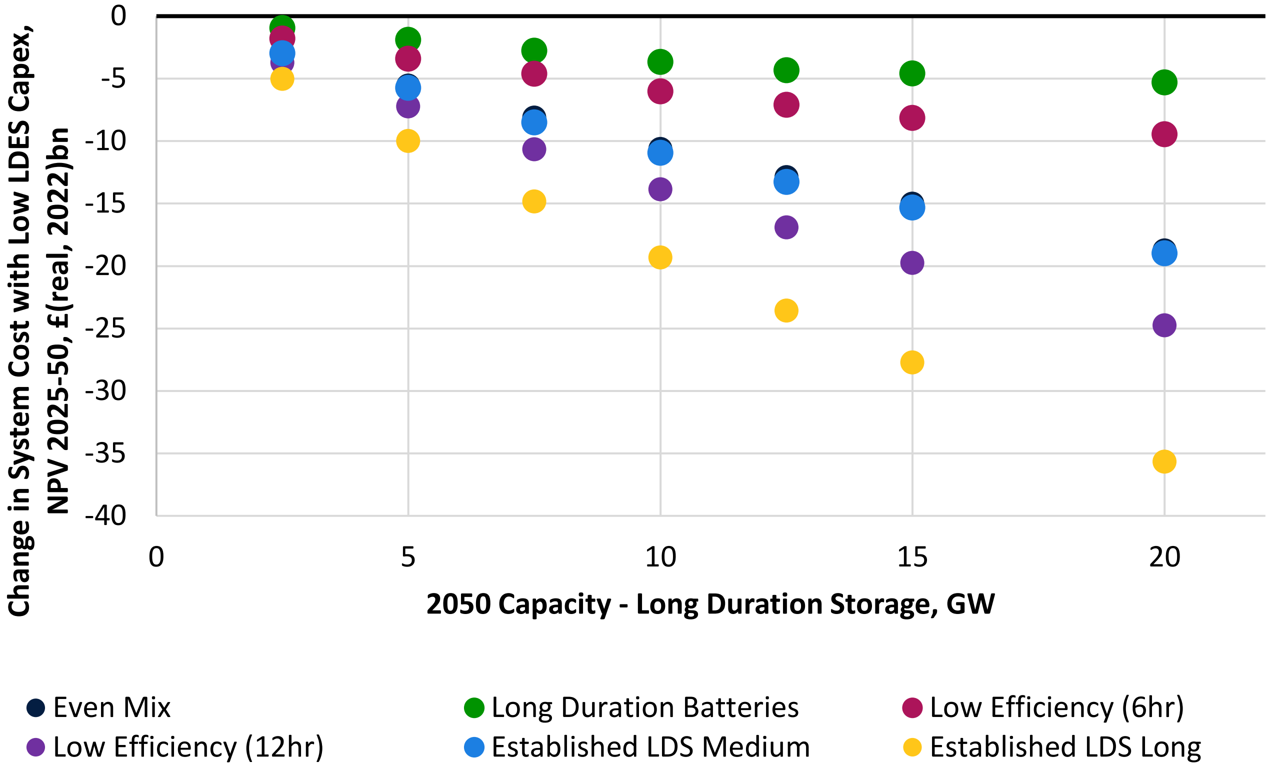


Figure 93: *Change in system cost (NPV) with medium LDES CapEx v LDES capacity in 2050 (coloured by LDES archetype) with Medium Gas CCS and Hydrogen counterfactual and LDES replacing peaking and wind capacity.*

