Imperial College London

Strategic Assessment of the Role and Value of Energy Storage Systems in the UK Low Carbon Energy Future

Report for

CARBON TRUST

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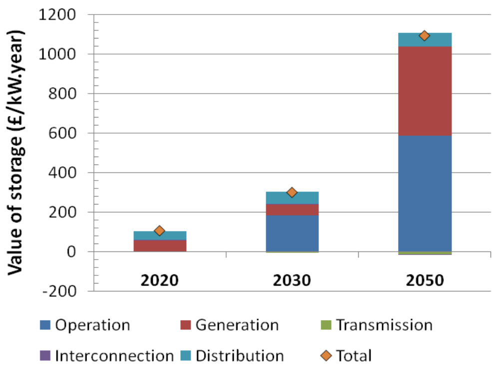
Foreword

Understanding the potential of electricity storage to reduce the costs of electricity generation in our future system is critical in guiding policy in this area. The Carbon Trust commissioned this study to address some of the key questions in relation to the future role of electricity storage in the UK: what are the cost targets and scale of deployment? What are the benefits of storage across different time scales and different sectors of the system (from real time operation to investment time scale, considering generation, transmission and distribution sectors)? What type of storage delivers the highest value and where should it be placed on the network?

The whole-systems cost minimisation approach of this study identifies significantly higher value than previous studies by balancing and aggregating benefits across various sectors, including networks, generation capacity and system operation. Different types of storage fulfil different functions. Bulk and distributed storage are found to provide most value when placed in Scotland and Southern regions respectively. The former can support system balancing and "firm-up" wind generation, while the latter can also avoid distribution network reinforcements driven by electrification of heat and transport sectors. The figure below shows that the value of storage increases very significantly in the scenario with increasing contribution of renewable generation for the example of distributed storage of 10 GW installed capacity. The figure also illustrates how various savings components evolve over time. In 2050 high renewables scenario, application of energy storage technologies could potentially generate total system savings of £10bn/year.



Value of storage increases very significantly with the level of penetration of renewable generation

Although scenarios with a high share or renewable generation are the most favourable for storage, even in predominantly nuclear scenarios, storage has a role to play. Large deployment of CCS, on the other hand, can reduce the scope for storage. Alternative technologies, such as flexible generation or interconnection are found to reduce the value of storage but do not displace its role, while demand side response is the most direct alternative to storage.

Operation patterns and duty cycles imposed on the energy storage technology are found to vary considerably, and it is likely that a portfolio of different energy storage technologies will be required, suited to a range of applications. Storage durations in excess of six hours yield little additional value, given the demand profile. Efficiency of storage has been found to affect the value modestly and only with higher levels of deployment efficiency becomes more relevant. We also demonstrate that changes in system management, including generation scheduling methodology and the improvements in wind output forecasting errors, may have a significant impact on the value of storage.

This analysis demonstrates that the value of energy storage technologies in low carbon energy systems with large contribution of renewable generation may be very significant; it will therefore be important to ensure that energy policy and market framework do not impose a barrier but rather facilitate the application of cost-effective energy storage technologies. The study shows that energy storage can bring benefits to several sectors in electricity industry, including generation, transmission and distribution, while providing services to support real-time balancing of demand and supply, network congestion management and reduce the need for investment in system reinforcement. These "split benefits" of storage pose challenges for policy makers to develop appropriate market mechanisms to ensure that the investors in storage are adequately rewarded for delivering these diverse sources of value. Further work is needed to understand how different market and policy frameworks would impact the deployment of alternative grid-scale energy storage technology solutions. Furthermore, this work should inform energy storage technology developments and related innovation policy in order to further reduce the cost of storage.

Summary

Context and key objectives

The UK government's commitment to reducing greenhouse gas emissions by 80% by 2050 poses significant challenges, including an unprecedented transformation of the GB electricity system. As part of this effort markets are expected to deliver and integrate significant amounts of intermittent renewable generation in combination with less flexible nuclear and Carbon Capture and Storage (CCS) plant while segments of the transport and heat sectors are expected to be electrified, adding further to the demands on the system.

Integration of the low capacity value of intermittent generation, accompanied with possibly very significant increases in peak demand driven by transport and heating electrification, may lead to very significant degradation in the utilisation of generation infrastructure and electricity network assets. As a result, system integration costs are expected to increase considerably.

Energy storage technologies have the potential to support future system integration. However, the potential value storage brings to the system, and therefore its cost targets, are poorly understood to date. A comprehensive whole systems analysis approach is developed in this study to establish the role and quantify the value of electricity storage, alongside alternative technologies, in facilitating cost-effective evolution to a low-carbon future. In this context the key objective of this work was to model and analyse the value of grid-scale storage in the future GB electricity systems (based on DECC Pathways), with the outputs intended to inform the UK energy policy. The study aims to assess:

(i) Cost and performance targets for grid-scale energy storage applications to facilitate a cost effective evolution to a low carbon future.

(ii) Sources of value of storage, i.e. savings in capital expenditure in all sectors including generation, transmission and distribution infrastructure, as well as savings in operation costs and the potential to enhance the ability of the system to accommodate renewable generation.

(iii) Impact of competing options including flexible generation, demand side response, and interconnection.

(iv) Changes in value of storage across key decarbonisation pathways including changes in fuel costs.

(v) Impact of various storage parameters on its value, including the importance of additional storage duration, storage efficiency and ability to provide frequency regulation services.

(vi) Impact of changes in system management on the value of storage, including generation scheduling methodology and the impact of improvements in wind output forecasting errors.

Approach and input assumptions

The underlying principles of the approach to assess the value of storage in this study are:

- **Technology-agnostic**: Storage technologies are represented through a limited number of generic key characteristics, allowing a wide range of technologies to be mapped onto the results.
- **Market-agnostic**: The objective function of the model minimises the overall system

cost (both capital and operating costs) under carbon constraints. This approach provides a reference value for storage that sets a benchmark to support policy and market development.

- **Long-term**: By simulating scenarios as far out as 2050, this study seeks to inform the strategic role for storage within future technology portfolios.

This study presents a whole-systems approach to valuing the contribution of grid-scale electricity storage in future low-carbon energy systems. This approach reveals trade-offs between multiple services that energy storage is able to provide, which result in generally higher aggregate values for storage than in previous approaches that considered such services in isolation.

The whole-systems approach applied minimises investment and operation cost to future GB systems, with appropriate representation of its generation system, transmission and distribution networks, while also including interconnection with neighbouring electricity systems of Ireland and continental Europe. The model simultaneously optimises investments into new generation, storage, interconnection, transmission and distribution assets while considering short-term operation of the entire system on an hourly basis. System adequacy and security requirements together with emission constraints are considered within the same framework. The model further includes a detailed representation of electricity demand, and considers the capability of demand response technologies, using the inputs supplied by our detailed bottom-up demand models.

Although we model real-time energy export and imports with neighbouring markets, we impose the constraint that UK is energy-neutral over a time horizon of one year, which is found to be important if consistency with the DECC Pathways is to be maintained. We further assume that UK is self-secure, i.e. that UK generation capacity needs to be sufficient to meet peak demand, with sufficient reserve margin held within the UK; this assumption implies that no contribution from interconnectors to system security can be expected.[1] In maintaining security, we have assumed the level of system reliability indices to be consistent with historical levels of security of supply.[2]

Storage technologies are represented through generic technology characteristics, such as round trip efficiency, storage duration (the ratio of energy and power capacity), speed of response, geographical location and voltage level of the network it connects to; bulk storage is connected at the transmission level, while distributed storage is connected to distribution networks. We have conducted a comprehensive analysis with a broad range of assumed storage cost levels to evaluate interdependencies between cost, optimal volumes deployed and system-level benefits of storage.

The core pathway chosen to focus the assessment of the value of storage is *Grassroots*, which is characterised by a rapid increase in the share of renewable energy in the electricity supply mix. It further comprises a high rate of electrification in transport and heat sectors accompanied by ambitious energy efficiency measures, in line with DECC Pathways. Our analysis focuses on snapshots for the years 2020, 2030 and 2050 in the Grassroots pathway, but we also assess the role of storage in distinctly different decarbonisation pathways, namely those relying on nuclear or CCS technology to achieve the 2050 emission targets.

[1] We also impose a self-security constraint for the European electricity system.

[2] The level of security is generally measured by a range of reliability indices including: LOLP = Loss of Load Probability; LOLE = Loss of Load Expectation; ENS = Energy Not Supplied. We note that the level of investment in generation capacity needed to maintain historical levels of security corresponds to the VoLL of above £10,000/MWh that is used in this work.

Value of storage in Grassroots pathway

We find that the potential system savings increase markedly as the system decarbonises towards 2050. This is illustrated in Figure E1. The composition of the annual system benefits is given in £bn per year, for a range of assumed energy storage costs (top horizontal axis) also corresponding to different optimal volumes of energy storage deployed by the model (bottom horizontal axis).[3]

The savings presented in Figure E1 are calculated as the difference in total system annuitised investment and annual operating costs between: (a) a counterfactual system, with energy storage not being available; and (b) the system with energy storage, given its cost, being optimally placed and operated to minimise the total system cost. Optimal levels of annuitised investment in new storage capacity are plotted as negative benefit (S CAPEX), and the resulting net system benefit is also depicted in the figure as the difference between storage expenditure and the resulting savings. We differentiate between savings in the following cost categories: generation investment (G CAPEX), interconnection investment (IC CAPEX), transmission investment (T CAPEX), distribution investment (D CAPEX) and operating cost (OPEX).

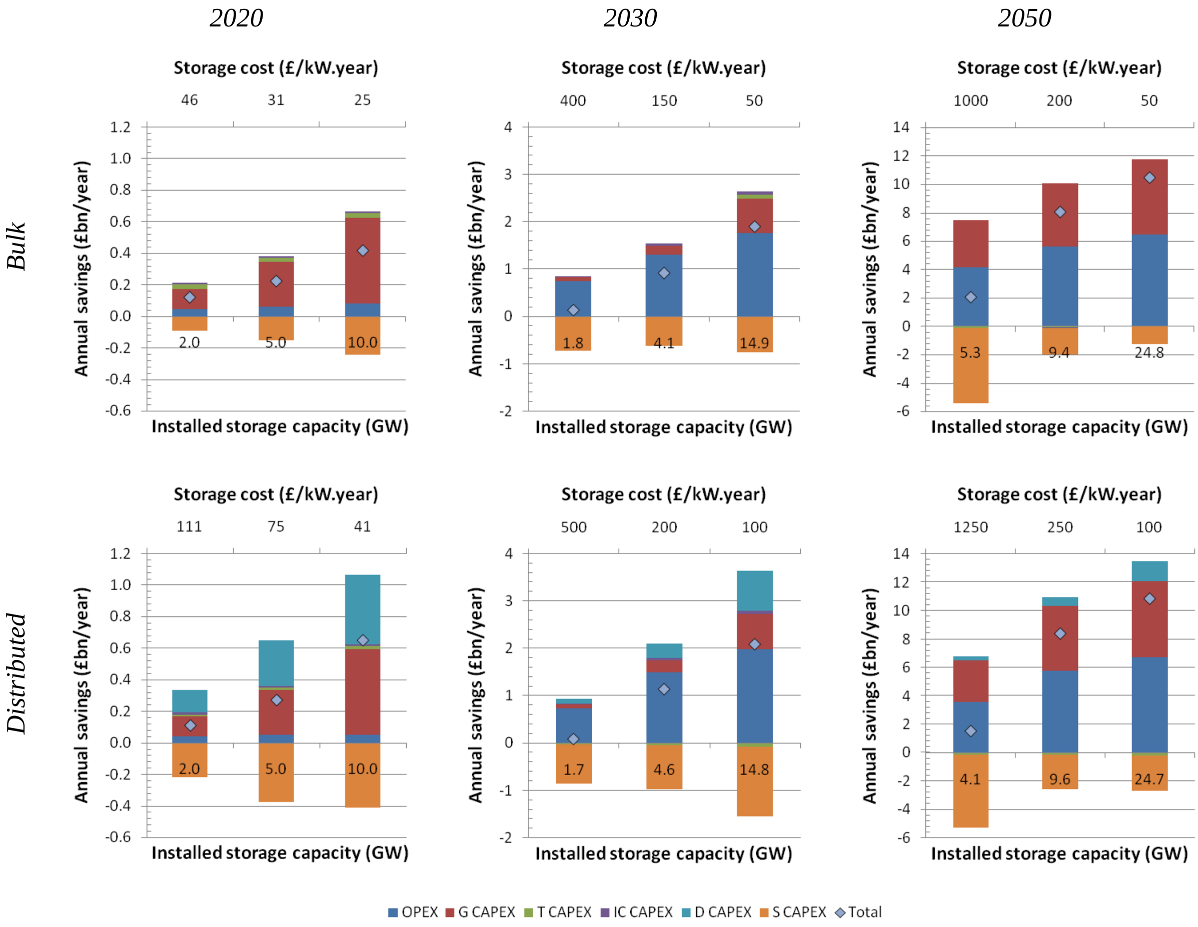


Figure E1: Net benefits of storage in Grassroots pathway

We observe that energy storage delivers multiple benefits: bulk storage technologies (i) reduce generation operating cost by enhancing the ability of the system to absorb renewable generation and displace low load factor backup generation with low efficiencies, (ii) reduce

[3] These results are presented for storage with 75% efficiency and 6 hours duration.

generation investment costs by contributing to delivery of adequacy / security of supply, and (iii) offset the need for interconnection and transmission investment. Distributed storage can, in addition, (iv) reduce the need for distribution network reinforcement driven by electrification of transport and heat sectors. In some cases the objective of overall cost minimisation may lead to an increase in cost in particular areas, such as expenditure in transmission network reinforcement (note that, for example, in 2030 bulk storage reduces need for transmission while distributed storage increases transmission investment). The magnitude of these savings will be system-specific and is driven by the characteristics of generation and demand, including their location. Net system savings increase radically between 2020 and 2050, given the assumptions associated with the growth in intermittent renewable generation and levels of electrification. For instance, in the case of bulk storage, with the cost of £50/kW.year, the achievable net annual system benefits are £0.12bn in 2020, around £2bn in 2030, while in 2050 we see an increase to over £10bn per year. Similar trends are observed for distributed storage.

The relative share of savings across different sectors vary, depending on the assumed system background and the deployment levels of storage. In Figure E2, the benefits are expressed per kW of storage capacity installed. The layout for top and bottom horizontal axes is the same as in Figure E1. In 2020, operational cost savings represent a relatively small proportion of the total savings and the total benefit is dominated by CAPEX savings in generation. OPEX savings, however, become a dominant component in 2030. As the installed capacity of storage increases, the relative share of operational savings reduces. It becomes increasingly more challenging to further reduce renewable curtailment and save generation operating cost.

We also observe that in 2030 the component of generation and distribution savings (G & D CAPEX) per kW of storage are at a fairly constant level across the assumed range of storage costs. The generation saving (G CAPEX) per kW of storage is around £50-60/kW.year in both 2020 and 2030, which is broadly equal to the annualised investment cost of new CCGT and OCGT capacity that storage displaces. Distribution network savings (D CAPEX) are broadly similar in both 2030 and 2050, and vary around the value of £60/kW.year.

Savings in generation capacity increase significantly after 2030, when emission constraints necessitate the use of abated plants for peaking services in the absence of storage, and storage is capable of displacing this expensive capacity, generating a very high value to the system. The system is unable to accommodate the high penetration of renewable generation (we observe a significant curtailment of renewable energy). In order to comply with the carbon emission target of 50 g/kWh in 2050, if storage is not available then significant additional capacity of CCS would need to be built. Adding storage increases the ability of the system to absorb intermittent sources and hence costly CCS plant can be displaced, which leads to very significant savings. Given that the generation CAPEX savings are also driven by reduced wind generation curtailment (OPEX), both CAPEX and OPEX benefits reduce (expressed in £/kW.year) with the increase of storage capacity deployed.

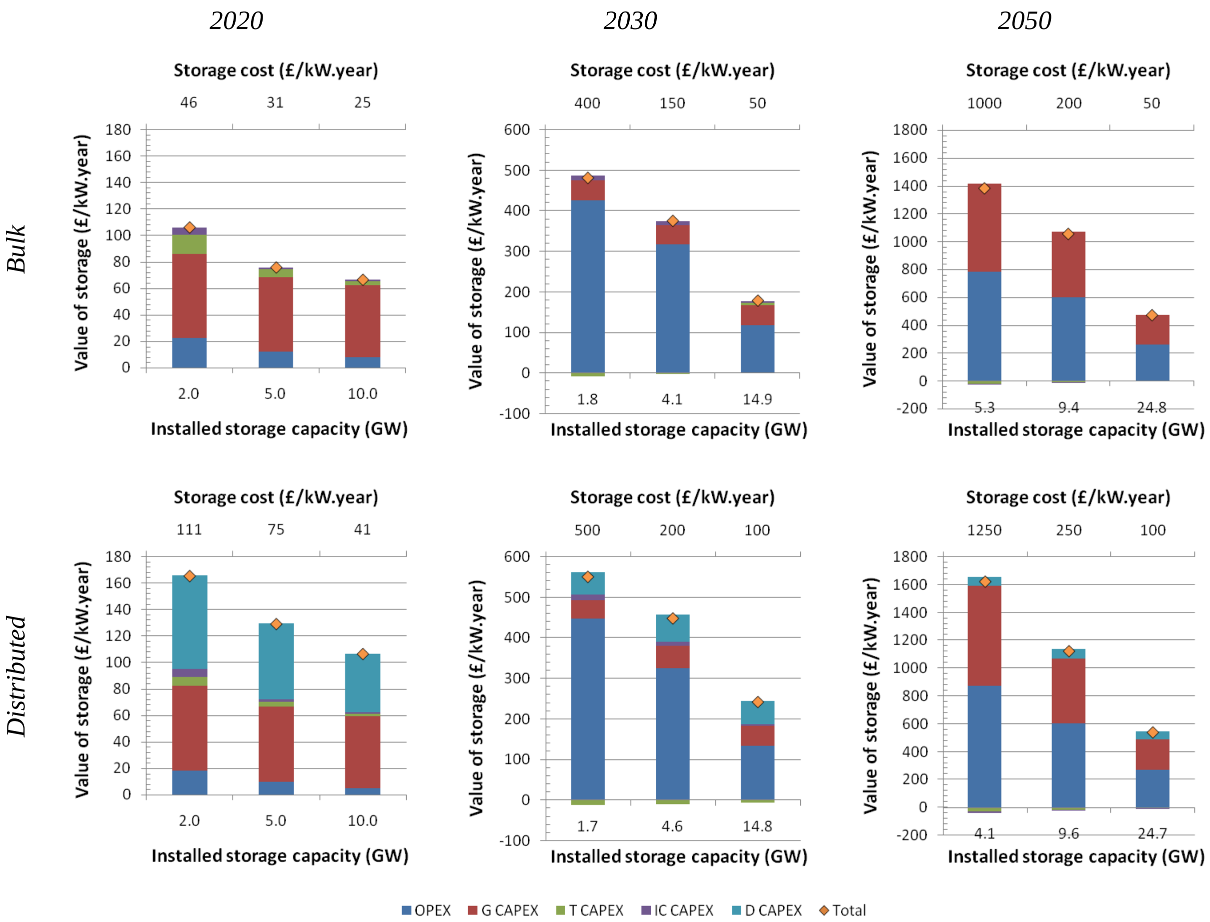


Figure E2: Value of storage in Grassroots pathway

We also observe some savings in transmission and interconnection (T & IC CAPEX) in 2030 as a result of adding bulk storage, while for distributed storage these may even become negative. This is the consequence of storage location: most bulk storage capacity is located in Scotland where it is able to balance the wind output locally and avoid the need for transmission reinforcement, while most distributed storage is located closer to large demand centres in the South and Midlands, driven by the opportunity to reduce distribution network reinforcement cost.

