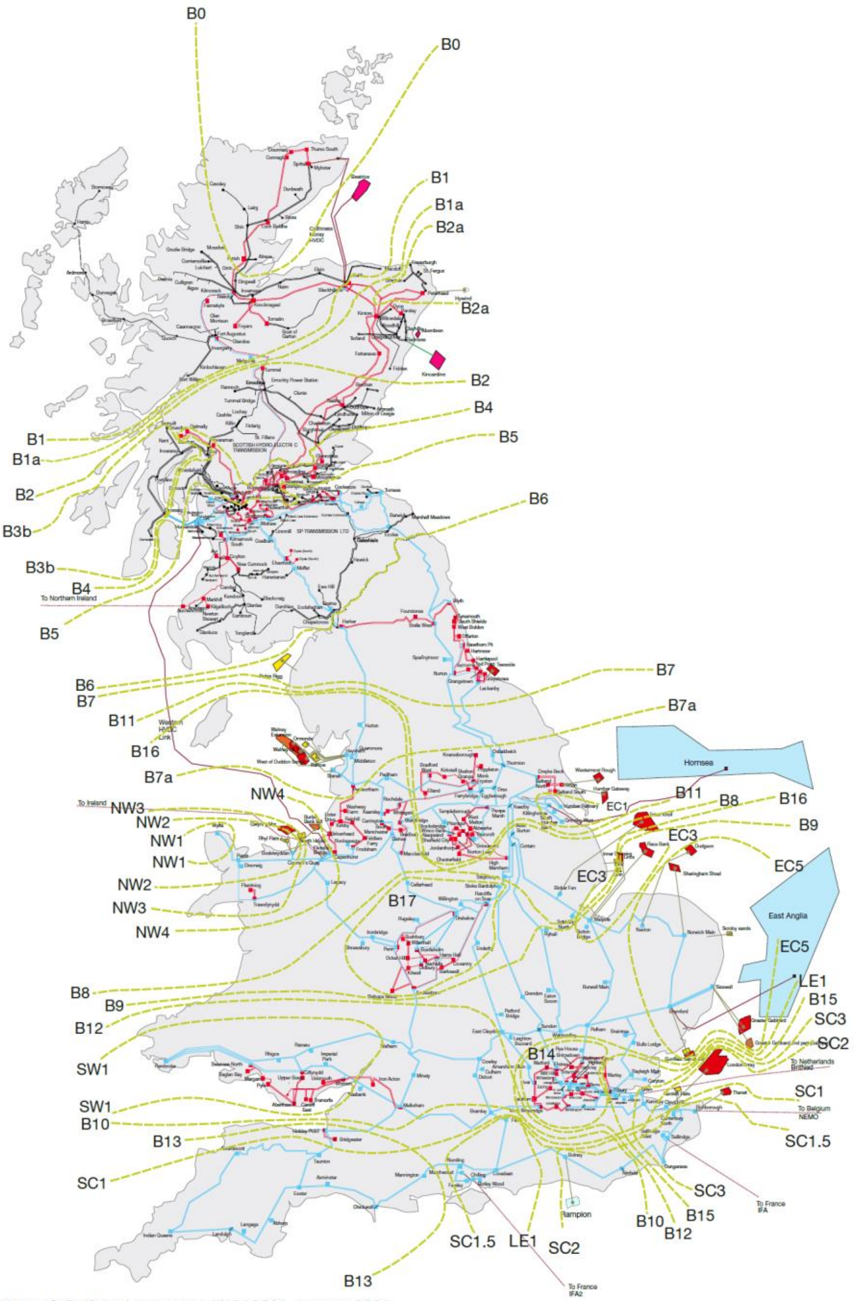
nationalgridESO

Storage for Constraint Management

A study by DNV on the potential application of storage technology for constraint management in Great Britain towards 2030



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Executive Summary

National Grid ESO (NGESO) undertakes the role of system operator for the electricity system of Great Britain. In this capacity, NGESO takes a central role within the GB energy industry, supporting the transition towards net-zero whilst operating the electricity system in a cost-efficient manner, bringing best value to customers. As residual balancer, NGESO is tasked to ensure that physical power flows on the system stay within the capability of the transmission network. As part of its recently published 5-point Plan to manage constraints on the system, NGESO is exploring the feasibility of energy storage as a means to reduce network constraint costs. Energy storage technology has the potential to provide relief in constrained network areas by absorbing and discharging power at different times and locations to avoid overloading network boundary points. NGESO has engaged DNV to conduct a techno-economic assessment of the storage technology potential to alleviate network constraints between now and 2030.

DNV's assessment involved the development of storage archetypes based on a screening of available and mature storage technologies; set up of a PowerFactory model environment representing the allocation of storage assets across the transmission network of GB; simulation of storage deployment aimed at reduction of network constraints; economic analysis of the levelized cost of storage participating in constraint management; assessment of the commercial competitiveness against other local constraint management providers; and a review of the other markets where storage operators could participate in a non-conflicting way with constraint management.

The simulation included 24 storage assets, each with a capacity of 50 MW and either 400 or 1,200 MWh, connected around 6 heavily constrained transmission network boundaries. We have performed the simulation in PowerFactory using power system analysis on a pre-fault basis with no contingency, which assumes that storage assets exclusively provide constraint management services (i.e. they do not participate in other markets) and there are no other generation assets involved in constraint management. Our analysis confirms the technical feasibility of the storage archetypes to provide constraint management services.

However, the absolute volumes of reduction in transmission line overloads sourced from individual storage units are limited, depending on the nature of constraints, as well as the location of storage assets and their functional specifications. The nature of network constraints (pattern, volume, frequency of occurrence) at the grid boundaries we have assessed, often does not allow storage assets to return to a "neutral state of charge" without causing overloads elsewhere in the network. Technical parameters, such as energy capacity (hours of continuous charge/discharge ability) and round-trip efficiency (reflecting energy lost in a charge/discharge cycle) limit the functional deployment of storage archetypes. Storage technology archetypes characterised by high round-trip efficiency and large energy capacity are shown to be comparatively effective in alleviating constraints and achieve a higher annual utilisation. For these reasons, as simulated, storage archetypes are functionally deployed only 23% of hours in a year (an average across all archetypes and all years) in the simulated environment, and are "idle" in the remaining time.

As a consequence of their limited utilisation, storage archetypes would need to recover capital and operating costs over a relatively limited number of hours. Based on the simulation, the outturn average levelized cost of storage (LCoS) across archetypes varies between 120 to 400 £/MWh. This is considered to be too high for most technologies in most locations compared to ca. 110 £/MWh that NGESO currently pays to procure constraint management services from other assets/providers. As modelled, the storage archetypes are therefore mostly not economic compared to other providers, and would not reduce the costs of constraint management for consumers. This outcome highlights the requirement for storage assets to be able to participate in other remunerable activities to be able to achieve a lower LCoS.

For reference, we have calculated for three storage archetypes a theoretical minimum LCoS of ca. 55 £/MWh (on average) on the assumption they could maximise remunerable operational hours to 95% of the year. We note that this is an extreme assumption that gives us the lower boundary of the LCoS that may be achievable, but does not factor in real-life challenges in delivering constraint management services alongside other services. On this basis, as a theoretical indicator of the potential saving against annual average constraint cost using the storage in this modelling exercise, and requiring a one-off capital investment of £420m, consumers could save c.a. £55m per annum.

From a qualitative assessment of 21 potential markets alongside the Balancing Market, we find that there are several alternative competitive marketplaces that storage assets may access to maximise remunerable deployment. The majority of these markets are not mutually exclusive (either by design or through technical requirements) so that storage operators can "stack" revenues across these markets during different time windows. There is also scope for revenue stacking during the same time window, especially with the new frequency response product (Dynamic Containment) and the Capacity Market. Access to various markets facilitates spreading cost recovery amongst these markets, so that the value potential from constraint management services can be greater if constraint management services are non-exclusive. However, in practice, revenue stacking across different services may be challenging due to locational factors, limitations in compatibility of services (e.g. different state of charge requirements), and economic optimisation by both NGESO and storage operators. In addition, storage connected to highly constrained circuits may find that the same constraints make it difficult to provide services that rely on active power flows.

This study finds that storage technology can feasibly be deployed in constraint management but has limited potential to reduce costs for consumers, if storage assets are contracted exclusively to provide constraint management services. The assessment also shows that the full potential value of storage for constraint management varies depending on storage operational parameters, physical characteristics of the transmission network and specific constraints, and the wider behaviour of storage assets.

1 Introduction

This report discusses the outcome of a study into the potential feasibility for storage technologies to be deployed in constraint management for the GB transmission system. The study was performed by DNV who have supported National Grid ESO (NGESO) in obtaining a comprehensive insight into the technical and economic characteristics of storage technologies and their potential to support the system needs, as part of the objectives set out in NGESO's Constraint Management 5-Point Plan[1].

This report sets out the objective of the study, the methodology that was applied, as well as presenting the final results and recommendations to NGESO going forward.

1.1 Background

NGESO undertakes the role of system operator for the GB electricity system. One of its roles as residual balancer is to ensure that the physical flows on the system stay within the capability of the transmission network. Flows on the network are initially determined by supply and demand in our energy markets. When load on a circuit meets or exceeds that circuits limits, this is known as a constraint.

NGESO manages these constraints by taking locational actions - by paying generators (or demand) in different locations to change their output (or consumption), thus changing the flow on the network. The amount NGESO has to pay network users to manage constraints in this way is known as the constraint cost.

As the electricity system decarbonises these constraint costs are expected to rise significantly, particularly between now and 2030, as renewable generation connects faster than new transmission capacity can be built. After 2030 planned increases in transmission network capacity are expected to significantly reduce the level of constraints.

On 25/02/21 NGESO launched its Constraint Management 5-Point Plan of measures to mitigate the expected increase in constraint costs, which are ultimately paid for by consumers. As part of this plan, NGESO wants to explore the technical feasibility of energy storage having a significant role in reducing network constraint[2] costs between now and 2030.

1.2 Objective

Based on the above background, the ultimate objective of the study is formulated as follows:

"To understand the techno-economic potential of commercially available storage technologies in alleviating network constraints in GB power system between now and 2030".

1.3 Scope

The scope of the analysis includes the following key steps:

1. To identify suitable energy storage technologies for constraint management. To create archetypes representative of these technologies based on the potential of their application for constraint management based on system needs in specific constrained locations, on the one hand, and feasible storage technology capabilities on the other.
2. To set up of the model environment representing the allocation of storage assets across the transmission network of GB.
3. To analyse the system value that storage archetypes can provide in alleviating constraint costs in the GB transmission system between now and 2030.

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[1] Constraint Management 5-Point Plan

[2] Throughout this report we will use the term "constraints": to reflect thermal overloads on transmission lines. We recognise that elsewhere NGESO commonly utilises "constraint management" to refer to transmission line thermal overloads, voltage and stability (frequency and voltage) issues management.

4. To explore the economic effect from employing storage archetypes for constraint management. To explore whether the revenue of technically feasible storage archetypes utilised for constraint remediation alone would be sufficient for them to have a business case. To investigate how access to additional revenue streams can improve the business case for selected storage solutions.
5. To study whether storage archetypes employed for constraint management exclusively would be competitive against other service providers, currently active in the Balancing Mechanism
6. To review the existing GB market mechanisms that could provide revenue streams for commercialisation of storage for constraint management. To identify barriers impeding participation of storage in constraint management.

1.4 How to read this report

This report consists of the following chapters:

- Chapter 2: Approach – explains the methodological approach that was followed for the study, the key assumptions that were taken regarding how the storage deployment for constraint management was modelled, as well as the /limitations of this analysis.
- Chapter 3: Storage Archetypes – presents the technical, operational and commercial data of the identified storage technologies that were used to develop the storage archetypes that were further used in the power system- and economic modelling.
- Chapter 4: Power System Modelling – sets out the detailed approach for modelling storage participation in constraint management, including the set-up of the GB transmission system in PowerFactory, scenarios, deployment strategy, selection of storage locations.
- Chapter 5: Economic Analysis – builds upon the findings of power system modelling and quantifies the levelized cost of storage (LCoS) based on the outcomes of the modelling; compares the obtained costs with the typical prices achieved in the balancing mechanism (BM) for constraint management services.
- Chapter 6: Prerequisites for Constraint Management and Access to Alternative Markets – analyses alternative available ancillary markets where storage could participate in addition to constraint management; qualitatively comments on the impact on the business case; explores wider considerations related to storage roll-out and development of projects in the market.

2 Approach

2.1 Approach

In collaboration with NGESO, DNV has designed an approach to the analysis that aims to address the objective of the project and provide NGESO with strategic understanding of storage potential in constraint management.

1. Storage archetypes
    a. Define 5 storage technology archetypes to represent current and future energy storage technology options.
    b. Define operational capabilities of storage technology applicable to a given archetype.
    c. Define costs per MW and per MWh (power capability and energy capability) for each archetype.
    d. Define a reasonable amount of storage in terms of power and energy that can be deployed in the UK system.
2. Power system modelling
    a. Set up the model of GB transmission system in PowerFactory based on the Future Energy Scenarios (FES) scenarios and Electricity Ten Year Statement (ETYS) power flows.
    b. Identify 6 most overloaded boundaries across the GB network and suitable locations for storage technology to be placed to support constraint management around those boundaries.
    c. Undertake modelling analysis of the GB electricity transmission network and simulate how energy storage, as defined under the step 1 Storage Archetypes, can mitigate boundary constraints.
    d. Evaluate the network boundary overloads with and without the storage and determine the volumes of overload that are avoided.
    e. Conclude on the technical feasibility of storage technologies for constraint management.
3. Economic modelling
    a. Estimate the levelized cost of storage (LCoS) based on the storage deployment metrics obtained in step 2 and costs of storage archetypes defined in step 1.
    b. Process historic balancing mechanism (BM) data to develop representative merit orders of providers (Balancing mechanism units – BMU) of constraint management service, including typical volumes and prices they receive for their service. Analyse which types of participant are the most active in the BM for selected network boundaries and explore at a high-level whether the merit order may change towards 2030.
    c. Based on the combination of the merit order at each boundary, typical prices achieved in the BM for constraint management, and the LCoS for the selected archetypes, conclude on the economic potential of technically feasible storage archetypes.
4. Analysis of alternative markets, potential business cases and other prerequisites for storage development
    a. Review the existing ancillary services markets, including their structure, requirements for participation and conclude on the technical feasibility of storage participation in those markets.
    b. Review the historical prices achieved in those markets and investigate their future development at a high level.
    c. Consider which of the service can be stacked to improve the business case of storage.
    d. Conclude on the potential of storage to have additional business cases and identify any relevant barriers.

e. Elaborate on any relevant wider considerations with regard to large scale storage deployment in GB the provision of ancillary services.

2.2 Limitations for this Assessment

The approach outlined above does not try to reflect in a high detail the commercial strategy of storage operators in the real world. Neither it is aimed to provide an exhaustive view on how storage assets could participate in the BM and what would be the outcome in terms of absolute annual constraint management volumes and cost.

The proposed approach is designed to support NGESO at a strategic level of decision making with regard to the role that storage can play as one of the tools for constraint management. The study should therefore indicate the direction and validate whether it is feasible for storage to be part of the solution. The study does not seek to provide a full quantitative insight and identify the optimum approach to utilising certain storage technologies to alleviate network constraints.

The concrete limitations and assumptions that underpin this study are:

1. Exclusivity of constraint management as a service – the modelling environment assumes that constraint management is the only market where storage technologies can participate. There are no other revenue streams or utilisation cases reflected in our simulation model.
2. Exclusivity of only storage participating in constraint management – there are no other BMUs reflected in our model that could also provide constraint management services. Our model only includes storage assets as potential service providers and reduces constraints through mathematically optimised dispatch of these storage assets. When there is no remaining (energy or power) capacity in the storage asset, then the constraint remains to be remediated via other assets, and this is outside of the scope of this study.
3. Ignoring commercial competitiveness of storage assets – we assume that storage units are competitive in the BM (reflecting the absence of other providers as per assumption (2)), and will always be called upon by NGESO to provide constraint management services. This maximises the potential utilisation of storage in the simulation and determines the maximum volume of overloads that storage assets could manage, revealing the lowest possible LCoS.
4. Optimistic storage cost assumptions – in our analysis we consider that storage technology will see significant uptake in development and deployment globally and in GB specifically. This reflects the high potential of the technology to provide ancillary services and support renewables integration. We therefore assume high potential for cost reduction in the near future.
5. Storage operation without insights into system needs – we assume that storage operators do not have any insight into the actual and near future forecasted power flows on the system, therefore cannot selectively deploy assets to address those constraints for which NGESO's willingness to pay would be the highest. Storage assets are deployed with perfect unawareness about the operational situation in the next hour, i.e. whenever its state of charge allows without considering the future needs.
6. Storage and locations – the study assumes 24 storage units of with power capacity of 50 MW each and 400-1200 MWh energy capacity, depending on the archetype. The potential 24 storage locations have been chosen in the system based on well-connected and evenly spread electrical network substations in the PowerFactory model on each side of the boundaries. Only 400 kV and 132 kV substations were considered. Whether these locations are physically suitable for the storage archetypes was not considered.
7. Power system modelling – all power system modelling and the simulations undertaken in this project have been based on NGESO's ETYS PowerFactory models. The results therefore reflect the accuracy of the operational scenarios depicted in the simulation models for the different years. The DNV work in this project is based on a simplification using pre-fault conditions with no contingency considered. This is in contrast to ESO operational analysis, where normally boundary capabilities and constraint costs are calculated based on credible contingencies in both planning and operation timescales.
8. Boundary capacity – the modelling and simulations in this project considers only the thermal capacity of the lines and boundaries as the modelling is based on static load flow calculation. Stability criteria such as voltage control, frequency and inertia are not considered to be limiting factors for the line and boundary limits. DNV work is based on circuits but is not based on the full DC load flow. It uses PTDF factors only for the storage units instead of using it for all units. DNV distributes the hourly boundary flow linearly over each

AC line crossing each boundary for all hours of the year based on the line flow from the base case (winter-peak) instead of using PTDF coefficient. In this way circuits' flow changes based on the boundary flow, not based on the actual generation background. This is different to a full circuit-based methodology using full DC load flow, where circuits' flow depends on the generation background and the PTDF coefficient for each generator. In a full circuit-based approach, for the same boundary flow with different generation background, different circuit flows are generated.

3 Storage Archetypes

3.1 Overview and Approach

DNV performed an initial high-level assessment of a range of energy storage system (ESS) technologies to determine their suitability as the basis for an archetype in the constraint management application.

DNV's initial high-level assessment considered:

- Flow batteries;
- Liquid air energy storage (LAES);
- Lithium ion (Li-ion);
- Hydrogen;
- Gravity energy storage (GES);
- Pumped hydroelectric storage (PHS);
- Compressed air energy storage (CAES); and
- Thermal energy storage (TES).

The assessment considered a range of technical and non-technical characteristics to determine a shortlist of five technologies which would be more suited to the Customer's requirements. Of the abovementioned technologies, the first five were shortlisted for detailed analysis. The following table summarises the reasons for the exclusion of the remaining technologies. It should be noted that the exclusion of these technologies from the detailed analysis does not mean that they cannot be used for network constraint management, however, they are viewed by DNV to be less suitable for the reasons discussed below.

Table 3-1 Summary of archetypes excluded from the shortlist

Technology	Reason for exclusion from the shortlist
Pumped Hydroelectric Storage (PHS)	PHS is a well-established ESS technology making up the majority of global storage capacity. While it is a proven technology with performance characteristics suitable to network constraint management, the geographical constraints remain a significant barrier to deployment for this application. Further, the development of PHS is impacted by long lead times, very high upfront CAPEX and planning/permitting difficulties.
Compressed air energy storage (CAES)	While CAES is suitable for long duration applications, the technology is less mature than PHS, has an effective round-trip efficiency (RTE) of approximately 42% - 50%, and has significant constraints in terms of location.
Thermal energy storage (TES)	While TES make up a large portion of global installed storage capacity, this is mainly in the form of molten salt combined with concentrated solar power (CSP). The technology is not as well suited for storage of electricity for conversion back to electricity. There are various options for full electricity – heat – electricity TES systems, however, they are generally limited by low RTE (approximately 40% - 45%).

DNV performed a detailed assessment of the shortlisted technologies to determine suitable operational parameters for the modelling (including technical performance parameters, size & capacity considerations) and estimates of CAPEX and OPEX. Additionally, DNV provided a qualitative view of each technology's suitability in terms of footprint/energy density, technology maturity, supply chain considerations/development times and alternative applications/services. DNV's research for this assessment is based on publicly available resources, discussions with ESS manufacturers and DNV's in-house knowledge and expertise.

3.2 Summary of Five Shortlisted Technologies

This section of the report provides a detailed description of the five ESS technologies assessed for the project.

Each technology has been chosen based on their high-level suitability to the transmission network constraint application. The following sections present an overview of each technology including a summary of the key characteristics in each case. The full set of operational characteristics for each technology are provided in Appendix .

3.2.1 – Flow Batteries

Flow batteries are an alternative form of electrochemical storage. 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. Flow battery technology is less developed than lithium-based chemistries, however, there are many successfully operational projects globally. While the majority of these are relatively small-scale systems, there are a number of large-scale projects (>50 MW) currently operational or in development which prove the capability of flow batteries to be deployed for grid scale applications. Rongke Power are currently developing a 200 MW/800 MWh flow battery in Dalian, China[3]. The first half of this project is expected to be operational by the end of 2021.

The ability to scale the energy capacity of the system independent of the power capacity, at a relatively low cost, is a key advantage of flow batteries if long duration services are required. Additionally, the ability to perform a very high number of cycles at high depth of discharge (DOD) with limited degradation, combined with a potential 20-year life makes the cost per cycle very competitive with competing technologies. The limited number of operational installations at scale increases the project risk, which could also make project financing more difficult. Companies involved in flow batteries include Invinity, CellCube, Sumitomo, and Lockheed Martin. The technology is considered TRL 6 – 8.

With the characteristics of fast response time, relatively high efficiency and suitability to long duration applications, flow batteries can provide a wide range of services. Unlike some other longer duration technologies, flow battery response times allow the provision of many ancillary services which form a significant portion of the energy storage business case in the UK to date. Additionally, flow batteries can provide a range of co-location services, due to their suitability to store larger quantities of energy and ability to follow a dynamic load profile.

Table 3-2: Summary of key characteristics for Flow batteries - further details are included in Appendix A. (Source: DNV experience & publicly available information)

Parameter	Value	Comment
High end of installation scale – Power Capacity	>50 MW	Flow batteries are modular, so they can be theoretically built at large scale (>50 MW). However, most commercial projects to date are much smaller.
High end of installation scale – Energy Capacity	>200 MWh	Flow batteries are modular, so they can be theoretically built at large scale (>200 MWh).
Discharge Duration	4 – 8 hours, but this is flexible	Energy capacity is a function of the volume of electrolyte. It should be noted that many manufacturers are currently choosing to standardise their offering which limits the flexibility of power to energy ratios. Most systems are fixed at 3 – 4 hours.
Charge Duration	Approximately 6.5 hours for a 4-hour system ranging up to 13 hours for an 8-hour system	The charge duration at rated power depends on the system POC round trip efficiency (RTE), discharge duration, power tapering characteristics and oversizing of the system. Due to losses, the charge time will be longer than the discharge time.
RTE (AC as measured at POC)	62% - 67%	Approximately 62% - 67% including auxiliary loads. Note that the POC RTE figure will be site specific and depends on the BOP design.
RTE (AC as measured at the	67% - 72%	Approximately 67% - 72% including auxiliary loads

[3] https://www.energy-storage.news/chinas-largest-solar-plus-flow-battery-project-will-be-accompanied-by-vrfb-gigafactory/

power conversion system (PCS))		
Cycle Life	>20,000	Note, the power stack component usually requires replacement during the operational lifetime
Expected lifetime	>20 years	
Capacity degradation	1% - 2%	Approximately 1% - 2% over operational life.
CAPEX	£400 - £550/kWh	Based on DNV experience. Total installed project cost (battery and BOP), including vanadium electrolyte, 8hr system
OPEX	£0.5 – £2.5/kWh	Based on DNV experience. 8 hr system

3.2.2 Liquid Air Energy Storage (LAES)

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. The components responsible for charging, storing energy and power recovery can be scaled independently. The technology is particularly suited to industrial locations where there is access to high grade waste heat or cold which improves the compression and expansion processes. Without any external heat or cold sources, the plant roundtrip efficiency is circa 50% - 55%. With the addition of high-grade waste heat (circa 400°C) this figure could rise to over 70% and potentially higher if also linked with a cold source. There is currently only one operational grid scale LAES plant; a 5 MW, 15 MWh demonstration plant developed by Highview Power (the leading manufacturer of LAES technology). Highview Power has other projects in development, such as a 50 MW, 250 MWh in Carrington, and a 50 MW, 400 MWh in Vermont, in addition to 2 GWh worth of proposals in Spain and 500 MWh in Chile.

The main challenge to this technology is the lack of proven operational sites at scale, although the earliest of Highview's current developments are expected to enter commercial operation in 2022. In order to take advantage of the key attributes of the technology it should be implemented at scale with a high capacity to power ratio. Until recently it would have been considered that this type of technology could be more cost effective over the lifetime than lithium-based batteries for sites above 100 MWh. However, the majority of recent projects at this scale have used lithium-based batteries. Highview Power is the leading company in this technology space, with their technology having a TRL of 8.

LAES is more suited to long duration applications. This includes services requiring storage of larger quantities of energy and can include a range of co-location services to balance out issues with generation intermittency.

Additionally, due to the use of a synchronous generator, LAES systems can provide inertial response, voltage support and reactive power services. LAES therefore offers multiple benefits to the network operator and can therefore capture multiple revenue streams. A static storage technology, such as a flow battery or Li-ion would need to be combined with a synchronous condenser and a stat com to provide the same services.

Table 3-3: Summary of key characteristics for LAES- further details are included in Appendix A. (Source: DNV experience, LAES manufacturer & publicly available information)

Parameter	Value	Comment
High end of installation scale – Power Capacity	>50 MW based on systems currently in development/operational Theoretical upper end of installation scale is 100s of MWs, up to approximately 500 MW	Modular, can be increased/scaled independent of energy capacity.
High end of installation scale – Energy Capacity	Approximately 500 MWh based on systems currently in development/operational Theoretical upper end of installation scale is 1000s MWhs	Modular, can be increased/scaled independent of power capacity. Energy capacity is a function of tank capacity.
Discharge Duration	6 – 12 hours	LAES can be scaled to higher durations, however, this range is preferred by manufacturers.

Charge Duration	6 – 24 hours	The size of charging device (compressor) dictates the charge rate and therefore charge duration.
RTE (AC as measured at POC)	50% - 55% standalone Up to 65% - 70% with waste heat/cold	50% - 55% for standalone installation – this is based on early projects, depending on specific site design. This can increase to 65% - 70% if installed with source of high-grade waste heat and combined with a cold source[4],[5].
RTE (AC as measured at PCS)	n/a	No PCS required as the expansion process is used to drive a synchronous generator
Cycle Life	>11,000	Assuming 1 cycle day for 30 yrs. A greater number can be specified; however, the system would be subject to increased O&M costs.
Expected lifetime	>30 years	Systems consist of established proven components with long operational histories in the power generation and industrial sectors. Greater than 30 years is possible if plant is maintained to suitable standards.
Capacity degradation	n/a	No capacity degradation occurs with CES. No performance degradation occurs as long as the system is suitably maintained.
CAPEX	£300 - £350/kWh (estimated) for 50 MW system	The costs of LAES systems are highly sensitive to scale and the maturity of the development pipeline. Larger scale and longer duration systems have cost efficiencies resulting in lower per kWh CAPEX figures. As the technology increases in maturity over the coming years with increased learning from operational projects, CAPEX figures are expected to come down. Additionally, development costs are dependent on the exact configuration of the site, which is flexible (in terms of power, energy and duration). Current costs for an 8-hour system may be in the range of approximately £300 - £350/kWh. However, for longer duration systems towards the end of this decade, costs are expected to reduce to approximately: • £270/kWh for a 50 MW, 12 hr system • £170/kWh for a 200 MW, 24 hr system
OPEX	£2.3m/year for a 50 MW system	The system OPEX does not scale significantly with increased duration. The majority of the OPEX requirements are for the generators and turbomachinery rather than the tanks.

3.2.3 Lithium Ion (Li-ion)

Lithium-ion (Li-ion) batteries are the current market leaders in terms of new projects deployed over the past three years. This stems from the high flexibility with regards to system sizing, high energy density, high system efficiency and the ability to deploy the systems quickly. In stationary applications, Li-ion systems are generally well suited to services requiring high power and short to medium duration (up to 2 to 4 hours to date). There is a range of Li-ion technologies based on different chemistries, each have individual performance and safety characteristics which make them suitable for certain applications.

[4] https://www.highviewpower.com/wp-content/uploads/2018/04/Highview-Brochure-November-2017-Online-A4-web.pdf
[5] DNV Experience

Traditionally, Li-ion systems have been designed with a duration of up to 4 hours. However, in recent years there have been vast improvements in Li-ion pricing and performance due to high levels of deployment and growing industry knowledge. As a result, it is becoming more common to see very large scale (>100 MW) Li-ion projects with medium durations. The most notable of these large-scale Li-ion projects currently online is the 300 MW/1,200 MWh system being developed by Vistra in California, with a number of other large Li-ion projects currently in development throughout the globe, such as InterGen's 320 MW / 640 MWh planned near to London. This trend of Li-ion systems being used for increasingly long-duration storage may enable them to surpass other technologies traditionally thought of as having advantages at these longer durations.

Leading UK suppliers of Li-ion systems include Fluence, Tesla, BYD, LG Chem, and Samsung SDI. The technology is considered TRL 9.

Li-ion has flexible performance characteristics and is suitable to a wide range of alternative applications. Li-ion systems can provide the full set of Network, Ancillary and Co-location services summarised in Figure 3-1, apart from those which require a synchronous generator.