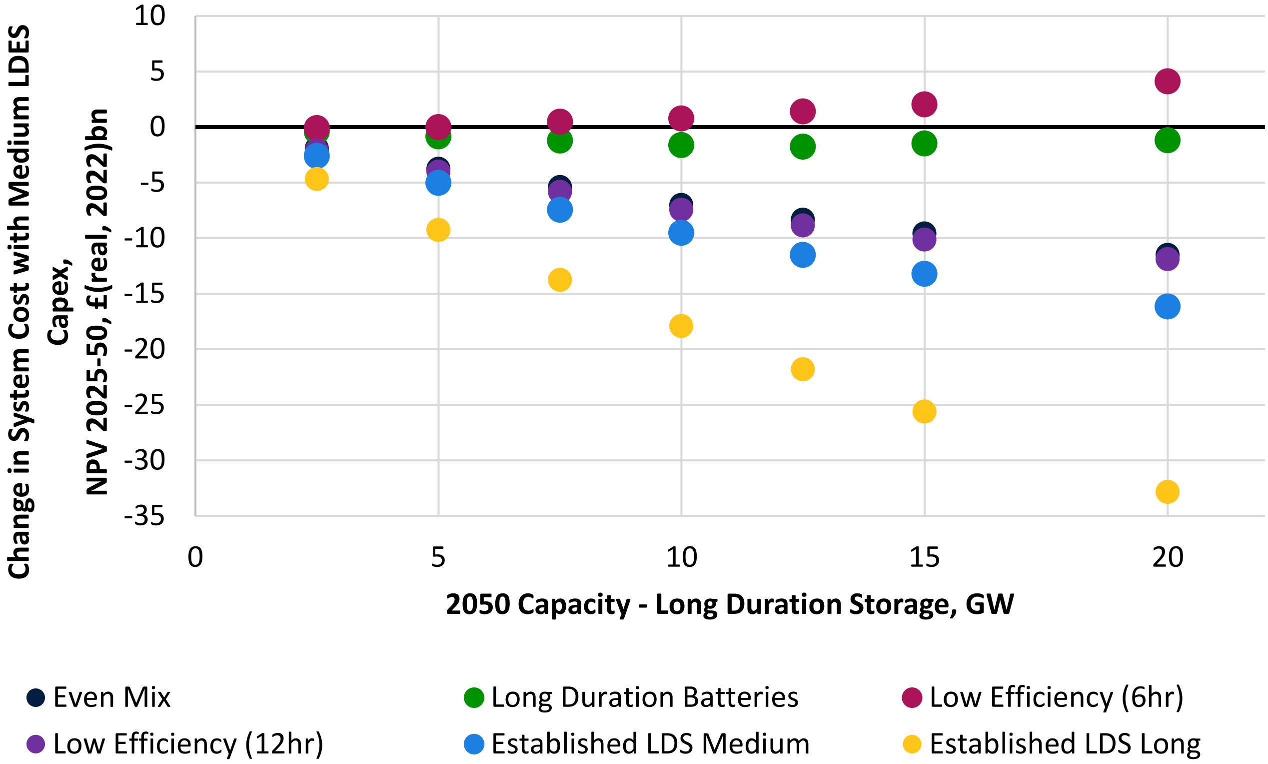
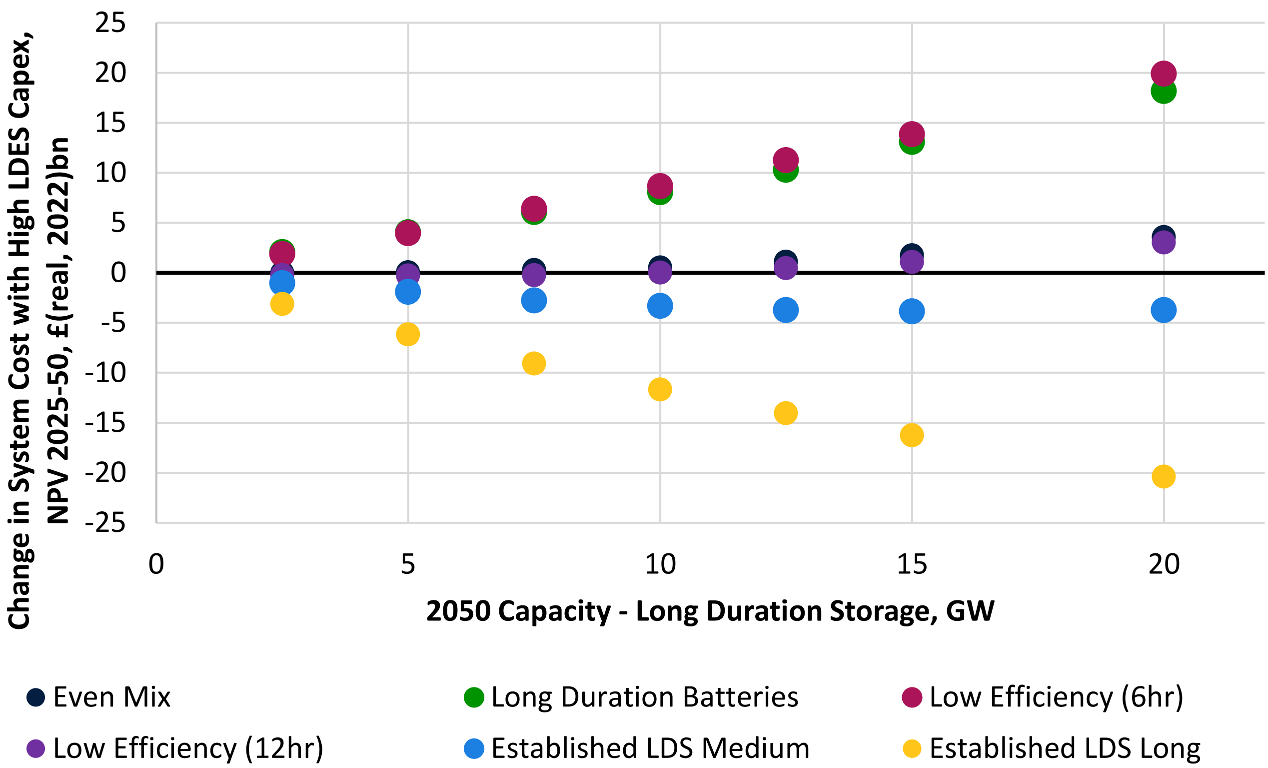