We highlight the importance of the assumptions associated with the cost of capital and lifetime when assessing the capitalised value of storage. For a given level of annualised cost of storage, which also provides a cost target that storage should not exceed in order to recover its cost when added to the system, a more risky and short-lived technology needs to be available at a much lower capital cost than if the same storage technology had a longer economic life and was considered to be technically mature.[4] Demonstration projects may play an important role in lowering the cost of capital and hence increasing the competitiveness of storage technologies.

4 For a mature and long-lived technology, similar to network assets with the assumed life of 40 years and WACC of 5.7%, the annuitised cost of storage of £100/kW.year would correspond to a capitalised value of storage of £1,563/kW. If we however assume a more risky technology, with an economic life of only 25 years and an appropriately higher WACC of 14.5% (similar to CCS technology), we obtain a capitalised value of storage of only £666/kW.

Impact of competing flexibility options

The range of scenarios considered in this study, including different levels of generation flexibility, interconnection and demand flexibility, shows that some of these solutions can be complementary to storage technology and some compete with storage more directly. Figure E3 presents the net benefits of storage in 2030 when competing with other flexibility options, as well as the values per kW of installed storage capacity. We observe that in the majority of cases, when storage faces competition from other options, the net benefit generated by storage reduces, and the optimal storage capacity drops.

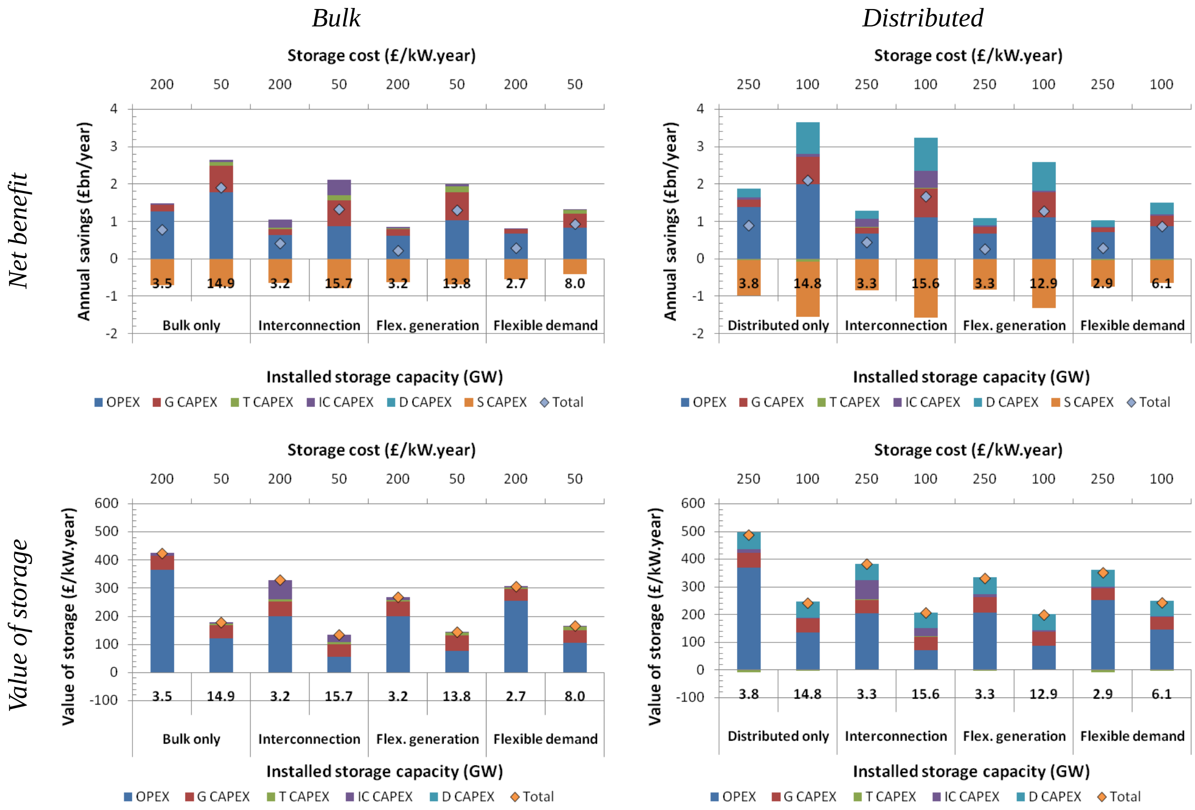


Figure E3: Net benefit and value of storage in 2030 in the presence of competing flexibility options. Storage duration is 24 hours. (Installed capacity is denoted beneath each bar)

The key impact of competing options is that OPEX savings of storage decrease compared to the storage-only case. OPEX savings predominantly result from avoided renewable curtailment. Competing flexibility options can deliver these savings and significantly reduce the scope for storage to deliver further avoided renewable curtailment. In case where interconnection exists alongside storage in the system, we observe that the reduced OPEX saving component is partly compensated by savings in interconnection CAPEX. Although the presence of interconnection and flexible generation reduces value of storage, volume of storage deployed is not affected. A highly flexible demand side, however, is the most direct competitor to energy storage. Both offer very similar services (deferring or avoiding distribution network reinforcement in particular) and are therefore not complementary. High levels of demand flexibility[5], as assumed in this study, have the potential to reduce the market size for storage in 2030 by more than 50%.

[5] Demand-side response makes use of inherent demand flexibility and it does not involve any compromise of the service that controlled appliances deliver to the consumers. However, there may be other factors that prevent a high uptake of demand side response, and this is hence treated as sensitivity in this study.

Roles of bulk and distributed storage and the impact of storage technology parameters

The capacity value of both bulk and distributed technologies has been found to be high throughout. Not only are these storage technologies able to displace (backup) generation capacity roughly on a MW per MW basis in maintaining capacity adequacy requirements,[6] but they can further facilitate a more effective use (i.e. higher load factors) of more efficient plant, or avoid the need for costly abated plants in providing peaking services in low carbon pathways.

Distributed storage delivers slightly less value from operational savings than bulk storage. Reduction in curtailment of wind during peak demand conditions is in some instances constrained by the distribution network capacity. Charging the storage during these periods increases peak load and would require distribution network reinforcements, the cost of which outweighs the potential OPEX savings. However, distributed storage tends to have a higher overall aggregated value due to distribution network savings, which are not accessible for bulk storage.

The optimal location for bulk storage is found to be predominantly in Scotland, where it supports the integration of wind and avoids additional transmission reinforcement with northern England. Distributed storage is predominantly located on networks in high demand regions in Southern GB, especially in conjunction with a high uptake of electrified transport and heating.

The value of storage is found not to be strongly affected by increases in storage duration beyond 6 hours. Given the shape of the peak demand as modelled in this study, three hours of storage duration are found to be sufficient to shifts peaks, which is the primary mechanism behind avoided network and generation capacity. As illustrated in Figure E4, additional storage duration leads to rapidly diminishing value per unit energy falling well below £20/kWh.year.

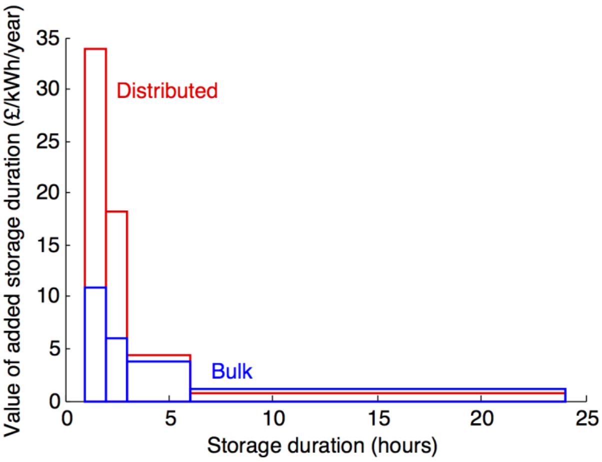


Figure E4: Value of adding energy capacity (duration) to a 10 GW storage in Grassroots pathway in 2030

Storage efficiency has been found to have limited impact on its value, in the systems considered; as long as the installed capacities are low and the potential for arbitrage i.e. saving renewable curtailment remains high, storage can effectively displace high cost energy, even with low round trip efficiency, while achieving savings in CAPEX. The average value of storage for 10 GW installed capacity in 2030 increases by less than 10% as a result of improvements in storage round trip efficiency from 50% to 90%. The change in the accessible

[6] Resource adequacy requires several hours of storage duration, if peaking generation is to be displaced securely, based on the shape of the demand profile derived for 2030.

market size, as a function of storage efficiency, is however much more significant.

We have also studied the use of fast storage (such as flywheels or super-capacitors) in providing primary frequency regulation. Although the market for fast storage is relatively limited (< 2 GW), the value and savings are very substantial (Figure E5) and come from significantly reduced need to run conventional generation part loaded and hence enhanced capability of the system to absorb renewable generation.

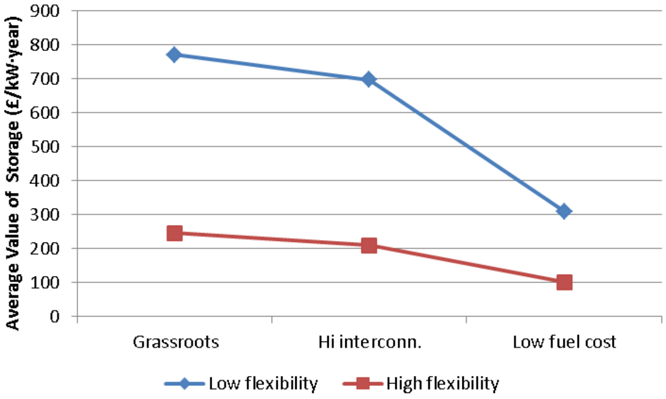


Figure E5: Value of frequency regulation provided by fast storage in the presence of competing options

However, the presence of flexible generation with significantly enhanced capability to provide fast frequency regulation services will materially reduce the value of fast storage (Figure E5). In addition to more flexible conventional generation, there may be a spectrum of other technologies that may contribute to this market and reduce the value of fast storage, such as refrigeration load or suitably controlled wind turbines. We have also observed that changes in fuel prices will have a major impact on the value of storage, as the savings in generation operating costs are a major driver of the value of storage (given that the value of saved wind will directly depend on fuel cost of conventional plant displaced).

Impact of forecasting error and generation system management approaches

Uncertainty over changes in wind output over several hours necessitates the presence of high reserve capacity and this is a major source of value for storage. Improved wind forecasting (50% improvement in the RMS error) will result in reduced reserve requirements and will hence reduce the value of storage as illustrated in Figure E6.

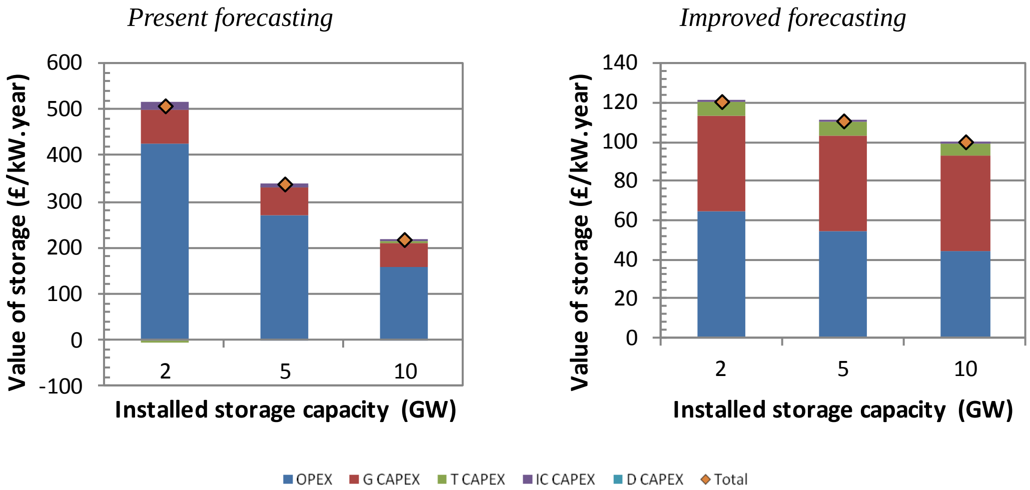


Figure E6: The impact of improved wind forecasting on the value of storage

Furthermore, the approach to allocating storage resource between energy arbitrage and reserve provision will be critical. Figure E7 presents the difference in the value of storage being evaluated using conventional deterministic scheduling and the stochastic scheduling approach.

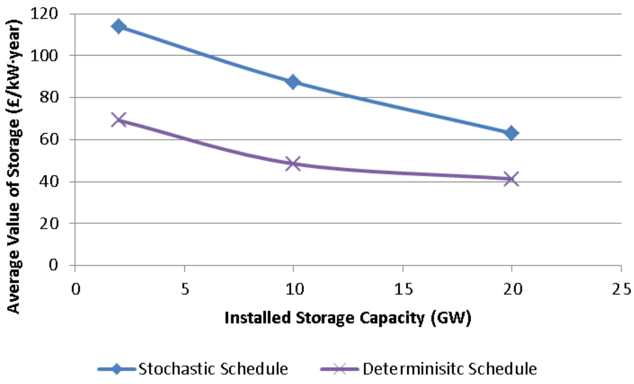


Figure E7: Value of storage under stochastic and deterministic scheduling

It will clearly be very important to optimally allocate the storage resource between providing reserve and conducting energy arbitrage, which only stochastic scheduling can facilitate. Stochastic scheduling is therefore superior to its deterministic counterpart, because the allocation of storage resources between energy arbitrage and reserve varies dynamically depending on the system conditions. We observe that with 2 GW of storage when considering a particular scenario, stochastic scheduling increases the value of storage by more than 75%, while for the installed capacity of 20 GW of storage this would be around 50%.

Impact of alternative pathways

Three future pathways lead to fundamentally different roles for storage. Although this study centres on Grassroots, a highly renewable pathway, we now present the comparison with CCS and nuclear-dominated pathways. From Figure E8 it is apparent that the net benefits are significantly reduced in pathways dominated by non-renewable generation. Whereas in Grassroots, 10 GW of bulk storage saves over £8bn/year (£1,000/kW.year) in 2050, in the Nuclear Pathway this results in net savings of less than 1£bn/year (£220/kW.year) and in CCS less than £0.2bn/year (£60/kW.year), as illustrated in Figure E8. The latter scenarios provide less opportunity for storage to contribute to reducing renewable curtailment and therefore allow less operating cost to be saved. On the other hand, there are storage technologies that may be already competitive in all of these scenarios.

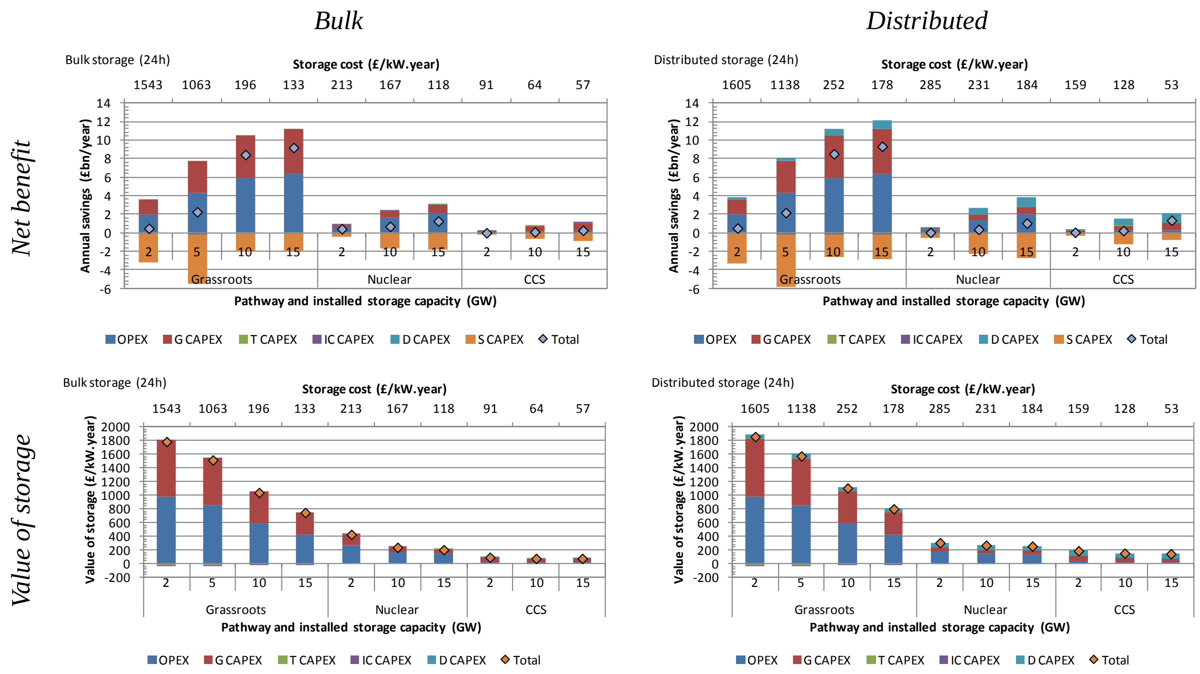


Figure E8: Net benefit and value of storage in Grassroots, Nuclear and CCS pathways

Given the lack of flexibility in the counterfactual of Grassroots, the system is unable to accommodate the high penetration of renewable generation and we observe significant curtailment of renewable energy. Given the need to comply with the carbon emission target of 50 g/kWh in 2050, significant additional capacity of CCS would need to be built. Adding storage increases the ability of the system to absorb intermittent sources and hence costly CCS plant can be displaced, which lead to very significant savings in Grassroots.