Table 3-4: Summary of key characteristics for Li-ion - further details are included in Appendix A. (Source: DNV experience & publicly available information)

Parameter	Value	Comment
High end of installation scale – Power Capacity	100s MWs	Modular systems – therefore, installation scale can be large. Generally limited by the requirements of the business case, connection capacity on the grid and supply chain.
High end of installation scale – Energy Capacity	1-1.5 GWh	The addition of extra modules increases energy capacity. Traditionally, Li-ion systems have been associated with high power/short duration applications as this suited the business case.
Discharge Duration	Up to 4 – 6	Theoretically, Li-ion could be developed with longer duration, however, this needs to be assessed for the particular business case.
Charge Duration	Up to 4 – 6/7	The charge duration at rated power depends on the system POC round trip efficiency (RTE), discharge duration, power tapering characteristics and oversizing of the system. Due to the high RTE of Li-ion, the charge duration at rated power is generally only slightly longer than the discharge duration.
RTE (AC as measured at POC)	84% - 86%	For a reference test cycle. During operation, this depends on cycling rate, ambient conditions, electrical equipment used, site electrical design etc.
RTE (AC as measured at PCS)	~90%	
Cycle Life	Up 7,000 cycles depending on cell chemistry	This depends on the exact system, but typically in the range of 4,000-7,000 cycles. This figure can be increased/decreased based on how well the system is maintained, the cycle rate, depth of discharge (DOD) for each cycle etc.
Expected lifetime	8-15 years	8-15 years for approximately 1 – 2 cycles/day. Lifetime extension possible by capacity augmentation.
Capacity degradation	Yes 1.5% - 3%/year	Capacity degradation is more of an issue for Li-ion than other ESS technologies. Generally, systems degrade to approximately 60% - 70% State of Health (SoH) in 8 – 15 years. When the End of Life (EoL) SoH is reached, battery degradation becomes unpredictable, performance degradation will occur and the system will have higher risk of safety issues.
CAPEX	£190-£240/kWh	For a 4-hour system, total installed project costs. Estimation for 1 GWh, 6hr system – approximately £130 - £190/kWh based on an internal DNV model. Note, beyond 4-hour duration, there is a lot of uncertainty in Li-ion CAPEX estimations. Note, as the majority of Li-ion installations to date are short duration, there is a reasonable amount of uncertainty in

		estimations for CAPEX of long duration systems. Even with shorter durations (1-2hrs), there is significant variability of CAPEX between markets and manufacturers/suppliers etc. Figure 3-1 presents a range of CAPEX estimates from various sources.
OPEX	Approximately 1% - 2.5% of CAPEX	Can vary depending on supplier, scope of services and availability guarantee.

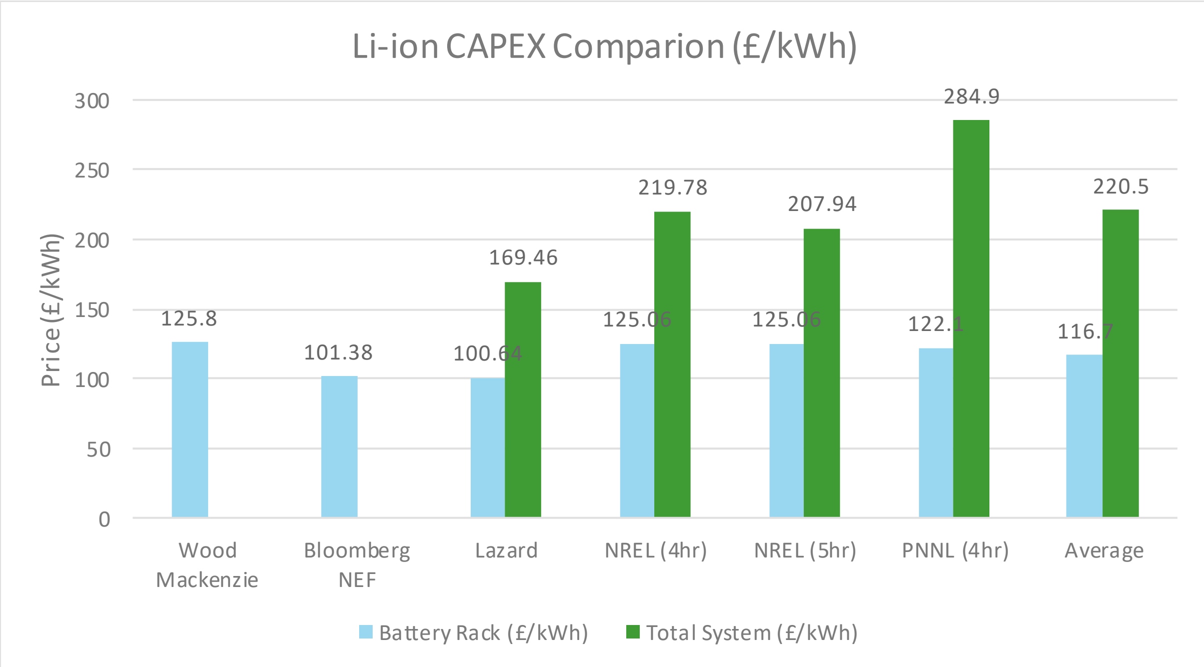


Figure 3-1: Li-ion 2020 CAPEX comparison (considering 4/5-hour systems) from various sources

3.2.4 Hydrogen

Electricity can be used to generate hydrogen from water in a process called electrolysis. Hydrogen gas can then be compressed and stored in tanks or in underground formations (aquifers, salt caverns, depleted gas fields). Hydrogen can also be liquefied, converted to synthetic fuels such as ammonia or methanol or blended with natural gas in pipelines.

Hydrogen can be used at a later time to generate electricity in fuel cells, engines or gas turbines. Fuel cells are more efficient than combustion processes but have a higher capital cost and lower lifetime. While combustion processes for generation from hydrogen have lower efficiency than fuel cells, they can use synchronous generation and therefore have additional benefits regarding inertia and other forms of stability (as discussed in the LAES section).

The overall efficiency of power-to-gas-to-power is low compared to other technologies (approximately 20-40%). However, it offers the possibility of storing very large quantities of energy for weekly / monthly balancing of renewables. Power and energy are decoupled, as for some of the other energy storage technologies.

There are several kinds of electrolysers and fuel cells depending on the electrolyte used: PEM (Polymer Electrolyte Membrane), alkaline, phosphoric acid, molten carbonate, solid oxide.

Hydrogen energy storage (for conversion of electricity – hydrogen – electricity) is relatively uncommon due to the low RTE. This disadvantage results in hydrogen being an uncompetitive option for many ESS services which require immediate conversion of hydrogen electricity.

However, there are numerous alternative applications for hydrogen gas if it is not immediately converted back to electricity via fuel cells. This can include the storage for long periods of time to balance out seasonal variance in demand, use of hydrogen as a chemical feedstock for industrial processes and various applications in the transport and heating sectors.

Table 3-5: Summary of key characteristics for Hydrogen - further details are included in Appendix A. (Source: DNV experience & publicly available information)

Parameter	Value	Comment
High end of installation scale – Power Capacity	100s MW	Approximately 1 MW – up to 100s MW
High end of installation scale – Energy Capacity	>1 GWh	Energy capacity is limited by geologic underground hydrogen storage possibilities. Natural gas is already stored underground for the winter season.
Discharge Duration		Function of volume of tanks/storage etc.
Charge Duration		Function of volume of tanks/storage etc.
RTE (AC as measured at POC)	20% – 40%[6]	Approximately 37% at POC, assuming 3% BOP losses, a 75% efficient PEM and 51% efficient FC. Note, another source claims higher efficiency at 47%[7]. However, DNV view this to be unrealistic.
RTE (AC as measured at PCS)	n/a	
Cycle Life		Electrolyser efficiency will decrease over time. Degradation rate is normally 0.1%/1000 hours. Electrolyser stacks would normally be replaced after 80,000-100,000 hours (lifetime is considered in terms of operational hours rather than cycles)[8]. Frequent turning off/on accelerates traditional electrolyser degradation, although newer designs are being optimised for intermittent operation with renewables. Fuel cell efficiency will also decrease over time. The degradation rate is approximately 0.2% - 0.3%/1000 hours. Fuel cell stacks would normally be replaced after 30,000-40,000 hours[8].
Expected lifetime	PEM approximately 20yrs depending on how much it is operated.	See "Cycle Life" section above. Lifetime depends on acceptable degradation level. For reference, 80,000-100,000 hours for electrolysers and 30,000-40,000 hours for fuel cells is a reasonable approximation.
Capacity degradation	n/a	No capacity degradation occurs due to the use of storage tanks.
CAPEX	Fuel Cells: 1,470.3 - £2,205.4/kW Electrolysers: £945.90 - £1156,10/kW Hydrogen Tanks: Approximately £3-£7/kWh of discharge capacity.	For Fuel Cells, CAPEX is \$2,000 - \$3,000/kW in 2020[8]. This equates to approximately **£1,470.3 - £2,205.4/kW** (converted at exchange rate of 0.74). Electrolyser CAPEX is approximately Eur1,234/kW[6]. This equates to approximately **£1,051.38/kW** (converted at exchange rate of 0.85). A range is specified here of +/- 10% of £1,051 to account for the uncertainty and variability in CAPEX. The CAPEX associated with hydrogen storage tanks is highly variable depending on the selected equipment and the storage pressure. Based on a range of sources[9], the approximate CAPEX of hydrogen storage, based on kWh of "discharge" capacity (assuming a 51% efficient fuel cell), is £3 - £7/kWh. However, this is highly variable and can be considerably higher based on some sources.
OPEX	Varies	For electrolysers – approximately 1%-2% of CAPEX/yr[6]

[6] DNV Hydrogen in the Electricity Value Chain
[7] https://www.sciencedirect.com/topics/engineering/round-trip-efficiency
[8] FCH 2 JU Multi-Annual Work Plan 2014-2020
[9] https://www.storeandgo.info/fileadmin/downloads/deliverables_2019/20190801-STOREandGO-D8.3-RUG-Report_on_the_costs_involved_with_PtG_technologies_and_their_potentials_across_the_EU.pdf

		For fuel cells: approximately 4% of CAPEX/yr[6] For hydrogen storage tanks: approximately 1.5% of CAPEX/yr[9]

3.2.5 Gravity Energy Storage (GES)

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. Once raised, the masses have potential energy, which is recovered over the discharge cycle as the masses are lowered, driving electric generators. The power to energy ratio of gravity energy storage is technically decoupled, however, the technology is generally suited to longer duration storage. Gravity energy storage is mainly composed of components which are well developed through other industries with long operational histories. The materials used in the system are inert and have low environmental impact. Gravity storage systems are capable of operating over long lifetimes (up to 40/50 years) which can be extended through preventative maintenance and mechanical component replacement. However, this technology has high upfront CAPEX (although the resulting LCOS over the project life can be competitive), has a low energy density and its TRL of approximately 6 – 8 is seen as a risk to investors. Companies which are presenting demonstration plants include Gravitricity and Energy Vault.

GES is more suited to long duration applications. This includes services requiring storage of larger quantities of energy and a range of co-location services to balance out issues with generation intermittency. The slow response time of GES rules out a number of ancillary services, however, due to the use of a synchronous generator, it is possible to provide reactive power support and inertial response (if the generator is already up and running rather than in idle/standby mode).

Table 3-6: Summary of key characteristics for GES - further details are included in Appendix A. (Source: DNV experience & publicly available information)

Parameter	Value	Comment
High end of installation scale – Power Capacity	50 - 200 MW	It should be noted that most installations to date have be smaller scale pilot projects (<1 MW). However, this technology shows potential for larger scale long duration applications.
High end of installation scale – Energy Capacity	GWh	Note – this technology is less mature than the others. Many installations are pilot projects. It has the potential for large scale deployment and long durations, however, this has not yet been proven at scale.
Discharge Duration	Up to 8 – 10 hours	Flexible – can range from low durations (1-2 hours) up to high durations 8 – 10 hours. However, larger scale, long duration projects have not yet been developed.
Charge Duration	Up to 10 – 12 hours	The charge duration at rated power depends on the system POC round trip efficiency (RTE), discharge duration, power tapering characteristics and oversizing of the system.
RTE (AC as measured at POC)	Approximately 76% - 79%	Assume BOP losses 3% - 4%
RTE (AC as measured at PCS)	n/a	
Cycle Life	>10,000	Based on minimum expected life of mechanical parts – overall lifetime and cycle life can be extended through maintenance/component replacement
Expected lifetime	30 – 40 years	Overall lifetime and cycle life can be extended through maintenance/component replacement
Capacity degradation	n/a	
CAPEX	£213.86 - £259/kWh	CAPEX estimates for a 10 MW/40 MWh (4 hours) system are approximately \$289 /kWh - \$350/kWh[10] (£213.86 - £259/kWh @ conversion rate of 0.74)

[10] https://www.energyvault.com/hubfs/EV%20Theme%20Images/Investor%20Relations%20page/EVIP-20210909-051.pdf

		There is uncertainty as to how this would scale for longer durations.
OPEX	$45.8/kWh[10]	For 10 MW/40 MWh (4 hours). There is uncertainty as to how this would scale for longer durations

3.3 Modelling the storage

In the remainder of this report, we do not refer to specific technologies but rather to archetypes that are based on a broad range of operational parameters and costs that are typical for a certain technology as set out above. However, an archetype could also represent other technologies with similar parameters e.g. a future technology with improved efficiency and costs. Initial modelling showed that Lithium-Ion batteries perform similarly to Gravity storage, and Flow batteries perform similar to Cryogenic Storage, both in terms of costs and constraint management potential. Based on preliminary modelling, we aggregated these technologies into the following archetypes:

Table 3-7 Storage technology archetype aggregation

Archetype	Technologies that the archetype broadly resembles
Archetype 1	Cryogenic Energy Storage and Flow batteries
Archetype 2	Hydrogen
Archetype 3	Lithium Ion and Gravity storage

4 Power System Modelling

4.1 Key findings

Our modelling simulates the mathematically optimal dispatch of storage units spread over 24 locations with the primary objective to minimise the thermal overload of 74 to 79 (depending on the year) high voltage lines crossing 6 different pre-selected boundaries in the power grid.

The modelling results show that it is technical feasible for storage technologies to provide constraint management services, but volumes of reduced overload by the storage units are limited due to the nature of constraints and power flow, storage locations, and storage specifications.

- In general, the volumes of constraints are significantly larger than what is realistic for storage technologies alone to handle;
- As regards storage specifications, high power and energy capacity as well as high efficiency are the most important factors for effective utilization of storage for constraint management.

4.2 Input data, Approach, and Model

The key purpose of the power system modelling is to determine how much storage technologies can reduce network constraints over the selected boundaries. This was achieved using the following network model inputs and power system modelling approach.

4.2.1 Network Model Input data

DNV received the following Electricity Ten Year Statement (ETYS) PowerFactory models from NGESO:

- Winter peak: 2021,2022, 2023, 2025, 2027, & 2030
- Summer minimum: 2021, 2024, 2025, & 2027.

The boundaries pre-selected by NGESO in this study were:

- B4, B6, B7a, EC5, SC1, & SC3

The boundary flows were received from NGESO and linearly interpolated to yield an hourly resolution for the following years:

- 2021, 2023, 2025, 2027, & 2030

4.2.2 Analysis of the PowerFactory models and selection of years

To identify the constraints at the six specific boundaries in the GB transmission grid and the resulting need for an energy storage, DNV first conducted a detailed analysis of the PowerFactory models from NGESO, which includes the thermal constraints of the transmission network, the defined boundaries, and configurations for the different years. Based on the load flow results of the PowerFactory models DNV identified the potential constraints in the six specified boundaries and the relevant yearly stages of development of the power system (including grid, generation, and load) from 2021 up to and including 2030.

The DNV work in this project is based on a simplification using pre-fault conditions with no contingency considered. This is in contrast to ESO operational analysis, and other such modelling work conducted by ESO, where normally boundary capabilities and constraint costs are calculated based on credible contingencies in both planning and operation timescales.

Considering the changes in constraints, operating conditions, and development stages the following selection of relevant years of development was made for the study:

- 2021, 2025, 2030.

This selection covers the full range of years for the study and reflects the range of constrained operation scenarios for the GB power system in the years from 2021 to 2030. In addition, these years accurately reflect the different development stages seen in the Electricity Ten Year Statement (ETYS) that directly impact the boundaries including:

- Planned grid development and reinforcements, e.g., commissioning/decommissioning of lines, transformers, & quad-boosters; and
- Expected changes in generation capacity and expected major changes in demand.

To illustrate the expected change in boundary flows and base capability over time the NGESO ETYS Scottish boundary B6 information is used as shown in Figure 4-1.

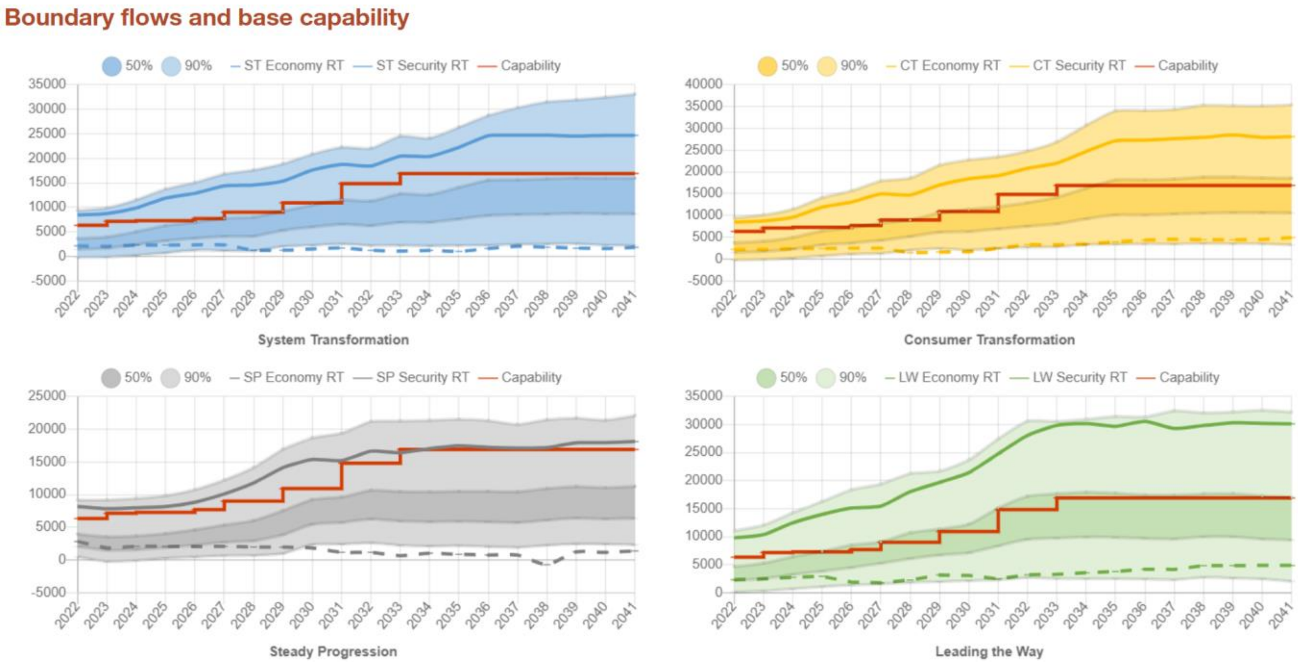


Figure 4-1: B6 boundary flows and base capability[11].

4.2.3 Storage archetypes

The characteristics and parameters for the storage archetypes detailed in section 3 were used as inputs for the power system modelling and the storage archetypes considered in the final optimisation modelling are included in Table 4-1.

Table 4-1: Storage archetypes for the optimisation modelling.

Storage	MW each	MWh each	h	Efficiency	Total MW 24 sites	Total MWh 24 sites
Archetype 1	50	400	8	Round trip: 85%	1,200	9,600
Archetype 2	50	1,200	24	Round trip: 55%	1,200	28,800
Archetype 3	50	1,200	24	Round trip: 37.5%	1,200	28,800

These archetypes have the same power rating, but different energy capacity which results in a different number of hours of full load power production. Also, the round-trip efficiency is different for each archetype. In terms of constraint management performance, the power rating and energy capacity of the storage are the most important parameters to consider. The three archetypes used in the analysis span the feasible range of these parameters.

In the power system modelling 24 storage units with the characteristics shown above are used, i.e. 24 storage units, of 50 MW each, and energy capacity from 400-1,200 MWh each, and round-trip efficiency between 37.5-85%, which in total is 1.2 GW and 9.6-28.8 GWh of storage capacity.

The same storage archetype is modelled on each of the 24 location in the network. A priori, it is not known if the congestion will be mitigated by injecting or consuming power at that location in the network and at that

[11] https://www.nationalgrideso.com/research-publications/etys/electricity-transmission-network-requirements/scottish-boundaries

moment in time. The action that is needed follows from the optimisation. To be ready for action in either direction, the storage assets revert to a rest state of 50% state of charge. That gives the most available energy in either direction. The sizes of the storage assets are chosen on the larger size within the archetype, so that even though the rest state is at 50% SoC, there is a sensible amount of energy in either direction available.

This report gives a first high level analysis of the feasibility of storage for congestion management, with a focus on the effects on all high voltage lines crossing boundaries for the storage-technology a generic archetype is chosen. When physically implementing a storage more detailed analysis of that specific technology, sizing in power and energy rating, proposed location, day-ahead and ancillary services market, SoC-management, amongst others, need to be done. This requires detailed modelling that goes beyond the scope of this study.

In the detailed analysis for a specific storage implementation on a specific site, one could decide to have a rest state different than 50%. That means that that storage is more often available for congestion management in one direction then in the other. For some locations this can be feasible but requires a specific forecast and SoC management. At best, the double energy content could be available, or the installed base can be halved.

4.2.4 Selection of storage locations

The 24 storage locations assumed in the study were selected based on well-connected and evenly spread-out electrical network substations in the PowerFactory model. An even number of storage locations were selected on each side of every boundary included in the study for balancing of the power flow.

A sensitivity analysis was conducted early on in the study to find storage locations that have greater impact on the boundary flows and minor updates of the locations were done throughout the study, but no optimisation of the storage locations was done. The total number of 24 locations and storage units remained constant throughout the study. The final selection of storage assets and the boundaries are shown in Figure 4-2.

The 24 substations where storage units were deployed in the PowerFactory model are:

- Stella West, Kemsley, Bolney, Bramley, Connahs Quay, Harker, Inverarnan, Inveraray, Killin, Tealing, Lovedean, Norwich Main, Penwortham, Strathaven, Eccles, Melksham, East Claydon, Pelham, Thornton, Sellindge, Taunton, Tilbury, Walpole, Padiham.

Most of the storage connections were made to substations at 400 kV level and a few, especially in northern parts in Scotland, are at 132 kV level.

Note that these storage locations were chosen to be indicative of the benefits of storage in different locations; in real world installations other factors would need to be considered, such as physical location suitability and availability of connections, that are beyond the scope of this project.

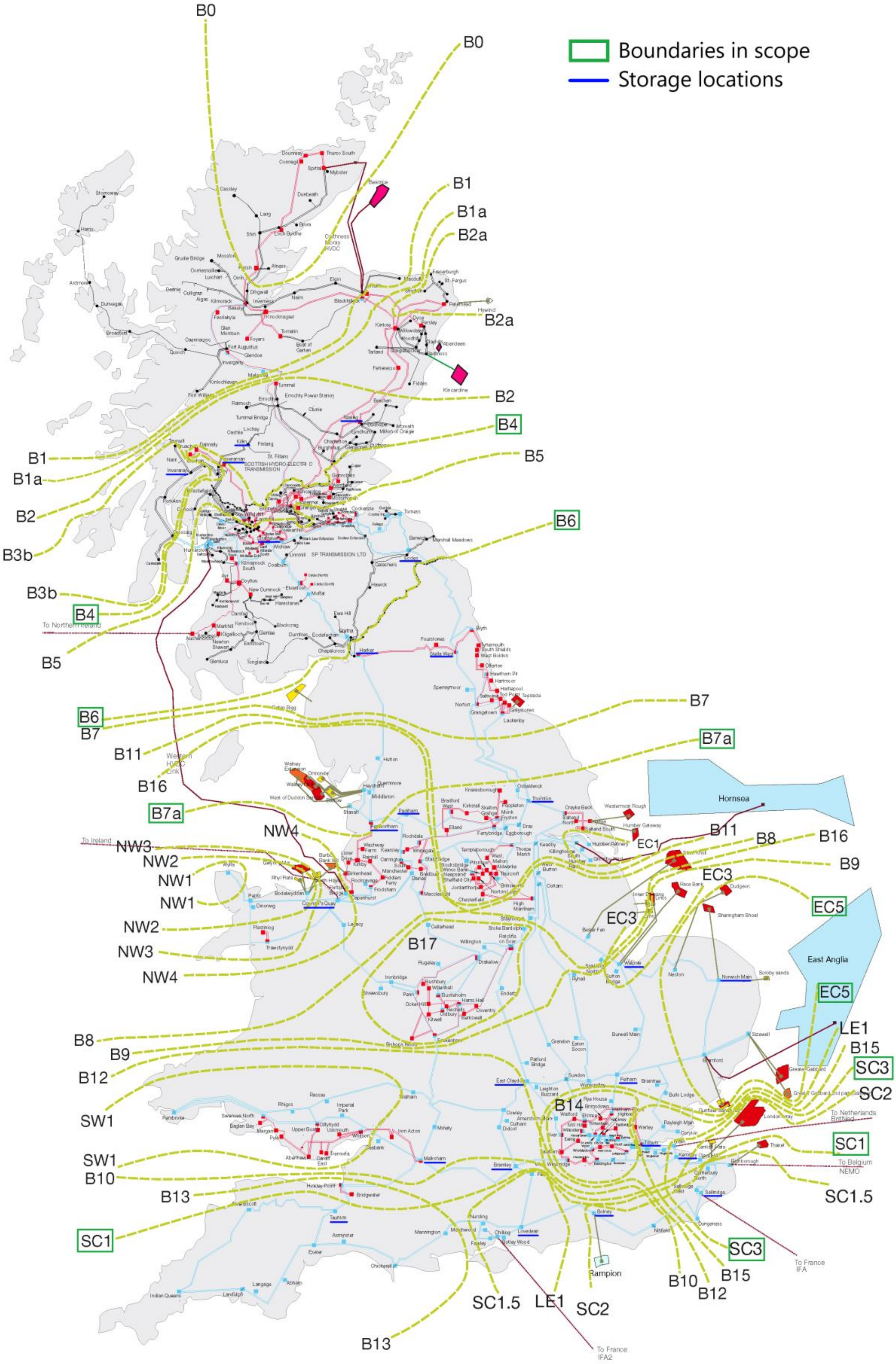


Figure 4-2: Boundaries included in scope and the 24 storage locations.

4.2.5 Determining the flow and constraint over the boundaries

In order to determine the flow over the boundaries for each hour of the year, the winter peak operating scenarios for the years 2021[12], 2025, & 2030 in the ETYS PowerFactory models were used as the base case, and new sets of each boundary with all line elements were created in PowerFactory. By solving the load flow simulation[13], this produced a snapshot of the total boundary flow and the distribution of flow over the lines crossing the boundaries for the base case peak hour. The peak hour was used to consider a realistic high constrained operating scenario.

For the AC lines dispatch the line flow distribution from the base case and the hourly total boundary flow data was used to determine the flow over each AC line crossing each boundary for all hours of the year. For the HVDC dispatch it was assumed that the HVDC flow is fully controlled and can be set to a fixed value. Based on the total boundary flow, the HVDC links were dispatched at full capacity but varying direction, done in a way to reduce the overall loading of the AC lines, or dispatched to zero when the total boundary flow is small.

The modelling and simulations in this project considers only the thermal capacity of the lines and boundaries as the modelling is based on static load flow calculation. Stability criteria such as voltage control, frequency and inertia are not considered to be limiting factors for the line and boundary limits. The starting point of the optimisation is a load flow of the full grid at the winter peak moment. From that the other hours of the year are derived by scaling and the effect of storage on the lines crossing boundaries calculated with the PTDF factors.

In this way circuits' flow changes based on the boundary flow not based on the actual detailed generation background. This is different to a full circuit-based methodology using full load flow, where circuits' flow depends on the generation background and the PTDF coefficient for each generator. In a full circuit-based approach, for the same boundary flow with different generation background, different circuit flows are generated.

As an example, to illustrate the distribution of the total flow, boundary B6 between Scotland and England shown in Figure 4-3 and the flow of year 2025 hour 01 is used. The resulting flow distribution is shown in Table 4-2.

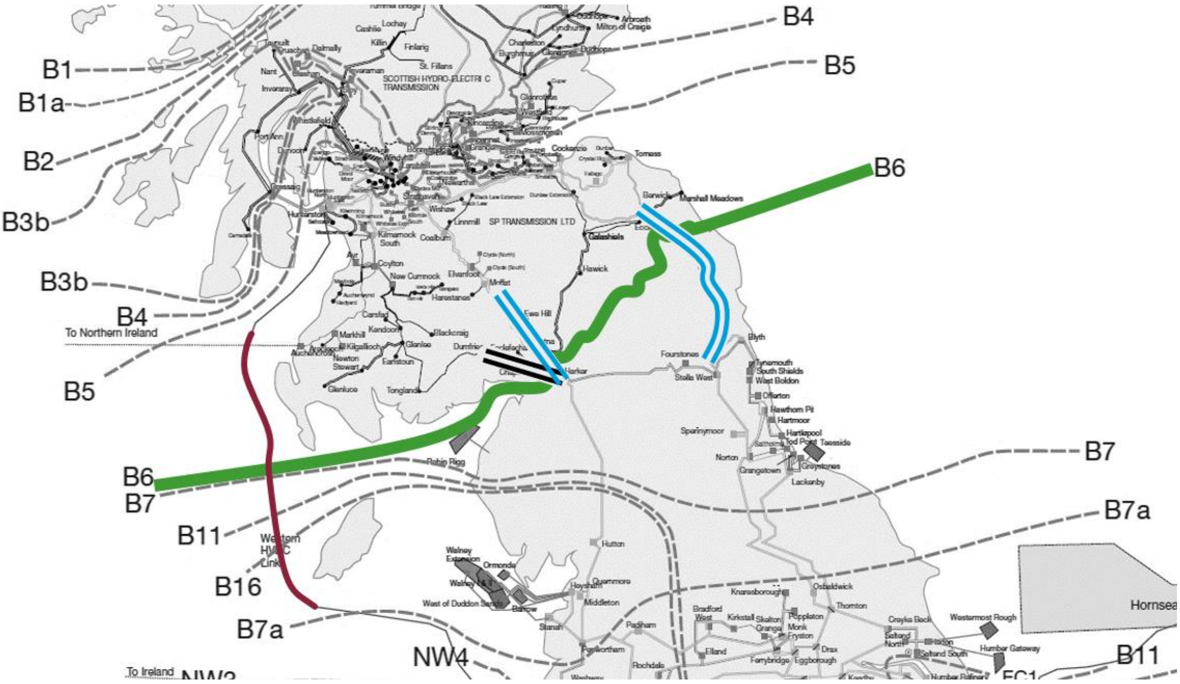


Figure 4-3: Boundary B6 in 2025 with 4x400 kV lines shown in blue, 2x132 kV lines shown in black and 1x HVDC link shown in red.