Figure 94: *Change in system cost (NPV) with high LDES CapEx v LDES capacity in 2050 (coloured by LDES archetype) with Medium Gas CCS and Hydrogen counterfactual and LDES replacing peaking and wind capacity.*



Annex D – Low Gas CCS and Hydrogen Deployment Scenario

The approach used in chapter 7 looks at alternative scenarios for Low Gas CCS and Low hydrogen (separately) by defining a new counterfactual which is then at the same level of emissions as the DESNZ NZ Higher scenario. This is done by increasing the renewable capacity while some of the CCS or Hydrogen capacity is removed. However, to test a scenario with low levels of both CCS and hydrogen was not possible using the same method.

This is because with the low levels of CCS and hydrogen combined 17TWh of unabated gas generation is required in 2050. Given 75GW of renewable capacity was added to replace 10TWh of additional unabated at low hydrogen levels, to replace 17TWh would mean that additional renewable capacity would need to be deployed at unrealistic levels meaning results from this analysis would not be plausible.

To look at the impacts LDES can have at a combined Low Gas CCS and Low Hydrogen scenario, the question has been looked at in a different way. Rather than defining a new counterfactual with consistent emissions, we ask "if we are in a world with low hydrogen and low gas CCS, what capacity and combination of LDES technologies would be needed to reach the same level of emissions we would have had with higher hydrogen and CCS ". Given most other technologies are already reaching maximum levels, LDES is one of the few solutions that could allow emissions to be reduced to the levels needed in the power sector.