Technology implications

We observe that the duty cycles imposed on the energy storage technology will vary depending on the design and control requirements of the power system, and on the scale and location of the storage itself. The different operating patterns are illustrated by Figure E9.

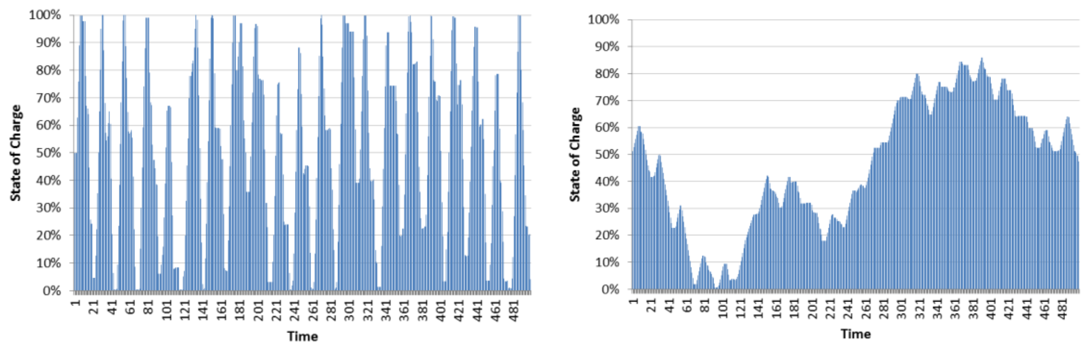


Figure E9: Two predicted patterns of storage use in a future low carbon grid, showing state of charge against time in hours

The diagram on the left shows the pattern of use for a distributed storage system with 6 hours storage duration, while the diagram on the right shows the pattern of use for a bulk storage system, with 48 hours duration. The difference in the number of cycles that the storage system has to manage, and the differing degrees of state of charge are evident. The distributed storage system requires the ability to both cycle more frequently and operate a wider depth of discharge range. It is hence likely is that a portfolio of different energy storage technologies will be required, suited to a range of applications and this should be taken into account when designing innovation and policy incentives.

The large number of important unknowns with respect to the technologies for grid-scale energy storage has led this study to adopt a technology-agnostic approach. Cost and lifetime of storage technologies, especially when applied to real duty cycles within the electricity network, are abstracted in this study by deriving annualised marginal capital cost targets.

The method of cost minimisation used in this work is equivalent to assuming that investment decisions are taken in a perfectly competitive market, in which market participants are exposed to the marginal costs they impose on the system, and receive the marginal benefit they provide to the system through revenues or cost savings. In practice, however, the take-up of technologies depends on choices made by electricity consumers and energy sector investors, which may not match the choices made by the model's cost minimisation algorithm. In reality, market failures, such as the impact of externalities, inefficient pricing or natural monopoly, mean the least-cost level of deployment might not take place in practice. Finally, there may exist some other real-life costs and constraints which the model has not taken into account. The task remains for the policy makers to develop regulatory and market frameworks that stimulate investment and operation that would facilitate cost-effective solutions.

Furthermore, the marginal cost functions presented here, give a clear indication of the sources, scale and conditions under which storage can deliver value to future energy systems. They can thus inform both the needs for technology innovation and desirable trajectories for their deployment.

The long-term perspective, reaching out to 2030 and 2050, further highlights the strategic value of storage in reducing the cost of the low-carbon transition. Delivering storage to the system in anticipation of such savings does, however, require support, due to relatively low values in the early stages of transition.

Key high-level findings

The following high-level observations can be drawn from the analysis carried out in this study:

- The values presented in this report tend to be higher than previous studies suggest. This is a direct result of the whole-system approach employed here that includes savings in generation capacity, interconnection, transmission and distribution networks and savings in operating cost. These savings all contribute towards the value of storage, but their relative share changes over time and between different assumptions.
- In the Grassroots pathway, the value of storage increases markedly towards 2030 and further towards 2050. Carbon constraints for 2030 and 2050 can be met at reduced costs when storage is available. For bulk storage cost of £50 per kW per year, the optimal volume deployed grows from 2 GW in 2020 to 15 and 25 GW in 2030 and 2050 respectively. The equivalent system savings increase from modest £0.12bn per year in 2020 to £2bn in 2030, and can reach over £10bn per year in 2050.
- The value of storage is the highest in pathways with a large share of RES, where storage can deliver significant operational savings through reducing renewable generation curtailment. In nuclear scenarios the value of OPEX is reduced as the value of energy arbitrage between renewable and nuclear generation is lower. CCS scenarios yield the lowest value for storage.
- A few hours of storage are sufficient to reduce peak demand and thereby capture

significant value. The marginal value for storage durations beyond 6 hours reduces sharply to less than £10/kWh.year. Additional storage durations are most valuable for small penetration levels of distributed storage.

- Distributed energy storage can significantly contribute to reducing distribution network reinforcement expenditure.
- In the Grassroots Pathway, storage has a consistently high value across a wide range of scenarios that include interconnection and flexible generation. Flexible demand is the most direct competitor to storage and it could reduce the market for storage by 50%.
- Bulk storage should predominantly be located in Scotland to integrate wind and reduce transmission costs, while distributed storage is best placed in England and Wales to reduce peak loads and support distribution network management.
- Higher storage efficiencies only add moderate value of storage. With higher levels of deployment efficiency becomes more relevant.
- Operation patterns and duty cycles imposed on the energy storage technology are found to vary considerably, and it is likely that a portfolio of different energy storage technologies will be required, suited to a range of applications.
- There remain a number of important unknowns with respect to the technologies involved in grid-scale energy storage, in particular relating to the cost and lifetime of storage technologies when applied to real duty cycles within the electricity network.

Policy implications and future work

Strategic importance:

- The time scales and rate at which the value of storage increases poses a strategic challenge. The long-term value will not be very tangible to market participants in 2020, yet a failure to deploy storage in a timely manner may lead to higher system costs in 2030 and beyond. Strategic policies may be needed to ensure markets can deliver long-term system benefits.

Technology support:

- Future work should include a potentially large spectrum of storage technologies with the objectives to deliver: lower cost; higher cycle life; longer calendar life; lower maintenance; improved safety; enhanced environmental compatibility; higher volumetric energy density; higher round-trip energy efficiency and easier integration. In addition, novel control strategies that can incorporate technology-specific constraints of the energy storage system will be needed, which is fundamental if the value of energy storage and its competitiveness are to be maximised. Furthermore, the question of the optimal design of the power electronics interface and control of the operation of tens of thousands of individual cells within a grid-scale storage system has not yet been resolved.

Policy and market development:

- The method of cost minimisation used in this work is equivalent to assuming that investment decisions are taken in a perfectly competitive market, while in reality, market failures, such as the impact of externalities, inefficient pricing or natural monopoly, mean the least cost level of deployment might not take place in practice.
- This analysis also clearly demonstrates that storage can bring benefits to several sectors in electricity industry, including generation, transmission and distribution, while providing services to support real time balancing of demand and supply and

network congestion management and reduce the need for investment in system reinforcement. These “split benefits” of storage pose significant challenges for policy makers to develop appropriate market mechanisms to ensure that the investors in storage are adequately rewarded for delivering these diverse sources of value.

- Further work is needed to understand how different market and policy frameworks would impact the deployment of alternative grid-scale energy storage technology solutions
- It is not clear whether government policies should incentivise the development and deployment of novel storage technologies, and if so, what sort of mechanisms should be considered, e.g. ranging from subsidies to direct procurement.

1 Modelling approach

1.1 Context

The UK electricity system faces very considerable challenges: by 2020, according to the Government Renewable Energy Strategy, it is expected that 30% of the UK electricity demand will be met by renewable generation; the electricity sector should be almost entirely decarbonised by 2030 with significantly increased levels of electricity production and demand driven by the incorporation of heat and transport sectors into the electricity system.

The key concerns are associated with the system integration cost, driven by radical changes in both supply and demand side of the low-carbon system. Generation mix in the low-carbon electricity systems may include significant amounts of low capacity value, variable and difficult to predict intermittent renewable generation (e.g. wind and solar) in combination with less flexible nuclear and CCS plant, leading to increased system integration costs associated with backup plants and system balancing. This will lead to a degraded utilisation of generation infrastructure and electricity network assets. The operating reserve requirements and need for flexibility at high penetrations of intermittent renewable generation will need to increase significantly above those in the conventional systems. Additional operating reserve is delivered through an increased amount of generating plants operating part-loaded, i.e. less efficiently, and/or through plants with higher costs, leading to an increase in real-time system balancing costs. The need for additional reserves and the lack of flexibility may also decrease the ability of the system to absorb intermittent generation. This may lead to significant curtailment of renewable power at high penetration levels (particularly when high outputs of renewable generation coincide with low demand). On the other hand, changes in the demand side driven by electrification will potentially require a very significant reinforcement of generation and network infrastructures. The utilisation of generating plant and networks will reduce very significantly, increasing the system integration costs of decarbonising these demand sectors.

In this context, the work carried out within this project evaluates the economic and environmental performance of the future UK low-carbon electricity system, focusing on reducing the need for investment in generation and network infrastructure and in improving the efficiency of system operation and asset utilisation through the application of storage technologies, with the outputs intended to inform the UK energy policy. In particular, the study aims to assess:

(i) Cost and performance targets for grid-scale energy storage applications to facilitate a cost-effective evolution to a low-carbon future.

(ii) Sources of value of storage, i.e. savings in capital expenditure in all sectors including generation, transmission and distribution infrastructure, as well as savings in operation costs and the potential to enhance the ability of the system to accommodate renewable generation.

(iii) Impact of competing options including flexible generation, demand-side response, and interconnection.

(iv) Changes in the value of storage across key decarbonisation pathways and for different assumptions on fuel costs.

(v) Impact of various storage parameters on its value, including the importance of additional storage duration, storage efficiency and the ability to provide frequency regulation services.

(vi) Impact of changes in system management on the value of storage, including generation scheduling methodology and the impact of improvements in wind output forecasting errors.

1.2 Whole-systems modelling of electricity system with storage

When considering system benefits of storage technologies it is important to consider two key aspects:

- **Different time horizons**: from long-term investment-related time horizon to real-time balancing on a second-by-second scale (Figure 1); this is important as storage technologies can contribute to both savings in generation and network investment but also to increase the efficiency of system operation.
- **Different assets in the energy system**: generation assets (from large-scale to distributed small-scale), transmission network (national and interconnections), and local distribution network operating at various voltage levels. This is important as storage technologies may be placed at different locations in the system, from bulk technologies connected to the national transmission network, such as large-scale storage to highly distributed technologies connected to local low-voltage distribution networks.

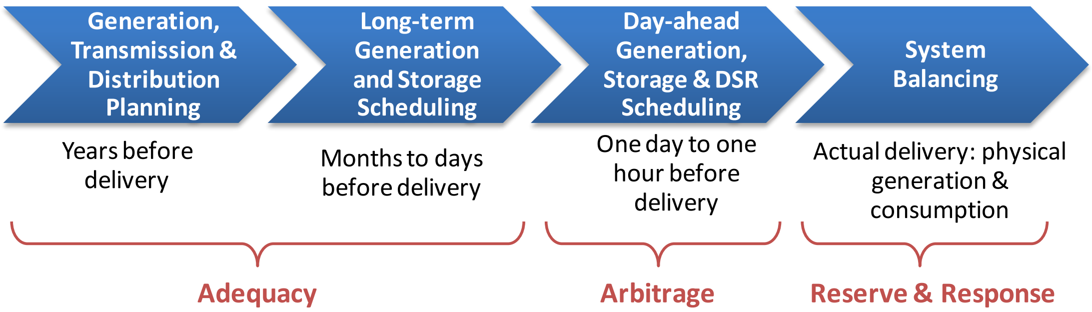


Figure 1: Balancing electricity supply and demand across different time horizons

Capturing the interactions across different time scales and across different asset types is essential for the analysis of future low-carbon electricity systems that includes alternative balancing technologies such as storage and demand-side response. Clearly, applications of those technologies may improve not only the economics of real-time system operation, but they can also reduce the investment into generation and network capacity in the long run.

In order to capture these effects and in particular trade-offs between different flexible technologies, it is critical that they are all modelled in a single integrated modelling framework. In order to meet this requirement we have developed *DSIM (Dynamic System Investment Model)*, a comprehensive system analysis model that is able to simultaneously balance long-term investment decisions against short-term operation decisions, across generation, transmission and distribution systems, in an integrated fashion.

This holistic model provides optimal decisions for investing into generation, network and/or storage capacity (both in terms of volume and location), in order to satisfy the real-time supply-demand balance in an economically optimal way, while at the same time ensuring efficient levels of security of supply. The DSIM model has been extensively tested in previous projects studying the interconnected electricity systems of the UK and the rest of Europe.[7] An

[7] DSIM model, in various forms, has been used in a number of recent European projects to quantify the system

advantage of DSIM over most traditional models is that it is able to simultaneously consider system operation decisions and capacity additions to the system, with the ability to quantify trade-offs of using storage (and other alternative mitigation measures), for real-time balancing and transmission and distribution network and/or generation reinforcement management. For example, the model captures potential conflicts and synergies between different applications of distributed storage in supporting intermittency management at the national level and reducing necessary reinforcements in the local distribution network. An overview of the model structure is given in Figure 2.

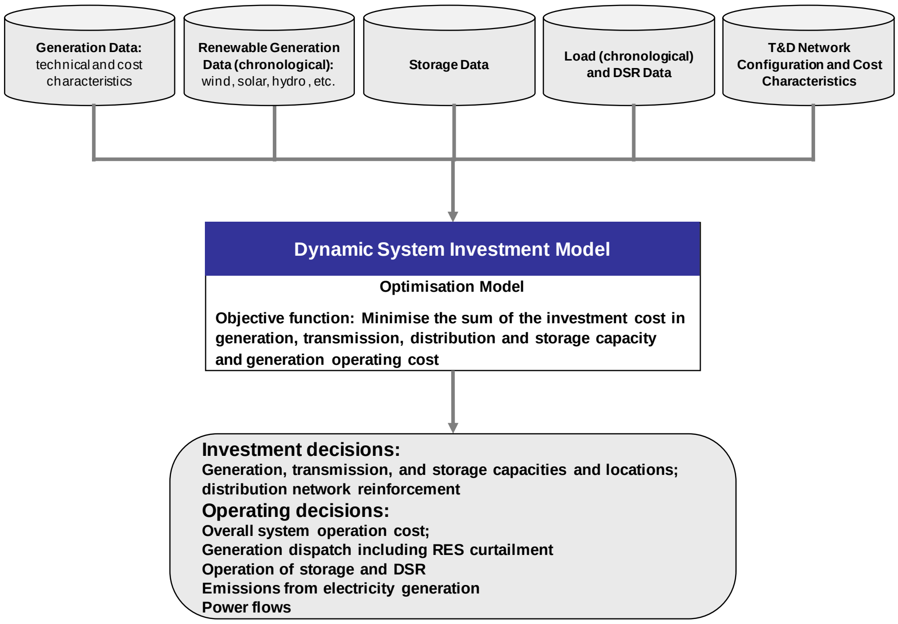


Figure 2: Structure of the Dynamic System Investment Model (DSIM)

The objective function of DSIM is to minimise the overall system cost, which consists of investment and operating cost:

- The investment cost includes (annualised) capital cost of new generating and storage units, capital cost of new interconnection capacity, and the reinforcement cost of transmission and distribution networks. In case of storage, the capital cost can also include the capital cost of storage energy capacity, which determines the amount of energy that can be stored in the storage. Various types of investment costs are annualised by using the appropriate Weighted-Average Cost of Capital (WACC) and the estimated economic life of the asset. Both of these parameters are provided as inputs to the model, and their values can vary significantly between different technologies.

- System operating cost consists of the annual generation operating cost and the cost of energy not served (load-shedding). Generation operating cost consists of: (i) variable cost which is a function of electricity output, (ii) no-load cost which is a function of a number of synchronised units, and (iii) start-up cost. Generation operating cost is

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infrastructure requirements and operation cost of integrating large amounts of renewable electricity in Europe. The projects include: (i) "Roadmap 2050: A Practical Guide to a Prosperous, Low Carbon Europe" and (ii)"Power Perspective 2030: On the Road to a Decarbonised Power Sector", both funded by European Climate Foundation (ECF); (iii) "The revision of the Trans-European Energy Network Policy (TEN-E)" funded by the European Commission; and (iv) "Infrastructure Roadmap for Energy Networks in Europe (IRENE-40)" funded by the European Commission within the FP7 programme.

determined by the assumed fuel prices and carbon prices (for technologies which are carbon emitters).

There are a number of equality and inequality constraints that are taken into account by the model while minimising the overall cost. These include:

- *Power balance constraints,* which ensure that supply and demand are balanced at all times.

- *Operating reserve constraints* include various forms of fast and slow reserve constraints. The amount of operating reserve requirement is calculated as a function of uncertainty in generation and demand across various time horizons. The model distinguishes between two key types of balancing services: (i) frequency regulation (response), which is delivered in the timeframe of a few seconds to 30 minutes; and (ii) reserve, typically split between spinning and standing reserve, with delivery occurring within the timeframe of half an hour to several hours after the request. The need for these services is directly driven by wind output forecasting errors and this will significantly affect the ability of the system to absorb wind energy. It is expected that the 4 hour ahead[8] forecasting error of wind, presently at about 15% of installed wind capacity, may reduce to 10% post-2020 and then further to less than 6%, which may have a material impact of the value of flexibility options. Calculation of reserve and response requirements for a given level of intermittent renewable generation is carried out exogenously and provided as input into the model.

  In DSIM, frequency response can be provided by:
  - Synchronised part-loaded generating units.
  - Interruptible charging of electric vehicles.
  - A proportion of wind power being curtailed.
  - A proportion of electricity storage when charging
  - Smart refrigeration.