[12] Due to the limited modelling details north of boundary B4 in the PowerFactory model for year 2021, model information from year 2023 was used instead to determine the distribution of flow over the boundaries.

[13] In all ETYS models, except 2021, the load flow simulation did not converge without changing the balancing procedure to "Distributed slack by synchronous generators".

Table 4-2: Boundary B6 flow distribution example, hour 01 of year 2025

Element	Distribution	Flow	Loading
2× 400 kV lines West	2× 24 %	2× 2.5 GW	126 – 129%
2× 400 kV lines East	2× 25 %	2× 2.6 GW	88 – 88%
2× 132 kV lines	2× 1 %	2× 0.1 GW	65 – 92%
1× Western HVDC link	*HVDC dispatch*	2.2 GW	100% North→South
Total flow:		**12.6 GW**	**North→South**

In the above example the 2x400 kV lines West carry 24 % of the total AC flow each, which results in an 26% and 29% overload. The thermal limits of the AC lines were determined based on the PowerFactory model information of nominal voltage, current and assumed power factor 0.9 for all lines.

4.2.6 Power transfer distribution function and storage dispatch model

The impact of dispatch of the storage assets in the 24 locations on the flow over each line was calculated using the sensitivity / distribution tool in PowerFactory. Using the sets containing all 24 storage locations and all the 74-79 line elements crossing a boundary (depending on the year being studied) the sensitivity of the dispatch of each storage unit on all the lines crossing the boundaries was determined by the power transfer distribution function (PTDF).

The PTDF shows the individual incremental change in real power that occurs on each boundary line due to the active power increase from each storage unit. That is, when a storage unit draws power from the system to charge itself it changes the flow of power on the circuits it is connected to. Because these circuits are part of a national network, the changing flows on the circuits closest to the storage unit will in turn change the flows on more distant circuits. How the circuits are connected to each other changes how flows on one circuit affect flows on the next, so the storage unit charging will have a larger effect on some circuits than others. The different effectiveness of storage at different locations to all different high voltage lines crossing boundaries is reflected in the model with the PTDF.

As congestion management should not cause imbalance in the power system, often there will be multiple storage assets dispatched spread across the whole power system. In some areas the storage assets are taking power from the system at the same time on different locations the storage assets are injecting power to the system. The effect on all these lines by all these storage assets is calculated in one step. That also assures that the storage assets needed to create power balance are not causing additional constraints elsewhere.

An exception on the power balance is made when the storage assets need to replenish the energy lost by not being 100% efficient. That energy is provided in the model by all other power plants in a proportional way. In reality the storage operator will have a bespoke and commercial process to replenish the lost energy but will also apply this only at moments not causing extra congestion.

In order to determine the optimal dispatch of storage assets to alleviate the boundary constraints, an optimisation model was created in Python. The optimisation model determines the optimal hourly dispatch of the storage units based on the following criteria, in order of priority:

1. Reduction of Overload – reducing constraints (Highest priority)
2. State of Charge (SoC) – keeping the storage ready for the next constraints by reducing the SoC to the rest state
3. Imbalance – to avoid introducing power imbalance in the power system
4. Dispatch –attain the results with the least total amount of power dispatched

Different weights for criteria 1-4 were evaluated in order to achieve realistic dispatching, whilst still maintaining the top priority to reduce overloaded lines at the boundaries.

4.2.7 Example of the PTDF, storage dispatch and reduction of constraints

The general method of optimising storage dispatch and line flow reduction in the model is shown in the example below, in which *Line 1* and *Line 2* are initially overloaded.

$$PTDF * Optimal\ storage\ dispatch\ (MW) = Change\ in\ line\ flow\ (MW)$$

	Boundary 1			Boundary X...		
	Line 1	Line 2	Line 1X	Line X1	Line X2	Line XX...
Storage1	0.112	0.110	0.462	0.161	0.000	-0.001
Storage2	0.112	0.110	0.161	0.462	0.000	-0.001
Storage3	0.696	-0.011	0.082	0.082	0.005	0.011
Storage4	-0.142	-0.133	0.069	0.069	0.001	0.004
Storage5	0.058	0.615	0.085	0.085	0.002	0.005
StorageX...	0.051	0.048	-0.116	-0.116	-0.002	-0.003

X

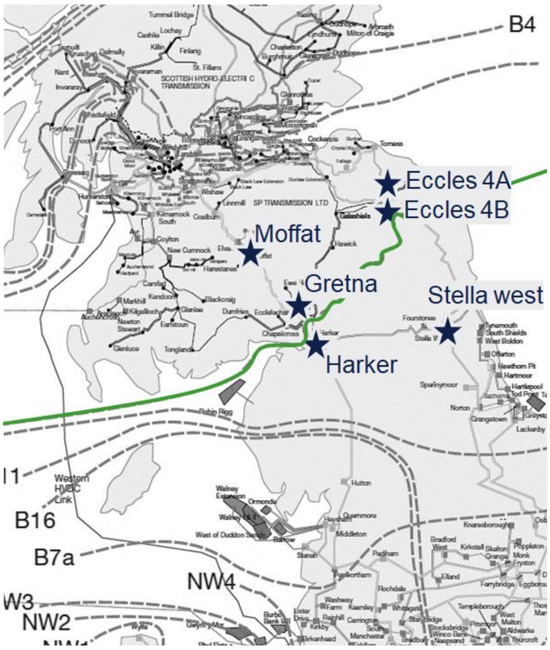
Storage1	12.5
Storage2	-12.5
Storage3	-45
Storage4	50
Storage5	-50
StorageX...	45

=

Line 1	Line 2	Line 1X	Line X1	Line X2	Line XX...
-39.0	-34.7	-5.9	-13.5	-0.4	-0.7

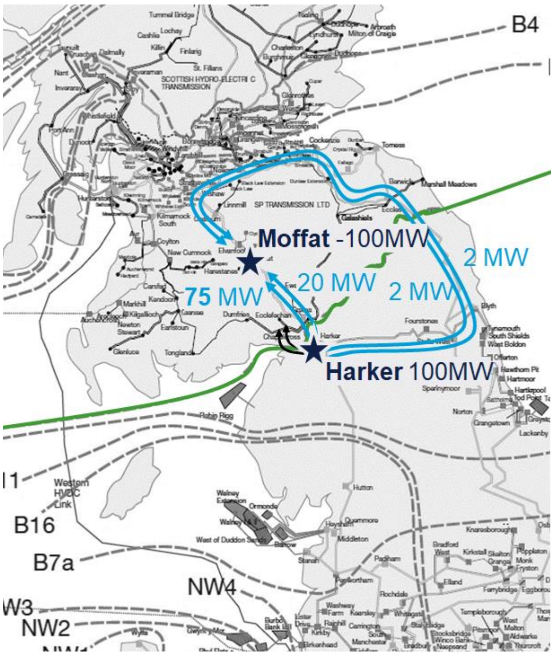
By dispatching the storage assets and multiplying this with the PTDF matrix, the change in line flow is obtained. For line 1 and 2 this results in an active power flow reduction over the lines of 39 MW and 34.7 MW, respectively. The flow over other lines is also affected, and the optimisation algorithm considers their limits.

The optimisation model considers all 24 storage locations and all 74-79 line elements to determine the optimal dispatch of the storage assets to find the maximum reduction in overload for all 8760 hours for the years 2021, 2025, and 2030.



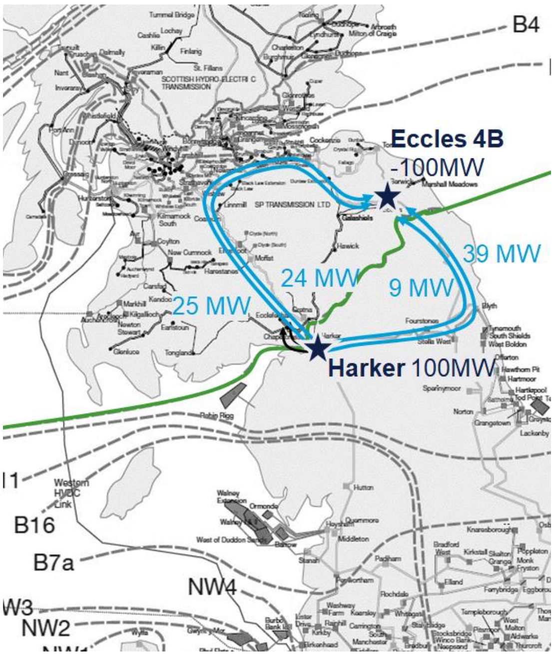
This example boundary is at the border between England and Scotland, B6, highlighted by the green line. Storage assets are located on both sides of the border and marked with a star on the diagram. Please note, that this is an example and not a recommendation on location, storage size or operations.

In this example, the lines in the west between Gretna and Harker are overloaded in the North to South direction. To alleviate this overload, storage assets are dispatched. The additional flow from the storage assets should flow in South to North direction to cancel out the North-South flow that is causing overloads. We provide two different examples to highlight the importance of location for effective storage dispatch. In each example, power is injected at Harker, but taken out at either Moffat or Eccles.



In this first case, 100 MW of power injected at Harker is taken out at Moffat. The overload of the lines in the west is reduced by 75 MW and 20 MW, respectively. Note, the overload is in North-South direction, and the flow between storage assets is in South-North direction, meaning they cancel each other out. The effect of the storage assets at Harker and Moffat can also be seen on the east coast, although with a limited load reduction of 2 MW per line.

The fact that two parallel lines get a different amount of flow is the result of either the detailed switching action at the specific substation or because only one of the parallel lines is connected to a substation.



In the second case, we change the location to take power out at Eccles. 100 MW is still injected at Harker, resulting in the load at the lines in the west being reduced by 25 MW and 24 MW, respectively, while the lines in the east see their load reduced by 9 MW and 39 MW, respectively.

The dispatch optimisation considers all available amounts of power (in the example fixed at 100 MW) of 24 storage locations (in the example only 3: Harker, Moffat, Eccles) and the effect on all 74-79 lines (in the example 6: 2 in the west, 2 in the east and 2 on 132 kV). This shows that the number of options to consider and effects to monitor and optimise can grow quickly, and therefore finding the most optimal solution is time consuming.

It also shows that a 100 MW of storage doesn't reduce the flow over a high voltage line by exactly 100 MW. The effect is calculated with a grid model in PowerFactory and captured in the PTDF matrix. This PTDF sensitivity is fixed and determined by the topology of the grid and type of lines used.

To further elaborate on this example:

We assume a maximum flow over the lines crossing B6, the base flow and the percentage of the maximum capacity this represents. A value above 100% signals an overloaded line. This distribution of the congested flow is a function of the specific location where electricity is produced and consumed and the topology of the grid. The maximum allowed value is determined by the materials and design of the lines (amongst other considerations).

	West-1	West-2	East-1	East-2	132kV-1	132kV-2
max MW	1953	1952	2983	2986	120	111
congested flow North-South MW	2516	2463	2625	2628	78	102
%	129%	126%	88%	88%	65%	92%
Overload (MW)	563	511	0	0	0	0

By injecting 1126 MW at Harker and taking out 530 MW at Gretna and 596 MW at Moffat, the flow over the lines will change by the amounts in the following table. With this approach, power balance is assured and from the optimisation it follows that this specific dispatch on these specific locations used the least amount of power.

	West-1	West-2	East-1	East-2	132kV-1	132kV-2
Storage flow South-North MW	563	511	17	17	2	4

Subtracting the storage flow from the congested flow gives the resulting flow, where the maximum loading of a line is now 100% and the congestion is remediated.

	West-1	West-2	East-1	East-2	132kV-1	132kV-2
resulting flow North-South MW	1953	1952	2608	2611	76	98
%	100%	100%	87%	87%	63%	88%

An important observation is that for 2252 MW of total storage dispatch across three substations only 1114 MW of flow reduction and only 1074 MW of constraint reduction is achieved. To illustrate this point, Figure 4-4 shows the total storage dispatch across 24 location for each hour and resulting reduction in constraints over the whole network as a sum for all circuits crossing the selected six boundaries. The data is presented for 2030 for Archetype 1. This can be used as an example to illustrate how the nature of constraints and power flow, and storage characteristics impact the effectiveness of the storage units for constraint management.

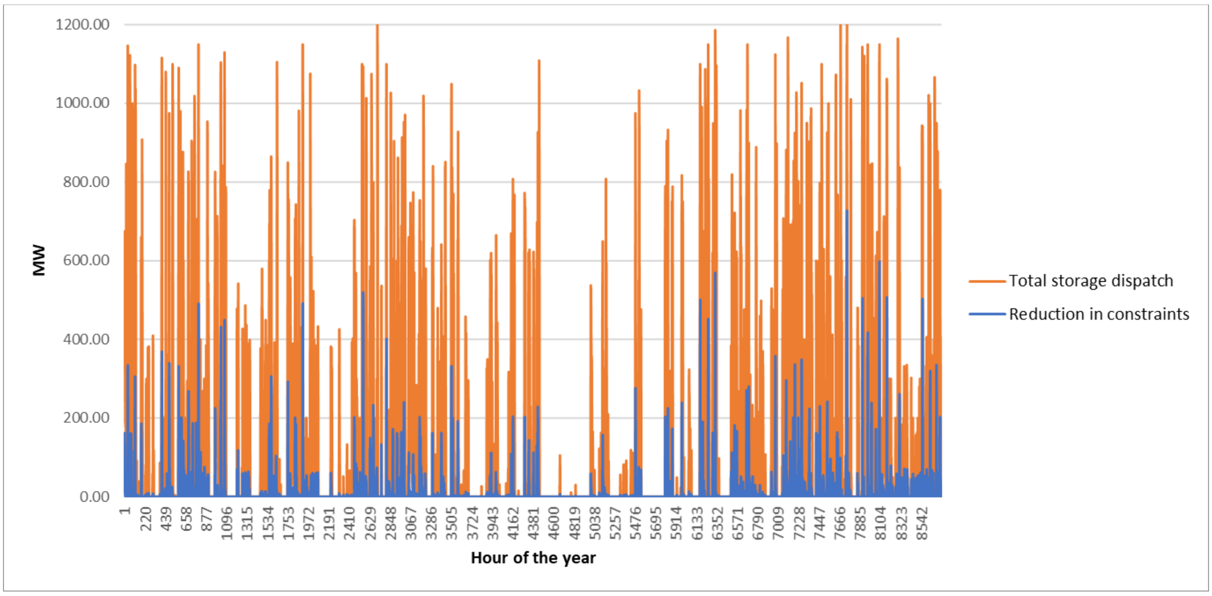


Figure 4-4: Example of total storage dispatch and reduction in constraints

Figure 4-4 shows that the ratio between the total storage dispatch and the reduction of constraints seen in the system is often below 0.5, despite this being the most optimal solution for the whole grid. This is caused by a combination of several factors:

1. less than 100% round trip efficiency in the storage units, as explained in chapter 3 and section 4.2.3;
2. the nature of the PTDF matrix and the power flow, resulting in the distribution of reduced power across all lines and not only those that are constrained, as explained in section 4.2.6;
3. the location of the storage units in relation to the constrained lines – this is in its nature similar to point 2, whereby due to the effect of PTDF matrix, explained in section 4.2.6, storage assets are less efficient in managing overloads on distant lines.

Figure 4-4 also shows that the effectiveness of storage assets in reducing network constraints, expressed as the ratio between total storage dispatch and reduction of constraints, varies on an hourly basis. This is caused by the fact that the modelling was performed for the whole network at once, i.e. all power flows affect each other. Because hourly injections and offtakes in each substation change from hour to hour, as generation and demand change, the value of the same MW of dispatch of the same storage unit varies between day and night, as well as between summer and winter.

5 Economic Analysis

5.1 Key findings

- Based on the deployment of storage archetypes as modelled in PowerFactory, the annual utilisation of storage for constraint management is low throughout the year, reflecting the physical nature of the constraint, the interplay with local generation and demand resources, and the technical characteristics of storage technology. This means the storage archetypes, as modelled, have access to relatively few remunerable hours.
- As a result, the levelized cost of storage, reflecting the cost storage operators would seek to recover from the provision of constraint management services, on most occasions exceeds the price paid to other constraint management service providers. This means that, when contracted exclusively to provide constraint management services, storage is mostly not competitive.
- A high-level calculation assuming storage archetypes could provide remunerable services at all technically available time shows that storage technologies in theory could realise a much lower price point to provide constraint management alongside other services. This would also make it more competitive with other providers of the constraint management service.

5.2 Approach and Input data

In order to gain insight into economic feasibility of storage for constraint management we build upon the insights obtained via power system modelling, combined with the costs of storage technologies obtained in the analysis of storage archetypes. We interpret the results through the prism of historic data describing the volumes and prices of constraint management services that NGESO procured in the last 2.5 years. Our approach can be summarised as follows:

Levelised Cost of Storage (LCoS) estimate

1. Based on the results from power system modelling, retrieve the annual volume throughput for each of the storage assets and transmission boundaries, respectively.
2. Based on the cost data of different archetypes, estimate the CAPEX of storage assets and annual OPEX. Estimate the net present value (NPV) of each asset's costs (apply discounting rate of 3.5% in line with Spackman approach, and assume 20 year lifetime).
3. Calculate NPV of annual volume throughput for 20 year lifetime based on the simulation results.
4. Calculate LCoS by dividing the NPV of storage costs by the NPV of useful volume throughput (useful throughput is explained in section 5.3.1) instigated by congestion management service provision.

Competitiveness analysis

1. Analyse the historic data about accepted constraint management bids and offers in the balancing mechanism (BM). The data was provided to DNV by NGESO.
2. Explore which balancing mechanism units (BMUs) are the most common providers of constraint management service surrounding a certain constraint group (boundary). Consider whether the merit order curve could change in the future due to the change of generation mix.
3. Construct a merit order curve of BMUs for each of the six studied boundaries. This merit order curve should reflect theoretical volumes that each BMU is ready to provide on average throughout a year and prices which NGESO would have to pay for these volumes to manage constraints of a given magnitude around a given constraint group.
4. Compare the LCoS of storage obtained in the previous phase with the typical prices in the merit order of BMUs and conclude on the competitiveness of storage in providing constraint management services under the assumption that constraint management is the only service that they can provide.

Assessment of storage utilisation by constraint management

1. Based on the results from power system modelling, retrieve storage asset utilisation.

2. Based on the storage archetype specification, estimate the maximum potential volume of energy that a storage asset could dispatch (charge or discharge) in a year providing some useful ancillary service. Compare this volume with the modelled storage dispatch (up and down) volumes from providing constraint management service.
3. Calculate theoretical minimum LCoS in £/ MWh based on theoretically maximised storage utilisation. Compare this LCoS with the LCoS estimated based on the modelled annual throughput from constraint management provision.
4. Conclude on the number of hours in a year / volume of energy for which the storage asset could be operating and providing other services, on top of providing constraint management as per the model outcomes.

In the following section we detail these steps and present the relevant metrics we have assessed.

5.3 Analysis

5.3.1 LCoS and utilisation

Within this project we work with the levelised cost of storage (LCoS) providing exclusively constraint management as the primary metric to assess its competitiveness against other BMUs active in this market. In order to calculate the LCoS we estimate the NPV of its costs and utilisation. LCoS is defined as a ratio between lifetime asset costs and lifetime constraint management energy throughput.

Costs

For the CAPEX of storage archetypes we used the values in £/MW or £/MWh for the three archetypes as presented in section 3.2. As noted in section 3, there is significant uncertainty in cost estimates for some of the storage technologies. Whilst for some archetypes low and high costs estimates are available, for others we have to operate with one value only. The table below reflects availability of the information for the consolidated archetypes. In what follows we use the lowest value in the range, which represents our expectation on how storage market will develop over the analysed period.

Table 5-1 Storage archetypes costs

	Archetype 1	Archetype 2	Archetype 3
CAPEX low /kWh	£200	£3	£130
CAPEX high /kWh	£250	£3	£190
CAPEX / kW	£-	£2,500	£-
OPEX /kW (annual)	£46	£-	£-
OPEX % of CAPEX (annual)	0%	2.5%	1%

In order to determine the lowest LCoS that can be achieved by each of the technologies, we have selected their size such that it reflects the optimal configuration in terms of power to energy ratio that we observe in the market. Consequently, the size of a given storage asset varies across archetypes. This led to the following combination of power and energy for the three archetypes as shown in *Table 5-2*. Note that the underlying rationale is to maximise the size of the storage assets as much as possible to achieve economies of scale and provide higher societal benefit in terms of constraint management cost reduction. We recognise that there is a risk to over-size the storage assets resulting in poor utilisation. Nevertheless, from our simulations it seemed that, if feasible, somewhat larger storage sizes would still have utilisation rates comparable to the ones achieved in this study. A combination of technical, market and space constraints for larger (or more) assets resulted in the sizes that we selected.

Table 5-2 Storage archetypes ratings

Storage	*Unit*	**Archetype 1**	**Archetype 2**	**Archetype 3**
Power	MW	50	50	50

Charging duration	h	24	24	8
Max Energy	MWh	1,200	1,200	400

The combination of costs and sizes discounted at 3.5% over 20 years of lifetime resulted in the NPV of storage assets cost as given in Table 5-3.

Table 5-3 NPV of storage archetypes costs

Archetype 1	£263,467,176
Archetype 2	£168,398,915
Archetype 3	£57,382,077

Energy throughput volumes

The other component of LCoS analysis, beyond storage costs, is the annual energy throughput. We note that in the model we use, in order to operate all the storage assets spread across GB, it is necessary to replenish their energy from time to time to keep them ready for the upcoming constraints. This is the outcome of the fact that storage has round-trip efficiency below 100%, and part of the energy is lost during charge and discharge. This replenishment of energy will inevitably cause imbalances in the system, despite the fact that the model is set up to minimise such imbalance. Because in the real world these imbalances would not be remunerated as a service under BM and would have to be covered financially by the storage asset owners, we do not take their volume into account when calculating the annual energy throughput.

Table 5-4 below contains the information about annual volume throughput for the three archetypes for three simulated years – 2021, 2025, 2030. The information presented is given as an average across 24 locations. We use the simulation results directly for the simulated years (2021, 2025, 2030), interpolate for the years in-between (2022-2024, 2026-2029) and extrapolate beyond 2030 up to 2040 (storage lifetime).

Table 5-4 Average annual useful energy throughput [MWh] per storage location from the simulations

	Archetype 1	**Archetype 2**	**Archetype 3**
2021	23727	9672	13732
2025	57742	31872	30074
2030	68150	34874	41090

Because the selected archetypes had different ratings, we also show the throughput per MWh of installed capacity averaged across 24 locations in Table 5-5. This reflects how many times in a year, each MWh of energy capacity is "utilised". It can be seen that the resulting values are negligible, compared to a number of hours in a year, indicating marginal utilisation of storage by constraint management.

Table 5-5 Average annual useful energy throughput [MWh] per MWh of installed capacity

Throughput [MWh] per MWh of installed capacity	**Archetype 1**	**Archetype 2**	**Archetype 3**
2021	20	8	34
2025	48	27	75
2030	57	29	103

Table 5-6 shows the reduction in overload volume in a year for the different archetypes as an outcome of the simulation.

Table 5-6 Overload reduction [MWh] per year from the simulations

		Archetype 1	**Archetype 2**	**Archetype 3**
Absolute [MWh]	**2021**	53,504	32,763	24,529
	2025	447,687	347,298	151,097
	2030	373,483	285,066	131,368

As % of total overload	**2021**	15.7%	9.6%	7.2%
	2025	5.1%	4.0%	1.7%
	2030	3.5%	2.7%	1.2%

Figure 5-1 presents this overload reduction in the context of total overload volume on each of the boundaries throughout a year.

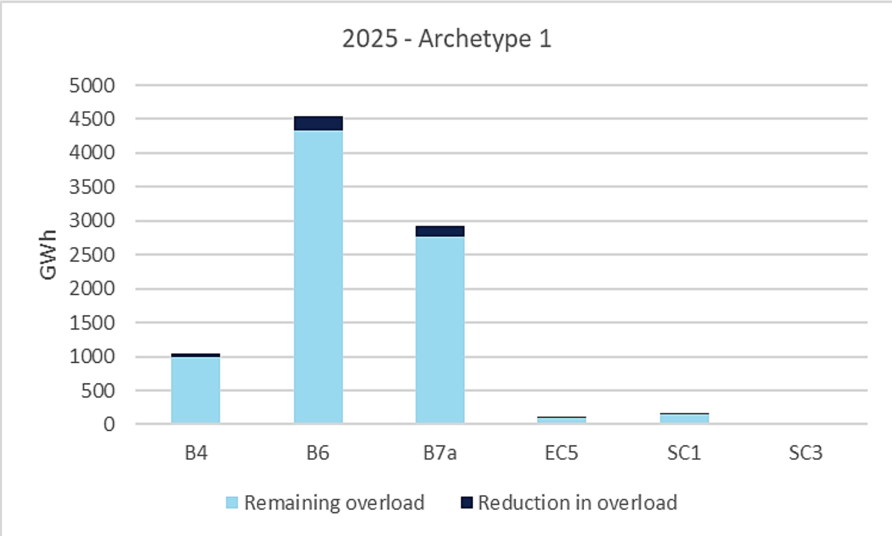


Figure 5-1 Annual overload reduction per boundary. Archetype 1, 2025.

At each given moment, the reduction in overload across several boundaries may be an outcome of a dispatch of the same storage asset. Owing to how the power flows are distributed across the network, it is often the case that taking an action on, for instance, B4, will also affect (over)load on B6 or even further south. In this figure we show individual overload reduction as the difference between the flow without any storage being dispatched in the system and the flows after all 24 storage assets have been dispatched in an optimal way from the entire system point of view. All boundaries and storage actions have been modelled simultaneously. That means that "nested benefits" are captured, and the benefits seen at each boundary can be added together to give the overall system benefit.

The data in Table 5-4 and Table 5-6 allows us to recognise that the reduction in constraint (overloads) is less that the total dispatch. The reason for this is that under the laws of physics, a megawatt of storage dispatch is spread across all lines which are connected to the busbar where this storage is placed. This means that not only the congested / overloaded line, but also some others will be affected. This reduces the efficiency of dispatched power in tackling the constraint, a concept that holds true for any BMU regardless of its type. This is a property of the power flow distribution in any electricity network as explained in section 4.2.6. As a service provider, the storage asset, however, will be remunerated for the service it delivers, i.e. number of MWh it dispatches on NGESO' command via BM, not the reduction in overload it achieves. Therefore, considering the annual energy throughput less the created imbalance is a fair metric to calculate the LCoS for constraint management.

To get a better understanding of how efficient the storage is in tackling constraints we present this information in a consolidated way in *Table 5-7*.

Table 5-7 Consolidated modelling outcomes per archetype per year for all 24 locations (MWh on yellow, % on red, MWh on blue background)

	Archetype 1			**Archetype 2**			**Archetype 3**		
	2021	**2025**	**2030**	**2021**	**2025**	**2030**	**2021**	**2025**	**2030**
Overloads	340,004	8,785,894	10,552,733	340,004	8,785,894	10,552,733	340,004	8,785,894	10,552,733
Total Dispatch	807,108	2,191,744	2,436,359	431,457	1,476,762	1,583,620	365,778	941,304	1,179,610
Useful Dispatch	569,447	1,385,812	1,635,594	232,131	764,931	836,984	329,561	721,776	986,161
Reduction in overloads	53,504	447,687	373,483	32,763	347,298	285,066	24,529	151,097	131,368

Useful/ Total Dispatch	71%	63%	67%	54%	52%	53%	90%	77%	84%
Reduction in overloads/ Useful Dispatch	9.4%	32.3%	22.8%	14.1%	45.4%	34.1%	7.4%	20.9%	13.3%
Total throughput per MWh installed	28	76	85	15	51	55	38	98	123
Useful throughput per MWh installed	20	48	57	8	27	29	34	75	103
Utilisation*	14%	38%	42%	10%	35%	38%	4%	11%	13%
Average utilisation*		31%			29%			9%	

*__Utilisation__ is calculated as *Total_dispatch / (8760*Efficiency*Rated_power)* representing a simple benchmark to compare archetypes. Note, the metric ignores differences in energy content between archetypes: Archetype 3 has a lower energy content (400 MWh) than Archetypes 1 and 2 (1200 MWh). Furthermore, this metric assumes that the maximum number of operational hours equals 8760. The table shows the utilisation of an archetype on aggregate across 24 locations for each of the years 2021, 2025, and 2030.
*__Average utilisation__ is calculated as the average annual **Utilisation** for a given archetype across 24 locations.

The NPV of the annual volume throughput is given in Table 5-8.

Table 5-8 NPV of storage archetypes energy throughput [MWh]

NPV Archetype 1	825,780
NPV Archetype 2	425,531
NPV Archetype 3	478,761

Locational difference in utilisation

The utilisation that was achieved across the tested archetypes within the modelled years is in a range from 9 to 31% as an average of simulated years for each archetype, according to Table 5-7. The average utilisation across all archetypes for all years is 23%.

Further variation in utilisation is caused by the network configuration and geographic location of generation and demand. This leads to the situation where even storage assets of the same archetype experience different levels of utilisation across the GB network. This is shown in Figure 5-2, where each dot represents one of the 24 locations implemented in the model. In this figure we have tried to attribute each location to one of the six boundaries based on the geographic proximity, although sometimes this can be ambiguous. Furthermore, we remind that the simulation that we have performed addresses all boundaries simultaneously, hence there are “nested effects” when a storage dispatch at one boundary may affect another.