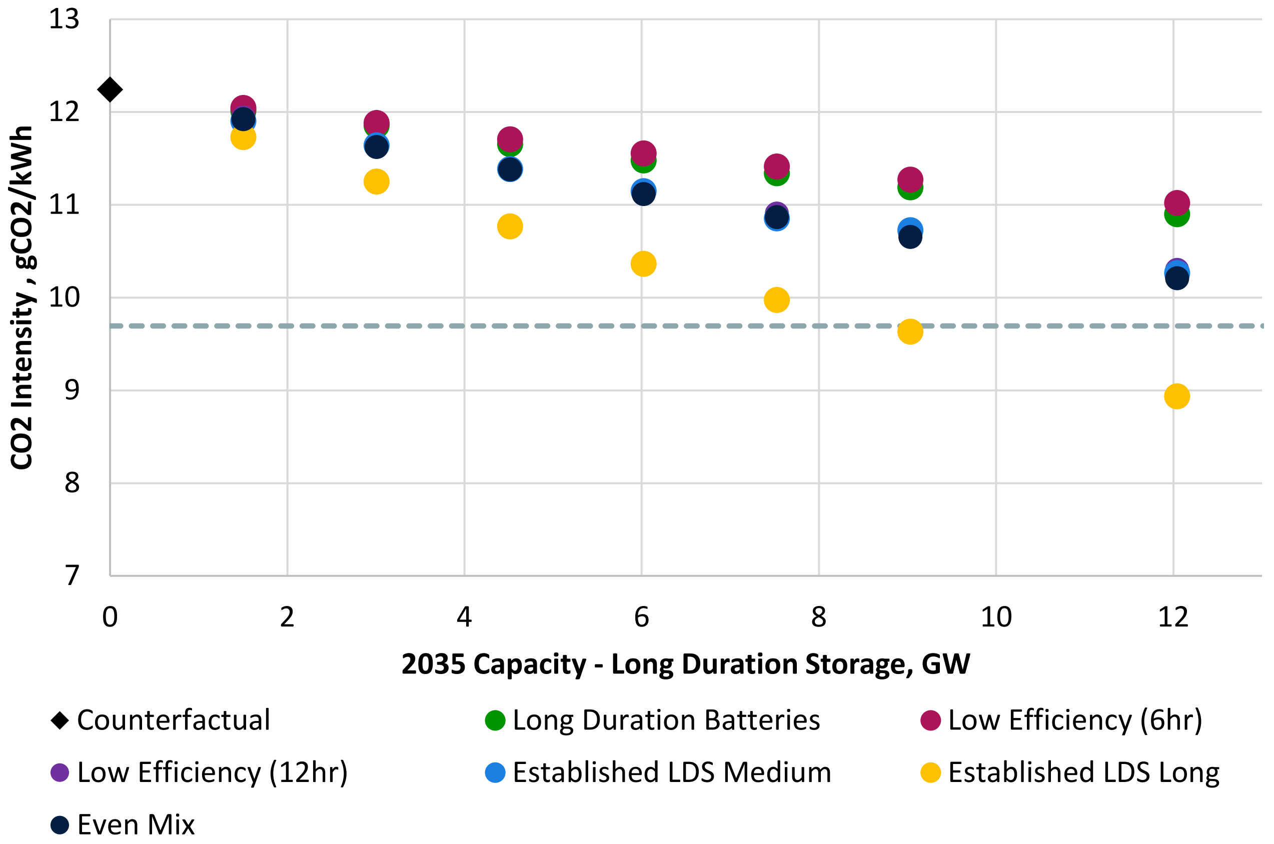
Emissions and generation impact

With low gas CCS and hydrogen, no LDES or extra renewables added, emissions in 2035 increase by around 2.5gCO2e/kWh and in 2050 increase significantly, by around 7.5 gCO2e/kWh. In 2035, 6.5GW of gas CCS is removed from the system and 2.5GW of hydrogen totalling 9GW of capacity. Only in the highest 2 capacity scenarios is the same amount of LDES added to the amount of gas CCS and hydrogen removed

In 2035, with LDES added emissions decline as wind capacity is able to be used more effectively. However only in 2 cases does adding up to 12GW of LDES get 2035 emissions intensity to the same point as the DESNZ NZ higher counterfactual. These 2 cases are adding 9.5GW and 12GW in 2035 of the Established LDES Long archetype.