  While reserve services can be provided by:
  - Synchronised generators
  - Wind power or solar power being curtailed
  - Stand-by fast generating units (OCGT)
  - Electricity storage
  - Interruptible heat storage when charging

  The amount of spinning and standing reserve and response is optimized ex-ante to minimise the expected cost of providing these services, and we use our advanced stochastic generation scheduling models to calibrate the amount of reserve and response scheduled in DSIM.[9,10] These stochastic models find the cost-optimal levels of reserve and response by performing a probabilistic simulation of the actual utilisation of these services.

- *Generator operating constraints* include: (i) Minimum Stable Generation (MSG) and maximum output constraints; (ii) ramp-up and ramp-down constraints; (ii) minimum up and down time constraints; and (iv) available frequency response and reserve

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8 4 hours is generally the maximum time needed to synchronise a large CCGT plant.

9 A. Sturt, G. Strbac, "Efficient Stochastic Scheduling for Simulation of Wind-Integrated Power Systems", *IEEE Transactions on Power Systems*, Vol: 27, pp. 323-334, Feb 2012.

10 A. Sturt, G. Strbac, "Value of stochastic reserve policies in low-carbon power systems", *Proceedings of the Institution of Mechanical Engineers: Part O-Journal of Risk and Reliability*, Vol: 226, pp. 51-64, Feb 2012.

constraints. In order to keep the size of the problem manageable, we group generators according to technologies, and assume a generic size of a thermal unit of 500 MW (the model can however commit response services to deal with larger losses, e.g. 1,800 MW as used in the model). The model captures the fact that the provision of frequency response is more demanding than providing operating reserve. Only a proportion of the headroom created by part-loaded operation is made available to frequency regulation

- *Generation:* DSIM optimises the investment in new generation capacity while considering the generators' operation costs and CO_2 emission constraints, and maintaining the required levels of security of supply. DSIM optimises both the quantity and the location of new generation capacity as a part of the overall cost minimisation. If required, the model can limit the investment in particular generation technologies at given locations.

- *Annual load factor constraints* can be used to limit the utilisation level of thermal generating units, e.g. to account for the effect of planned annual maintenance on plant utilisation.

- *Demand-side response constraints* include constraints for various specific types of loads. DSIM broadly distinguishes between the following electricity demand categories: (i) weather-independent demand, such as e.g. lighting, industrial demand etc., (ii) heat-driven electricity demand (space heating / cooling and hot water), (iii) demand for charging electric vehicles, and (iv) smart appliances' demand. Different demand categories are associated with different levels of flexibility. Losses due to temporal shifting of demand are modelled as appropriate. Flexibility parameters associated with various forms of DSR are obtained using detailed bottom-up modelling of different types of flexible demand, as described in Section 1.5.

- *Power flow constraints* limit the energy flowing through the lines between different areas in the system, respecting the installed line capacity as the upper bound (DSIM can handle different flow constraints in each flow direction). The model can also invest into enhancing network capacity if this is cost-efficient. Expanding transmission and interconnection capacity is generally found to be vital for facilitating efficient integration of large intermittent renewable resources, given their location. Interconnectors provide access to renewable energy and improve the diversity of demand and renewable output on both side of the interconnector, thus reducing the short-term reserve requirement. Interconnection also allows for sharing of reserves, which reduces the long-term capacity requirements.

- *Distribution network peak load constraints* are devised to determine the level of distribution network reinforcement cost, as informed by detailed modelling of representative UK networks. DSIM can model different types of distribution networks, e.g. urban, rural, etc. with their respective reinforcement cost (more details on the modelling of distribution networks are provided in Section 1.4).

- *Emission constraints* limit the amount of carbon emissions within one year. Depending on the severity of these constraints, they will have an effect of reducing the electricity production of plants with high emission factors such as oil or coal-fired power plants. Emission constraints may also result in additional investment into low-carbon technologies such as nuclear or CCS in order to meet the constraints.

- *Security constraints* ensure that there is sufficient generating capacity in the system to supply the demand with a given level of security and estimates the Loss of Load Expectation (LOLE).[11] If there is storage in the system, DSIM may make use of its capacity for security purposes if it can contribute to reducing peak demand, given the energy constraints.

  DSIM allows for the security-related benefits of interconnection to be adequately quantified. Conversely, it is possible to specify in DSIM that no contribution to security is allowed from other regions, which will clearly increase the system cost, but will also provide an estimate of the value of allowing the interconnection to be used for sharing security between regions.

Specific constraints implemented in DSIM for the purpose of studying balancing technologies, in order to reflect the following policy-related objectives, are:

- UK is *self-sufficient* in terms of capacity, i.e. there is no contribution from other regions to the capacity margin in the UK and vice versa.
- UK is *energy-neutral*. This means that the net annual energy import / export is zero. This allows the UK to import power from and export to Europe / Ireland as long as the annual net balance is zero. In other words, the UK system is still able to export power when there is excess of available energy, for example when high wind conditions coincide with low demand, and import energy from Europe when economically efficient e.g. during low-wind conditions.

1.3 System topology

The configuration of the interconnected GB electricity system used in this study is presented in Figure 3. Given that the GB transmission network is characterised by North-South power flows, it was considered appropriate to represent the GB system using 4 key regions and their boundaries, while considering London as a separate zone. The two neighbouring systems, Ireland and Continental Europe are also represented as areas. Both economics and reliability consideration are involved in transmission network and interconnection designs.[12]

Network lengths in Figure 3 reflect the equivalent distances which take into account the additional local network investment that interconnection may require. Network capacities indicated in the figure refer to the capacities expected to be in place by 2020.

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[11] LOLE is the expected number of hours when electricity demand exceeds available electricity supply capacity.

[12] M. Castro, D. Pudjianto, P. Djapic, G. Strbac, “Reliability-driven transmission investment in systems with wind generation”, *IET Generation Transmission & Distribution*, Vol: 5, pp. 850-859, Aug 2011.

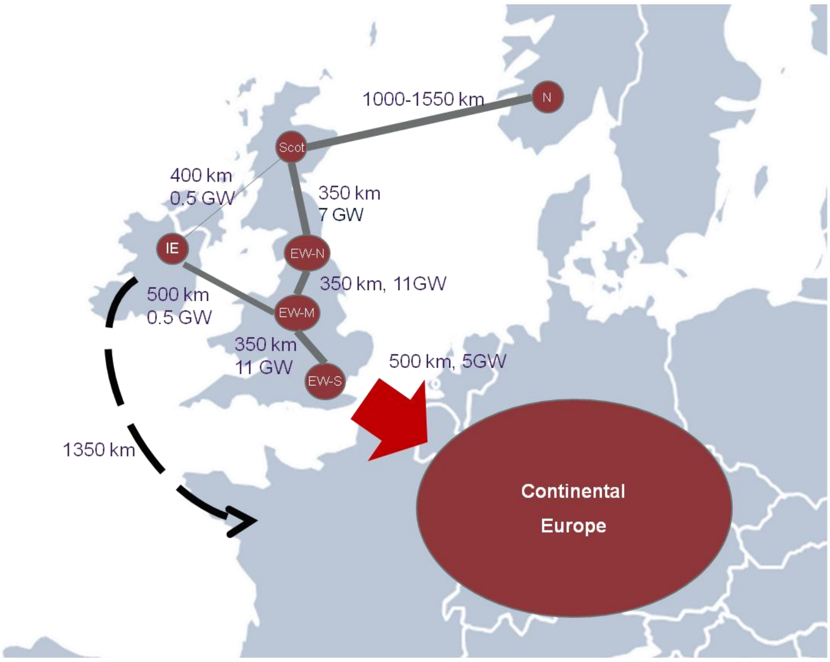

Figure 3: System topology used in the study

1.4 Distribution network modelling

In line with the general modelling approach, Great Britain (GB) is split into five regions for the purpose of evaluating the distribution network investment in various scenarios. The regions are as follows:

- Scotland,
- North England and Wales,
- Midlands,
- London, and
- South England and Wales.

Total GB distribution network reinforcement cost, which is a component of the overall system cost, is obtained as the sum of reinforcement costs in individual regions. The modelling is based on a range of distribution statistical network models.[13,14,15] The capability to generate many statistically similar network configurations allows for a number of design policies to be tested on a network with the same statistical properties as the network of interest. Any conclusions reached are applicable to areas with similar characteristics.

Based on the geographical representation of GB in this study through five regions, and the allocation of different DNO areas to these regions, we derive the actual number of connected consumers, length of LV overhead and underground network and the number of pole-mounted and ground-mounted distribution transformers for the GB regions (the actual data on distribution network characteristics have been obtained from the DNOs). The mismatches in control parameters between the actual and representative networks characterised using this process are less than 0.1% which confirms that the representative networks closely map

[13] J.P. Green, S.A. Smith, G. Strbac, "Evaluation of electricity distribution system design strategies", *IEE Proceedings-Generation, Transmission and Distribution*, Vol: 146, pp. 53-60, Jan 1999.

[14] C.K. Gan, N. Silva, D. Pudjianto, G. Strbac, R. Ferris, I. Foster, M. Aten, "Evaluation of alternative distribution network design strategies", 20th International Conference on Electricity Distribution (CIRED), 8-11 June 2009, Prague, Czech Republic.

[15] C.K. Gan, P. Mancarella, D. Pudjianto, G. Strbac, "Statistical appraisal of economic design strategies of LV distribution networks", *Electric Power Systems Research*, Vol: 81, pp. 1363-1372, Jul 2011.

regional aggregate values.

The unit cost data used in our study are based on cost figures approved by Ofgem (2008) used in the recent distribution price control review. Table 1 shows an excerpt from the list of cost items.

Table 1: Network equipment cost

Asset	Units	Cost (£k)
LV overhead line	km	30.0
LV underground cable	km	98.4
11/0.4 kV ground mounted	#	13.2
11/0.4 kV pole mounted	#	2.9
HV overhead line	km	35.0
HV underground cable	km	82.9
EHV/11 kV ground mounted	#	377.9

1.5 Overview of the bottom-up modelling of flexible demand

It is expected that new electricity demand categories such as electrified heating or transport will play an increasingly important role in decarbonising the electricity sector. Imperial has gained detailed understanding of specific features of these new demand sectors, and has developed detailed bottom-up models in the past which produce hourly demand profiles based on large databases of transport behaviour and building stock data. This allows us to develop detailed hourly profiles behind long-term projections for different demand categories contained in long-term development pathways, which typically only specify annual energy consumption figures.

Understanding the characteristics of flexible demand and quantifying the flexibility they can potentially offer to the system is vital to establishing its economic value.[16] For there to be regular flexible demand, controlled devices (or appliances) must have access to some form of storage when rescheduling their operation (e.g. thermal, chemical or mechanical energy, or storage of intermediate products). Load reduction periods are followed or preceded by load recovery, which is a function of the type of interrupted process and the type of storage. Achieving flexible demand means carefully managing this process of load reduction and load recovery. This requires bottom-up modelling of each individual appliance or device and understanding how it performs its actual function, while exploiting any flexibility that may exist without compromising the service that it delivers.

In our analysis we consider the following types of flexible demand:

- *Electric vehicles.* EV loads are particularly well placed to support system operation, given the relatively modest amount of energy needed daily, generally short driving times, and relatively high power ratings expected for EV batteries.[17] We have the capability to quantify how much of EV charging demand can be shifted to times that are more efficient from the system perspective, ensuring at the same time that passengers are still able to complete all of their intended daily journeys.

[16] G. Strbac, "Demand side management: Benefits and challenges", *Energy Policy*, Vol: 36, pp. 4419-4426, Dec 2008.

[17] "Report on the economic and environmental impacts of large-scale introduction of EV/PHEV including the analysis of alternative market and regulatory structures", Deliverable 3.1 of Grid-for-Vehicles (FP7 project No. 241295), August 2011. Available at: http://www.g4v.eu/datas/reports/G4V_WP3_D3_1_economic_and_environmental_impact.pdf.

Our modelling of EVs is based on statistics for light-vehicle driving patterns calibrated with the GB driving data. We envisage two approaches to charging EVs: uncontrolled and optimised in real-time. The first approach is where EV charging is done on demand. Such a policy may increase peak demand significantly, although the extra energy needed is relatively small. The second approach is to optimise EV charging in real-time by making charging part of a communication and control infrastructure. Coordinated EV charging has the potential to reduce a range of system cost categories, ranging from reduced operating cost to lower CAPEX expenditure to ensure a secure operation of the system.[18,19,20]

Our modelling also includes efficiency losses during battery charging and other in-vehicle use (such as air conditioning). Our vehicle energy requirements vary through the course of a year to reflect the changes in consumption due to air conditioning in summer and heating in winter. We further distinguish between driving patterns typical for workdays and weekends.[21]

- *Heat pumps.* Our model can identify thermal load patterns (for cooling and heating) for a variety of building types and sizes covering both commercial and domestic sector, and for a broad range of construction characteristics and insulation levels, size, occupancy patterns, indoor temperature settings and outdoor temperatures. We are hence able to identify the main factors that affect a building's energy needs and to develop heating and cooling load simulation methodologies. The modelling is then used to investigate the buildings' thermal response under different control strategies. This provides insights into the trade-offs between energy consumed and comfort level against power reduction when performing different Heating, Ventilation and Air Conditioning (HVAC) control strategies. Performance models of HVAC appliances enable appropriate transformation of thermal load into electrical load with the built-in sensitivity to year-round fluctuations in outdoor temperature.

  Our heating model takes into account hourly temperature variations when developing hourly annual profiles for heat demand. This is achieved by using domestic heating demand profiles based on the data collected through the Carbon Trust's MicroCHP Accelerator project, which are further calibrated using National Grid Gas regression coefficients to capture the temperature dependency of daily space heating requirements. We finally convert heating demand into electricity demand using the assumptions on heating technology mix contained in 2050 pathways (i.e. split between air-source heat pumps, ground-source heat pumps, resistive heating and any non-electric heating technologies). In our calculation we consider the temperature dependency of heat pump Coefficients of Performance (COP), which are particularly relevant for air-source heat pumps (ASHP).

- *Appliances*. The aim of smart operation of wet appliances is to adapt, i.e. shift in time the appliance usage in response to electricity system conditions, thus providing a range of services, such as generation/demand balancing, peak reduction, and network congestion management. In this analysis we focus on three types of wet appliances:

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18 ENA, SEDG, Imperial College, "Benefits of Advanced Smart Metering for Demand Response based Control of Distribution Networks", April 2010. Available at: http://www.energynetworks.org/modx/assets/files/electricity/futures/smart_meters/Smart_Metering_Benerfits_Summary_ENASEDGImperial_100409.pdf.

19 C.K. Gan, M. Aunedi, V. Stanojevic, G. Strbac and D. Openshaw: "Investigation of the Impact of Electrifying Transport and Heat Sectors on the UK Distribution Networks", 21st International Conference on Electricity Distribution (CIRED), 6-9 June 2011, Frankfurt, Germany.

20 D. Pudjianto, P. Djapic, M. Aunedi, C. K. Gan, G. Strbac, S. Huang, D. Infield, "*Smart Control for Minimizing Distribution Network Reinforcement Cost due to Electrification*", Energy Policy (accepted).

21 Green eMotion, EU FP7 project.

washing machines, dishwashers, and tumble dryers. The data relevant for the use of appliances is sourced from previous European-level projects,[22] and includes information such as diversified appliance demand profiles, which are important to determine when controllable demand is available, or the allowed shifting times according to consumer preferences resulting from the relevant surveys. According to this input database, between 1 and 3 hours shifting is allowed for washing machines, and 1 to 6 hours for dishwashers. The model can also include refrigeration appliances that can potentially contribute to providing frequency regulation services to the system, which are currently predominantly sourced from part-loaded synchronised generation.[23]

1.6 Importance of stochastic scheduling when modelling benefits of storage in supporting real-time balancing

As discussed, the operating reserve requirements and the need for flexibility at high levels of penetration of intermittent renewable generation will increase significantly above those in the conventional systems and storage technologies could potentially significantly contribute to delivery of these services. Generation scheduling is an established technique that simulates the commitment and dispatch decisions of the elements of a power system considering the need for flexibility and various types of reserve services. These decisions are arrived at by minimising the system cost subject to operational constraints (e.g. start-up times for thermal units) that limit the ability of the system to adjust to changing circumstances. By performing two simulations that differ in only one aspect, for instance with and without storage, one can quantify the effect of the difference, in terms of system operating costs or carbon emissions, for example.

In a traditional scheduling simulation, deterministic wind and demand time series would be used as inputs to the cost minimisation algorithm, while reserve requirements would be specified as exogenous criteria. Such deterministic methods are able to establish the value of the arbitrage function of storage, but the value of storage as a provider of reserve is linked to the exogenous reserve criteria that must be chosen by the analyst. For example, if the total reserve requirement at a particular time is defined as a fixed proportion of the aggregate wind output at that time, then the value of storage in providing reserve is linked to the analyst's choice of the proportionality constant. Furthermore, exogenous reserve criteria are necessarily static whereas the economically efficient amount of reserve would vary according to the dynamic cost of providing it, and the risk and cost of unserved energy demand.

Such pitfalls can be avoided by simulating system operation using stochastic scheduling. Stochastic scheduling accounts for the uncertainties explicitly, by providing the commitment algorithm with a range of possible outcomes (e.g. wind realisations) that are weighted according to their probability of occurrence. A stochastic scheduling simulation tool is designed to provide optimised generation schedules in the light of wind, demand and generator outage uncertainties, with the Value of Lost Load (VoLL) as the only security parameter (e.g. various types of reserves committed are the output of, rather than the input to, generation scheduling optimisation model). This is also informed by a complementary approach that uses Partial Differential Equation framework to assess the option value of

[22] Imperial College London, "Value of Smart Appliances in System Balancing", Part I of Deliverable 4.4 of Smart-A project (No. EIE/06/185//SI2.447477), September 2009.

[23] M. Aunedi, J. E. O. Calderon, V. Silva, P. Mitcheson, and G. Strbac, "Economic and environmental impact of dynamic demand", report for the Department of Energy and Climate Change (DECC), November 2008. Available at: http://www.supergen-networks.org.uk/filebyid/50/file.pdf

storage.[24]

Wind realisations, wind forecast errors and generator outages are synthesised from models and fed into a scheduling model, which finds the optimal commitment and dispatch decisions given the uncertainties and constraints. The decisions are found using a scenario tree which represents a discretisation of the range of outcomes of the stochastic variables (e.g. available wind output), with each path through the tree representing a possible outcome or scenario.