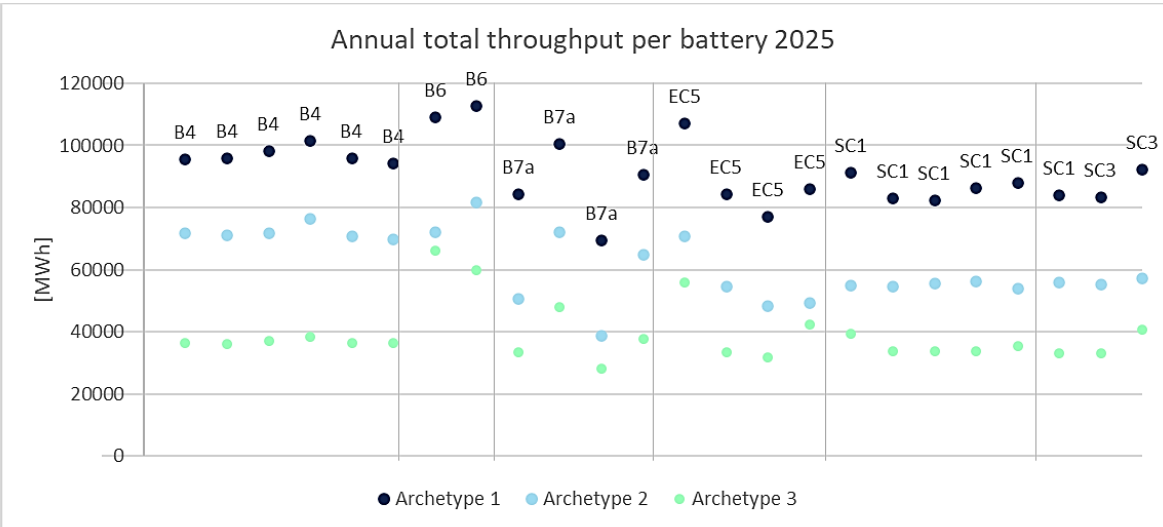


Figure 5-2 Annual utilisation variation across 24 locations

For completeness, we also indicate the five most utilised network locations in each year modelled in Figure 5-3 below.

Figure 5-2 shows there is a significant difference between the most- and the least utilised assets. For this reason, we have calculated LCoS for the highest-, lowest- and average utilisation across the 24 locations modelled for each of the archetypes, reflecting the impact of the geographic location of storage within the network. In general, we observe that the highly utilised locations get more concentrated around the South of Scotland moving towards 2030. This may be caused by reinforcements taking place in other parts of the network, which may reduce the overloads in England.

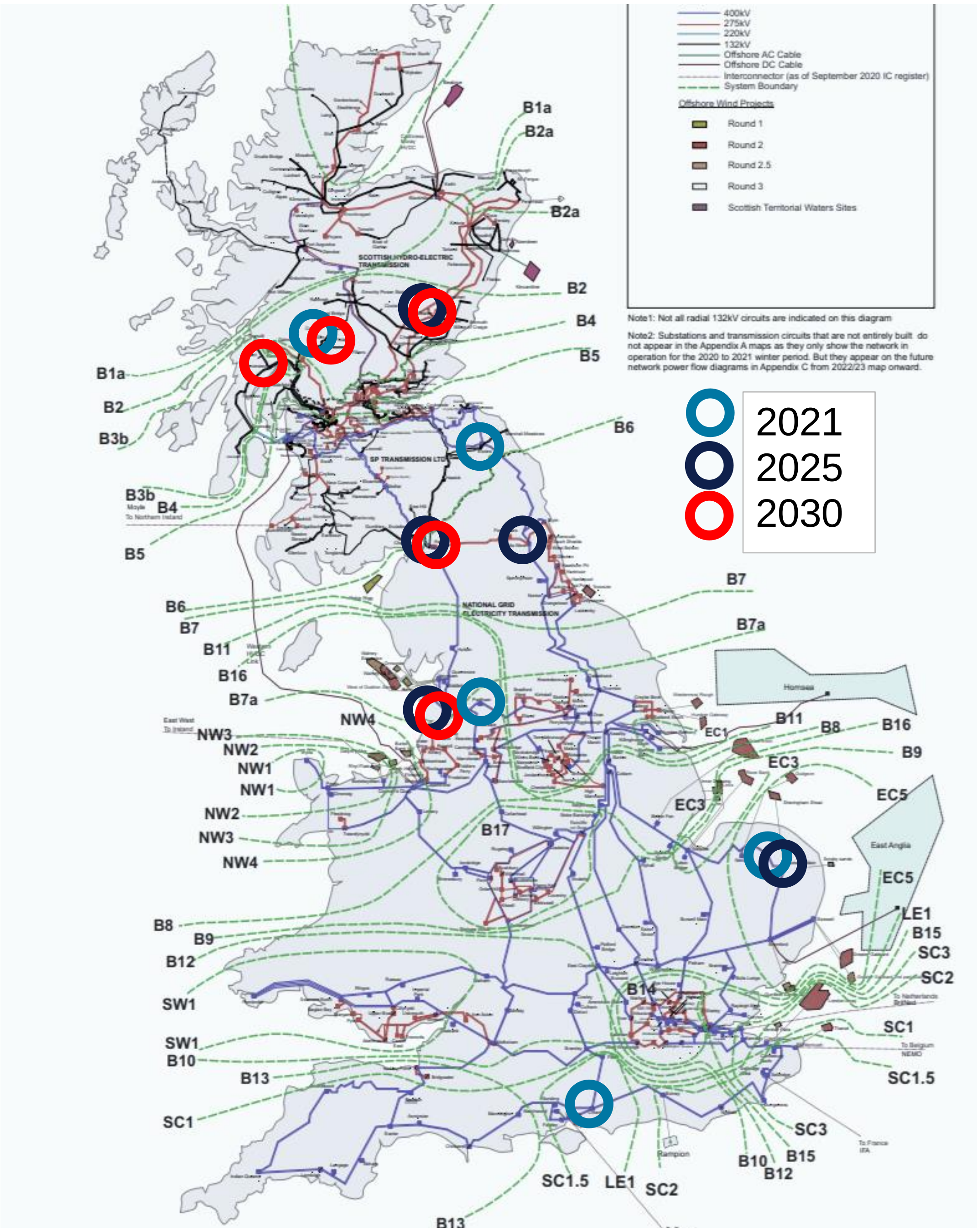


Figure 5-3 Most highly utilised storage locations

LCoS summary

Figure 5-4 summarises the LCoS analysis presenting the outcomes across the tested archetypes for three utilisation levels based on the geographic location of an asset.

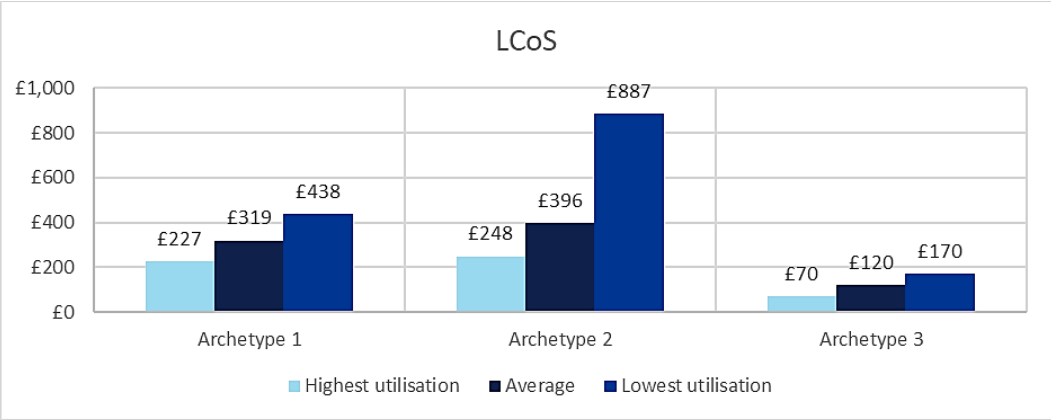


Figure 5-4 LCoS of storage archetypes based on the simulation results

Table 5-9 below provides the underlying data. In this table Highest and Lowest utilisation – refers to the maximum and minimum utilisation across the 24 locations for a given archetype. The average utilisation in *Table 5-9* corresponds to the utilisation numbers quoted in *Table 5-7*, where utilisation is calculated as an aggregate of the 24 locations for a give archetype.

Table 5-9 LCoS of storage archetypes based on the simulation results.

	Highest utilisation	Average	Lowest utilisation
Archetype 1	***£227***	***£319***	***£438***
Archetype 2	***£248***	***£396***	***£887***
Archetype 3	***£70***	***£120***	***£170***

5.3.2 Competitiveness against other BMUs

To analyse the economic competitiveness of the storage for constraint management we have considered historic dynamics in the BM. Namely, the type of providers, the average price per MWh of energy that they ask, and the average size of bid or offer that they have historically provided. Because of the fact that the generation mix, as well as network configuration and demand, vary across the GB network, we have performed separate analyses for the 6 boundaries selected in this study. NGESO have provided us with the detailed records of all actions taken in the BM during the past 2.5 years, which included information about the date, name of the BMU, constraint group where the action is taken, volume of service, price paid and type of constraint.

We created the “merit orders” of BMUs across each boundary to approximate the availability and willingness of constraint management service providers to deliver (or take from the market) a certain volume of energy for a given price. In order to construct such merit orders we have picked the BMUs responsible for 80% of the total number of accepted bids and offers for the selected period. From our analysis, this share adequately represents BMUs that are expected to be regularly available to provide the service throughout a year. For those BMUs, we calculated the average volume per bid or offer and the price per MWh of service provided across the last 2.5 years. *Figure 5-5* provides an example of such a merit order for B4, where we have also indicated the fuel type for the BMUs comprising its parts.

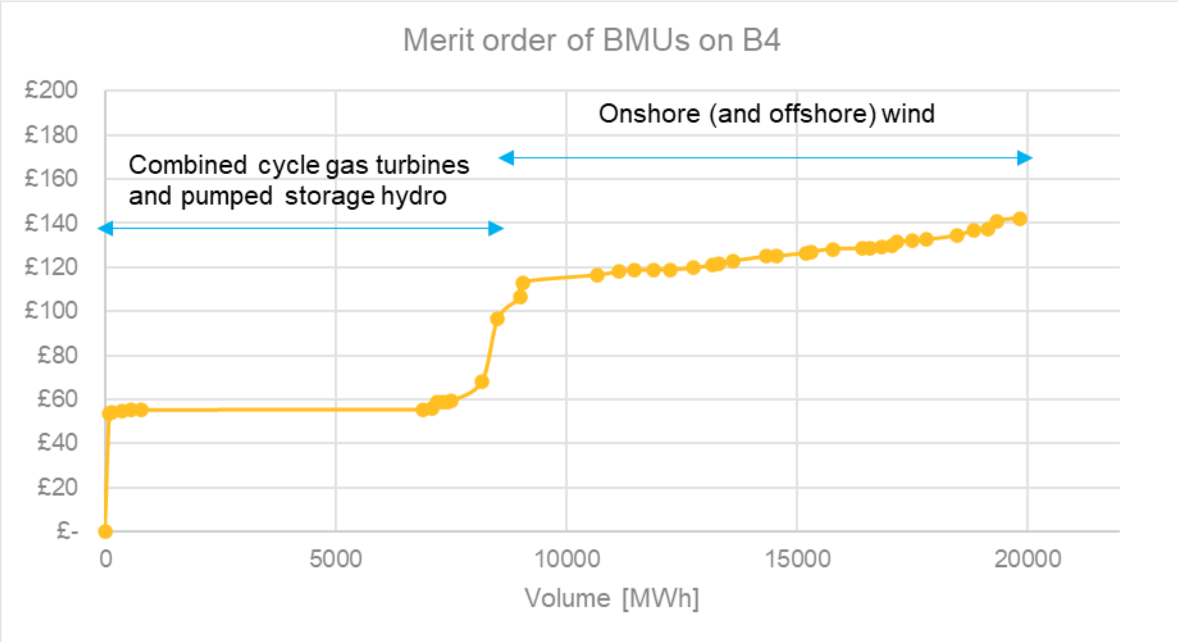


Figure 5-5 Representative merit order of BMUs on B4

Each dot on this graph represents a BMU that is <u>on average throughout a year</u> willing to provide a certain volume of service at a certain price. The way to read this merit order is as follows: for the first ~7000 MWh of constraint management service on B4, NGESO on average pays 59 £/MWh; for the following 2000 MWh, the price rises from 59 to ~110 £/MWh; then the price of service levels off and slowly increases for any volume beyond 10000 MWh going from 120 to 140 £/MWh. The change in price is mainly driven by change in the type of BMU. We observe that the first "step" (horizontal part of the curve) in this curve is comprised of gas and hydro generators, who are asking roughly 59 £ for each MWh of service that they provide. The second "step" of the curve is all onshore wind plants, asking ca. 120 £ for each MWh of service (usually reduction in output), which reflect the level of support that they would receive for their generated energy in the alternative "not providing the constraint management service" case.

The situation on another Scottish boundary, B6, is very similar to B4 due to the similarities in the local generation mix and network structure. This is also reflected in the merit order for B6, which has a similar shape, although a different scale on the X axis. However, here we observe a far higher proportion of wind to CCGT and pumped hydro.

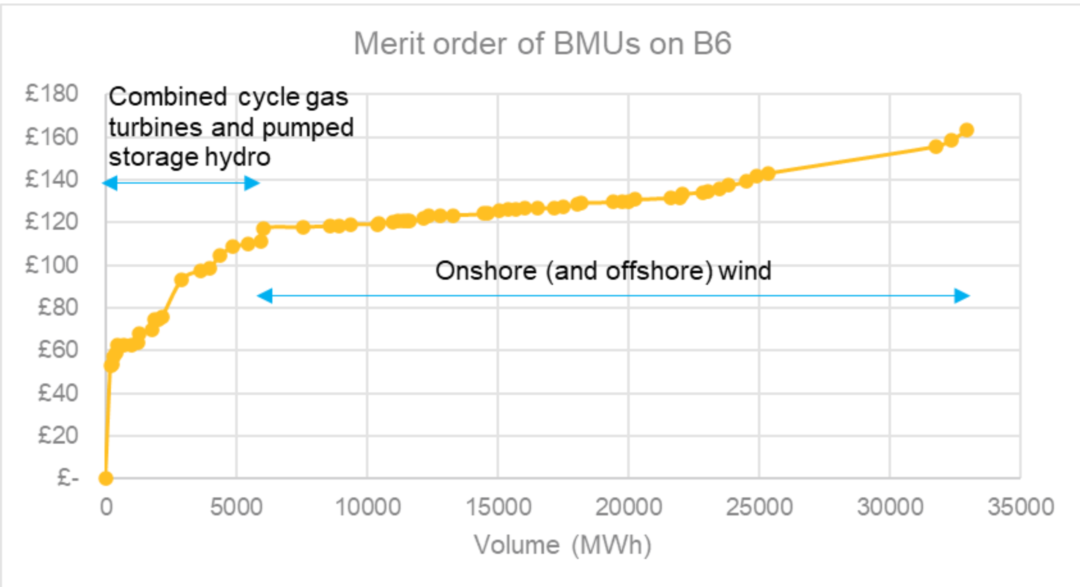


Figure 5-6 Representative merit order of BMUs on B6

In contrast, the merit order looks quite different for the Southern boundary SC3. The constraints are driven by interconnectors there, rather than by onshore wind. Hence the providers of constraint management service are normally traders, whose opportunity cost for providing constraint management service is dependent on the expected congestion rent and not on the particular fuel price or governmental support.

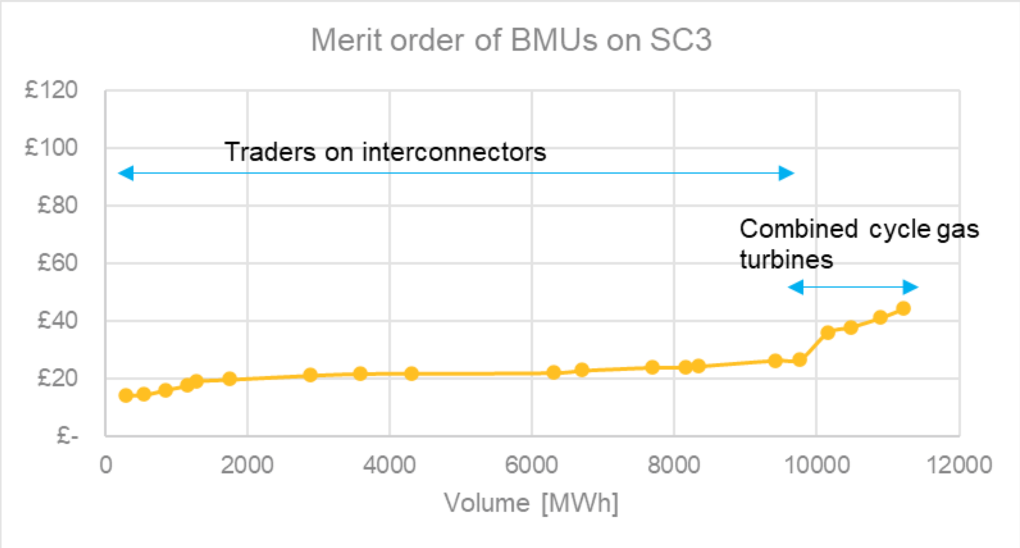


Figure 5-7 Representative merit order of BMUs on SC3

In Figure 5-8 we present the average prices achieved on each boundary's merit order in the context of obtained LCoS figures.

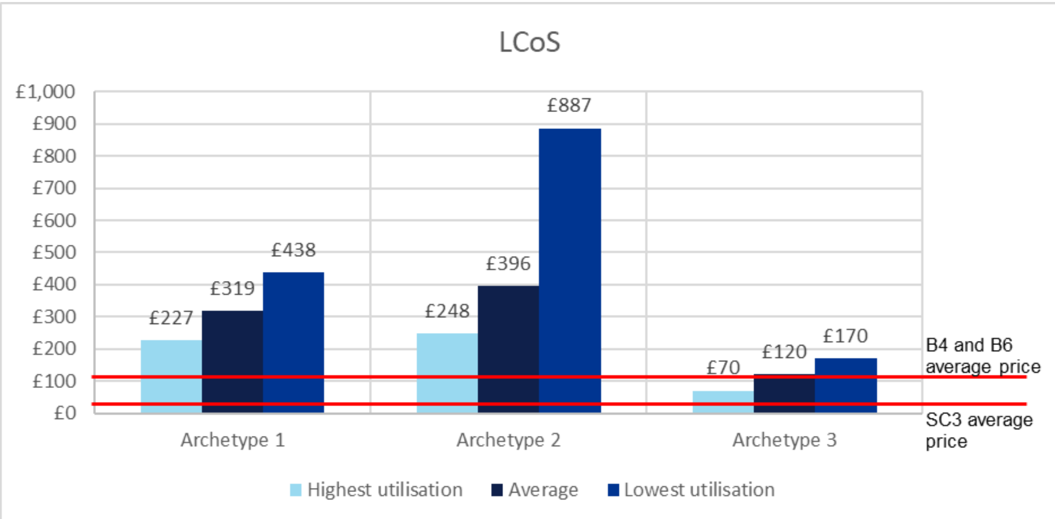


Figure 5-8 Comparison of LCoS and average merit order prices

Judging the relative position of storage in this merit order based on only historic data would not provide a complete picture. Whilst BM is a complex market, often difficult to forecast, it is possible to make general remarks on how the generation mix in GB will evolve. Therefore, we can speculate on what the direction of price change (if any) will be for the BM in the coming years, before 2030. *Figure 5-9* and *Figure 5-10* present the generation mix (installed capacities per fuel type) and production mix (energy generated per fuel type) in GB for the period from 2022 to 2030.

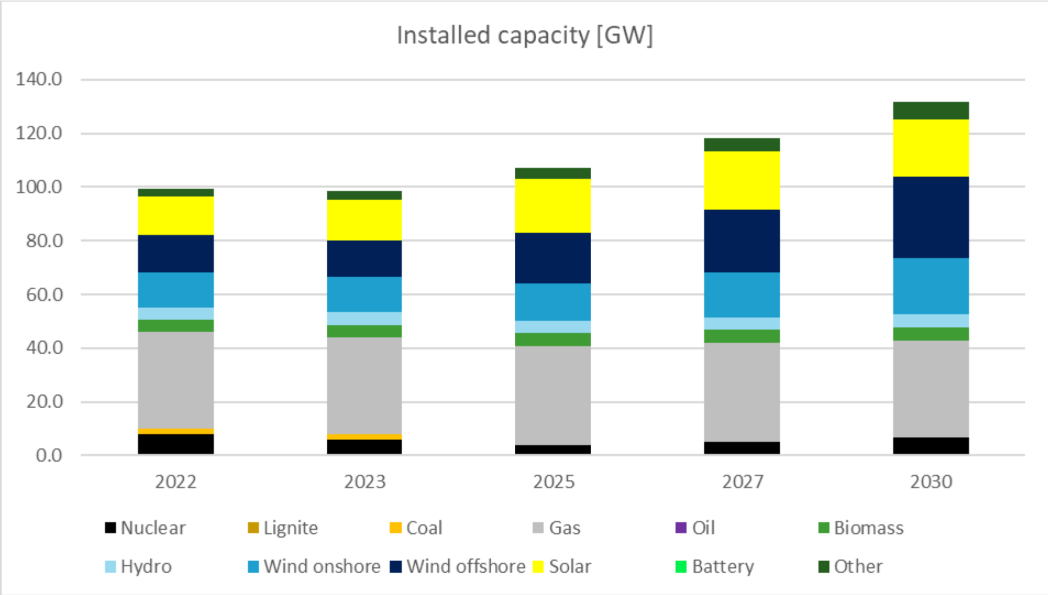


Figure 5-9 GB generation mix evolution[14]

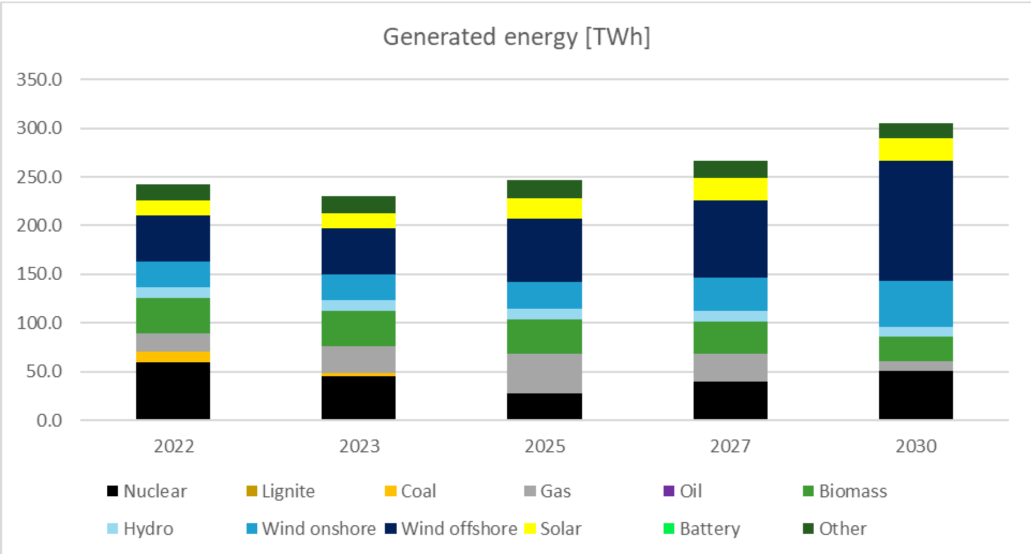


Figure 5-10 GB production mix evolution[15]

Our high-level observation is that the generation mix features even more renewables, more unpredictable power flows due to intermittency and higher interconnectivity, and less utilisation hours for conventional power plants. All these factors are likely to contribute to even higher prices per MWh of service in the BM. We therefore expect that the merit order curve will either remain similar or increase in £ per MWh. In other words, it may become easier for new entrants, including storage, to participate in the BM.

As it was shown in Figure 5-8, the storage LCoS estimated in our modelled environment is at the level of 120-400 £/MWh as an average for a given archetype. At present this may not be sufficient to be competitive against other BMUs, assuming that the constraint management service was the only service that storage was providing. Except for some of the heavily utilised locations in Scotland, storage would not have a business case, especially in the Southern regions, where most of the BMUs are traders/interconnectors.

We recognise that the assumption that constraint management is the only ancillary service that storage may provide, is not attractive for storage operators. Therefore, we have considered a theoretical extreme where storage assets are utilised at their technical maximum, evenly spreading their costs across all possible

[14] Source: DNV power price forecasting model for Europe https://www.dnv.com/power-renewables/services/advisory/ppf-updates.html
[15] Source: Idem

activities. This allows us to estimate what is the minimum LCoS that storage operators could achieve and would that make them more competitive with other constraint management providers.

5.3.3 Storage utilisation by constraint management

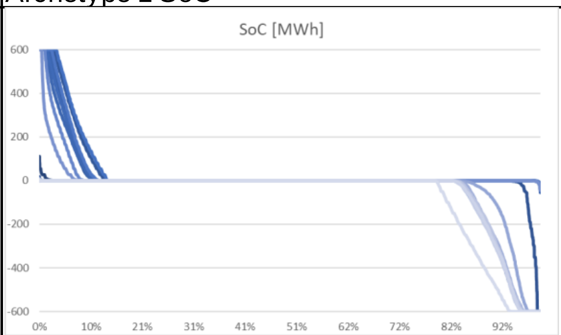
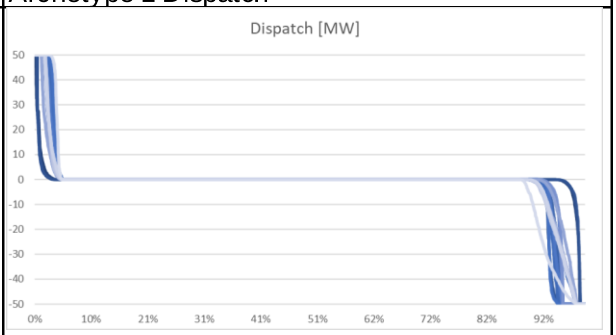
As explained in section 2.2, one of the important assumptions that we made in the model is that constraint management is the only service which storage assets are providing. In the real life, a storage operator would seek to stack services in order to increase the utilisation of its assets, thereby achieving a better business case. When constraint management is the only service which effectively employs storage, it will also be the main driving force behind how storage assets are utilised, i.e. will define the time and volume when energy needs to be absorbed from- or injected into the grid, how much energy needs to be dispatched in one or another direction, and how much opportunity there is for storage to replenish and return to its neutral state of charge. The latter one, as we will show, is especially important as there may be situations when there are constraints to be managed but none of the suitably located storage assets is in a right state of charge to provide the service. The combination of constraint volumes and patterns, together with technical storage characteristics are the main two factors determining how storage assets are utilised.

In order to get more insight in how much of the time in a year the storage units are actually providing the constraint management service, we have plotted load duration curves for the storage dispatch and state of charge (SoC) for all storage locations.

Table 5-10 contains the duration curves drawn for one archetype but across different years. Each line in this graph is one of the 24 storage locations. The SoC varies from +600 to -600 MWh for this archetype (and from +200 to -200 MWh for Archetype 3) reflecting that we have picked the neutral SoC at 50% of storage energy capacity such that at any moment a storage can be dispatched up or down (this is elaborated in detail in chapter 4). Our operational strategy therefore aims at returning each storage to 50% charge state whenever this would not exacerbate the network state, as explained in section 4.

In line with *Table 5-6*, one can observe an increase in the amount of time when dispatch (and state of charge) is non-zero, confirming that the throughput volume increases from 2021 to 2030.