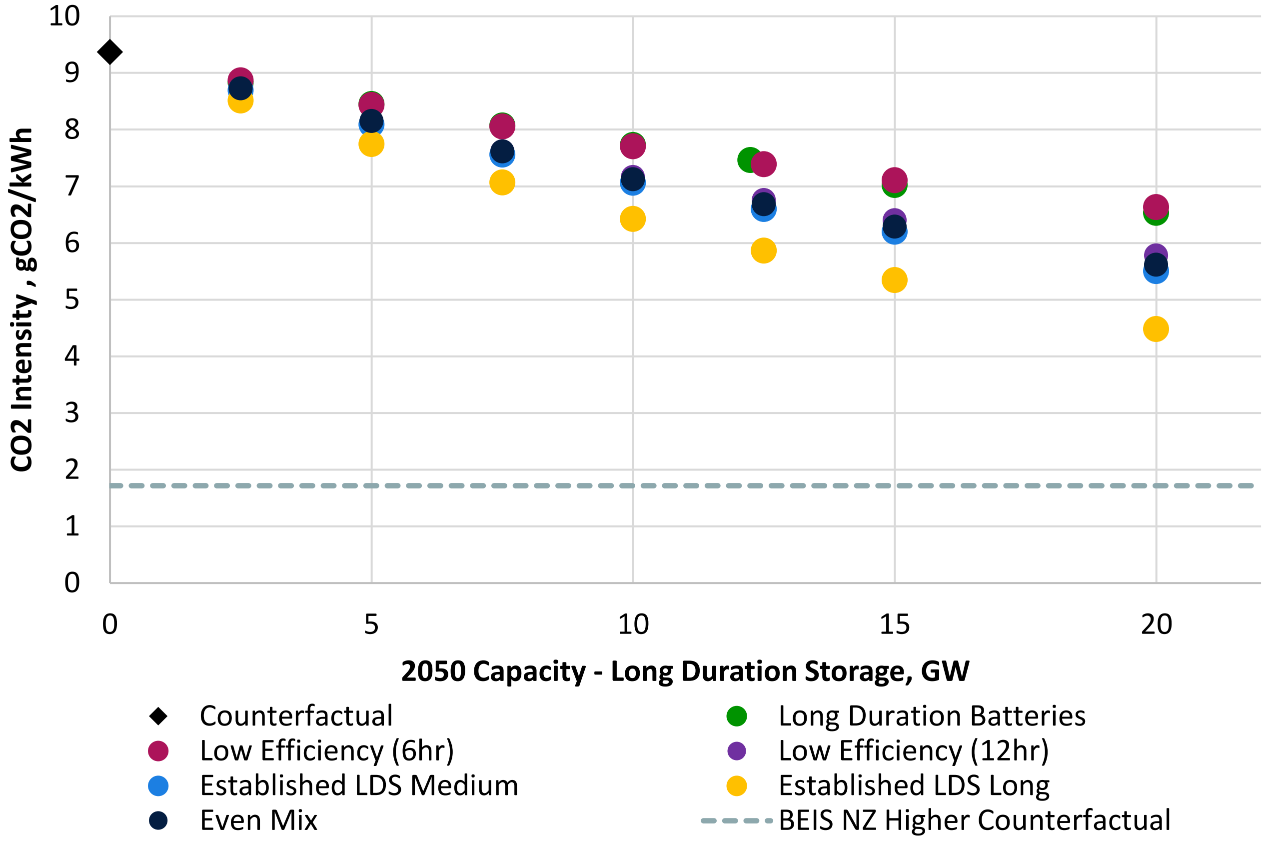
While most LDES scenarios do not meet the required level of emissions, it is important to note that in most cases the amount of LDES capacity is lower than the amount of hydrogen and CCS capacity removed. While adding LDES on its own does make a large contribution in reducing emissions, it would need to be added alongside some additional renewables to reach the target level of emissions.

Figure 95: *Emissions intensity v LDES capacity in 2035 (coloured by LDES archetype) with the low gas CCS and hydrogen and LDES replacing peaking capacity. Compared to emissions in the Core counterfactual*



In 2050, with LDES added, emissions decline as wind capacity is able to be used more effectively. However, in no scenario does adding up to 20GW of LDES get 2050 emissions intensity to the same point as the DESNZ NZ higher counterfactual. This is because significantly higher levels of gas CCS and hydrogen capacity have been removed than the LDES capacity added. 12.5GW of gas CCS and 40GW of hydrogen are removed totalling 52.5GW more than double the maximum amount of LDES added. The LDES does make a significant contribution though to reaching the same level as the DESNZ Net Zero Higher Demand scenario with emissions, by reducing 2.5-4gCO2e/kWh in the 20GW scenarios. This is higher than in 2035 as there is more renewable capacity on the system in 2050.

Figure 96: *Emissions intensity v LDES capacity in 2050 (coloured by LDES archetype) with the low gas CCS and hydrogen and LDES replacing peaking capacity. Compared to emissions in the Core counterfactual*



This publication is available from: https://www.gov.uk/government/publications/long-duration-electricity-storage-scenario-deployment-analysis

If you need a version of this document in a more accessible format, please email smartenergy@energysecurity.gov.uk. Please tell us what format you need. It will help us if you say what assistive technology you use.