By simulating system operation with stochastic scheduling, we not only ensure that the value of storage can be assessed without reliance on the analyst's choice of reserve criteria, but also that the utilisation of the storage system will find the optimal balance between arbitrage and reserve.

The difference in the value of storage arising from the application of stochastic scheduling is shown in Section 3.5.3.

1.7 Annualised cost of capital

Cost of capital associated with energy storage systems will be driven by technical risks (e.g. uncertainty associated with plant failures and life span) and commercial risks (e.g. low revenues driven by unfavourable market condition). In this context it is useful to observe that distribution and transmission network assets for instance benefit from many years of experience and carry lower technical risks (e.g. mature technology, with life span of more than 40 years) and financial risk (regulated business with predictable revenues), than novel technologies, such as CCS or storage. Therefore, the annual return from investments in network assets can afford to be lower than technologies with shorter expected life and higher commercial risk.

We annualise costs of investment in generation, transmission and distribution assets using typical asset lives from the Electricity Generation Cost Model (and other sources for non-generation assets), and values for the Weighted-Average Cost of Capital (WACC), taken from a recent study prepared for the Committee for Climate Change (as presented in Table 2).

[24] S.D. Howell, P.W. Duck, A. Hazel, P.V. Johnson, H. Pinto, G. Strbac, N. Proudlove, M. Black, "A partial differential equation system for modelling stochastic storage in physical systems with applications to wind power generation", *IMA Journal of Management Mathematics*, Vol. 22, pp. 231-252, July 2011.

Table 2: Weighted Average Cost of Capital (WACC) reflecting risk and engineering life expectancy for different asset classes

Technology/asset	**Economic life** (years)	**Real Pre-tax WACC**	**Capital cost** (£/kW)	**Annualised cost** (£/kW/yr)
Conventional coal	35	7.5%	1,643	133.9
Conventional gas (CCGT)	30	7.5%	669	56.6
Coal CCS	25	14.5%	2,876	431.6
Gas CCS	25	14.5%	1,314	197.2
Nuclear	40	11.5%	3,030	352.9
OCGT	40	7.5%	599	47.5
Transmission/Interconnection	40	5.7%	1,500*	96.0*
Distribution	33	5.3%	n/a**	n/a**

** The figures for transmission refer to £/MW-km (capital cost),i.e. £/MW-km/yr (annualised cost).*
***Investment costs of the variety of distribution asset types (lines, cables, transformers etc.) that were considered in modelling are given in the Appendix.*

Based on the assumed WACC and economic lifetime, we convert capital cost into annualised cost using the following expression:

$$A = C \times \frac{WACC}{1 - (1 + WACC)^{-n}}$$

where n represents the asset lifetime (in years), C represents the capital cost for a particular technology, and A is the annualised cost.

Neither the lifetime nor the risk can be generalised for storage. Pumped hydro can operate for more than 30 years and is technologically and operationally proven. Novel technologies may not last that long and are perceived as higher risk by investors. To maintain the general applicability of this study, storage values are presented as annual returns. These can be converted back to capital cost targets using the same approach. For a given lifetime and risk, the annual value is multiplied by the discount factor to produce the maximum permissible capital cost.

We illustrate the importance of WACC and lifetime assumptions for the capitalised value of storage on the example of an annualised cost of £100/kW.year. For a mature and long-lived technology, similar to transmission and distribution network assets, with the assumed life of 40 years and WACC of 5.7% (similar to network assets), this would correspond to a capitalised value of storage of £1,563/kW. If we however assume a more risky technology, with an economic life of only 25 years and an appropriately higher WACC of 14.5% (similar to CCS technology), we obtain a capitalised value of storage of £666/kW. In other words, for a given level of annualised cost of storage, which also provides a cost target which the storage should not exceed in order to recover its cost when added to the system, a more risky and short-lived technology needs to be available at a much lower capital cost than if the same storage technology had a longer economic life and was considered to be technically mature.

2 Input parameters and key assumptions

2.1 Technology-neutral representation of storage

The remit of this project is to identify the value of future storage solutions, so that it can inform technology development needs. It is therefore necessary in the first instance to remain agnostic to the particular technologies available today or projected for the future. Hence this study takes a technology-neutral approach and represents storage systems through generic characteristics. A deliberately wide field of parameters is explored to ensure that potentially attractive options are not excluded from the scope of the study on the basis that under today's technology availability matrix they are deemed unfeasible.

The following parameters and units are used to characterise a storage system in this study:

- Rated capacity [GW]
- Storage duration [h]
- Round trip efficiency [%]
- Voltage level of connection [distribution networks (distributed) or transmission networks (bulk)]
- Location on the network [region for bulk; rural, semi-rural/urban, or urban for distributed]
- Lifetime [years]
- Cost [£/kW]

These properties are discussed in this section and the value space explored is further summarised in Table 3 and Table 4.

The level of storage deployment is expressed in GW as the sum of the nameplate capacities of all storage installations. Any presently existing storage capacity on the GB network (namely pumped hydro) is excluded from this figure. The model allows two approaches to analyse the value of storage. In the first one a given capacity that is to be deployed is specified at the outset of the analysis and the model optimises the location and operation of energy storage to minimise total system costs. This approach is effective when interrogating the average value of storage without the need to specify its cost, thus enabling the comparison of the relative merit of different storage types. Alternatively, annuitised cost of storage is specified and the model optimises the location and the capacity of storage endogenously. Both approaches are applied in this study.

The storage duration[25] is a measure of the ratio between the energy a storage installation is capable of storing (in kWh) and its rated power (in kW).[26] Practically this value is more relevant to the type of service storage fulfils; short duration storage will perform primarily power related functions, which require power over short periods of time (such as frequency regulation), whereas a system with long storage duration is capable of shifting larger amounts of energy across longer timescales. In this analysis storage duration is a parameter of the installation.

[25] Several terms are commonly used to refer to storage duration: "reservoir size", "storage energy capacity" or "time constant of storage".

[26] One can conceptualise this value as the time it takes to deplete a full storage reservoir at full power.

Round trip efficiency is the ratio of energy delivered from storage to the energy used to charge it. This value can be further broken down into charge and discharge efficiency (which can affect the value and sizing of the energy capacity) and a time-dependent efficiency as a consequence of self-discharge, evaporation or other technology-specific effects. This differentiation has been avoided to maintain efficiency categories that remain generic.

Table 3: Efficiency categories analysed (default efficiency is 75%)

Efficiency	**[%]**
Low	50
Medium	75
High	90

Bulk and distributed storage are differentiated by the voltage level at which they connect to the network and the capacity such installations can have. A principal difference between the two types, in terms of their role and value, is their ability to provide distribution network savings, which is only possible with distributed storage. This distinction can, however, have wider reaching consequences for the way bulk and distributed storage are deployed.

The GB network is represented as shown in Figure 3. Storage can be located in any of the five GB regions, with different demand profiles, wind resources and network constraints affecting its value and operation. The optimal location is left to the model, unless the relative merit of storage in different locations is analysed directly.

The lifetime of storage technologies not only depends on the type of technology and its level of maturity, but crucially on the operation pattern in terms of number of cycles, depth of discharge and rate of charge and discharge. The complexity and technology specific nature of the interrelation of lifetime and operation does make lifetime an unsuitable parameter within a technology-agnostic modelling framework. Instead, the value of storage is expressed on an annual basis, such that results can be applied across technologies with different life expectancies.

As discussed above in the context of storage capacity, technology costs can be applied as endogenous or exogenous variables in the model. A range of storage costs are considered (see Table 4) and the model deploys storage up to the level where the marginal value of deploying an additional unit of energy storage becomes less than the cost of that unit. (Note that higher cost values located in brackets in the last row of Table 4 refer to the extra-high cost case studies carried out for year 2050.)

Table 4: Cost categories for generic bulk and distributed storage technologies

Cost category	**Bulk (£/kW.year)**	**Distributed (£/kW.year)**
L	50	100
LM	75	125
M	100	150
MH	150	200
H	200	250
EH	400 (1000)	450 (1250)

This approach is used to analyse the relationship between the cost of storage and the optimal volumes deployed.

The endogenous technology costs approach, conversely, deploys a given quantity of storage ‘free of charge’ and the marginal and average values for this quantity are produced as model output.

2.2 Sources of value

Unlike commercial electricity price-based valuations of storage, this study values storage based on the total system savings with respect to different base case scenarios. The objective function minimises the total system annuitised capital investment and operating costs, thereby trading off numerous competing options.

Once a system optimal solution has been found the total saving can be attributed to its constituent parts. Here we differentiate between the following types of saving in:

- **Generation capital** (G CAPEX) – arises when investment in plant can be avoided without adversely affecting the security of supply and the ability to meet peak demand.
- **Transmission network** (T CAPEX) and **Interconnection** (IC CAPEX): model balances the annual cost of constraints and investment in interconnection and transmission network capacity. Storage can offset the need for transmission network and interconnection reinforcement by shifting in time the delivery of energy across congested transmission network.
- **Distribution network** (D CAPEX): These only apply to distributed storage connected to the distribution networks. By discharging during peak periods storage can reduce the need for distribution network reinforcement.
- **Operational savings** (OPEX): principally a measure of system efficiency, but with a range of operational causes, including avoided curtailment of RES (displacing other more costly generation), higher load factors for more efficient plant and improved scheduling of plants with low efficiency (such as spinning reserve).

2.3 Defining the benefit: Gross and Net benefit, Average and Marginal value

Gross benefit of adding storage to a system is defined as the reduction in total annual system costs enabled by storage, ignoring its costs (expressed in £/year). The Net benefit is numerically equal to the difference between Gross benefit and expenditure associated with the installation of storage (expressed in £/year).

This report however focuses on quantifying the *value* of storage associated with a given installed capacity. We define *average* and *marginal* value of storage. Average value of storage is numerically equal the ratio of Gross benefit created by storage of a given capacity and the capacity installed (expressed in £/kW.year). The marginal value on the other hand is the value that is created if one additional unit of storage is added. The marginal value is important, because it provides the upper cost limit for storage deployment for a given amount of installed capacity. Only if the cost of one additional unit is lower than its marginal value, should further storage be installed. For the last unit installed the marginal value is therefore equal to the cost of that unit.

Diagram in Figure 4 shows both marginal and average values (it is well known that the average value will always be greater than the marginal value). They can be read in the following way: for a given storage cost C the installed capacity is given by the marginal value curve as P.[27] For capacity P storage generates an average system value of V. The numerical difference between the two values (V-C) is a measure of the benefit that storage creates to the wider market.

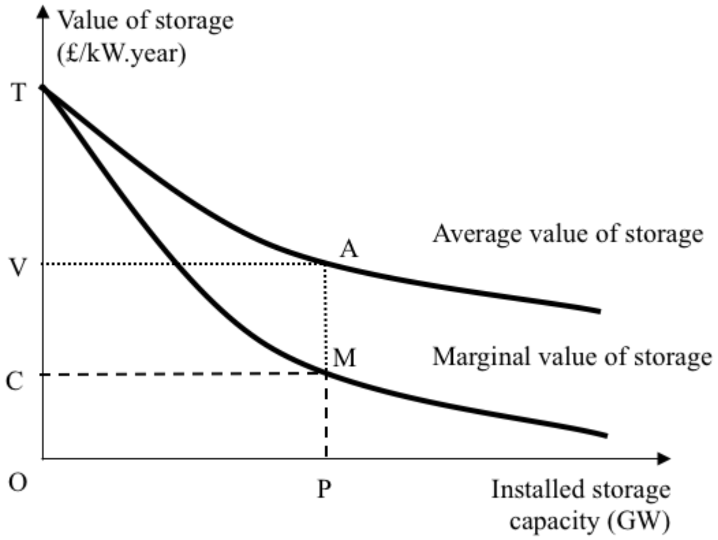

Figure 4: Average and marginal value curves.

We also observe from Figure 4, that the Gross benefit numerically equal to the area defined by points T-O-P-M-T. Subtracting expenditure associated with installing this amount of storage, represented by the rectangular C-O-P-M, Net benefit can be obtained and is represented by the area T-C-M-T.

2.4 Pathways, Scenarios and Cases

We distinguish between different possible futures. At the highest level we identify different *Pathways*. These describe a holistic narrative for the development of generation and demand towards the year 2050. This study builds on pathways developed by DECC in its Carbon Plan.[28] The central pathway is Grassroots, explained in more detail in the following sections. Due to its high component of renewable energy, Grassroots can be characterised as a pathway that is favourable for storage. We therefore also include a CCS and a Nuclear pathway to provide comparisons.

Scenarios in this study represent deviations from a given pathway, used to explore the sensitivity of the value of storage to such changes. Our scenarios include changes in the level of interconnection with neighbouring countries, changes to the flexibility of generating assets, different levels of demand flexibility and high or low fuel costs.

Furthermore, we test particular *cases* within each scenario. Cases are defined by the specification of storage itself: the installed capacity, storage duration, efficiency and costs, as set out in the previous Section.

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[27] The marginal value curve shows how much storage should be installed for a given cost (in this discussion we implicitly assume that storage duration and efficiency are specified).

[28] HM Government, "The Carbon Plan: Delivering our low carbon future", December 2011.

2.4.1 The Grassroots pathway

The Grassroots pathway is described by DECC as: *a (tacitly) high fossil fuel price pathway where the public embraces high energy demand reductions and multilateral innovation drives reductions in renewable technology costs, bringing them on an economic par with other forms of low carbon generation*.

The pathway narrative provides assumptions for demand and generation mix, which are translated and interpreted to be integrated into the present model. The demand scenario is disaggregated from annual energy values into load profiles with hourly resolution for different regions of the GB network. Given the sensitivity of the heat demand to temperatures, the analysis is conducted for an average with three days representing a cold snap of a 1 in 10 cold winter. The temporal resolution is required to simulate storage, and it further reveals capacity constraints during peak load. As shown in Figure 5 peak load reaches 104 GW in 2030. To ensure security of supply, additional peaking plant in the form of conventional gas and OCGT is added to the generation mix.

This additional capacity is in line with the value of lost load (VoLL) of above £10,000/MWh. The generation mix of the Grassroots scenario and the reinforced capacity used in this study are also shown in Figure 6 for the year 2030. 2020 and 2050 scenarios are shown in the Appendix.

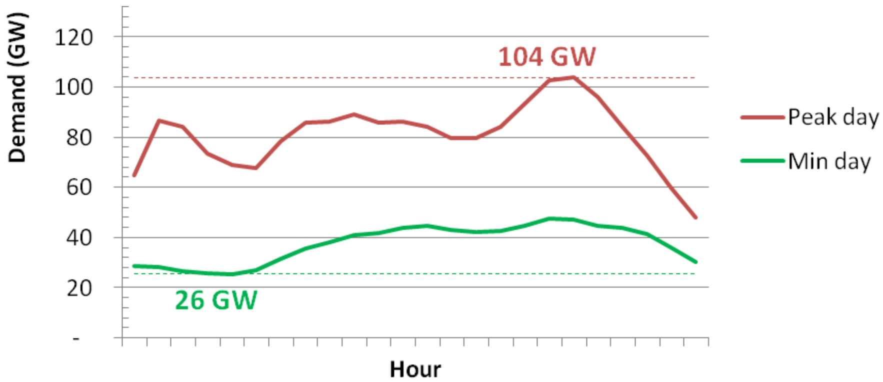


Figure 5: Load profiles for the highest and the lowest demand day in 2030. Disaggregated Grassroots scenario data reveals a peak capacity constraint.

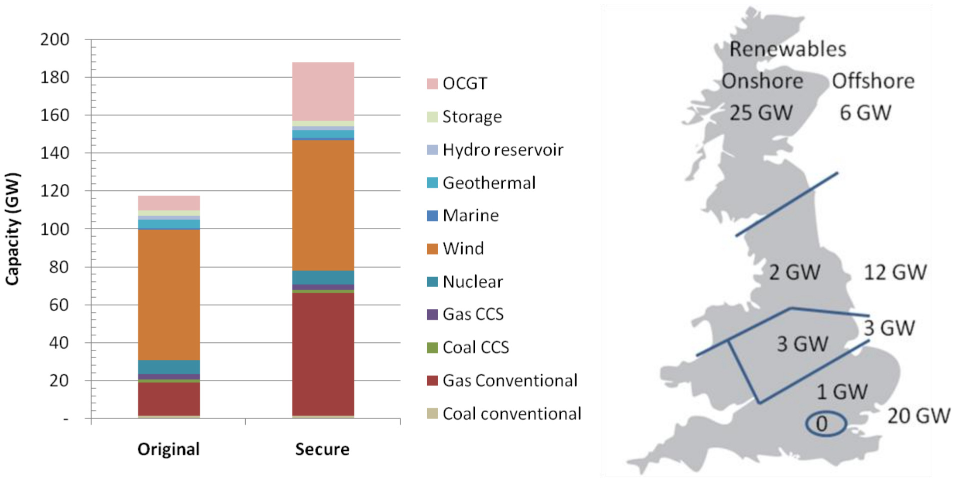


Figure 6: Generation mix for Grassroots 2030 before and after adding additional capacity to ensure resource adequacy (left) and the allocation of wind resource (right)

On the demand side, the Grassroots pathway is characterised by a fast electrification of transport and heating sectors, accompanied by highly ambitious measures in the area of improved building insulation and energy efficient consumer behaviour. In the heating sector about 50% of heat demand in the residential and commercial sectors is met using electricity, while 63% of road transport is assumed to be based on EVs or PHEVs.

2.4.2 Examining the impact of alternative technology options

It is important to recognise that in addition to storage technologies, there are a range of other potential options available to mitigate both supply and demand-side system integration challenges, as presented in Figure 7.

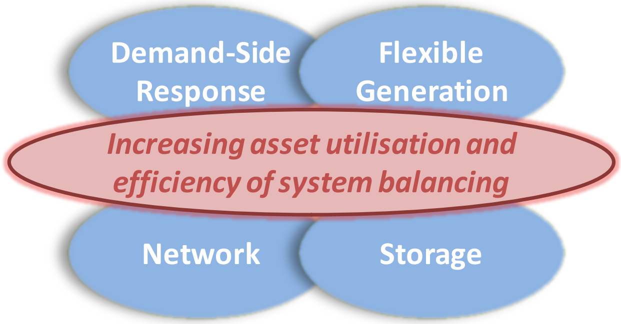


Figure 7: Technology options for mitigating system integration cost in low carbon systems

These include increased flexible generation, demand-side response and enhanced transmission regional interconnections, all of which could contribute to growing real-time system balancing requirements and the need to effectively maintain security of supply. The use of different mitigation techniques in future will depend on their technical and cost characteristics. Each mitigation technique only becomes economically attractive where the associated costs are lower than the accrued benefits, otherwise alternative actions would be pursued, e.g. using conventional generation capacity to provide backup, or curtailing wind output instead of storing it.