Table 5-10 SoC and Dispatch duration curve for 2021, 2025 and 2030

<table>
<tr><th></th><th>Archetype 1 SoC</th><th>Archetype 1 Dispatch</th></tr>
<tr><td>2021</td><td>
</td><td>
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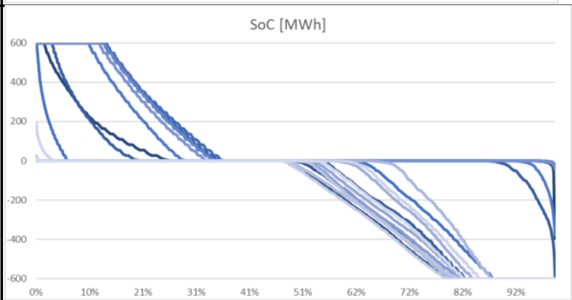
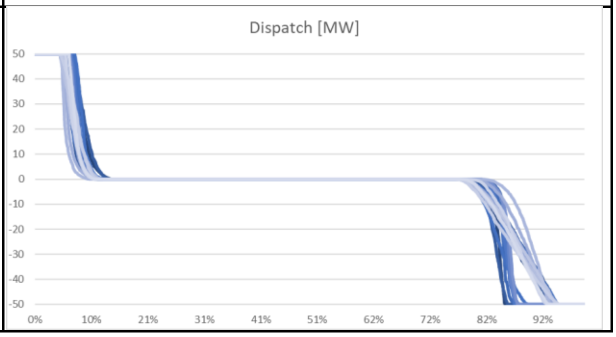
<tr><td>2025</td><td>
</td><td>
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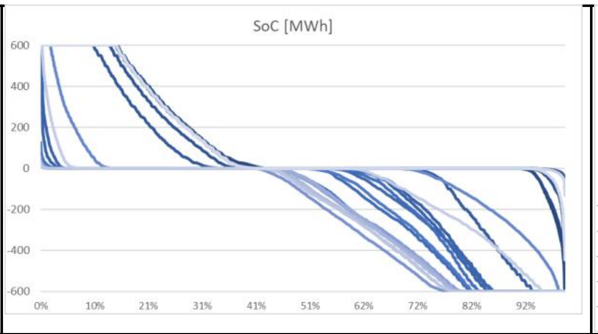
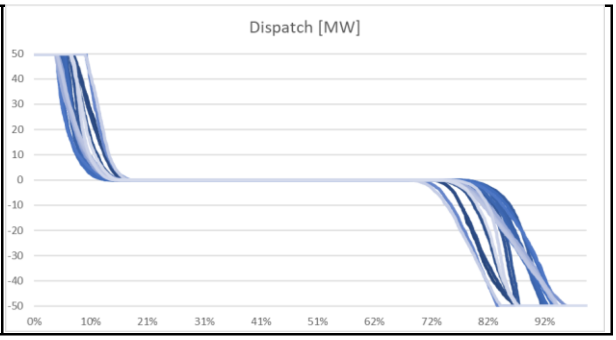
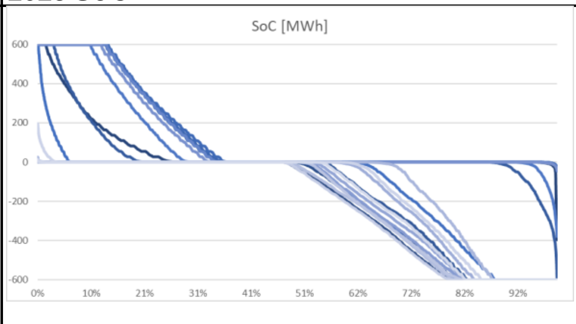
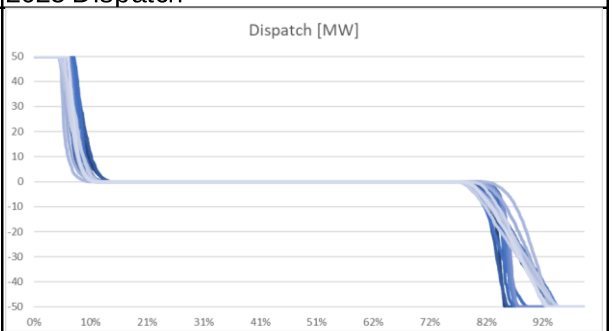
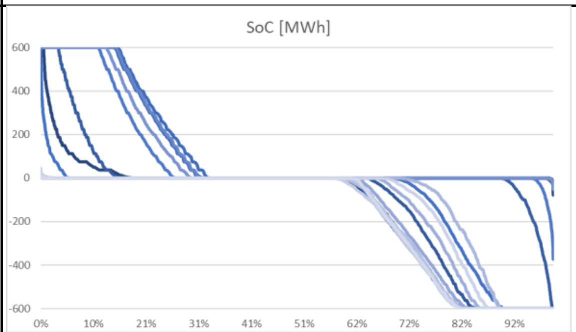
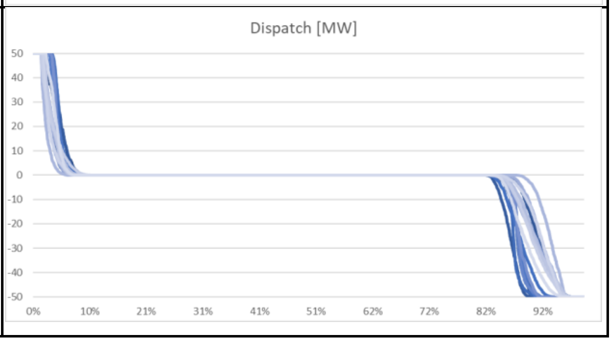
2030		

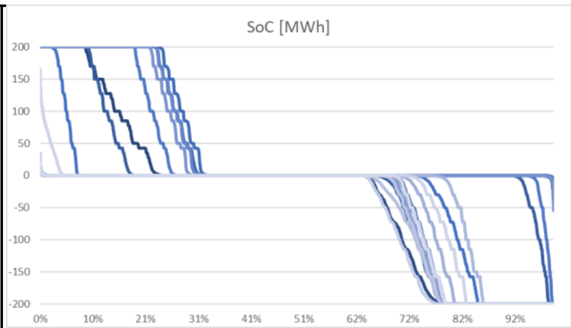
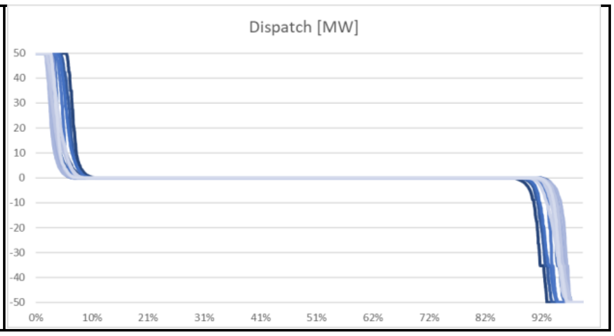
Between 2021 and 2030 the volume of constraints to be managed increases – this can be seen from the reduction in the amount of time that the storage assets are in an idle state, i.e. zero dispatch. Similarly, the time that storage units spend in non-zero SoC is decreasing, implying that on average storage assets are more occupied in 2030 than in 2021.

At the extremes of SoC curve, we see a large proportion of time spent in fully charged or fully discharged states. This is a sign that the nature of constraints (pattern, volume, frequency of occurrence) is such that they do not allow the storage assets to return to the neutral state. Similarly, the SoC curves show large proportion of time in non-zero state where storage assets are partially charged and unable to move from that state back to the neutral state without causing additional overloads. This is an indirect outcome of the modelling environment, in which storage assets are only dispatched when their dispatch will not cause additional constraints in the network (see section 4), reduction of overloads is given a higher weight than the return to the neutral SoC. Hence, the optimisation algorithm will not allow to return to neutral SoC, if it causes additional overloads in the system.

It is also worth considering how the operational characteristics of different storage archetypes affect their utilisation. This is shown in *Table 5-11*, where we compare the three archetypes on their performance for 2025.

Table 5-11 SoC and Dispatch duration curves for the modelled archetypes

	2025 SoC	2025 Dispatch
Archetype 1		
Archetype 2		

Archetype 3		

It can be seen that depending on the operational characteristics the level of utilisation (amount of time with non-zero dispatch) does not vary significantly – we observe a subtle trend of decrease in utilisation from Archetype 1 to 3, i.e. the width of the horizontal part at zero level of the dispatch plot increases. The difference in this case is mainly driven by the energy capacity of the storage (for how many hours in a row it can be dispatched) and its efficiency (how much energy it needs to absorb/ release to return to the rest state to get ready for addressing each next constraint). We remind that Archetype 1 has high efficiency and high energy capacity; Archetype 2 has low efficiency and high energy capacity; Archetype 3 has smaller energy capacity and higher efficiency in our simulation.

Furthermore, the amount of time that the storage spends at different SoC level (zero, maximum, minimum) varies, with a similar trend of increase in the amount of time at zero SoC moving from Archetype 1 to 3. In this case, the difference is mainly driven by the round-trip efficiency of an archetype, affecting how much time it takes to replenish the energy content and return to the rest state. In our interpretation of *Table 5-10*, we have explained how the nature of constraints results in scarce opportunities to return to the neutral SoC. In this context, storage archetypes with higher round-trip efficiency will perform better as they need less energy (and consequently time at fixed power rating) to replenish.

Before presenting the theoretical LCoS that storage assets could achieve, it is important to understand the perspective and incentives that are experience by a storage operator. As a storage operator, one aims to minimise the width of horizontal line at the zero-dispatch level. This means having as many hours as possible where storage is being dispatched, hence providing some service. The Idealised Dispatch duration curve, from the perspective of profit-maximising storage operator, would look like as shown in *Figure 5-11*. We see that all of the time dispatch is non-zero and is at maximum power capacity. The requirement to keep the storage balanced over the year results in 50% of time at positive- and 50% of time at negative dispatch. There are many SoC duration curves that could correspond to this dispatch scenario, hence we do not show them.

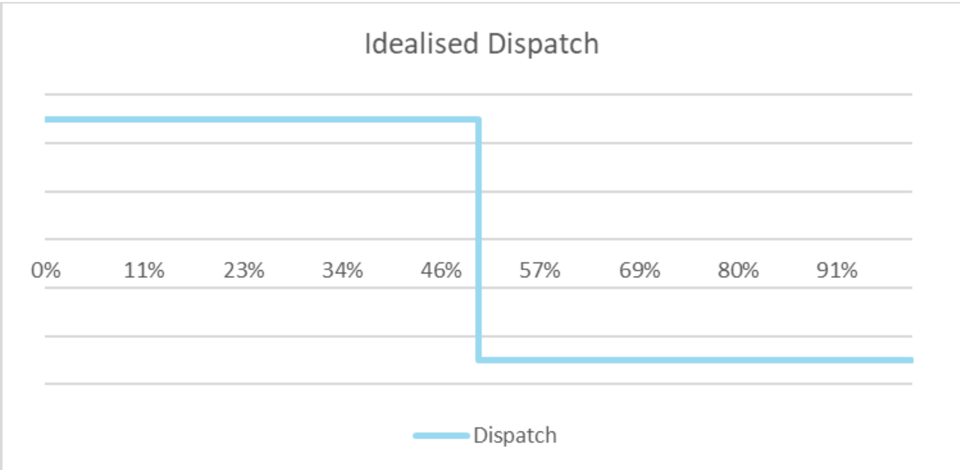


Figure 5-11 Profit-maximising storage operator - ideal Dispatch duration curve

There are two possible ways to achieve the Idealised Dispatch:

- Add more services to the business case by participating in alternative non-concurrent markets; and
- Increase the energy capacity of the assets.

The former option depends on the practical or regulatory factors governing market access, such as exclusivity of different markets and ability to participate based on the required technical and operational parameters. We discuss this further in chapter 6.

The latter is an investment question – increase in energy capacity will result in higher capital and operational expenditure – but also a technical constraint in terms of the maximum physical size of a storage unit. Furthermore, Idealised Dispatch does not mean maximised utilisation – one needs to consider the utilisation of both power- and energy component. *Figure 5-11* only tells us about utilisation of power component, but it is still possible that the energy capacity remains underutilised, depending on the exact dispatch sequence, e.g. a sequence of hours with dispatch at rated power changing the direction each hour will give us the Idealised Dispatch curve, but it will only use a single hour of the energy component. Therefore, the most accessible option to improve the storage business case is to maximise its participation in different markets.

Since we observed that there is some idle time when storage assets could potentially provide services other than constraint management, we have estimated the theoretical situation where storage utilisation is fully maximised in a way that for each MWh of dispatch, regardless of the direction, it gets paid. The number of hours the storage can operate in a year is assumed to be 95% of the total, 8760, reflecting that there will be some time needed for maintenance and downtime. The maximum volume of energy that the storage can provide as a service is limited by its power output level and efficiency. Taking these technical limitations in the account, the maximum energy throughput and number of operating hours can be estimated as given in *Table 5-12*.

Table 5-12 Theoretical LCoS assuming 95% utilisation and being paid for each hour and each MW regardless of direction

Archetype 1	£82
Archetype 2	£72
Archetype 3	£12

Finally, we have estimated the economic effect that could be achieved if storage would provide its service at the price equal to the above given LCoS. To calculate that we assume that storage is operated in a reality similar to our simulation environment. Furthermore, we assumed an average LCoS of 55 £/MWh, based on *Table 5-12*, and an average annual storage dispatch of 1,000,000 MWh, as a total from 24 assets in line with *Table 5-6*, which otherwise would be procured in BM at a typical price of ca. 110 £/MWh (see *Figure 5-5*, *Figure 5-6*, *Figure 5-7*). This gave us *1 TWh/yr x (110-55) £/MWh = £55m/yr*.

As a rough indicator of the situation where 95% utilisation is achievable and storage assets could deliver as much constraint management service as in our simulation, this could result in a reduction of constraint costs equal to £55m annually.

5.4 Conclusions

The economic analysis of modelling results has shown that although storage can play a role in constraint management, it is limited. We have tested a number of storage archetypes of a certain capacity located near the most constrained GB boundaries based on the maximum technical capabilities of storage technology at the current stage. We have assumed optimistic cost development as we expect the global storage market to grow substantially in the coming years. We have also taken into account limitations in the supply chain and land area requirements to realise these storage projects – this has resulted in modelling 24 assets of 50 MW each. Whilst in reality storage technology can develop, and industry may significantly scale up, we believe that the selected number of locations and storage sizes reasonably represent potential developments by 2030.

The LCoS varies by archetype, with some technologies being more mature, available at lower cost or being characterised by better efficiency. The combination of technology specific factors, together with the nature of constraint management needs (their magnitude, frequency of occurrence and duration) have resulted in LCoS ranging from 70 to 890 £/MWh depending on the archetype and location of an asset. The variation is driven by technology costs and annual energy throughput volumes against which these volumes are depreciated.

In terms of its economic competitiveness in providing constraint management service exclusively, we found that some archetypes can be competitive, depending on their costs and operational parameters. However, this will highly depend on the level of utilisation, driven among others by the geographic location where these assets are installed. While in the northern parts of the network, the majority of BMUs delivering constraint management service are wind assets, delivering the service at a relatively high price of ca.120 £/MWh, in the south these are often traders on interconnectors. The latter are able to deliver the constraint management service at the level of 20 £/MWh – a value that storage cannot compete with in our modelling environment.

Overall, we conclude that the provision of constraint management on an exclusive basis, i.e. not being able to engage in other ancillary service markets, will not create a viable business case for storage. Therefore, we consider that, in order to achieve a positive business case, storage operators would need to be able to participate in services besides constraint management. Assuming that these services could be stacked, i.e. delivered non-concurrently, making each storage asset utilised and remunerated for 95% of a year, the LCoS could be reduced significantly to a range from 12 to 82 £/MWh. On this basis, NGESO potentially would be able to save ca. £55m annually for consumers by contracting storage to provide constraint management in some hours of a year, and allowing it to play in other markets in the other time.

In this section, we have considered the impact that storage could have on constraint management costs for consumers. We note that there are other benefits that we have not studied in detail in this project. These are touched upon in the next chapter. An example of such an important benefit of contracting storage for constraint management is the fact that storage assets would displace other conventional BMUs, or allow wind farms not to be curtailed, in this way resulting in CO2 emission reduction and higher volume of RES integration in the system.

6 Prerequisites for Constraint Management and Access to Alternative Markets

6.1 Key findings

- There are several alternative competitive marketplaces besides the Balancing Mechanism that storage technologies may access to maximise remunerable deployment depending on technical requirements of the services and their technical capabilities.
- Frequency response services provide attractive revenue opportunities for those storage archetypes that can qualify for the service.
- Reserve services provide a less attractive option compared to frequency response services, as STOR is dominated by thermal technologies which are difficult for storage to compete with.
- The Capacity Market is open to all storage technologies and we consider it a good option as it provides constant revenues and is stackable with all services.
- Reactive power services are stackable and can be provided by all storage archetypes. For those storage archetypes for which a synchronous generator operator is not available, they will need to be coupled with a PCS/inverter to provide reactive power. This is also a requirement of the Grid Code for generators above 10MW. Due to limited information on pricing and volumes, a future storage operator should explore further the benefits of providing these services.
- Black start (restoration) is only technically accessible when storage technologies are coupled with a PCS/inverter capable of operating in grid forming mode rather than grid following This is a service provided based on bilateral agreements so a storage operator should explore further the benefits of providing Black Start with NGESO.
- The wholesale market provides arbitrage opportunities for storage providers who can charge when prices are low and discharge when prices are high.
- A key consideration for flexibility providers is the extent to which revenues from one service can be “stacked” with revenues from other services. Based on contractual exclusivity terms our analysis shows that flexibility providers are able to move freely between revenue streams in different time periods, but they have more challenges to provide multiple services during the same time window due to contract terms or regulatory arrangements. In practice, even where allowed from a contractual and/or regulatory perspective, revenue stacking across different services may be challenging due to locational factors, limitations in compatibility of services (e.g. different state of charge requirements), and economic optimisation by both NGESO and storage operators. In addition, storage connected to highly constrained circuits may find that the same constraints make it difficult to provide services that rely on active power flows.

6.2 Analysis

This section consists of the following steps

- Overview of markets and services and relevant technical requirements;
- Relevant technical parameters for each storage technology;
- Mapping of the services/markets that storage technologies can provide based on technical parameters;
- Overview of historical prices, volumes and typical participating technologies of markets/services that are technically feasible for each technology, if available;
- Stackability considerations for relevant services; and
- Wider considerations related to storage technology. Reflection on the latest technology developments, market growth – future potential and current pace, cost reduction, supply chain development and limitation,

plausibility of having 24 large scale storage projects spread across GB, plausibility of getting all storage assets connected at transmission level, connection time.

Results of our analysis are presented in section 6.3.

6.2.1 Overview of markets and services

Next to constraint management (via the Balancing Mechanism), there are other services and markets in which storage could participate. Our analysis starts with an overview of all available markets and services and their technical parameters. The following table presents an overview of all markets and services in scope of this study. ESO services are undergoing a large reformation at this moment. Therefore we present all services that are currently active as well as the future products that are under development.

In addition to the existing and under-development services presented below, ESO has indicated potential future revenue opportunities for storage providers. These are not included in the table below as they are not standardised and will provide ad-hoc opportunities. These opportunities include the NOA Stability Pathfinder, where the ESO is seeking stability services from new providers who can offer solutions that address specific system needs. [16] In addition, ESO is deploying innovative stability services contracts and innovative reactive power contracts, which subject to technical requirements and the technical solution can be relevant for storage technologies. [17]

Table 6-1 Overview of markets and services

Service type	Market / service	Description	Status
Frequency response services	Firm Frequency Response (FFR)	FFR is the firm provision of dynamic or static response to changes in frequency. FFR providers supply a certain amount of power or demand reduction when large frequency variations occur in the system. There are two types of FFR: • Dynamic: is a continuously provided service used to manage the second-by-second changes on the system • non-dynamic (static): is typically a discrete service triggered at a defined frequency deviation.	For more details see the Markets Roadmap
	Low Frequency Static	National Grid ESO soft-launched a trial of a closer to real time market for frequency response services in June 2019, moving to a new auction platform in December 2019. This was in order to reduce barriers to entry for parties who couldn't forecast what their assets would be doing a month ahead (as required in FFR monthly tenders). Low Frequency Static (LFS) is one of the 2 types of service available in the FFR weekly auctions.	The weekly frequency response auction trial closed in November 2021, with the final auction being held on Friday 26 November.
	Dynamic Low High	National Grid ESO launched a trial of a closer to real time market for frequency response services in December 2019, in order to reduce barriers to entry for parties who couldn't forecast what their assets would be doing a month ahead (as required in FFR monthly tenders). Dynamic Low High (DLH) is one of the 2 types of service available in the FFR weekly auctions.	The weekly frequency response auction trial closed in November 2021, with the final auction being held on Friday 26 November.
	Dynamic Containment	Dynamic Containment (DC) is a fast-acting post-fault service to contain frequency within the statutory range of +/-0.5Hz in the event of a	The soft-launch of DC began in August 2020 and it's still ongoing.

[16] More information at ESO's website.
[17] More information at ESO's website: innovative stability contracts and reactive power services contracts.

		sudden demand or generation loss. The service delivers very quickly and proportionally to frequency but is only active when frequency moves outside of operational limits (+/- 0.2Hz). There will be two distinct services which can be provided independently: • Dynamic containment low frequency • Dynamic containment high frequency	This means that the rules are still under development. This product is one of the 3 future products that intend to replace the Firm Frequency Response (FFR) product. For more details see the Markets Roadmap
	Dynamic Regulation	Dynamic Regulation (DR) is a pre-fault service designed to slowly correct continuous but small deviations in frequency. The aim is to continually regulate frequency around the target of 50Hz.	For more details see the Markets Roadmap
	Dynamic Moderation	Dynamic Moderation (DM) is a pre-fault service designed to rapidly deliver the service with the aim of keeping frequency within operational limits. It helps to manage sudden large imbalanced by responding quickly.	For more details see the Markets Roadmap
Balancing reserve services	Fast Reserve	Fast reserve provides rapid and reliable delivery of active power through increasing output from generation or reducing consumption from demand sources.	Firm fast reserve service procurement was put on hold in 2020 and firm fast reserve contracts won't be used any longer. NG ESO intends to continue to use optional fast reserve contracts until Fast Reserve is fully replaced by the new Reserve Products. For more details see the Markets Roadmap
	Slow Reserve	Slow reserve is a post-fault service designed to provide distinct positive and negative reserve and support the ESO with meeting its obligations to restore frequency to +/-0.2Hz within 15 min. There will be two distinct services which can be provided independently: • Negative slow reserve • Positive slow reserve	Negative slow reserve and Positive slow reserve will be the first products in the new reserve suite to be launched. They are expected in 2022. For more details see the Markets Roadmap
	Quick Reserve	Quick reserve is fast-acting reserve product which is intended to bridge the gap between the new frequency response services of Dynamic Containment, Dynamic Moderation and Dynamic Regulation, and the slower reserve product(s).	This service is still under development. For more details see the Markets Roadmap
	Short Term Operating Reserve	The STOR service provides additional power (active power from either generation or demand reduction) to NG ESO when demand on the Transmission Network is greater than forecast.	STOR was discontinued during 2020 Q4 and Q1 2021. Since April 2021, it is procured again. It is expected that STOR will remain as a Reserve Product during the Transition Period of the Reserve Reform, but it

			may be replaced by the new products (i.e. slow reserve) For more details see the Markets Roadmap
	Demand Turn Up	The Demand Turn Up (DTU) service encourages large energy users and generators to either increase demand or reduce generation at times of high renewable output and low national demand. This typically occurs overnight and during weekend afternoons in the summer.	The product will be (most likely) replaced by the new Reserve products which will include both upward and downward activation. For more details see the Markets Roadmap
	Super SEL	Super SEL is utilised to directly decrease the sum of the minimum MW level or Stable Export Limit (SEL) of generators synchronized to the system by lowering the minimum generating level at a generator synchronised. Super SEL service does not require a change in energy output of the generation, it is to give access to a reduced minimum active power level.	Open
	BM Start Up	The BM Start-Up Service is a mechanism for National Grid to access generation in the Balancing Mechanism which is not otherwise planning to run (the participants would not by typically available on the day). The service contains two elements: • BM Start-Up deals with bringing a BM Unit to a state where it can synchronise within BM timescales. • Hot Standby deals with holding the BMU in such state of readiness to synchronise, where the BMU is capable of being held in such a state.	Open, although since July 2020, there has been no instructions for this service.
	Replacement Reserve	Replacement Reserve is a harmonised service across participating European TSOs for the provision of both an increase and decrease of active power.	Under development. For more details see the Markets Roadmap
Reactive power services	Obligatory Reactive Power Service	The Obligatory Reactive Power Service (ORPS) is the provision of varying reactive power output. At any given output generators may be instructed to produce or absorb reactive power to help manage system voltages close to its point of connection. All generators covered by the requirements of the Grid Code are required to have the capability to provide reactive power.	Open
	Enhanced Reactive Power Service	It has the same definition as the obligatory service, except that the ERPS can be offered by providers that do not have the obligatory requirement to provide reactive power, and have the capability to generate or absorb reactive power.	Open. No tenders have been submitted in seven and a half years, and no contracts have been agreed in nine years. There is a proposal from NG ESO to remove this service.[18]

[18] https://www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc-old/modifications/cmp305-removal

System security services	Intertrips	Intertrip services are required as an automatic control arrangement where generation may be reduced or disconnected following a system fault event. This is a service that may be required as a condition for the connection or can also be offered under a commercial arrangement.	Open. According to ESO's plan on system security, ESO will further develop Intertripping capabilities exploring new short and long term solutions for Intertripping services.
	Black Start (Restorations Services in the future)	Black Start is the procedure to restore power in the event of a total or partial shutdown of the national electricity transmission system.	Open, under reformation. As part of the new Electricity System Restoration Standard (ESRS), the ESO will need to procure additional restoration services from traditional and non-traditional sources
	Maximum Generation	Max Gen is required to provide additional short term generation output during periods of system stress for system balancing. This service allows access to unused capacity outside of the Generator's normal operating range.	Not actively procured
Capacity market	Capacity Market	The Capacity Market is a service that ensures security of electricity supply by providing a payment for reliable sources of capacity.	Open
Wholesale	Day-ahead and intraday trading	Day-ahead and intraday trading in the wholesale market is selling and buying large volumes of electricity from other market parties.	Open

In order to map storage archetypes against these services, we looked into the technical requirements of each service and assessed whether the different storage archetypes are eligible to participate. The technical requirements which we have assessed are:

- Minimum capacity: The minimum level of power required to participate in a service
- Maximum capacity: The maximum level of capacity, usually per unit, that is allowed to participate in a service.
- Maximum response time: From receiving an activation notification, the maximum time required for a unit to deliver the full service.
- Minimum sustain time: The minimum time that a unit is required to uninterruptedly deliver the service
- Maximum recovery period: The maximum time that a unit is required to recover at least the 'energy recovery'[19] volume.

In the table below, we present a summary of relevant technical requirements for each service/market.

Table 6-2 Overview of selected technical requirement for each service/market

Service type	Market / service	Max Response time	Min Capacity	Max capacity	Min sustain time	Recovery time
Frequency response services	Firm Frequency response (FFR) static	30 sec (secondary response)	1MW	N/A	30 min	N/A

[19] Energy recovery: the minimum volume of active energy (MWh) capable of being recovered by way of State of Energy management in a single Settlement Period.

	Firm Frequency response (FFR) dynamic	2 sec start, 10 sec full delivery (primary) 30 sec (secondary) 10 sec (high frequency)	1MW	N/A	20 sec (primary) 30 min (secondary) Indefinitely (high frequency)	N/A
	Low Frequency Static (LFS)	1 sec (full delivery)	1MW	20MW per unit for auction participation	30 min	N/A
	Dynamic Low High (DLH)	1MW within 2 sec (primary) 10 sec (primary, full delivery) 30 sec (secondary) 10 sec (high frequency	1MW	20MW per unit for auction participation	30 sec (primary) 30 min (secondary) Indefinitely (high frequency)	N/A
	Dynamic Containment (DC)	1 sec (full delivery), no faster than 0.5sec		100MW/unit	Continuous across contract delivery. For energy limited assets (e.g. batteries): 15 minutes full contracted capacity	20% of Response Energy Volume in 30 minutes.
	Dynamic Moderation (DM)	0.5 sec (max ramp start), full delivery within 1sec	1MW	100MW/unit	30 minutes for energy limited assets	20% of Response Energy Volume in 30 minutes.
	Dynamic Regulation (DR)	2 sec (max ramp start), 10 sec full delivery	0.1MW	100MW/unit	60 minutes for energy limited assets	20% of Response Energy Volume in 30 minutes.
Balancing reserve services	Fast Reserve	2 min	25 MW	N/A	> 15 min	N/A
	Demand Turn Up	6 hours	1 MW	N/A	3.5 -4.5 hours	N/A
	STOR	20 min	3MW	N/A	2 – 4 hours	1200 minutes
	RR	30 min	1 MW	N/A	15 min	N/A
	Quick Reserve	30 s	1MW	-	20 minutes	
	Slow Reserve	15 min	1MW	-	120 min	30 min
	Super SEL	6 hours	10 MW	N/A	N/A	N/A
	BM start up	89 min	These details are defined in bilateral agreements. This service is only relevant for generation connected to the transmission system.			

Reactive power services	Obligatory Reactive Power Service	2 min	See Grid Code		N/A	N/A
	Enhanced Reactive Power Service	This is a voluntary service for generators that can provide reactive power over and above the Grid Code and obligatory reactive power service (ORPS) requirements. It is relevant for storage technologies that can be used as synchronous generators. However, the service has not been used in 7 years and there is a proposal from ESO to remove this service.				
System security services	Intertrips	100 milliseconds	These details are defined in bilateral agreements. This service is generally provided by generation connected to the transmission system. In the future, demand assets could also participate in intertripping capabilities.			
	Black Start	2hrs after receiving the instruction	For Black Start, other technical parameters are more relevant when assessing the technical capabilities of a technology.[20] These technical requirements are subject to future changes.			
	Maximum Generation	These parameters are agreed via bilateral agreements. Stations contracted for Max Gen have the ability to increase generation above its normal operating range when required. This service is no longer procured by the ESO.				
Capacity market	Capacity Market	4 hours	1 MW	N/A	Minimum 0.5 hours for storage	N/A
Wholesale	Day-ahead and intraday trading	N/A	N/A	N/A	N/A	N/A

Relevant technical parameters for each storage technology

To compare the service/market technical requirements with the technical characteristics of the storage technologies archetypes. In the following table we summarise the relevant technical requirements per technology. The full characteristics overview can be found in Appendix A.

Table 6-3 Technical parameters of storage archetypes

Storage	**Flow battery**	**CES**	**H2**	**Li-ion**	**Gravity**
Power	50 MW	50 MW	50 MW	50 MW	50 MW
Response time	150-250 ms	Charge: 30 min Discharge: 10-15 min	1s	150-250 ms	1-5 s
Discharge duration	4-8 hours	6-12 hours	N/A	Up to 4-6 hours	Up to 8-10 hours
Charge duration	6.5-13 hours	6-24 hours	N/A	Up to 4-6 hours	Up to 10-12 hours
Reactive characteristics	Yes, with PCS	Capable of providing react. power	Yes, with PCS.	Yes, with PCS	Depends on the spec of motor used

6.2.2 Mapping of the services/markets that storage technologies can provide based on technical parameters

Based on outputs of previous sections and work packages, we mapped the service/markets requirements against the technical characteristics of each storage type. Table X below provides a summary of this mapping based only on technically considerations.

[20] Restoration Services | National Grid ESO

As previously mentioned, there is an ongoing process to reform all balancing and reserve services, therefore there are services that are now active that will not be in the near future, as well as services that are under development. To make the distinction clearer, we include colour coding to indicate the status of each service/market.

We can make the following observations:

- Flow and Li-ion batteries are technically capable of providing 73% of the listed services. The remaining 27% are services that are generally only applicable to conventional generation plants.
- Hydrogen storage has the capabilities to participate in nearly as many services as flow and Li-ion batteries (68%). The only exception being the fastest response balancing service, dynamic moderation.
- LAES is only suitable to provide 5 services (23% of the total) due to its slower response time. LAES is suited to provide slow reserve services, reactive power, as well as to participate in capacity markets and wholesale market.
- Gravity storage, like LAES, is also not suited for fast response services, such as frequency services, reserve services. However, its slightly faster response allows Gravity Storage to participate in more reserve products than LAES. Gravity storage is able to provide 10 services (45% of the total).
- All technologies can participate in the Capacity and Wholesale Markets.
- None of the technologies can participate in Super SEL, and BM start-up services, since they are typically for traditional power plants. Intertrip services may be possible in some cases.
- In the future we expect that technical requirements may ease so that more technologies can participate in more markets, especially with regard to Restoration Services (Black Start).

Colour Code	Meaning
(amber)	Service is currently available, but will probably be phased out in the future
(orange)	Service is not available anymore (e.g. auctions are closed)
(green)	Service is up and running
(pale yellow)	Service under development

Table 6-4 Map of storage archetypes against services

Service type	Service/ Market	Flow	CES	H2	Li-ion	Gravity	Comments
Frequency Response Services	FFR static	√	X	√	√	√	Monthly FFR tenders will most likely be phased out by Q4 2022/2023 when the new frequency products are in place, although this is not confirmed by the ESO.
	FFR dynamic	√	X	√	√	X	
	Low Frequency Static (LFS)	√	X	√	√	X	The weekly frequency response auction trial closed in November 2021, with the final auction being held on Friday 26 November.
	Dynamic Low High (DLH)	√	X	√	√	X	
	Dynamic Containment (DC)	√	X	√	√	X	DC offers a significant uplift in payments compared

Service type	Service/ Market	Flow	CES	H2	Li-ion	Gravity	Comments
							to current rates in the FFR market, but the fast response speeds and need for high quality monitoring equipment means that technical considerations should be explored.
	Dynamic Moderation (DM)	√	X	√	√	X	For more details see the Markets Roadmap
	Dynamic Regulation (DR)	√	X	√	√	X	For more details see the Markets Roadmap
Balancing Reserve Services	STOR	√	√	√	√	√	Technically feasible, but service is expected to be phased out soon.
	Fast Reserve	√	X	√	√	√	Discontinued since June 2020 and will be replaced by the new reserve products.
	Demand Turn Up	√	√	√	√	√	It has not been procured recently, most likely it will be replaced by the new reserve products.
	Super SEL	X	X	X	X	X	Only relevant for conventional generation
	BM Start up	X	X	X	X	X	Only relevant for conventional generation
	RR	√	X	√	√	√	Assessment was performed based on current requirements. Requirements might change in the future since the service is under development
	Quick Reserve	√	X	√	√	√	Assessment was performed based on current requirements. Requirements might change in the future since the service is under development
	Slow Reserve	√	X	√	√	√	Assessment was performed based on current requirements. Requirements might change in the future since the service is under development

Service type	Service/ Market	Flow	CES	H2	Li-ion	Gravity	Comments
Reactive Power Services	Obligatory Reactive Power Service	X	√	X	X	√	Will be a mandatory service for storage that is treated as a generator in the Grid Code
	Enhanced Reactive Power Service	√ (with PCS)	√	√ (with PCS)	√ (with PCS)	√ (Depends on the motor)	Technically feasible for any asset with device, which absorbs or inject reactive power. There has been no tender submissions for the last 7 years.
System Security Services	Intertrips	X	X	X	X	X	Technically not usually feasible due to required response time < 100ms
	Black Start	√ (with PCS)	√	√ (with PCS)	√ (with PCS)	√ (Depends on the motor)	Technically feasible when coupled with a PCS/inverter capable of operating in grid forming mode
	Max Gen	N/A	N/A	N/A	N/A	N/A	Currently discontinued, large generators
Capacity Market	Capacity Market	√	√	√	√	√	Storage is technically capable of participating in this market, however storage is subject different de-rating factors depending on its characteristics.
Wholesale market	Day-ahead and intraday trading	√	√	√	√	√	Storage can participate in the wholesale market as any other generator.

6.2.3 Revenue streams

Having summarised the range of services where the different technologies are technically capable of participating, we further investigate the price and volume levels as well as technology participation that these services have shown historically. This will provide an indication of potential revenue that the different storage archetypes can access.

In this step, we only present those services that are currently open and for which there is publicly available historical data on procured prices and volumes. Therefore, all services that are closed, under development or of bilateral nature, are not included in the following overview. For those services that are now open but foreseen to be closed in the future, we include information since it might serve as an indication for the expected prices of the services that will replace them.

Firm frequency response

Figure 6-1 shows the volume requested for FFR has seen an increase from 2018 to 2020. In particular, the dynamic FFR volume has grown significantly from mid-2019, seeing its peak demand in September 2020 at around 1200 MW. From 2021 the volume requested in monthly tenders decreased because there it was only supplementing the volume procured through the trial on weekly auctions, which ceased in November 2021.

Figure 6-1 shows, that the there is a pattern on the type of the technologies that provide static and dynamic FFR. Most of the static FFR volume comes from thermal technologies. Conversely, most of the dynamic FFR volume comes from storage. Demand-side flexibility assets secured record FFR contracts in the monthly tenders of summer 2020.

Finally, Figure 6-2 shows that the average capacity payment for dynamic FFR saw a steep increase in 2020 compared to previous years, averaging £7.1/MW/h. On the other hand, static FFR prices have been relatively stable along the years. Higher prices are observed during winter.

It is expected that this service will be replaced by the new frequency services: DC, DM, and DR.

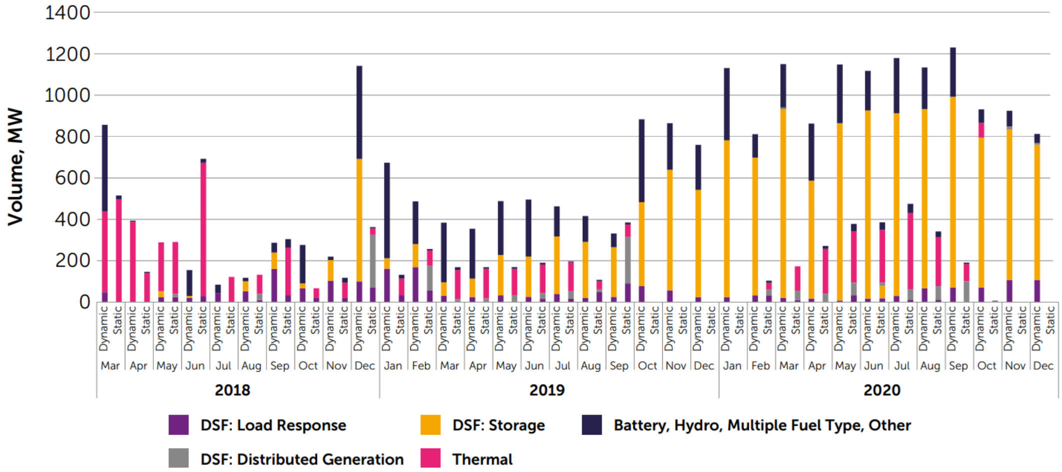


Figure 6-1 Dynamic and static FFR contracts secured in the monthly market by technology, MW. Power Responsive Annual Report 2020[21]

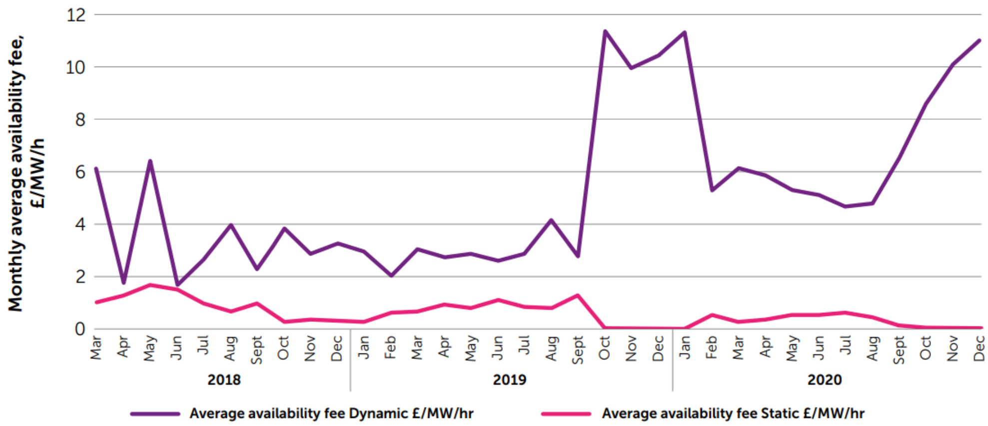


Figure 6-2 Average dynamic and static FFR availability fees for accepted tenders, £/MW/hr. Power Responsive Annual Report 2020

Dynamic Containment

There is limited data on historical procurement of the dynamic containment product since it is a relatively new product. Information within this report reflects only trends of 2020, and from September 2021, when the DC procurement started running on the EPEX platform, whilst Dynamic Containment was introduced only in October 2020.

[21] Power-Responsive-Annual-Report-2020.pdf (powerresponsive.com)

Dynamic containment has been exclusively provided by battery storage technologies since procurement started in October 2020. The service had attracted over 300 MW of battery projects by December 2020, all securing competitive prices through the daily pay-as-bid auctions.

Regarding volumes, Figure 6-3 indicates the volume that has been procured since the start of DC. The volume has linearly increased, and NG ESO foresees a requirement of 1400MW by 2025.[22] In the first months, and up to November 2021, undersupply was observed and as a result prices remain at the cap price for assets that were qualified to deliver the service. After the launch of the DC service in 2020, the market price stabilized near the market cap at £17/MW/h and have continued at that level until November 2021 as depicted in Figure 6-4. This development may show an undersupply problem as this is not how a market behaves generally. As from November 2021, the prices starting to fluctuate between £1/MW/h and £22/MW/h, lowering the average monthly clearing price down to £10.4/MW/h in December. It is unclear how the prices will develop in the future; however, the past 3 months have shown that the prices are generally lower than what was seen at the start of the year.

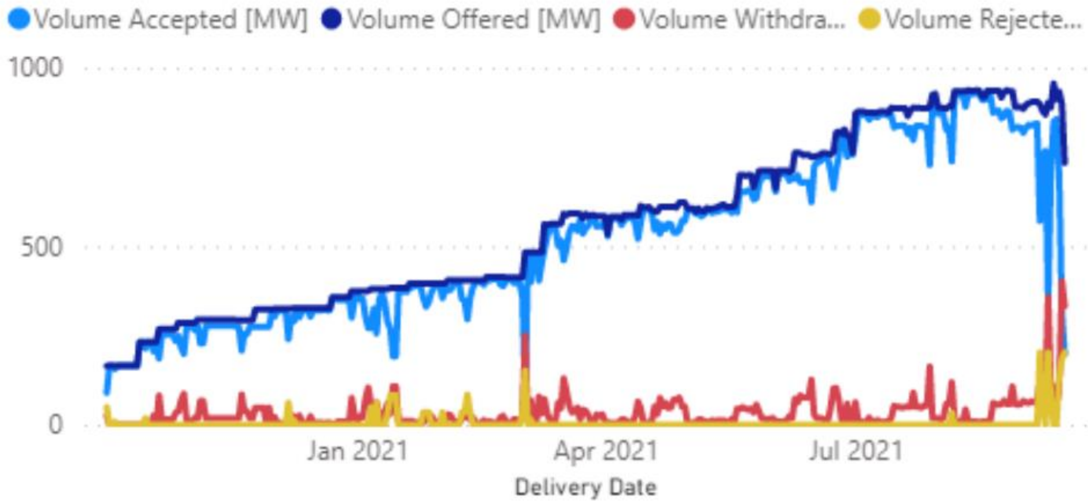


Figure 6-3 Dynamic Containment volumes (accepted, offered, withdrawn, rejected). NG ESO webinar

[22] https://www.nationalgrideso.com/document/206296/download

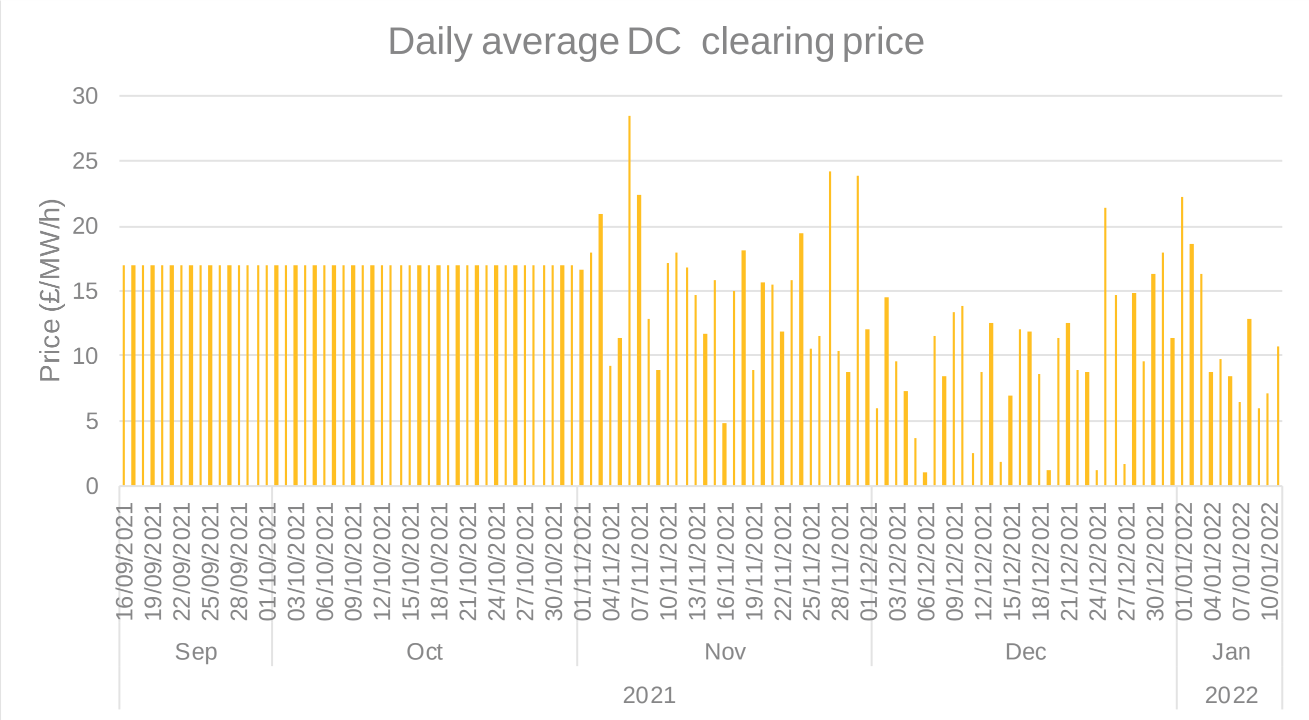


Figure 6-4 Availability clearing prices per day of successful Dynamic Containment bids, £/MW/h. Data retrieved from NGESO website.[23]

Short term Operational Reserve

The procurement of the STOR product changed from long-term to daily auctions in 2021. Tendered routes to market for Short Term Operating Reserve (STOR) were put on hold throughout 2020, due to compliance considerations with the Clean Energy Package . Figure 6-5 presents volumes and prices of the daily auctions this year. The procured volume has been roughly stable across the months, at around 1200 MW. Whereas the prices have seen an increase in the last month of this year, peaking at nearly £6/MW/h. The 2021 price average is at £3.4/MW/h.

Compared the previous years, however, the STOR volume has decreased significantly, as seen in Figure 6-6. Prior to 2020, the average contracted STOR capacity was at 4000 MW. It is expected that the market will restore back to pre-2020 levels as market participants get familiar with the new market structure.

Finally, Figure 6-7 shows the breakdown of technologies providing STOR capacity in 2021. Thermal technologies such as CCGTs and OCGTs are the predominant technology contracted for this service.

[23] https://data.nationalgrideso.com/ancillary-services/dynamic-containment-data

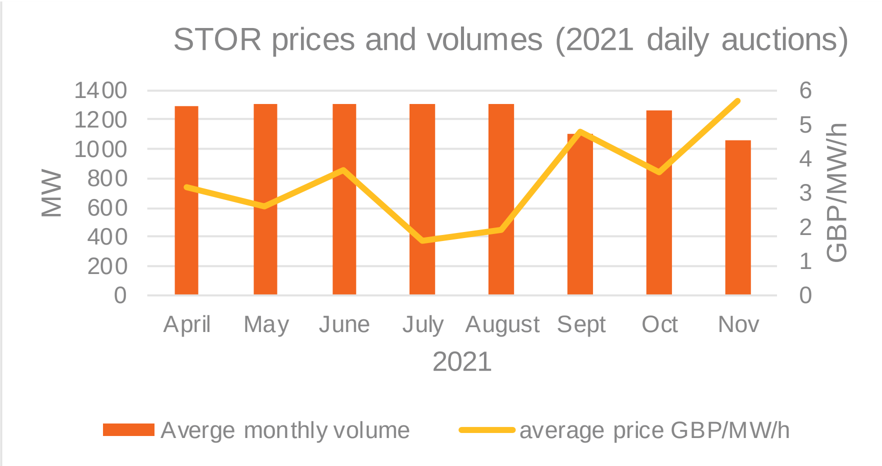


Figure 6-5 STOR monthly average market clearing price and monthly average contracted volumes. Data extracted from NGESO website[24]

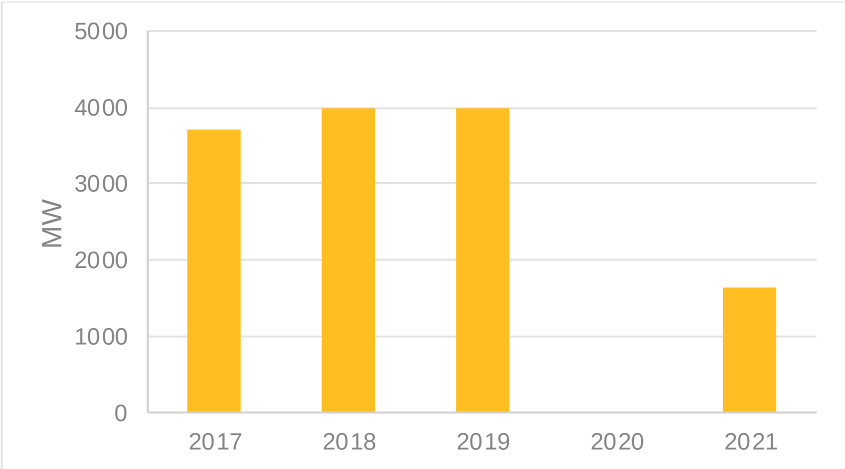


Figure 6-6 Contracted STOR capacity volumes (long-term and daily auctions)[25]

24 h\ttps://data.nationalgrideso.com/ancillary-services/short-term-operating-reserve-stor-day-ahead-auction-results/r/stor_da_auction_results_

25 Data extracted from NGESO website and power responsive 2019 report. https://www.nationalgrideso.com/document/189221/download

http://powerresponsive.com/wp-content/uploads/2020/04/Power-Responsive-Annual-Report-2019.pdf?utm_source=Energyst&utm_medium=Energyst&utm_campaign=Annual%20Report%202019

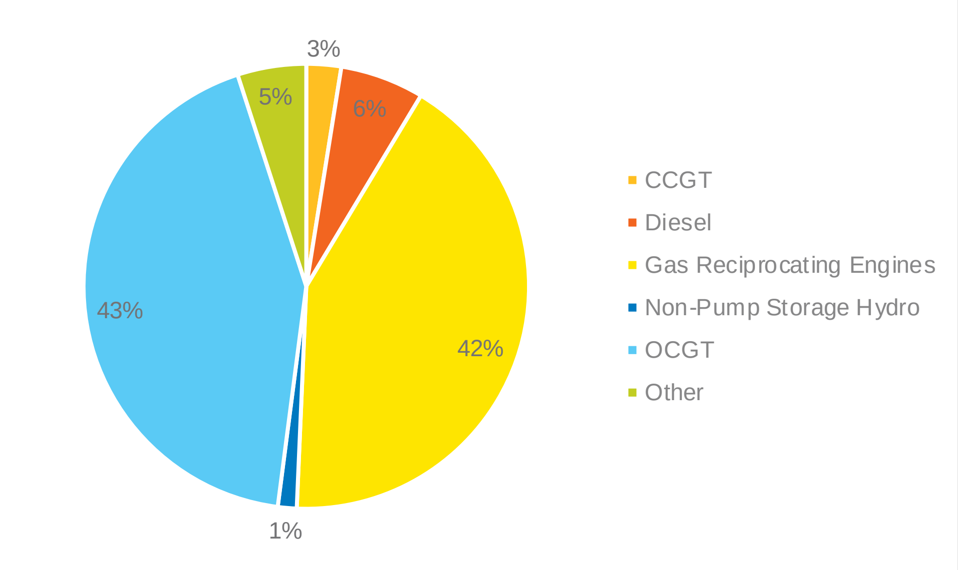
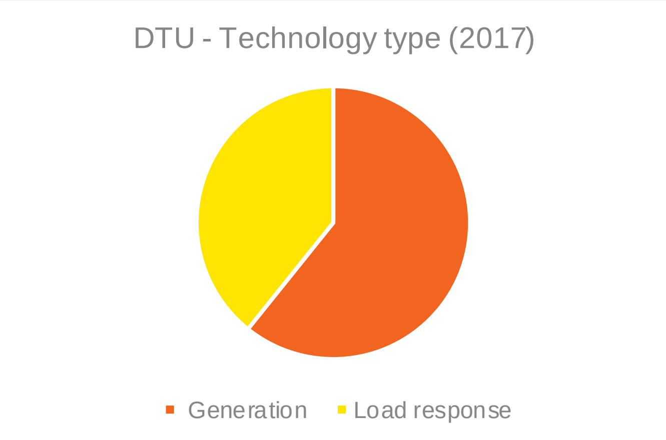


Figure 6-7 Breakdown of contracted availability per technology (2021. ESO data on STOR day ahead auction results)[26]

Demand turn-up

Figure 6-8 shows that the demand turn-up has not been procured since 2019. Before then, the procured volume constantly decreased down to around 100 MW, which is a relatively low volume for system services. We could only find a public capacity price from the 2017 tender, which was £2.9/MW/h. The utilisation prices remained relatively stable across the years, at around £65/MWh.



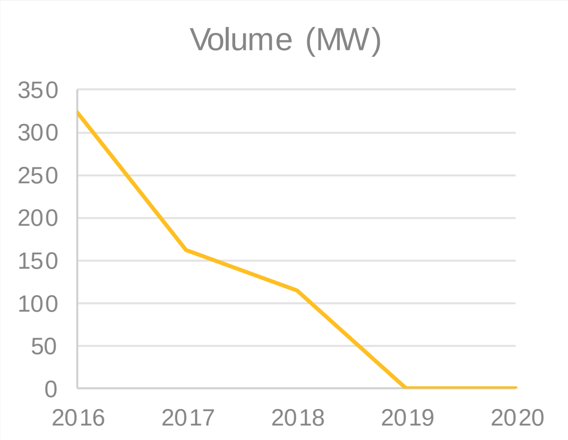


Figure 6-8 DTU participating technologies breakdown in 2017 and DTU volume 2016-2020 [27]

Table 6-5 Availability and utilisation price for DTU[28]

[26] https://data.nationalgrideso.com/ancillary-services/short-term-operating-reserve-stor-day-ahead-auction-results/r/stor_da_auction_results_

[27] Data extracted from: https://www.nationalgrideso.com/sites/eso/files/documents/EXT%20Demand%20Turn%20Up%202019.pdf & https://www.nationalgrideso.com/document/85351/download

[28] Data extracted from: https://www.nationalgrideso.com/sites/eso/files/documents/EXT%20Demand%20Turn%20Up%202019.pdf & https://www.nationalgrideso.com/document/85351/download

	Average utilisation price (£/MWh)	Average availability price (£/MW/h)
2016	61.41	Not available
2017	67.53	2.9
2018	65.33	Not available

Capacity Market

There are two types of auctions at the capacity market, T-4 and T-1. T-4 auction contracts capacity for a period of four years, whereas T-1 for one year.

Figure 6-9 shows the historical auction clearing prices for both T-4 and T-1. The prices for T-4 average have shown a relatively stable trend across the years, averaging £16.6/kW/year. On the other hand, T-1 auctions showed low prices in the past - £1/kW/year - and significantly higher price in 2020, reaching £45/ kW/year. [29]. This is a different trend from what we observed in 2018 and 2019 T-1 auctions (0.77kW/year and £1.00kW/year respectively).

Like for the prices, T-4 auction volumes remained relatively stable over the years, between 40,000 and 50,000 MW. Whereas T-1 volumes have decreased over the years, starting at 6,000 MW in 2017 to around 2000 MW in 2020.

Finally, regarding type of assets participating in the capacity market, most of the capacity awarded in T-4 corresponded to thermal and nuclear plants. Whereas for T-1 most of the capacity was awarded to interconnectors in 2019.

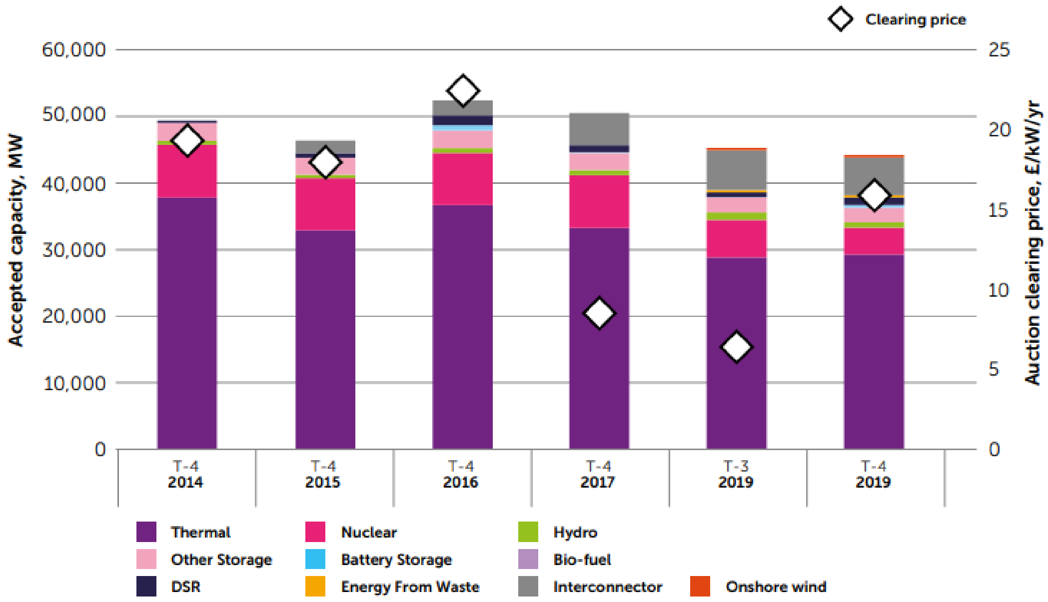


Figure 6-9 Clearing price and accepted capacity by technology of T-4 Capacity Market auctions MW and £/kW/yr[30]

[29] https://www.emrdeliverybody.com/CM/Published-Round-Results.aspx

[30] Power responsive report 2020

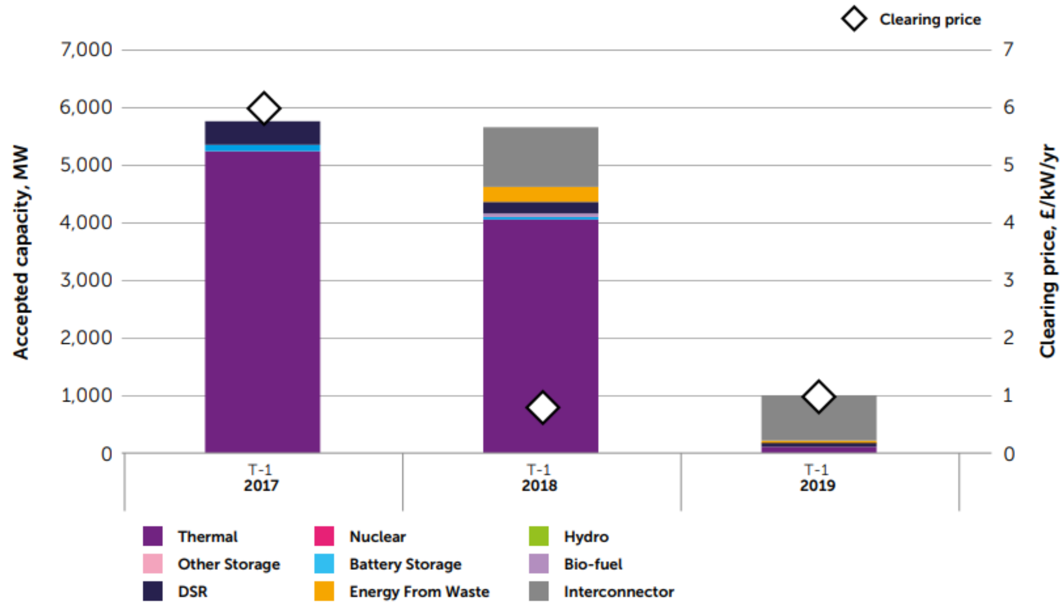


Figure 6-10 Clearing price and accepted capacity by technology of T-1 Capacity Market auctions MW and £/kW/yr[31]

Wholesale market

The potential for revenues in wholesale markets, especially day-ahead and intraday markets, depends on the arbitrage opportunities for storage technologies. For example, storage operators can charge their asset when wholesale prices are low and discharge (selling energy back to the grid) when prices are high. To assess the revenues potential for this activity we looked into the price volatility of wholesale prices in GB as well as in the overall wholesale prices trends.

Figure 6-11 shows that wholesale prices have increased recently. Although the trend of future prices is uncertain, the increase of wholesale prices and the volatility of them (*Figure 6-12*) indicate attractive arbitrage opportunities for storage operators.