In this context we quantified the value of storage in the presence of alternative technology solutions:

(i) ***Interconnection***: Increasing interconnection capacity reduces balancing cost and enhances the ability of the system to accommodate renewables. We have hence optimised the capacity of interconnection between GB and Continental Europe and GB and Ireland, beyond 2020.[29] The interconnection cost of ca. £1,500/km is based on a number of recently planned projects. We then examine the value of storage and volumes deployed in the presence of interconnection.

(ii) ***Flexible generation***: Our analysis shows that enhancing the flexibility of conventional generation would facilitate more cost effective integration of renewables. To understand the impact of increasing flexibility generation on the value of storage we have modified

[29] We have based the capacities of interconnectors in 2020 on the National Grid's "Operating Electricity Transmission Networks in 2020" report published in June 2011. It is envisaged that there will be in total 5 GW of interconnection between GB and Central Europe (3 GW between GB and France (IFA and IFA2 interconnectors), 1 GW between GB and the Netherlands (BritNed), 1 GW between GB and Belgium (NEMO). In addition, 0.5 GW of interconnection is expected to be built between GB and Ireland (East-West). Also, there is the intra-GB Moyle interconnector between Scotland and Northern Ireland with a capacity of 0.5 GW.

the dynamic parameters of conventional generation; in particular, we examined the effect of reducing minimum stable generation and increasing the response capabilities of fossil fuel plant (details are presented in the Appendix). The cost associated with delivering increased generation flexibility is presently not well understood.

(iii) ***Demand-side response:*** Flexible demand side, in the form of electrified space and water heating in residential and commercial sectors, electrified transport sector and smart appliances in the household sector, may contribute to provision of energy arbitrage, reserve and frequency regulation services.[30] We hence examined the extent to which DSR may reduce the value of storage. We do not attribute any specific cost to DSR in the model as the main cost associated with the deployment of DSR is the roll-out of smart metering infrastructure, which the government has already mandated, although we recognise significant uncertainties related to the customer acceptance levels.

In addition, we recognise that the value of storage will be affected by fuel costs given the energy arbitrage task between renewable generation and other forms of generation. We have hence carried out studies to examine the extent to which increase in fuel costs will increase the value of storage (we used DECC's fuel cost projections, as described in the Appendix).

2.4.3 Storage value over time

The base case and most of the analysis focus on the year 2030 – a period when decarbonisation of generation and electrification of demand are expected to have reached significant levels. However, storage, along with all other technologies will undergo a transition towards 2030 and beyond. It is therefore important to consider how the value of storage builds up over time and how the respective sources of value potentially driving the deployment may change. For this reason the 2030 results are complemented by further studies for the year 2020 and 2050. In all cases the assumptions of the base case scenario are rooted in the DECC Grassroots scenario.

The scenarios for 2020, 2030 and 2050 are characterised by uptake of wind energy in line with the DECC Grassroots scenario. In 2030 a carbon constraint of 130 gCO_2/kWh applies. Electrified heating and transport are widely deployed. By 2050 the carbon constraint reaches 50 gCO_2/kWh, necessitating the use of abated peaking plants to stay within the carbon budget. For a detailed breakdown of the generation mix in each period see the Appendix.

2.4.4 Alternative generation pathways: Nuclear and CCS

Value of storage will significantly depend on the characteristics of the system, in terms of generation technologies with associated cost characteristics, network design approaches, demand profiles etc. There is a very significant uncertainty associated with development and deployment of future low carbon generation technologies. We have therefore carried out a set of studies to investigating the how the value of storage changes in different generation development scenarios.

The bulk of the analysis is carried out for the Grassroots pathway, comprising of large penetration of renewables. However, in Section 3.3 we contrast these results with alternative pathways, namely a CCS pathway and a nuclear pathway. In both cases, mid-merit and peaking plants are still in the form of traditional fossil fuel based power plant.

[30] In the case of electric vehicles, provision of frequency regulation is based on a rapid reduction of charging for short period of time (of a proportion of the vehicle fleet), rather than injecting power back into the grid.

The generation mix for each pathway is shown in Figure 8.

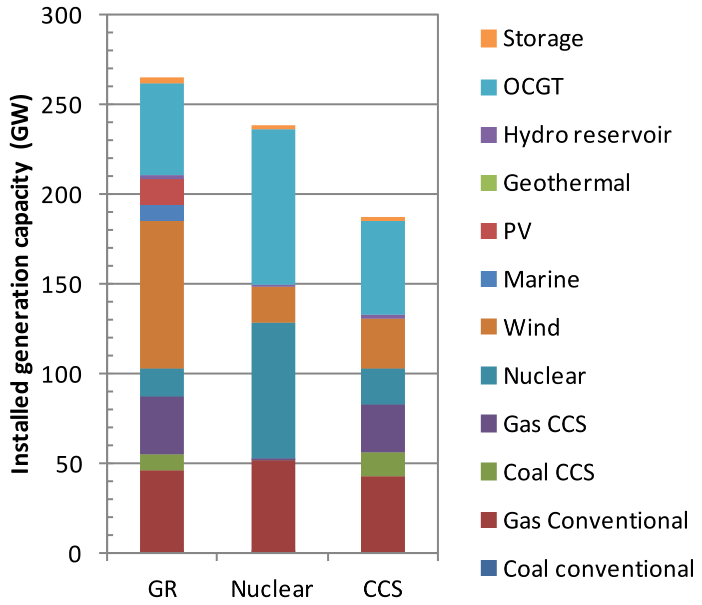


Figure 8: Generation mix for Grassroots (GR) and Nuclear and CCS pathways for the year 2050

It is important to note that different generation pathways are characterised by quite different demand backgrounds. For example, in nuclear scenario electrification of heat and transport sectors is significant while the energy efficiency measures are modest, resulting in high energy consumption and high peak demand. On the other hand, in the CCS scenario, the level of electrification is lower and this is reflected by lower energy and lower peak demand.

3 Key Results

This section provides an overview of some of the key findings selected from a large number of simulations. Some of these results are complemented by further material which can be found in the Appendix.

As part of this study a wide range of systems scenarios were simulated. These are specifically selected to present favourable and unfavourable environments for storage. The focus is both on the absolute value of storage and the sensitivity of this value to changes in scenario assumptions.

As a general finding, the values presented in this report are higher than previous studies suggest. This is a direct result of the “whole-systems” approach employed here. The aggregation of value from across the system, including savings in generation, networks and operation gives new insight, not only on the value of storage, but also regarding its role in future systems. It also poses challenges for policy makers to develop appropriate market mechanisms to ensure that the diverse sources of value are rewarded for investors in storage. These implications are further discussed in Section 5.

We are further able to present the sensitivity of these findings to different scenarios and assumptions about some of the key alternatives to electricity storage, including a more flexible demand side. The interdependency and trade-offs between different options in delivering low-cost system solutions reconfirm the need for system-wide studies to inform policy makers on the choices before us in the transition towards a low-carbon future.

Modelling results underlying these observations are explained in the next sections and further detail is provided about trends behinds these findings. The base case scenario we refer to is the adjusted version of Grassroots (see Appendix for further detail) and unless stated otherwise all following examples refer to the year 2030.

3.1 Grassroots pathway

In core runs of the Grassroots pathway we focus on the value that storage can provide in the UK electricity system if there are no other flexible options deployed in the system (such as new interconnections, flexible generation or demand-side response). We analyse how this value changes depending on the storage cost, type and duration. The focus of our studies is on year 2030, but we have also analysed how the value of storage evolves over time, i.e. what levels it can be expected to reach in 2020 and 2050.

After exploring the value of storage as the only flexible option being added to the system, we investigate the impact of the presence of other competing options, namely interconnection, flexible generation and flexible demand. We quantify the reduction in the value of storage when it is exposed to competition from other sources of flexibility.

Following that, we study the impact of alternative underlying pathways on the value of storage, providing an insight into how the storage would perform in markedly different routes to a low-carbon electricity system in the future. Finally, we conclude the chapter with a range of sensitivity analyses, testing the effect of various technology characteristics of storage on the potential benefits for the system.

3.1.1 Value of storage in 2030

Net benefits of storage

Figure 9 presents the net system benefits of bulk storage in Grassroots pathway in 2030, for 6, 24 and 48 hours of storage duration. (A similar chart format will be used for presenting the results throughout the text.) In each chart the composition of annual system benefits is given in £bn per year, for a range of assumed storage costs (top horizontal axis) also corresponding to different optimal volumes of storage proposed by our model (bottom horizontal axis). Optimal level of investment into energy storage is also plotted as negative benefit, resulting in a net system benefit that is also depicted in the figure ("Total").

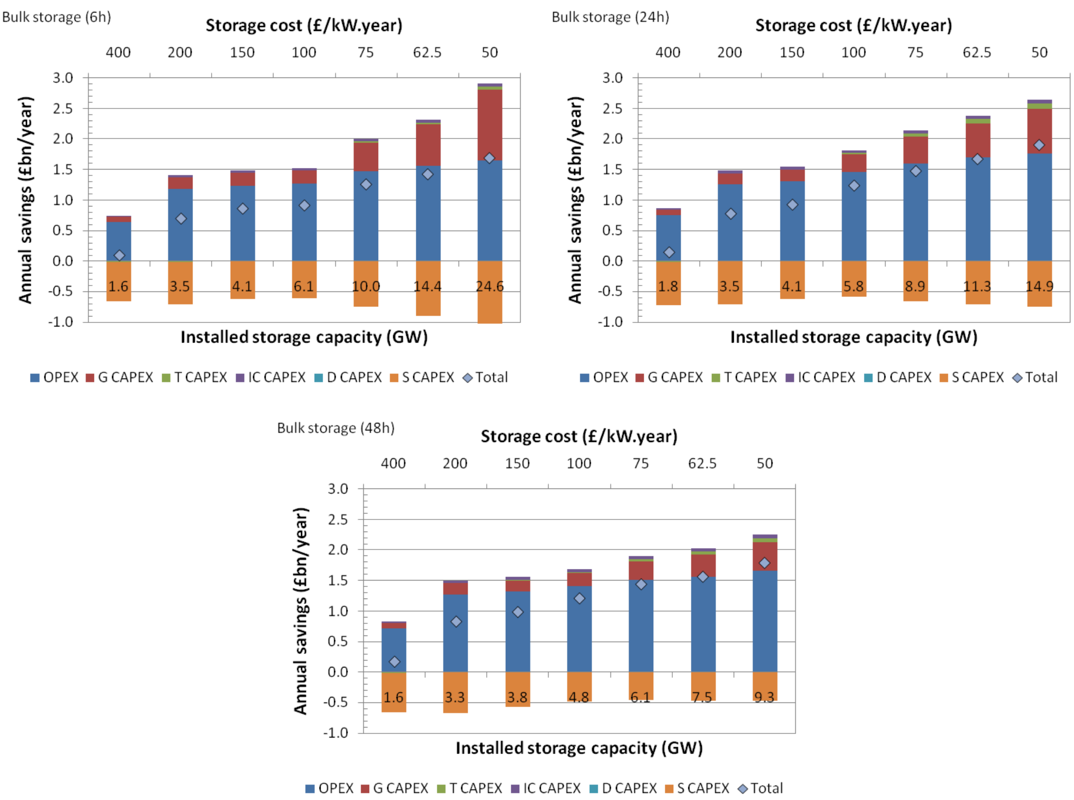


Figure 9: Annual net benefit of bulk storage for the Grassroots scenario in 2030 (for 6-hr, 24-hr and 48-hr durations)

Net benefits from deploying storage, after discounting its investment cost from gross system benefits, reach up to about £1.8bn/year when bulk storage is available at the lowest assumed cost (£50/kW.year). This value is not highly sensitive to storage duration, although we do notice an increase in benefits for higher durations.

OPEX savings represent a dominant savings component for lower storage volumes; for higher volumes however we notice a saturation effect in OPEX savings resulting in lower average OPEX savings per kW of storage capacity. Total investment in storage does not vary greatly, although its cost is assumed to vary in a relatively broad range. This is due to the model choosing higher volumes of storage when it is available at lower cost as part of the optimal solution.

Generation CAPEX savings are the second most pronounced savings component, which increases with larger storage capacity. We also observe a modest effect of storage on interconnection and transmission CAPEX, which becomes more visible towards higher storage volumes (i.e. lower costs).

With respect to the optimal storage volume, it increases as the storage cost drops, as expected. We also notice that storage duration is a factor determining how much storage should be added to the system. Higher durations suggest a lower optimal volume of storage if it is available at the same cost. This is a consequence of a much larger energy that can be stored in a 48-hour storage rather than in e.g. 6-hour storage having the same installed capacity in GW.

Figure 10 quantifies the annual system benefits obtained by deploying distributed storage of various durations. Most of the trends are similar as for bulk storage, with the key difference that distribution CAPEX savings become available as savings component. This results in about £2bn/year of net savings for the lowest cost case (£100/kW.year), i.e. even higher than for bulk storage available at half that price. We also notice that for the same cost, a lot more distributed storage capacity is chosen as part of the optimal solution than for bulk storage (e.g. for storage cost of £100/kW.year and 24-hour duration it is optimal to build about 6 GW of bulk storage, but if distributed storage is available at the same price, the model chooses about 15 GW).

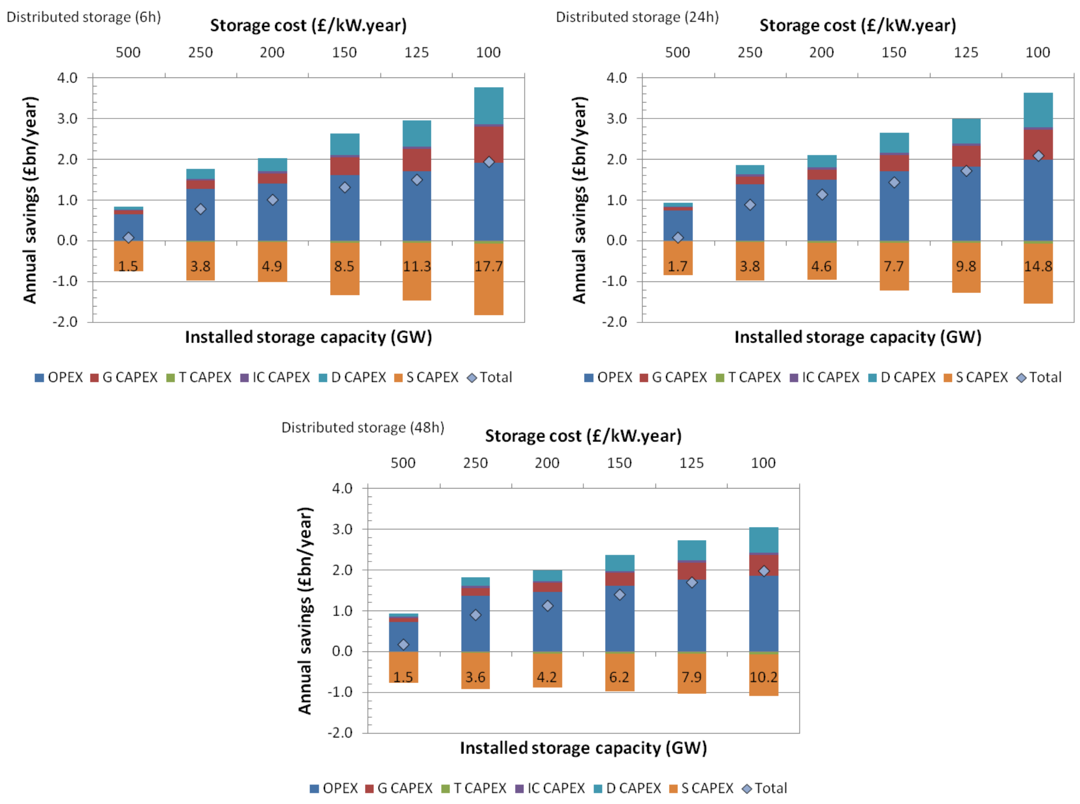


Figure 10: Annual net benefit of distributed storage for the Grassroots scenario in 2030 (for 6-hr, 24-hr and 48-hr durations)

Average value of storage

We further present in Figure 11 the average value of storage for the same cases as before, obtained by dividing the gross system benefits of storage for a particular cost case (not considering storage investment cost) with the optimal volume of storage deployed in that same case. This provides interesting insights into how a unit of storage (1 kW) performs in terms of providing benefits to the system.

We note that across the range of storage costs there is a relatively stable generation CAPEX saving of about £50/kW.year, which results from displacing OCGTs and CCGTs from the system (i.e. from storage replacing generation capacity to provide security of supply).

OPEX savings component is dominant as the result of reduced RES curtailment, although it diminishes with higher storage penetration, as it becomes progressively more challenging to reduce RES curtailment and hence reduce OPEX. There is only a minor impact on interconnection and transmission CAPEX (no new GB interconnections are allowed in this scenario).

More storage capacity gets built as the cost of storage decreases, i.e. higher duration implies lower optimal storage capacity, given that the storage with higher duration can store more energy for the same capacity, and can therefore achieve similar reductions in RES curtailment as higher-capacity storage with lower duration.

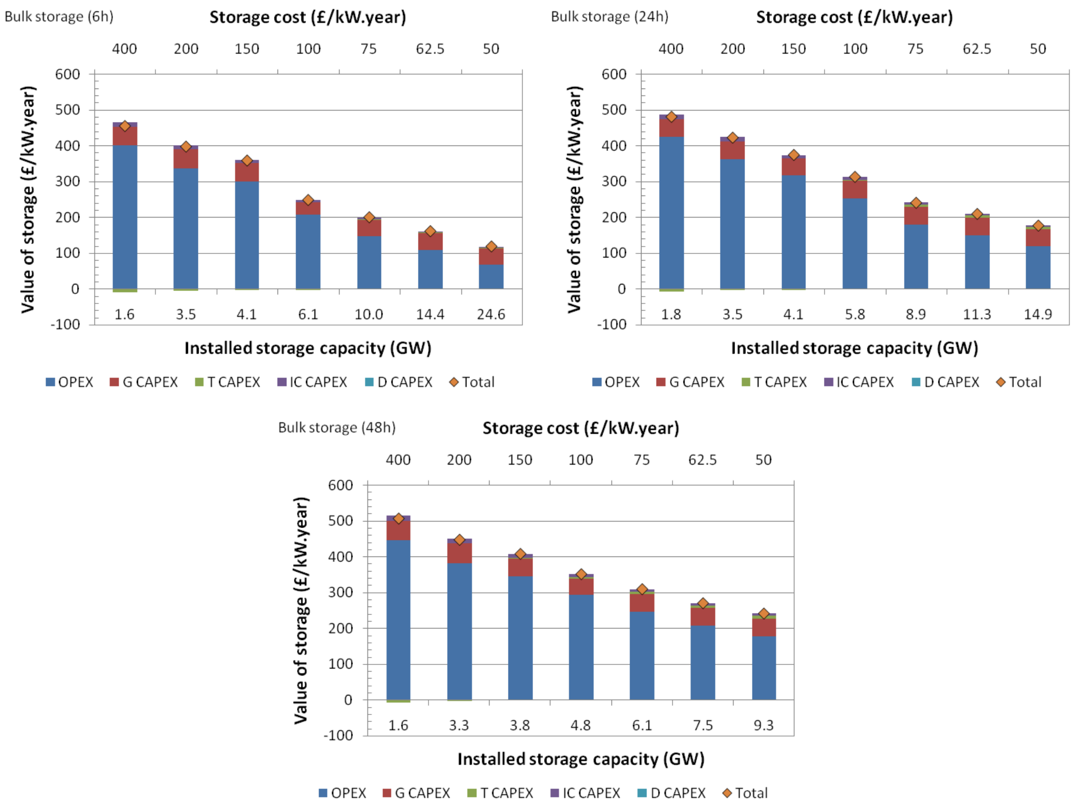


Figure 11: Value of bulk storage for the Grassroots scenario in 2030 (for 6-hr, 24-hr and 48-hr durations)

Similar to bulk, we present the results for the average value of distributed storage in Figure 12. Distributed storage achieves similar levels of generation CAPEX and OPEX savings as bulk storage, but also generates relatively constant distribution CAPEX savings in the amount of around £60/kW.year. We again notice that the optimal volumes are much higher than for bulk storage with similar cost.

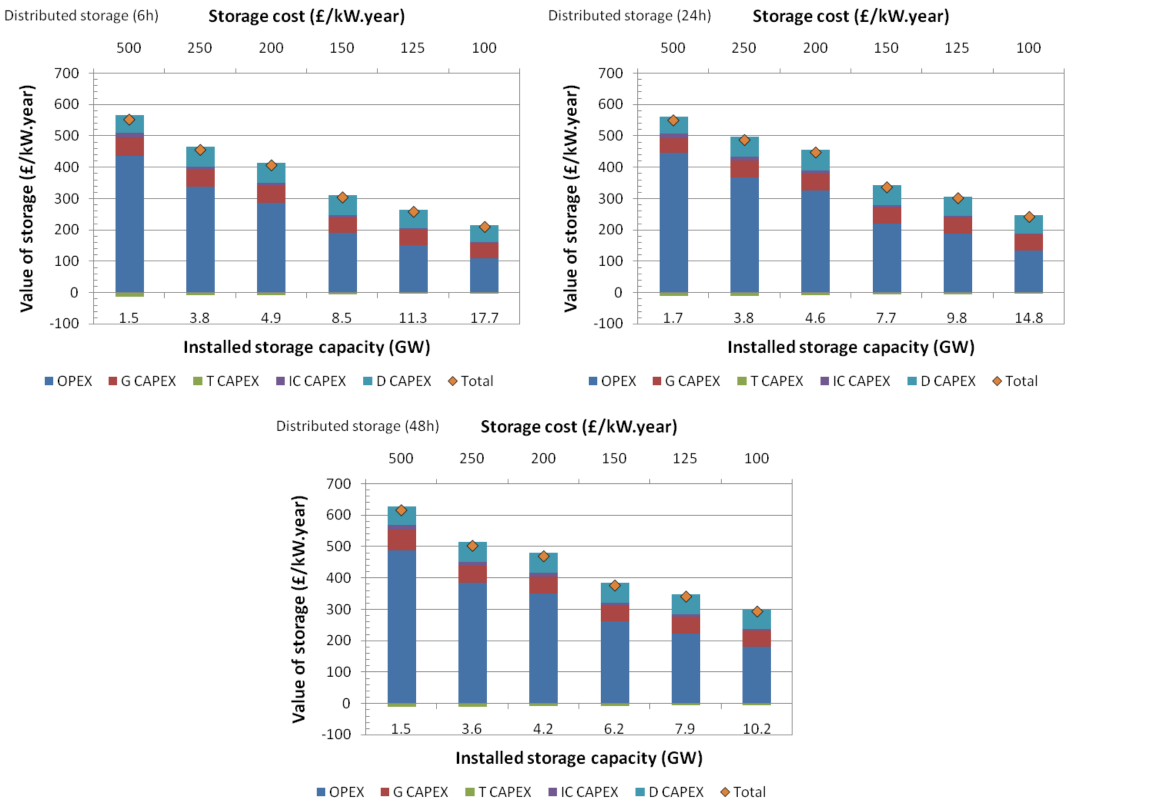


Figure 12: Value of distributed storage for the Grassroots scenario in 2030 (for 6-hr, 24-hr and 48-hr durations)

Average vs. marginal value of storage

Figure 13 compares average and marginal values of bulk storage for the same cases as before, but now plotted as lines with optimal volumes as x-axis coordinates. The meaning of average and marginal value of storage is in line with the definitions in Section 2.3, so that the average value refers to gross system benefits divided by the volume of storage (i.e. allocated equally to every kW of storage capacity), while marginal value refers to the additional value to the system of adding 1 kW of storage capacity at the point where there is already some capacity on the system. Marginal value is the curve which is relevant for determining the optimal volume of storage in the system, by finding where it crosses a horizontal line corresponding to the assumed storage cost.

As expected, we observe that the marginal value is always lower than the average, and both appear to start at approximately the same value for zero storage capacity (i.e. the benefit of the first kW is both marginal and average for that kW). Marginal curves are not very different between 0 and 5 GW for different storage durations; it is beyond 5 GW where the curve becomes very flat i.e. highly sensitive to changes in storage cost and duration.

Another observation is that the gap between average and marginal values tends to be smaller for shorter durations (6 h) than for longer (24 and 48 h). This means that longer-duration storage creates more benefits for the system above its investment cost.

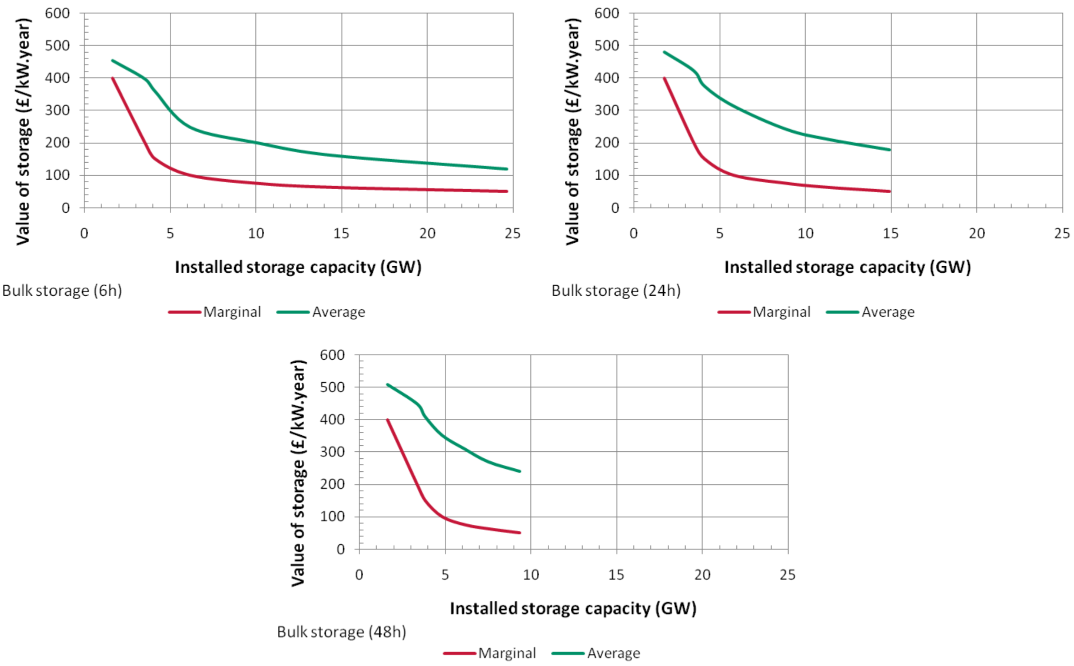


Figure 13: Average and marginal value of bulk storage for the Grassroots scenario in 2030 (for 6-hr, 24-hr and 48-hr durations)

In a similar fashion, Figure 14 illustrates the relationship between average and marginal value curves for distributed storage. Trends are rather similar, and we again notice that for the same cost level more distributed than bulk storage capacity gets built, because of the additional benefits of reducing distribution CAPEX which are not accessible to bulk storage.

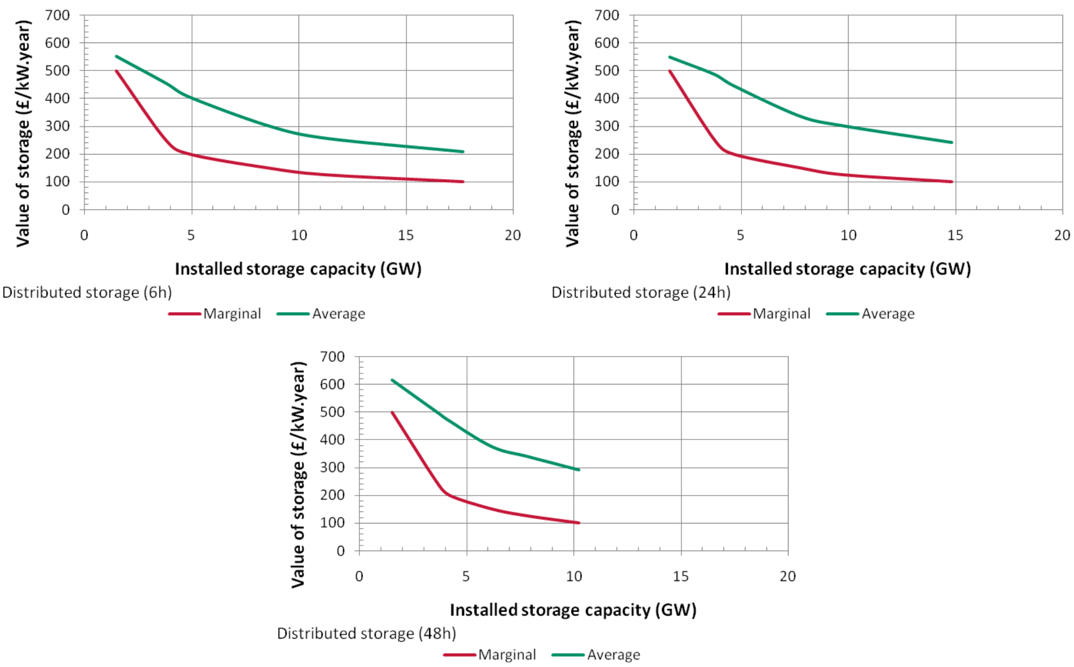


Figure 14: Average and marginal value of distributed storage for the Grassroots scenario in 2030 (for 6-hr, 24-hr and 48-hr durations)

It is important to note that the installed storage capacity in these diagrams does not refer to a build up over time. Instead they represent a snapshot. At this point in time the first few units of storage can deliver significant system savings as they choose to displace the most costly system components. The marginal value of these storage units is subsequently high. If more storage is present in the system the cost of the alternatives that this additional storage displaces drops until a point is reached when the marginal value of storage is equal to the cost of storage and further deployment does not yield any further system cost reductions.

In the idealised, open and competitive marketplace assumed here, all storage units can expect to realise the annual marginal value of the last unit installed, even if the first few units added a greater value to the system. The aggregation of system surplus is represented by the average value, which builds up as the integral of the marginal value. A fast decline in marginal value thus leads to discrepancies between marginal and average value. Note that for the same installed capacity with identical marginal value storage can have different average values, depending on how valuable the first few units are.

Figure 13 and Figure 14 give an indication of the steep drop of the marginal value over the first 4 GW. As a result the average value is continually higher than the marginal value.

Impact on renewable curtailment

The narrative of the scenarios prescribes a CO_2 constraint for each year analysed. The presence of storage does not lead to these scenarios exceeding their CO_2 reduction targets, and rather ensures that the constraint can be met at a lower cost.

A major part of the OPEX reduction stems from the better integration of renewable sources of energy. Figure 15 shows the extent of curtailed renewable energy before and after deployment of storage. Even in the high cost cases, storage is capable of more than halving the curtailment of renewables from initially around 30 TWh in the base case scenario to less than 15 TWh per year. The impact of storage on reducing wind curtailment has been found to be very similar for distributed and bulk storage.

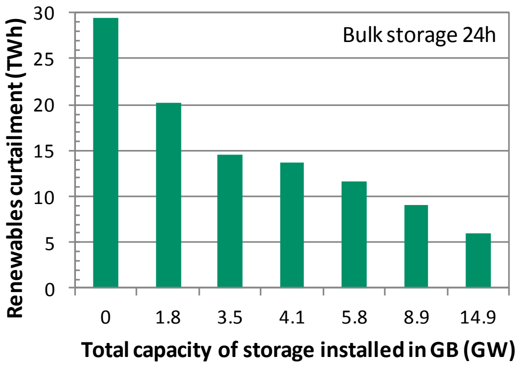


Figure 15: Impact of storage on renewable curtailment (bulk storage, 24-hour case). Storage more than halves the amount of renewable energy curtailed. High cost cases are sufficient to avoid the first 50% of curtailment. Further improvements only materialise with significant cost reductions.

Impact on transmission investment

With respect to the savings in transmission cost in the UK, we observe that bulk storage is generally more effective in reducing transmission CAPEX than distributed storage. The reason for this is the conflict between using storage to reduce transmission and distribution network capacity simultaneously. Given that reinforcements in distribution network are likely to be more expensive than in the transmission network, it is generally more beneficial for distributed storage to target the reduction of distribution network capacity, while forgoing the opportunity to produce savings in transmission investment.

For instance, if we install 5 GW of storage in the system, the impact on the reinforcement of the Scotland-England transmission link will be markedly different depending on whether the storage is bulk or distributed. For bulk storage, the new transmission capacity is reduced from 6.4 GW in the reference case (without storage) to 5.7 GW, while in the case of distributed storage this capacity actually increases to 8.4 GW. These two cases also differ in the location of storage within the UK; bulk storage is predominantly installed in Scotland to support wind integration, while distributed storage is located according to the level of demand which is the highest in the south of the UK, in order to capture distribution CAPEX savings in those networks where the requirements for reinforcement are also the highest.

Different location-specific behaviour of bulk and distributed storage

The role of storage in the system is greatly affected by whether it is connected to the high voltage network (bulk) or at the distribution level. The key difference between bulk and distributed storage in our modelling framework is the access to distribution network savings, which are not available to bulk storage. This distinction has wide reaching consequences for the optimal location of storage within the GB network and the function it performs in these locations.

Figure 16 illustrates the trade-offs on an example spanning three consecutive days in Scotland for the year 2030. Wind output (24 GW) initially exceeds demand (7.5 GW) and drops during day 2. The way storage is operated in these conditions depends on its type. Bulk storage is charged during the high wind period capacity, and discharged once the wind has dropped, except for a brief period with low demand during the second night. The resulting demand + storage profile is highly volatile with 25 GW peaks and even negative loads reaching –8 GW, which are handled via the transmission link with England and Wales.

Distributed storage, on the other hand, follows a different operating strategy. The charge and discharge pattern is less responsive to wind. Instead, distributed storage discharges in order to reduce peak load on all three days, even during periods of high wind. It also charges during periods of low wind if demand is low, resulting in a flattened demand profile at the level of about 9 GW. The surplus variable wind output exceeding 16 GW in this case is exported to England and Wales, via a reinforced transmission link.

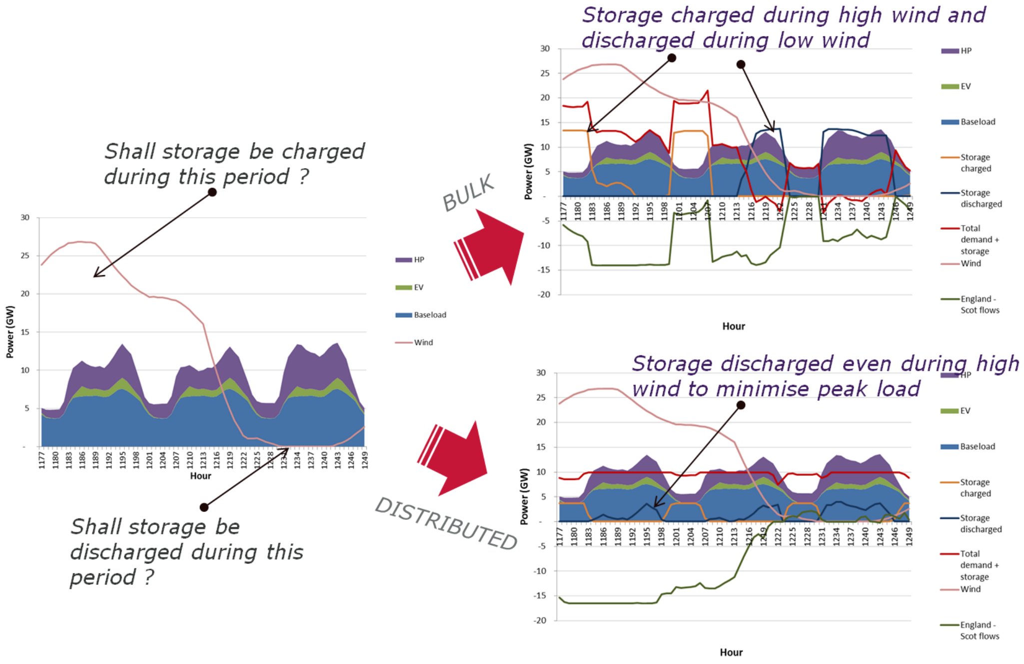


Figure 16: Operating principles for bulk and distributed storage

Different operating patterns of bulk and distributed storage also have implications for their optimal location in the GB network. Figure 17 shows the optimal allocation between Scotland and England & Wales (E&W) by quantifying the part of storage capacity that is installed in Scotland, for different storage durations.