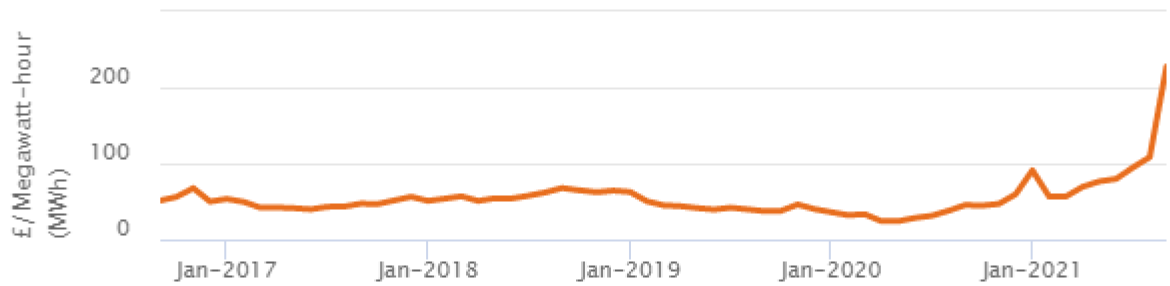


Figure 6-11 Average wholesale prices in GB[32]

[31] Power responsive report 2020
[32] https://www.ofgem.gov.uk/energy-data-and-research/data-portal/wholesale-market-indicators

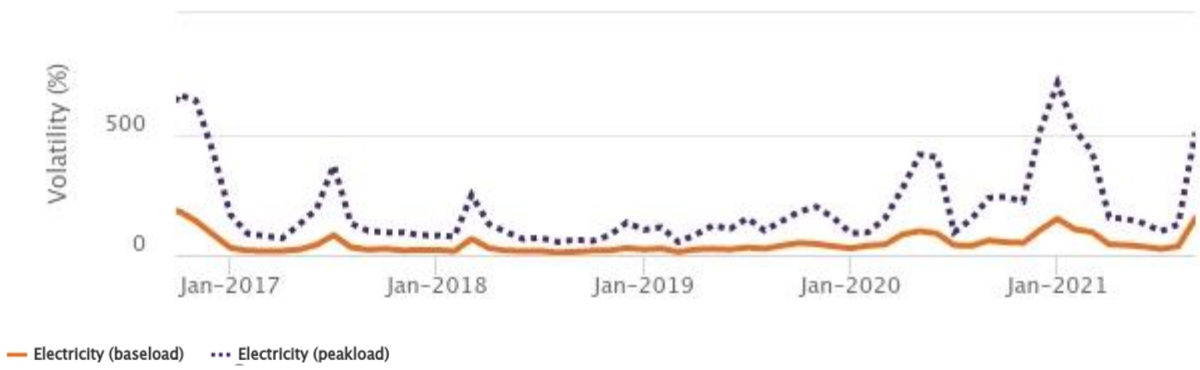


Figure 6-12 Price volatility of electricity by month (day-ahead)[33]

Summary

In this table we summarise the latest price levels for each service in all technologies that are technically capable of providing such service.

Table 6-6 Overview of potential service availability/utilisation remuneration per archetype

Service type	Service/ Market	Potential service availability/utilisation remuneration per archetype: Flow	CES	H2	Li-ion	Gravity	Comments
Frequency Response Services	FFR static (£/MW/h)	0.3	X	0.3	0.3	0.3	2021 weekly auctions trial has stopped, therefore we used 2020 average monthly tender prices.[34]
	FFR dynamic (£/MW/h)	7.1	X	7.1	7.1	X	
	Dynamic Containment (DC) (£/MW/h)	15	X	15	15	X	Average price September to December 2021.[35]
Balancing Reserve Services	STOR (£/MW/h)	3.4	3.4	3.4	3.4	3.4	Average price daily auctions 2021 (April – Nov)[36]
	Demand Turn Up (£/MW/h) (£/MWh)	2.9 67.5	2.9 67.5	2.9 67.5	2.9 67.5	2.9 67.5	Average tender prices. Latest tender results available are in 2017.[37] The availability window is limited to 6 months - an average of 9 hours per day during weekdays and 3 hours on weekends.[38]
Capacity Market	Capacity market T-4 (£/kW/year)	2	2	2	2	2	T-4 auction delivery year 2024-25.[39]
Capacity Market	Capacity market T-1 (£/kW/year)	5.1	5.1	5.1	5.1	5.1	T-1 auction delivery year 2021-22.[40]

[33] https://www.ofgem.gov.uk/energy-data-and-research/data-portal/wholesale-market-indicators
[34] https://powerresponsive.com/wp-content/uploads/2021/03/Power-Responsive-Annual-Report-2020.pdf
[35] https://data.nationalgrideso.com/ancillary-services/dynamic-containment-data
[36] h\ttps://data.nationalgrideso.com/ancillary-services/short-term-operating-reserve-stor-day-ahead-auction-results/r/stor_da_auction_results
[37] https://www.nationalgrideso.com/document/85351/download
[38] https://www.nationalgrideso.com/document/88466/download
[39] https://www.emrdeliverybody.com/CM/T42024.aspx
[40] https://www.emrdeliverybody.com/CM/T12021.aspx

The table below presents a summary of the average volumes and dominant technologies for each service.

Table 6-7 Overview of service volumes and participating technologies

Service type	Service/ Market	Volume	Technologies	Comments
Frequency Response Services	FFR static	~196 MW	Largely dominated by thermal	Average monthly volumes 2020
	FFR dynamic	~ 1050 MW	Largely dominated by storage	
	Dynamic Containment (DC)	~ 500 MW	Only BESS	Average monthly volumes from Oct 2020 to Aug 2021. Operability Strategy Report 2022[41] suggests a need for 1,400MW by 2025 and more after that.
Balancing Reserve Services	STOR	~ 1250 MW	Dominated by thermal	Average daily procurement in 2021 auctions
	Demand Turn Up	~ 200 MW	Dominated by DSR	Average of historical procurement volumes (2016-2018)
Capacity Market	Capacity market T-4	40819.9 MW	Largely dominated by thermal	Procured volume in 2020
Capacity Market	Capacity market T-1	2252.1MW	Largely dominated by thermal	Procured volume in 2020

6.2.4 Stackability considerations

We have shown that operators of storage technologies seeking to maximize value from their assets have numerous options for their strategy. A key consideration for flexibility providers is the extent to which revenues for constraint management can be "stacked" with revenues from providing other services. In some cases they have the option to stack services during the same time period by providing multiple services simultaneously; in other cases they will have to use revenue streams in different time periods to take advantage of opportunities at different times of the day.

Considering commercial exclusivity terms, flexibility providers are able to move freely between revenue streams in different time periods, but they have more challenges to provide different services during the same time window due to contract terms or regulatory arrangements. For example, Capacity Market rules allow revenue stacking for an asset without risk of penalty, but this is not the case for some of the balancing services (e.g. STOR).

The matrix below shows the possible combinations for revenue stacking across all analysed services based on contractual exclusivity terms. To be noted, that NGESO is in process of reforming the balancing services and revenue stacking allowance is subject to further changes. Particularly, NGESO is seeking to review the exclusivity clauses within balancing services contracts to ensure efficient service provision within NGESO as well as between NGESO and DNOs.

[41] https://www.nationalgrideso.com/document/227081/download

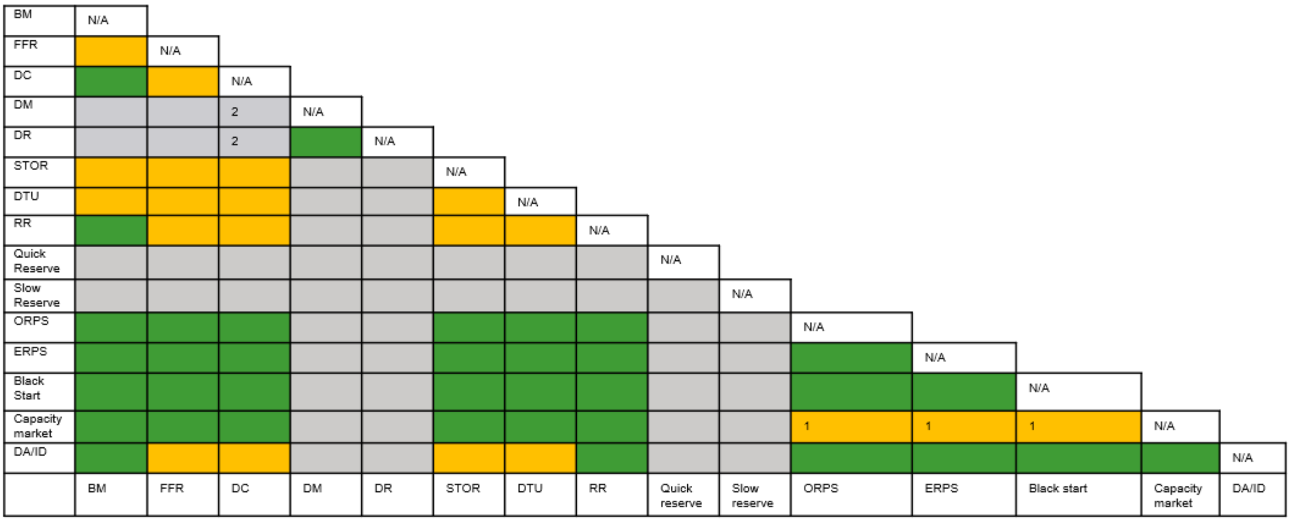


Figure 6-13 Revenue stacking matrix for same time period. Green = Stackable, Yellow = Non-stackable, Grey = not determined yet.[42] 1: Service not listed as a Relevant Balancing Service under the Capacity Market Rules. 2 DM and DR cannot stack with DC at launch, they may stack in future.

In addition to contractual exclusivity terms, stackability depends also on economic and technical factors that could limit the participation of storage in multiple services at the same time. For instance, even when contracts allow revenue stacking with Constraint Management services, the requirements of different services may not be compatible. Some services will need the storage to be at a different state of charge to others, which creates a technical barrier, but could also affect the economics for the storage operator (e.g. they may need to charge when prices are high) who will seek to maximise returns from accessing different markets, and would choose which services to provide. In addition, the physical location of the storage asset will affect its ability to provide different services. When a resource is located in a constrained area, they are usually less suitable for offering other services, such as frequency response services, from a system perspective. This is particularly relevant at times when duration of the constraints is significantly long.

6.2.5 Wider Considerations for Storage

The assessment presented in this report shows the theoretical financial suitability (in terms of LCoS) of a set of ESS archetypes in performing a network constraint management service, based on the set of operational parameters defined in Section 3.2. There are several wider considerations for ESS deployment that this sort of feasibility/modelling assessment cannot take into account. These include current market conditions, the predicted growth rate of the ESS market, technology maturity, cost reduction potential, supply chain considerations etc. The purpose of this section of the report is to provide a high-level overview of these points and discuss how they could impact ESS deployment.

As mentioned previously, Li-ion is the market leading ESS technology in new grid scale installations. This is largely due to its superior performance characteristics, short development timescales and relatively low cost for shorter durations (most financially viable ESS applications to date in the UK have been more suited to short duration technologies). Li-ion battery energy storage systems (BESS) is a well-established mature technology which has been proven numerous times at a large scale. There is no significant concern around the possibility of developing Li-ion BESS up to 400 MWh (the sizing assumption considered for the base case, 50 MW, 8 hour systems), although the deployment of Li-ion above discharge durations of 4 – 5 hours is relatively uncommon. As the analysis considered the deployment of 400 MWh in 24 separate locations, it is worth noting that even for Li-ion's well established supply chain, an energy storage pipeline of this scale is very large (totalling 1,200 MW/9,600 MWh).

Of the remaining archetypes, flow batteries are the most well established in terms of the number of prominent manufacturers, technology maturity and resiliency of supply chains/manufacturing capability. As discussed in

[42] Matrix produced by DNV with data from NG ESO webpage and ENA (https://www.energynetworks.org/industry-hub/resource-library/open-networks-2020-ws1a-p5-dso-revenue-stacking.pdf)

section 3.2.1, while large scale flow batteries are being developed (up to 800 MWh), most installations to date are of a smaller scale. Additionally, many manufacturers of the technology are limited by their production capabilities resulting in longer lead times for large projects. While flow battery projects of the scale considered in this project are possible, a full pipeline of 24 large scale flow battery projects may need to be spaced out over a number of years.

LAES are also a relatively mature ESS archetype with performance characteristics suited to long duration applications such as network constraint management. However, as with flow batteries, LAES may be hindered by longer development/lead times. It is worth noting that while there are numerous well established flow battery manufacturers there are only a few prominent producers of the technology. Referring back to Section 0, it is feasible to develop LAES systems of the sizes considered in the base case assessment (50 MW, 24 hours, 1200 MWh). However, as with flow batteries, a pipeline of 24 projects of this scale could present issues regarding supply chains and development lead times.

Hydrogen and Gravity are the least mature ESS technologies considered in this analysis. Both technologies have characteristics suited to longer duration storage applications, although hydrogen is held back by low efficiency. While electrolyser and fuel cell technology have been proven at relatively large scale (approximately 50 MW for fuel cells and up to 100 MW for electrolysers), full power – hydrogen – power systems are uncommon and have not been proven consistently at scale. While it may be technically feasible (financial feasibility will depend on the business case) to develop a 50 MW power – hydrogen – power system with a duration of approximately 6 hours and above, developing a portfolio of 24 large scale hydrogen systems could present a number of issues. Similarly, while gravity energy storage has technical characteristics suited to constraint management and some manufacturers quote long lifetimes and CAPEX resulting in low LCOE figures, the maturity of the technology raises concerns over its suitability for the development of large portfolio. However, in DNV's opinion, while the immaturity of these archetypes may present issues now, it is still worth considering the suitability of their technical operational characteristics for long duration applications.

Further to considerations regarding archetype maturity, deployment capacities, lead times development experience, the NGESO should consider the associated footprint of long duration energy storage. This is a factor which may increase the difficulty in developing a given project. In particular, gravity energy storage has a low energy density and therefore a large site footprint. Coupled with the required height for gravity energy storage systems, these points could present problems regarding site selection and permitting. It is noted that some types of gravity energy storage raise/lower masses in decommissioned mine shafts. While these types of installations do not have the same limitations regarding site footprint and the required height of the system, there are issues regarding the limited number of suitable sites. While flow batteries also have a relatively low energy density, they are generally installed as containerised systems and would not be subject to same concerns regarding permitting and height. LAES systems offer flexibility in design/configuration and the footprint of a site is therefore flexible. For example, if the footprint of a site is a concern, certain components can be stacked to reduce the total area.

Based on the limitations of each archetype regarding site selection (footprint, permitting etc.), manufacturing and supply chain considerations and technology maturity, developing/procuring a portfolio of 24 large scale long duration ESS across the UK is likely to present issues, particularly if only one ESS archetype is considered. Ultimately, DNV view a more likely scenario to be that electricity system needs could be addressed by a combination of ESS archetypes, thereby reducing the strain on the supply chain/manufacturing centres for any one technology.

6.3 Conclusions

Aside from the Balancing Mechanism, we have found a total of 21 services/markets that were, are or will be available for participation. Regarding the access of storage archetypes to those markets/services, on the basis of technical requirements, we make the following observations:

- Flow and Li-ion batteries are technically capable of providing 73% of the listed services. The remaining 27% are services that are generally only applicable to conventional generation plants.
- Hydrogen storage has the capabilities to participate in nearly as many services as flow and Li-ion batteries (68%). The only exception being the fastest response balancing service, dynamic moderation.
- CES is only suitable to provide 5 services (23% of the total) due to its slower response time. LAES is suited to provide slow reserve services, reactive power, as well as to participate in capacity markets and wholesale market.

- Gravity storage, like LAES, is also not suited for fast response services, such as frequency services and reserve services. However, its slightly faster response allows Gravity Storage to participate in more reserve products than LAES. Gravity storage is able to provide 10 services (45% of the total).
- All technologies can participate in the Capacity and Wholesale Markets.
- None of the technologies can participate in Super SEL and BM start-up services, since they are typically for traditional power plants. Intertrip services may be possible in some cases.

When considering the opportunities for substantial revenues from access to other services our conclusions are:

- **Frequency response services** (FFR, DC, DM, DR) provide a viable option and good revenue opportunity for storage operators. Although these services are under reform, we expect that the future new products will be suitable for most storage archetypes which will have a competitive advantage compared to other technologies (non-storage technologies) due to fast response capabilities (especially battery storage). We have already observed that Dynamic Containment (DC) has attracted the interest of storage providers due to high prices and limited competition. In addition DC can be stacked with BM and Capacity Market providing additional revenue streams, although committing capacity to DC may reduce the capacity that can be offered in the BM[43]. Moreover, taking FFR as an example of the development of future frequency response services, we note that FFR dynamic achieved higher prices and volumes compared to the static FFR. On the basis that FFR dynamic is closer to the new frequency response services compared to static FFR, we also expect that the market size and prices of these products will provide attractive business case for storage operators.
- **Reserve services** (STOR, Demand Turn Up, Quick Reserve, Slow Reserve) provide a less attractive option compared to frequency response services. DTU already received limited interest from the providers as the market size and unit prices are small. STOR on the other side is one of the services with the largest market size. Nevertheless it is dominated by thermal technologies which are difficult for storage to compete with. In addition, reserve services are currently not stackable with other services which limits the revenue opportunities for the assets (although this is subject to future changes). Quick Reserve and Slow Reserve are future products which have not been implemented yet. Although participation to STOR is still an option for all storage archetypes, current trends do not present large revenue potential for storage.
- **Capacity Market:** Capacity market is open to all storage technologies and we consider it a good option as it provides constant revenues and is stackable with all services. De-rating factors have decreased, which in turn has an impact on revenue opportunities. Since de-rating factors are more favourable the longer the storage duration is, we consider Capacity Market more attractive for storage with longer durations. However this does not exclude other storage archetypes from participating in the services.
- **Reactive power services** are stackable and can be provided by all storage archetypes. For those storage archetypes for which a synchronous generator operator is not available, they will need to be coupled with a PCS/inverter to provide reactive power. Due to limited information on pricing and volumes, future storage operator should explore further the benefits of providing these services.
- **Black start** is only technically accessible when storage technologies are coupled with a PCS/inverter capable of operating in grid forming mode rather than grid following mode. Similar to reactive power services, this is a service provided based on bilateral agreements so a storage operator should explore further the benefits of providing Black Start with NGESO. To be noted, that black start (or restoration services) technical requirements are subject to change to allow for greater participation of technologies.
- **Wholesale market** provides arbitrage opportunities for storage providers who can charge when prices are low and discharge when prices are high. The market is open to all generators and provides a positive case for additional revenues for storage as we observe high wholesale prices and high volatility.

[43] See worked example here https://www.nationalgrideso.com/document/184466/download

7 Summary of Findings

Our analysis has shown that application of storage technologies for constraint management is a technically viable way to reduce network overloads between now and 2030. However, if storage is contracted for constraint management on an exclusive basis, none of the tested storage archetypes achieve a clear business case in the sense that the cost of storage would be consistently lower than that of other providers of constraint management services.

Whilst the study did not aim to identify exact volumes or constraint cost savings based or an optimal amount of storage deployed across Great Britain, it did show that, under the right conditions, the storage technology has the potential to create some value for current and future network users by reducing the costs for constraint management. In this study the focus was on a detailed representation of how storage affects the flows on the network, with less priority given to the identification of the optimal number of storage assets and their capacity per location. This allowed to better understand the effect of each MW of storage dispatch on the flows across network boundaries, and how the same asset can reduce overloads in multiple locations. In contrast, this approach did not consider smart deployment strategies such as intertemporal optimisation by which a storage operator does not dispatch its asset against the first constraint that it sees, but seeks to withhold the asset from deployment to maximise the price it realises in the BM.

The assessment indicates that the full potential value of storage for constraint management is limited because of the nature (duration, frequency and magnitude) of network constraints, the nature of circuit flows in a meshed network (effectiveness of location specific actions) and the technical capabilities of the storage asset (e.g. round-trip efficiency and energy capacity). The interplay between these factors results in storage assets often remaining idle, waiting for an opportunity to return to the ready state such that the required dispatch does not exacerbate the network overloads. The utilisation that was achieved by the tested archetypes as an average across the modelled years is in a range from 9 to 31%, depending on the archetype. This means that storage operators would need to recover capital and operating costs over a relatively limited number of hours, making them less cost competitive. However, this also leaves significant time to participate in other ancillary market service to release revenues and spread costs, potentially bolstering competitiveness in the constraint management market.

We find that storage assets with higher round-trip efficiencies and higher energy capacity tend to perform better. This allows them to achieve lower levelized cost of storage (LCoS) and become more competitive in the merit order of balancing mechanism units (BMUs) providing the same service. Based on the simulation, the outturn average levelized cost of storage (LCoS) across archetypes varies between 120 to 400 £/MWh. This is considered to be too high for most technologies in most locations compared to ca. 110 £/MWh that NGESO currently pays to procure constraint management services from other assets/providers. Considering the commercial competitiveness of storage, we found that it largely depends on the geographic location. Storage assets installed in the northern part of GB will achieve higher utilisation levels and will compete with more expensive BMUs, both factors improving the potential for commercial feasibility of storage deployment in those regions. In contrast, deployment in southern regions leads to lower utilisation (fewer network overloads) and a less competitive position for storage given the presence of cheaper BMUs in the merit order.

Appendix A – Detailed Technology Characteristics

Detailed Flow Battery Technology Characteristics

Parameter	Value	Comment
High end of installation scale – Power Capacity	>50 MW	Flow batteries are modular, so they can be theoretically built at large scale (>50 MW). Rongke Power are currently developing a 200 MW/800 MWh flow battery in Dalian, China, proving the ability to deploy at large scale. However, most commercial projects to date are much smaller. It should be noted that the development of a large-scale project would currently result in long lead times due to the manufacturing and production capability limitations of most flow battery suppliers. While key suppliers are going through phases of scaling up their production capacity, many would be currently limited to approximately 10 MW/year.
High end of installation scale – Energy Capacity	>200 MWh	Flow batteries are modular, so they can be theoretically built at large scale (>200 MWh). The same details stated above regarding lead times, project development and production capacities apply. However, the bottleneck in production generally stems from the stack (power unit) development rather than production of the electrolyte and tanks.
Discharge Duration	4 – 8 hours, but this is flexible	Energy capacity is a function of the volume of electrolyte. This allows the flexibility to do long durations, typically in the range of 4 – 8 hours. It should be noted that many manufacturers are currently choosing to standardise their offering which limits the flexibility of power to energy ratios. Most systems are fixed at 3 – 4 hours. However, bespoke systems with longer durations are available for specific project requirements. Flow batteries exhibit power tapering, which is discussed further below. Therefore, a typical system has to be oversized on the DC side to allow discharge at rated power for the rated system duration. For example, a 10 MW, 8 hr system will be able to discharge continuously at 10 MW for 8 hr at the point of connection (POC) if it's DC energy capacity is oversized above 80 MWh.
Charge Duration	Approximately 6.5 hours for a 4 hour system ranging up to 13 hours for an 8 hour system	The charge duration at rated power depends on the system POC round trip efficiency (RTE), discharge duration, power tapering characteristics and oversizing of the system. Due to losses, the charge time will be longer than the discharge time. For example, a 10 MW, 8 hr system could have a discharge duration of 8 hrs at nominal power, however, to fully charge the system at nominal power (10 MW) could take approximately 11 – 13 hours (assuming a RTE of approximately 65%).
Power Characteristics (tapering etc.)	n/a	Charge/discharge power tapering will occur at high/low SOC, however, this is typical of batteries (including Li-ion). Some flow batteries are oversized appropriately to allow continuous charge/discharge at rated power for the system duration.
Reactive Power Characteristics	Full four quadrant operation	This is dependent on the power conversion system (PCS) installed with the flow battery, however, a standard PCS should have full four quadrant capabilities.

RTE (AC as measured at POC)	62% - 67%	Approximately 62% - 67% including auxiliary loads. Note that the POC RTE figure will be site specific and depends on the BOP design.
RTE (AC as measured at PCS)	67% - 72%	Approximately 67% - 72% including auxiliary loads.
Cycle Life	>20,000	Note, the power stack component usually requires replacement during the operational lifetime.
Expected lifetime	>20 years	
Capacity degradation	1% - 2%	Approximately 1% - 2% over operational life.
Response time		150 ms – 250 ms for full power stable response from receipt of signal including communications delay.
Availability	>95%	Dependent on what the specific manufacturer will offer in the performance guarantees.
SOC restrictions/DOD constraints		100% DOD
Continuous cycling capability	Yes	This is an advantage over Li-ion
Self-discharge	0%	n/a
Location constraints	n/a	No location constraints
Battery footprint	Approximately 70 MWh/acre for a 4-hour system excl. BOP	This metric is highly variable between manufacturers and depends on system duration (higher duration will result in higher energy density (MWh/acre)).
Site footprint	Tbc	
CAPEX	£400 - £550/kWh	Based on DNV experience. Total installed project cost (battery and BOP), including vanadium electrolyte, 8hr system.
OPEX	£0.5 – £2.5/kWh	Based on DNV experience. 8 hr system
Component replacement	£0.	
Vanadium End of Life (EOL) Residual Value	£60/kWh	Through a simple process the electrolyte can be recycled and reused. Some flow battery projects operate through an electrolyte leasing scheme, where the cost of the electrolyte is essentially an OPEX and it is never fully owned. In these cases, the electrolyte would have no EOL value to the battery owner.
Alternative services		With the characteristics of fast response time, relatively high efficiency and suitability to long duration applications, flow batteries can provide a wide range of services. Unlike most longer duration technologies, flow battery response times allow the provision of many ancillary services which form a significant portion of the energy storage business case in the UK to date. Additionally, flow batteries can provide a range co-location services, due to their suitability to store larger quantities of energy and ability to follow a dynamic load profile.

Detailed LAES Technology Characteristics

Parameter	Value	Comment
High end of installation scale – Power Capacity	>50 MW based on systems currently in development/operational Theoretical upper end of installation scale is 100s of MWs, up to approximately 500 MW	Modular, can be increased/scaled independent of energy capacity. Due to the modular nature of the technology, the potential scale/size is not limited, and could theoretically be increased up to the region of 500 MW.

		In a single system, discharge capacity can be scaled to several hundred MWs, similarly with the compressors on the charge side, of which the main OEMs (such as MAN, Siemens, GE) have established products.
High end of installation scale – Energy Capacity	Approximately 500 MWh based on systems currently in development/operational Theoretical upper end of installation scale is 1000s MWhs	Modular, can be increased/scaled independent of power capacity. Energy capacity is a function of tank capacity. Current construction techniques for tanks easily enable up to 300 MWh per tank. Batches of tanks can be used in a single system to enable GWh scale installations.
Discharge Duration	6 – 12 hours	CES can be scaled to higher durations, however, this range is preferred by manufacturers. Duration is only limited by tank capacity.
Charge Duration	6 – 24 hours	The size of charging device (compressor) dictates the charge rate and therefore charge duration. Charge rate/duration, discharge capacity etc can all be scaled independently to suit application requirements.
Power Characteristics (tapering etc.)	No tapering over the rated charge/discharge duration.	The system uses a synchronous generator which can provide (depending on scale of the system), the transmission system with stability levels of: • >1.8 GVAs inertia • >500 MVA SCL at 100 ms • +/- 100 MVAr fixed terminal voltage via On Load Tap Changer
Reactive Power Characteristics	Capable of providing reactive power	This will depend on the exact specifications of the synchronous generator used on the discharge cycle to produce electricity. The system is capable of providing MVArs throughout full range of operations, including at 0 MW active power. It can operate in target voltage and constant MVAr modes.
RTE (AC as measured at POC)	50% - 55% standalone Up to 65% - 70% with waste heat/cold	50% - 55% for standalone installation – this is based on early projects, depending on specific site design. This can increase to 65% - 70% if installed with source of high-grade waste heat and combined with a cold source[44,45]. Efficiency can change over time as air density (depends on ambient temperature and humidity) impacts the compressor efficiency. The impacts of this would require detailed dynamic modelling. A flat efficiency curve is to be assumed across the charge cycle.
RTE (AC as measured at PCS)	n/a	No PCS required as the expansion process is used to drive a synchronous generator.
Cycle Life	>11,000	Assuming 1 cycle day for 30 yrs. A greater number can be specified, however, the system would be subject to increased O&M costs.

[44] https://www.highviewpower.com/wp-content/uploads/2018/04/Highview-Brochure-November-2017-Online-A4-web.pdf

[45] DNV Experience

Expected lifetime	>30 years	Systems consist of established proven components with long operational histories in the power generation and industrial sectors. Greater than 30 years is possible if plant is maintained to suitable standards.
Capacity degradation	n/a	No capacity degradation occurs with LAES. No performance degradation occurs as long as the system is suitably maintained. Design margins are factored in to provide ensure both power discharge and energy capacity metrics achieve rated values over project life. Wear and tear of components results in slight reduction in the RTE of cycles over the lifetime. Depending on turbo-machinery and operational schedule, this is estimated as a drop of 1% - 2% between maintenance windows of 6 years (recoverable through maintenance). A non-recoverable drop of 0.5% - 1% occurs over the full lifetime. As a simplifying assumption, it is safe to assume a linear trend of non-recoverable efficiency reduction over the project life. O&M activities allow for recoverable performance during overhaul.
Response time Discharge	10 - 15 minutes	CES has a slow response time, however, the technology could be co-located with faster responding, short duration storage technologies such as flywheels/supercapacitors to produce a fast response, long duration hybrid system. CES is generally designed to achieve 15 min discharge response from standstill to full power. This reduces to 10 minutes when the system is in “stability” mode (generator synchronized and being motored by the grid).
Response time Charge	30 mins from standstill.	
Availability	94%	Based on 97% availability for charge and discharge systems independently.
SOC restrictions/DOD constraints	100%	Based on DNV experience.
Continuous cycling capability	Yes	
Self-discharge	<1%/day	The system is capable of storing for long term, up to months at a time. However, as the cryogenic fluid is stored in thermal isolated tanks at low pressure, there is a small amount of self-discharge (<1%/day). Therefore, if the system is used for long term storage, a small amount of ongoing energy input will be required to maintain full SoC.
Location constraints	No	No location constraints, however, the system efficiency can be greatly improved if there is a source of high-grade waste heat/cold available. Planning considerations: • Use of molten salts subject to EU Directive Seveso III (COMAH upper tier in UK)

		• Visual impact – tall structure up to 45m, however, can be designed to lower height (>30m) • Noise – is designed to industrial standards and specific limits achievable through noise attenuation
Construction Time	2+ years (approx. 27 months)	For a standard system design – circa 50 MW charge/discharge & 300 MWh (6 hrs). Note: this excludes the commissioning period.
Site footprint	Approximately 83.33 MWh/acre for a 50 MW, 5 hr system (250 MWh)	Flexibility in design results in flexibility in footprint, so this figure is a high-level estimate. It is also possible to stack some components to reduce footprint.
CAPEX	£300 - £350/kWh (estimated) for 50 MW system	The costs of LAES systems are highly sensitive to scale and the maturity of the development pipeline. Larger scale and longer duration systems have cost efficiencies resulting in lower per kWh CAPEX figures. As the technology increases in maturity over the coming years with increased learning from operational projects, CAPEX figures are expected to come down. Additionally, development costs are dependent on the exact configuration of the site, which is flexible (in terms of power, energy and duration). Current costs for an 8 hour system may be in the range of approximately £300 - £350/kWh. However, for longer duration systems towards the end of this decade, costs are expected to reduce to approximately: • £270/kWh for a 50 MW, 12 hr system • £170/kWh for a 200 MW, 24 hr system
OPEX	£2.3m/year	The system OPEX does not scale significantly with increased duration. The majority of the OPEX requirements are for the generators and turbomachinery rather than the tanks.
Component replacement	No major component replacement required during lifetime	Critical components (compressors, turbines, generators etc.) are designed for 30 years. During major maintenance events, assessments will be carried out for generator rewinds, re-wedges, compressor rotor replacements etc.
Alternative services		CES is more suited to long duration applications. This included services requiring storage of larger quantities of energy and can include a range of co-location services to balance out issues with generation intermittency. Additionally, due to the use of a synchronous generator, LAES systems can provide inertial response, voltage support and reactive power services. It's also worth stressing that as the LAES generator is a mechanical synchronous technology, which provides grid stability services simultaneously with providing energy charging and discharging, it offers multiple benefits to the grid operator and can therefore capture multiple revenue streams. A static

	storage technology, such as a flow battery or Li-ion would need to be combined with a synchronous condenser and a stat com to provide the same services.

Detailed Li-ion Battery Technology Characteristics

Parameter	Value	Comment
High end of installation scale – Power Capacity	100s MWs	Modular systems – therefore, installation scale can be large. Generally limited by the requirements of the business case, connection capacity on the grid and supply chain. Li-ion installations >100 MW are becoming increasingly common. However, these are more often relatively short durations (1 – 2 hours).
High end of installation scale – Energy Capacity	1-1.5 GWh	The addition of extra modules increases energy capacity. Traditionally, Li-ion systems have been associated with high power/short duration applications as this suited the business case. Certain market products (e.g. FFR, dynamic containment) value fast response with high power over short durations. However, long duration and high energy capacity Li-ion projects are becoming increasingly common. This is partly due to the ongoing improvements in Li-ion performance and price. Part of the bottleneck in deployment of longer duration Li-ion systems is that with limited cycling, it is difficult to make the business case stack up.
Discharge Duration	Up to 4 – 6	Theoretically, Li-ion could be developed with longer duration, however, this needs to be assessed for the particular business case.
Charge Duration	Up to 4 – 6/7	The charge duration at rated power depends on the system POC round trip efficiency (RTE), discharge duration, power tapering characteristics and oversizing of the system. Due to the high RTE of Li-ion, the charge duration at rated power is generally only slightly longer than the discharge duration.
Power Characteristics (tapering etc.)	Generally, no tapering across the **usable SoC range**	Li-ion systems are generally capable of providing a flat charge/discharge curve (constant power) across a wide SOC range within the specified optimal operational temperature range. Tapering of charge/discharge power can occur at very high or low SOC (>95% or <5%, exact figures depend on the specific system) and when the cell temperatures fall outside the optimal range.
Reactive Power Characteristics	Full four quadrant operation	This is dependent on the power conversion system (PCS) installed, however, a standard PCS should have full four quadrant capabilities.
RTE (AC as measured at POC)	84% - 86%	For a reference test cycle. During operation, this depends on cycling rate, ambient conditions, electrical equipment used, site electrical design, etc.
RTE (AC as measured at PCS)	~90%	
Cycle Life	Up 7,000 cycles depending on cell chemistry	This depends on the exact system, but typically in the range of 4,000-7,000 cycles. This figure can be increased/decreased based on how well the system is maintained, the cycle rate, depth of discharge (DOD) for each cycle, etc.
Expected lifetime	8-15 years	8-15 years for approximately 1 – 2 cycles/day. Lifetime extension possible by capacity augmentation.
Capacity degradation	Yes 1.5% - 3%/year	Capacity degradation is more of an issue for Li-ion than other ESS technologies. Generally, systems degrade to approximately 60% - 70% State of Health (SoH) in 8 – 15 years. When the End of Life (EoL) SoH is reached, battery degradation

		becomes unpredictable, performance degradation will occur and the system will have higher risk of safety issues. There are a number of factors which influence the rate of degradation, including: • Cycle rates • Depth of the cycles • Cell temperature Capacity degradation can differ between manufacturers and cell chemistries. Longer lifetimes are achievable through capacity augmentation (the addition of extra, or replacement of, battery modules/racks). Note, this results in additional CAPEX.
Response time	150 ms to 250 ms	Within ~150 ms – 250 ms of an instruction signal, including any communications latency (full power, stable response within 150 ms is very difficult to achieve, but it is required for services in certain markets, e.g.: DS3 services in Ireland).
Availability	97% -98%	High levels of availability, this also depends on the level of redundancy in the site design. Generally, ongoing maintenance requirements increase for higher availability resulting in higher OPEX.
SOC restrictions/DOD constraints	Yes	Depth of Discharge is usually limited to approx. 90%. However, specific limits depend on the manufacturer. It could range from 85% - 95%.
Continuous cycling capability	No	Back-to-back, deep cycling can cause excessive degradation to Li-ion systems. Some systems are rated to perform 2 back-to-back cycles, with thermal management systems appropriately sized to dissipate the associated heat build-up and maintain cells with the optimal operational temperature range. However, it would be unusual for Li-ion systems to perform more than 2 back-to-back cycles.
Self-discharge	2% - 3% per month	
Location constraints	No	
Site footprint	Approximately 25 – 35 MWh/acre	Li-ion BESS have a high energy density relative to the other energy storage technologies considered in this review. Note, the site footprint is presented as a range due the variability between installations. This can depend on the site layout and equipment selection. The market is currently seeing an increase in deployment of more energy dense, battery cabinet/cube style installations. Traditional containerised BESS units have a lower energy density (and would represent the upper end of this range).
CAPEX	£190-£240/kWh	For a 4-hour system, total installed project costs. Estimation for 1 GWh, 6hr system – approximately £130 - £190/kWh based on an internal DNV model. Note, beyond 4 hour duration, there is a lot of uncertainty in Li-ion CAPEX estimations. Note, as the majority of Li-ion installations to date are short duration, there is a reasonable amount of uncertainty in estimations for CAPEX of long duration systems. Even with shorter durations (1-2hrs), there is significant variability of CAPEX between markets and manufacturers/suppliers etc. Figure 3-1 presents a range of CAPEX estimates from various sources.

OPEX	Approximately 1% - 2.5% of CAPEX	Can vary depending on supplier, scope of services and availability guarantee.
Component replacement	Yes	Module replacement/augmentation if lifetime greater than 10-15 years is required. Annual module cost reduction – approximately 7%/year for the next 5 years, 5%/year (higher uncertainty here) for the next 5-10 years. Battery module costs account for approximately 50% - 60% of total system cost. Major BOP equipment (PCS, transformers, switchgear etc.) should not need to be replaced in the same timeframe.
Alternative services		Li-ion has flexible performance characteristics and is suitable to a wide range of alternative applications. Li-ion systems can provide the full set of Network, Ancillary and Co-location services summarised in section 6, apart from those that require a synchronous generator.

Detailed Hydrogen Technology Characteristics

Parameter	Value	Comment
High end of installation scale – Power Capacity	100s MW	Approximately 1 MW – up to 100s MW Largest electrolysis projects to date have been 100 MW. Electrolysis projects in the pipeline are several 100's of MW and even > 1 GW. The largest fuel cell project to date is a 50 MW power plant in South Korea using Doosan's phosphoric acid fuel cell technology. Gas turbines running on mixtures of hydrogen and other gases have been operated at refineries and industrial process plants for a number of years.
High end of installation scale – Energy Capacity	>1 GWh	Energy capacity is limited by geologic underground hydrogen storage possibilities. Natural gas is already stored underground for the winter season.
Discharge Duration		Function of volume of tanks/storage etc.
Charge Duration		Function of volume of tanks/storage etc.
Power Characteristics (tapering etc.)		Tapering: there would be a compressor behind PEM to put hydrogen in tanks. Feedback loops can be installed for double compression towards end of charge cycle.
Reactive Power Characteristics		Fuel cells generate DC power and require an inverter to generate AC power. In principle, they have same reactive power characteristics as a battery as this is provided by the inverter. Engines and gas turbines generate AC power by means of a conventional generator, so also have rotating mass and provide inertia.
PEM Efficiency (no postproduction treatment)	PEM = 77%[46]	PEM efficiency increase to 81% is predicted by 2050 There would be efficiency degradation over time – approximately 0.0001% - 0.0002% degradation per hour of operation. After 10% degradation the PEM stack would be replaced – this would take approximately 50,000 – 100,000 hrs operation.

[46] DNV Hydrogen in the Electricity Value Chain

Production Efficiency (with compression)	74% - 75%[46]	75% (compression to 250bar) 74% (compression to 700bar)
Production Efficiency (with liquefaction)	61%[46]	More commonly used over compression Cryogenic storage achieves a higher volumetric energy density, however, it results in higher costs and much lower efficiency
Electricity production	30% - 51%[46]	30% for gas engine 51% for fuel cell
Full POC RTE	20% – 40%[46]	Approximately 37% at POC, assuming 3% BOP losses, a 75% efficient PEM and 51% efficient FC. Note, another source claims higher efficiency at 47%,[47] although DNV does not consider this to be realistic currently.
Cycle Life		Electrolyser efficiency will decrease over time. Degradation rate is normally 0.1%/1000 hours. Electrolyser stacks would normally be replaced after 80,000-100,000 hours (lifetime is considered in terms of operational hours rather than cycles)[48]. Frequent turning off/on accelerates traditional electrolyser degradation, although newer designs are being optimised for intermittent operation with renewables. Fuel cell efficiency will also decrease over time. The degradation rate is approximately 0.2% - 0.3%/1000 hours. Fuel cell stacks would normally be replaced after 30,000-40,000 hours[8].
Expected lifetime	PEM approximately 20yrs depending on how much it is operated.	See “Cycle Life” section above. Lifetime depends on acceptable degradation level. For reference, 80,000-100,000 hours for electrolysers and 30,000-40,000 hours for fuel cells is a reasonable approximation.
Capacity degradation	n/a	No capacity degradation occurs due to the use of storage tanks.
Response time	1s for PEM Tbc for FC	PEM electrolyser – approximately 1s for min to max load. A PEM electrolyser can respond to new set point very fast. Pressurised alkaline electrolyser: 2 – 5 s min to max load Fuel Cell: electrochemical devices with very fast response times as long as there is hydrogen and oxygen flow in the electrodes. However, from a cold stand-by, the response time will be longer than batteries. This is due to the requirement to warm up they system, and for valves & blowers to actuate to drive the hydrogen and oxygen flows.
Availability	>95%	>95% for full plant with converters/transformers/compressors etc. depends on size of plant, how many stacks (higher no. stacks higher redundancy). The number of stacks depends on the manufacturer.
SOC restrictions/DOD constraints	n/a	
Continuous cycling capability	Yes	
Self-discharge	0.4%	Depends on storage. For cryogenic vessel storage, losses of approximately 0.4%/day occur.
Location constraints		This is only relevant if using underground caverns for hydrogen storage.

[47] https://www.sciencedirect.com/topics/engineering/round-trip-efficiency
[48] FCH 2 JU Multi-Annual Work Plan 2014-2020

		Safety distances to hydrogen storage tanks might impose some location constraints (nearby buildings, etc)
Site footprint	For electrolysis – approximately 25 – 50 MW/acre For fuel cells – approximately 20 – 25 MW/acre Footprint of hydrogen storage depends on storage pressure and capacity.	Due to the lack of operational electricity – hydrogen – electricity energy storage projects, it is difficult to estimate the total site footprint. High level data regarding the footprint of electrolysis sites (using electricity to create hydrogen) and fuel cell units is presented below. Footprint of a 1 GW grid-connected electrolysis plant is estimated to be between 24.7 - 42 acres for alkaline and 19.8 – 32.1 acres for PEM[49]. PEM fuel cells: a 40 ft container can house 1.5 MW of PEM fuel cell capacity[50] (excluding inverter and cooling). This is slightly less than the density of containerised Li-ion (approximately 2 MW- 2.5 MW per container).
CAPEX	Fuel Cells: 1,470.3 - £2,205.4/kW Electrolysers: £945.90 - £1156,10/kW Hydrogen Tanks: Approximately £3-£7/kWh of discharge capacity.	For Fuel Cells, CAPEX is $2,000 - $3,000/kW in 2020[8]. This equates to approximately **£1,470.3 - £2,205.4/kW** (converted at exchange rate of 0.74). Electrolyser CAPEX is approximately Eur1,234/kW[46]. This equates to approximately **£1,051.38/kW** (converted at exchange rate of 0.85). A range is specified here of +/- 10% of £1,051 to account for the uncertainty and variability in CAPEX. The CAPEX associated with hydrogen storage tanks is highly variable depending on the selected equipment and the storage pressure. Based on a range of sources[51], the approximate CAPEX of hydrogen storage, based on kWh of "discharge" capacity (assuming a 51% efficient fuel cell), is £3 - £7/kWh. However, this is highly variable and can be considerably higher based on some sources.
OPEX		For electrolysers – approximately 1%-2% of CAPEX/yr[46] For fuel cells: approximately 4% of CAPEX/yr[46] For hydrogen storage tanks: approximately 1.5% of CAPEX/yr[9]
Component replacement	Yes	FC and electrolyser stacks – refer to cycle life section above.
Alternative services		Hydrogen energy storage (for conversion of electricity – hydrogen – electricity) is relatively uncommon due to the low RTE. This disadvantage results in hydrogen being an uncompetitive option for many ESS services which require immediate conversion of hydrogen electricity. However, there are numerous alternative applications for hydrogen gas if it is not immediately converted back to electricity via fuel cells. This can include the storage for long periods off time to balance out seasonal variance in demand, use of hydrogen as a chemical feedstock for industrial processes and various applications in the transport and heating sectors.

[49] Integration of Hydrohub GigaWatt Electrolysis Facilities in Five Industrial Clusters in The Netherlands, ISPT
[50] Ballard ClearGen™),
[51] https://www.storeandgo.info/fileadmin/downloads/deliverables_2019/20190801-STOREandGO-D8.3-RUG-Report_on_the_costs_involved_with_PtG_technologies_and_their_potentials_across_the_EU.pdf

Detailed GES Technology Characteristics

Parameter	Value	Comment
High end of installation scale – Power Capacity	50 - 200 MW	It should be noted that most installations to date have be smaller scale pilot projects (<1 MW). However, this technology shows potential for larger scale long duration applications.
High end of installation scale – Energy Capacity	GWh	Note – this technology is less mature than the others. Many installations are pilot projects. It has the potential for large scale deployment and long durations, however, this has not yet been proven at scale.
Discharge Duration	Up to 8 – 10 hours	Flexible – can range from low durations (1-2 hours) up to high durations 8 – 10 hours. However, larger scale, long duration projects have not yet been developed. DNV notes that the technical characteristics of the system are suited to long duration storage.
Charge Duration	Up to 10 – 12 hours	The charge duration at rated power depends on the system POC round trip efficiency (RTE), discharge duration, power tapering characteristics and oversizing of the system.
Power Characteristics (tapering etc.)	No tapering	The transition from mechanical movement to a constant discharge profile can be challenging. However, this can be mitigated with smart control systems. Unlike battery storage, gravity based energy storage does not exhibit any power tapering at high/low SoC or ambient temperatures.
Reactive Power Characteristics	Capable of providing reactive power	This will depend on the exact specifications of the synchronous motor/generator used on the charge/discharge cycle
RTE (AC as measured at POC)	Approximately 76% - 79%	Assume BOP losses 3% - 4%
RTE (AC as measured at LV side of transformer)	80% - 83%	Due to the lack of operational projects, there is limited publicly available information on this. Claims vary from 80% - 90%, however, rarely specify the point of measurement and whether the figure is full RTE or just the charge/discharge efficiency. Based on DNV experience, the full RTE would be in the range of 80% - 83% (claims of up to 90% RTE appear unrealistic).
Cycle Life	>10,000	Based on minimum expected life of mechanical parts – overall lifetime and cycle life can be extended through maintenance/component replacement
Expected lifetime	30 – 40 years	Overall lifetime and cycle life can be extended through maintenance/component replacement
Capacity degradation	n/a	
Response time	1 – 3 seconds, depending on the exact technology	Note – this assumes the system is in an equivalent "active" mode. An additional ~2 seconds may be required for the response if the system is completely shut down.
Availability	Approximately 95% - 96%	
SOC restrictions/DOD constraints	n/a	100% usable SoC range
Continuous cycling capability	Yes	
Self-discharge	No	
Location constraints	Yes	Theoretically, the system is not geographically constrained. However, this technology has a very low energy density resulting is large site footprint. Additionally, the requirement to

		raise masses to large heights (approximately 100m) results in permitting difficulties which increases constraints on locations.
Site footprint	Large footprint 80.38m^2/MWh[52] Approximately 45 – 55 MWh/acre	Relatively low energy density. Additionally, systems also have a high vertical footprint which may pose permitting issues.
CAPEX	£213.86 - £259/kWh	CAPEX estimates for a 10 MW/40 MWh (4 hours) system are approximately \$289 /kWh - \$350/kWh[52] (£213.86 - £259/kWh @ conversion rate of 0.74) There is uncertainty as to how this would scale for longer durations.
OPEX	\$45.8/kWh[52]	For 10 MW/40 MWh (4 hours). There is uncertainty as to how this would scale for longer durations
Component replacement	n/a	No component replacement required over standard 30-35 year lifetime, however, the lifetime can be extended by component replacement and maintenance.
Alternative services		GES is more suited to long duration applications. This includes services requiring storage of larger quantities of energy and a range of co-location services to balance out issues with generation intermittency. The slow response time of GES rules out a number of ancillary services, however, due to the use of a synchronous generator, it is possible to provide reactive power support and inertial response (if the generator is already up and running rather than in idle/standby mode).

[52] https://www.energyvault.com/hubfs/EV%20Theme%20Images/Investor%20Relations%20page/EVIP-20210909-051.pdf

Appendix B – Detailed Modelling Results and Inputs

Storage

Table 7-1 Storage archetype parameters (per location)

	Unit	**Archetype 1**	**Archetype 2**	**Archetype 3**
Power	MW	50	50	50
Charging duration	h	24	24	8
Max Energy	MWh	1200	1200	400
Efficiency	%	55%	40%	85%
CAPEX	GBP	£240,000,000	£128,600,000	£52,000,000
OPEX (per year)	GBP	£2,300,000	£3,215,000	£520,000

Overloads

Table 7-2 Annual overloads to be managed [MWh]

	B4	**B6**	**B7a**	**EC5**	**SC1**	**SC3**	**SUM**
2021	16,104	1,453	322,447	-	-	-	**340,004**
2025	1,042,454	4,547,137	2,932,651	115,320	148,332	-	**8,785,894**
2030	498,031	6,809,197	1,556,944	254,870	2,117	1,431,575	**10,552,733**

Storage dispatch

Table 7-3 Useful and Total dispatch [MWh] (sum for 24 locations)

	Archetype 1			**Archetype 2**			**Archetype 3**		
	2021	**2025**	**2030**	**2021**	**2025**	**2030**	**2021**	**2025**	**2030**
Useful Dispatch	569,447	1,385,812	1,635,594	232,131	764,931	836,984	329,561	721,776	986,161
Total Dispatch	807,108	2,191,744	2,436,359	431,457	1,476,762	1,583,620	365,778	941,304	1,179,610

Total dispatch is the sum of each MW of storage dispatch across all locations for both directions. Useful dispatch is calculated as total dispatch less created imbalances, assuming that the imbalances will not constitute a remunerable service, and hence cannot be used to calculate the relevant LCOS. Total dispatch for each individual location is presented below.

Table 7-4 Total storage dispatch for each individual asset [MWh]

	2021			**2025**			**2030**		
	Archetype 1	**Archetype 2**	**Archetype 3**	**Archetype 1**	**Archetype 2**	**Archetype 3**	**Archetype 1**	**Archetype 2**	**Archetype 3**
SUM	**807,108**	**431,457**	**365,778**	**2,191,744**	**1,476,764**	**941,304**	**2,436,357**	**1,583,619**	**1,179,610**
1	9,971	6,017	2,447	109,050	72,126	66,228	133,950	86,407	54,732
2	32,915	8,878	15,828	91,355	55,054	39,360	131,844	85,202	55,165
3	33,173	8,605	15,792	82,825	54,420	33,765	120,610	82,319	48,723

4	9,285	4,319	3,223	83,221	55,077	33,125	105,355	80,018	44,821
5	44,176	36,171	21,748	84,300	50,512	33,514	101,212	76,731	46,083
6	35,877	28,973	16,577	112,767	81,628	59,826	79,446	49,797	39,920
7	36,212	28,836	15,894	95,375	71,748	36,413	85,077	54,845	52,446
8	37,352	28,668	16,445	95,853	70,948	36,164	88,352	61,732	52,485
9	39,846	30,688	17,964	98,098	71,574	37,003	89,245	25,404	47,374
10	40,969	32,144	18,621	101,306	76,329	38,442	92,687	53,920	40,528
11	33,628	8,049	15,086	82,348	55,414	33,896	77,232	50,049	39,276
12	44,478	37,542	19,978	106,976	70,609	55,936	93,973	55,354	45,140
13	37,842	31,123	16,529	100,432	72,150	48,102	77,282	50,082	37,072
14	32,312	18,142	15,285	95,803	70,892	36,240	145,366	82,684	82,362
15	31,123	13,696	14,184	94,196	69,661	36,427	90,900	53,157	41,652
16	32,722	9,192	15,620	86,177	56,105	33,846	90,237	69,644	46,943
17	25,782	6,129	12,168	84,297	54,676	33,453	90,876	67,430	46,426
18	32,772	9,318	15,347	77,133	48,124	31,749	88,541	53,643	41,545
19	33,237	9,669	15,755	69,490	38,780	28,276	92,301	63,857	46,390
20	33,310	8,469	15,089	88,046	53,787	35,528	91,549	54,043	44,229
21	33,211	9,788	15,609	84,024	55,873	33,223	93,792	55,528	47,857
22	33,903	8,578	15,708	92,344	57,066	40,717	148,535	109,262	85,666
23	33,350	8,039	15,202	85,930	49,351	42,362	110,281	80,296	45,506
24	49,662	40,425	19,679	90,399	64,860	37,708	117,714	82,215	47,269

Note that the locations of assets have been adjusted slightly between the simulation years. Some locations were added, and some were removed based on the preliminary analysis of most severe overloads for each year. Table 7-10 below contains an overview of the selected locations for each simulation year.

Table 7-5 Total useful energy dispatch (throughput) used in LCOS calculation [MWh]

	Archetype 1			**Archetype 2**			**Archetype 3**		
	High utilisation	**Low utilisation**	**Average**	**High utilisation**	**Low utilisation**	**Average**	**High utilisation**	**Low utilisation**	**Average**
2021	35,039	6,551	23,727	21,749	2,324	9,672	19,594	2,205	13,732
2025	71,301	43,937	57,742	42,281	20,087	31,872	50,782	21,682	30,074
2030	99,716	51,848	68,150	57,748	13,427	34,874	71,617	30,993	41,090

Average useful dispatch is calculated as total useful dispatch divided by 24. High (low) utilisation useful dispatch is calculated as the maximum (minimum) dispatch across 24 locations from Table 7-4 scaled by the ratio of the total useful dispatch to the total dispatch. The scaling is necessary because useful dispatch per location is not directly available as an outcome of modelling. Calculation of useful dispatch can only be done as an aggregate of 24 locations because of how storages affect flows on individual circuits.

Reduction in congestion

The reduction in congestion is calculated as follows: for overloaded lines only – the sum of individual differences between the power flow prior to storage dispatch, and the post-dispatch flow on those lines.

Table 7-6 2021 Reduction in congestion [MWh]

	Archetype 1	Archetype 2	Archetype 3
B4	2,076	969	641
B6	678	775	89
B7a	50,750	31,018	23,798
EC5	-	-	-
SC1	-	-	-
SC3	-	-	-
SUM	**53,504**	**32,763**	**24,529**

Table 7-7 2025 Reduction in congestion [MWh]

	Archetype 1	Archetype 2	Archetype 3
B4	45,832	35,592	15,491
B6	218,174	169,943	70,716
B7a	171,644	134,754	59,096
EC5	12,022	6,994	5,774
SC1	15	16	19
SC3	-	-	-
SUM	**447,687**	**347,298**	**151,097**

Table 7-8 2030 Reduction in congestion [MWh]

	Archetype 1	Archetype 2	Archetype 3
B4	9,158	6,893	2,816
B6	184,809	134,123	66,152
B7a	131,241	110,350	42,444
EC5	12,865	8,608	8,435
SC1	3,453	2,299	1,220
SC3	31,958	22,793	10,301
SUM	**373,483**	**285,066**	**131,368**

Efficiency of storage dispatch

Table 7-9 Efficiency of storage dispatch [MWh or %]

	Archetype 1			Archetype 2			Archetype 3		
	2021	**2025**	**2030**	**2021**	**2025**	**2030**	**2021**	**2025**	**2030**
Overloads	340,004	8,785,894	10,552,733	340,004	8,785,894	10,552,733	340,004	8,785,894	10,552,733
Useful Dispatch	569,447	1,385,812	1,635,594	232,131	764,931	836,984	329,561	721,776	986,161
Total Dispatch	807,108	2,191,744	2,436,359	431,457	1,476,762	1,583,620	365,778	941,304	1,179,610
Reduction in overloads	53,504	447,687	373,483	32,763	347,298	285,066	24,529	151,097	131,368

Reduction as % of total overloads	15.7%	5.1%	3.5%	9.6%	4.0%	2.7%	7.2%	1.7%	1.2%
Useful/ Total Dispatch	71%	63%	67%	54%	52%	53%	90%	77%	84%
Reduction in overloads/ Useful Dispatch	9.4%	32.3%	22.8%	14.1%	45.4%	34.1%	7.4%	20.9%	13.3%
Total throughput per MWh installed	28	76	85	15	51	55	38	98	123
Useful throughput per MWh installed	20	48	57	8	27	29	34	75	103
Utilisation*	14.0%	37.9%	42.1%	10.3%	35.1%	37.7%	4.1%	10.5%	13.2%
Average utilisation*	31%			29%			9%		

*__Utilisation__ is calculated as *Total_dispatch / (8760*Efficiency*Rated_power)* representing a simple benchmark to compare archetypes. Note, the metric ignores differences in energy content between archetypes: Archetype 3 has a lower energy content (400 MWh) than Archetypes 1 and 2 (1200 MWh). Furthermore, this metric assumes that the maximum number of operational hours equals 8760. The table shows the utilisation of an archetype on aggregate across 24 locations for each of the years 2021, 2025, and 2030.
*__Average utilisation__ is calculated as the average annual **Utilisation** for a given archetype across 24 locations.

The first 4 rows of data in this table are taken from Table 7-2, Table 7-3, Table 7-6, Table 7-7 and Table 7-8; the remaining rows are calculated to understand the efficiency of storage dispatch in greater detail.

24 storage locations

Table 7-10 Storage locations

	2021	2025	2030
1	Stella West 400kV	Stella West 400kV	KIIN1-
2	Bolney 400kV	Kemsley 400kV	Tealing 400kV
3	Bramley 400kV	Bolney 400kV	INVE1K
4	Connahs Quay 400kV	Bramley 400kV	Eccles 400kV
5	Eccles 400kV	Connahs Quay 400kV	Stella West 400kV
6	Harker 400kV	Harker 400kV	Thornton 400kV
7	INVE1K	INVE1K	Walpole 400kV
8	INVR2-	INVR2-	Norwich Main 400kV
9	KIIN1-	KIIN1-	Padiham 400kV
10	Lovedean 400kV	Tealing	Connahs Quay 400kV
11	Melksham 400kV	Lovedean 400kV	Pelham 400kV
12	Norwich Main 400kV	Norwich Main 400kV	Melksham 400kV
13	Penwortham 400kV	Penwortham 400kV	East Claydon 400kV
14	STHA4A	STHA4A	Penwortham 400kV
15	TEAL2J	Eccles	Taunton 400kV

16	Pelham 400kV	Melksham 400kV	Tilbury 400kV
17	East Claydon 400kV	East Claydon 400kV	Kemsley 400kV
18	Thornton 400kV	Pelham 400kV	Bramley 400kV
19	Kemsley 400kV	Thornton 400kV	Sellindge 400kV Compound A
20	Sellindge 400kV Compound A	Sellindge 400kV Compound A	Lovedean 400kV
21	Taunton 400kV	Taunton 400kV	Bolney 400kV
22	Tilbury 400kV	Tilbury 400kV	Harker 400kV
23	Walpole 400kV	Walpole 400kV	STHA4A
24	Padiham 400kV	Padiham 400kV	INVR2-

Extreme utilisation case

Table 7-11 Total useful energy dispatch (throughput in MWh) used to calculate the LCOS for a theoretical extreme dispatch

	Archetype 1	Archetype 2	Archetype 3
Per year for all years	226,504	164,730	350,051

The above values reflect an assumption of a storage unit being operated at rated power for 95% of hours in a year (8760) with individual efficiencies for each archetype, i.e. the formula is *Efficiency*Rated_Power*0.95*8760*.

LCOS

Table 7-12 LCOS summary [£/MWh]

	Extreme utilisation	Highest utilisation	Average	Lowest utilisation
Archetype 1	82	227	319	438
Archetype 2	72	248	396	887
Archetype 3	12	70	120	170

In this table Highest and Lowest utilisation refers to the maximum and minimum utilisation, respectively, across 24 locations for a given archetype. Average utilisation is calculated based on the total useful dispatch across all locations for a given archetype, divided by 24.