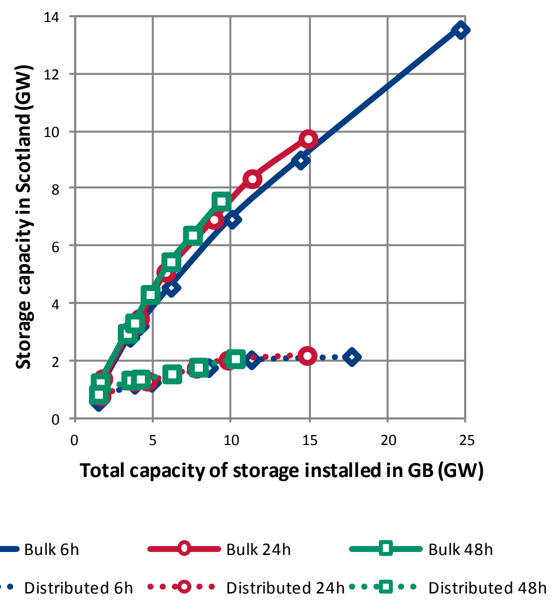


Figure 17: Share of total storage located in Scotland. Bulk storage is predominantly located in Scotland.

Bulk storage is preferably placed in Scotland, where it supports the integration of wind and avoids costly reinforcement of additional transmission links with northern England. Only 20-30% of the 10 GW of bulk storage is located in the E&W region in this scenario. For distributed storage we observe and opposite trend. 80-85% of capacity is located in E&W and only 15-20% in Scotland. The dominant positioning of distributed storage in E&W can be explained by a higher value accruing from avoided distribution network reinforcement.

Comparison of benefits of bulk and distributed storage

As discussed, storage technologies can simultaneously support different sectors of the electricity system and facilitate more efficient operation and investment of assets across the entire electricity system. As this report points out, this is critical for establishing the business case for storage. The model developed can explicitly consider synergies and conflicts of storage resources being used in multiple markets, specifically considering:

(i) Contribution that energy storage resource can provide in reducing operating cost and enhance the ability of the system to absorb renewable generation. This includes consideration of energy storage based provision of frequency regulation and various forms of reserves and balancing services, particularly important in scenarios with significant penetration of intermittent generation.

(ii) Contribution of energy storage technologies to displacing the need for conventional generation capacity and contributing to security of supply

(iii) Contribution of energy storage to reducing the need for transmission network and interconnection

(iv) Use of energy storage to enhance the ability of the distribution networks to accommodate increased levels demand and generation.

As storage generates benefits in different applications there will be synergies and conflicts across these applications. For example, application of distributed storage in Scotland to reduce electricity peak load and the associated distribution network reinforcement cost, may lead to a higher capacity requirement of the transmission network between Scotland and England. On the other hand, the application of distributed storage to reduce the cost of transmission may prevent higher savings to be achieved in reducing distribution network cost. Understanding this complexity is crucial for making the right decisions in the investment and operation of bulk and distributed storage. In this context, optimal location and operation of bulk and distributed storage are likely to be different.

In addition to the cost-based case studies, we have carried out a range of numerical studies investigating the magnitudes and sources of values of bulk and distributed storage. Results of some of our studies with 2, 5, and 10 GW of installed bulk and distributed storage capacities using the Grassroots scenario are summarised in Figure 18.

Trade-offs between savings in operating cost and savings in system capacity cost are evident, particularly in transmission and distribution networks. The value of distributed storage with respect to savings in operating cost and transmission is generally lower when compared to the respective contribution of bulk storage. However, the total value of distributed storage after taking into account savings in distribution network cost can be larger than the total value of bulk storage. This suggests that in order to maximise the overall value of distributed storage, some trade-off has been made resulting in less savings in operating and transmission cost but has optimal savings in distribution cost. In these studies bulk storage, which has no access to distribution network savings, contributes larger shares to generation CAPEX and operational savings instead. The value of bulk storage for these two sectors is therefore typically slightly greater than from distributed storage.

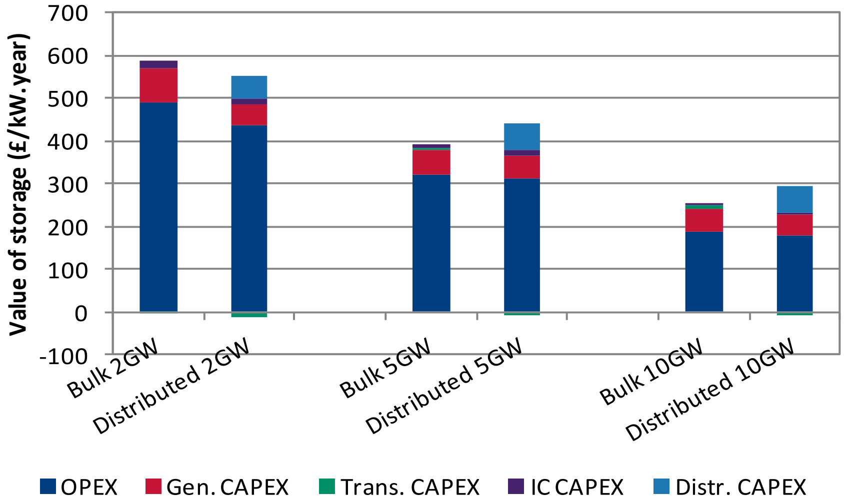


Figure 18: Trade-off between various cost savings for bulk and distributed storage

The application of distributed storage in reducing electricity peak load may also reduce the ability to avoid renewable curtailment. However the difference in performance of bulk and distributed storage is relatively small (less than 10% of the total savings in renewable curtailment). This explains why the savings in OPEX are lower for distributed storage than for bulk.

In most cases the additional value from distribution network savings more than makes up for the lower OPEX savings, such that distributed storage is more valuable than bulk. A notable exception to this rule can be found in the 2 GW case shown in Figure 18. Here, bulk storage is more valuable to the system outright. Distributed storage has therefore not merely sacrificed OPEX savings for the sake of more valuable distribution network savings. The OPEX savings are lower, because distributed storage is constrained by the distribution network capacity. During periods of high wind and high demand, the distribution network capacity may not be sufficient for distributed storage to charge from surplus wind. The distribution network is not further reinforced, since this would carry higher costs than the resulting saving from avoided wind curtailment. Thus, bulk storage is generally better placed to avoid wind curtailment. In cases with higher installed storage capacities this difference does, however, become smaller and distributed storage tends to capture greater overall savings.

3.1.2 Value of short-duration storage

We further explore the impact on the value of storage of short duration, for the example of 1 hour, which is illustrated in Figure 19. We notice that, unlike previously, when lower duration implied higher optimal storage capacity, the model chooses to build less 1-hour storage than e.g. 6-hour storage. This is because of severe restrictions on energy that can be shifted by storage, which also means it becomes much more difficult to avoid renewable curtailment e.g. during prolonged windy periods. We also notice that net benefits for a particular cost level decrease compared to the 6-hour case.

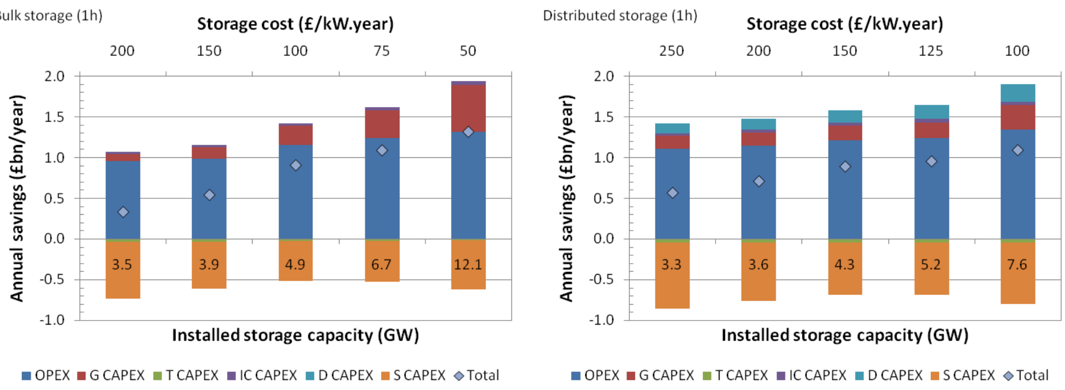


Figure 19: Annual net benefit of bulk and distributed storage of short duration (1 h) in Grassroots pathway (2030)

Components of average value of short-duration storage are presented in Figure 20, while Figure 21 illustrates the relationship between average and marginal values. We notice that especially for low storage capacities, the savings components for generation and distribution CAPEX (for distributed storage) are lower than in cases with higher durations, as a result of a significantly limited ability of storage to reduce peaks in demand which can last for a longer period.

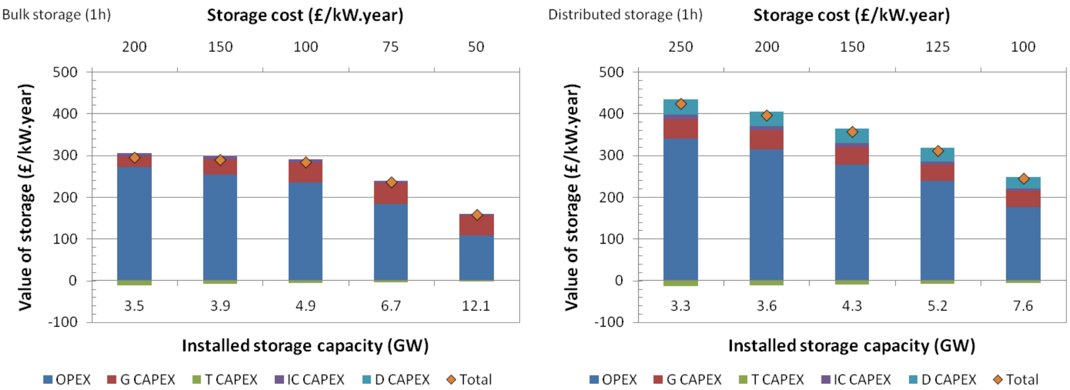


Figure 20: Value of bulk and distributed storage of short duration (1 h) in Grassroots pathway (2030)

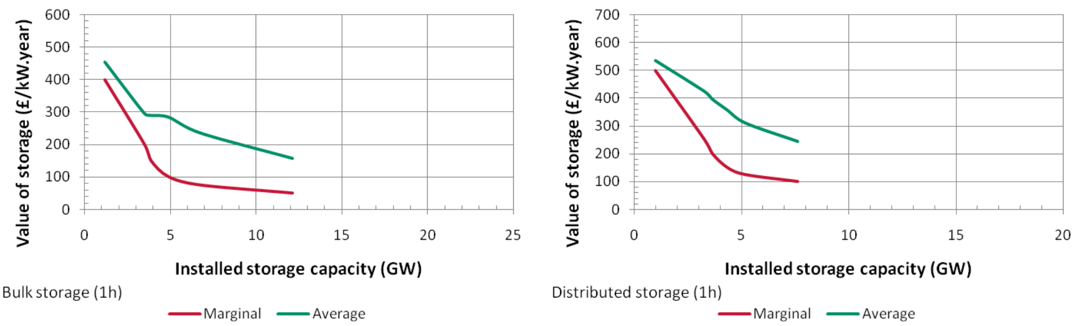


Figure 21: Average and marginal value of bulk and distributed storage of short duration (1 h) in Grassroots pathway (2030)

3.1.3 Increase in value from 2020 to 2050

In order to assess the evolution of the value of storage across time, we present the results of our analysis of the Grassroots pathway in years 2020 and 2050, and then compare them to

2030 results to illustrate how the scale of the storage value increases rapidly as the system evolves towards progressive decarbonisation.

Figure 22 illustrates the net benefits of storage in 2020, on the example of 24-hour duration. Numbers on the top and bottom horizontal axes again correspond to cost-volume pairs resulting from our optimisation, although in this instance they have been obtained by using different values of storage volume rather than cost as inputs (2, 5 and 10 GW). These pairs of values are however unique, and the same results would have been obtained if the marginal storage cost (top axis) were plugged into the model to obtain optimal volumes.

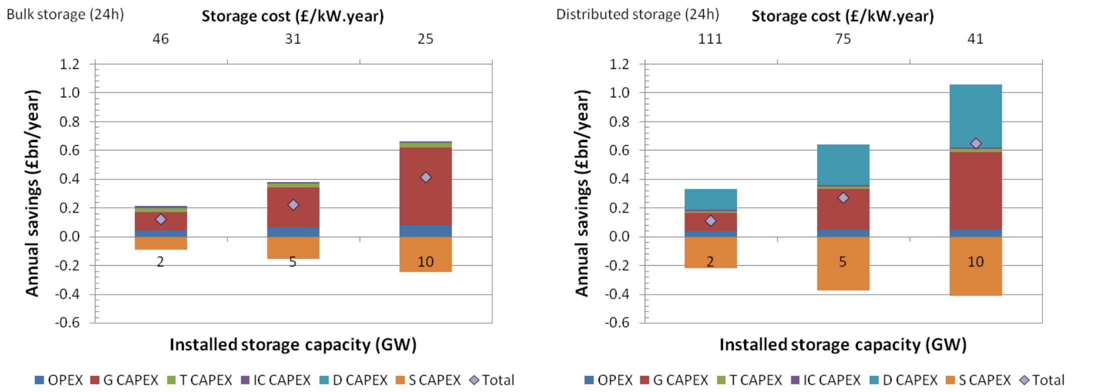


Figure 22: Annual net benefit of bulk and distributed storage in Grassroots pathway in year 2020 (24-hr duration)

Net savings in 2020 are dominated by generation CAPEX savings in the case of bulk storage, while the benefits of distributed storage represent a balanced mix of generation and distribution CAPEX savings. OPEX savings in 2020 are very low, as there is very little renewable curtailment which storage might help to avoid. We also observe that for the range of storage volumes assumed, the equivalent storage costs are lower than the cost range assumed in 2030 cases, for both bulk and distributed storage. This suggests that with higher storage cost we would only see a very small amount of storage capacity being added to the system. Also, the level of net benefit is far smaller than in 2030; for a comparable level of cost (e.g. about £50/kW.year for bulk and £100/kW.year for distributed) we obtain benefits in 2020 that are an order of magnitude smaller than in 2030.

Figure 23 illustrates the average value per unit of storage capacity in 2020. As in the case of net benefits, the value is dominated by generation CAPEX for bulk storage, and generation and distribution CAPEX for distributed storage, with a very small proportion of OPEX savings. Generation CAPEX component is relatively stable across the cases analysed, at the level of around £60/kW.year, which is broadly equal to the cost of an avoided kW of new generation capacity. Distribution CAPEX on the other hand exhibits a saturation effect, dropping from about £70/kW.year for 2 GW of distributed storage to about £50/kW.year for 10 GW of distributed storage.

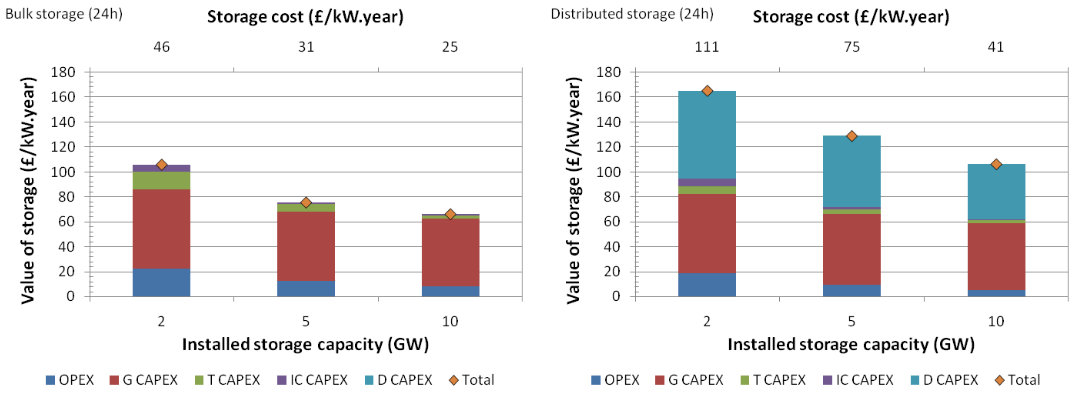


Figure 23: Value of bulk and distributed storage in the Grassroots scenario in year 2020 (for 24-hr duration)

A comparison between the average and marginal value curves for bulk and distributed storage in 2020 are shown in Figure 24. For bulk storage, we observe that the marginal value is less than half of the average value, while for distributed storage the ratio varies more across the range of storage volumes considered. The values of distributed storage are also visibly higher than for bulk; as already discussed, the difference is the result of the additional distribution CAPEX saving which is accessible to distributed, but not to bulk storage.

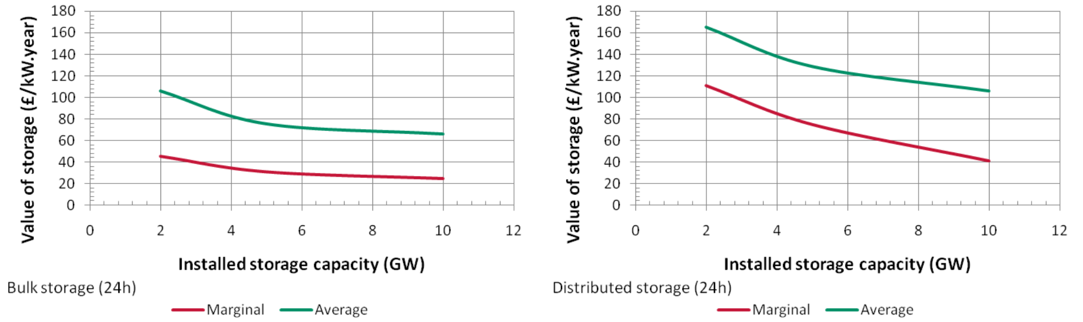


Figure 24: Average and marginal value of bulk and distributed storage in the Grassroots scenario in year 2020 (for 24-hr duration)

Figure 25 presents the net benefits of bulk and distributed storage in year 2050, following the assumptions of the Grassroots pathway. These are in stark contrast with the results for 2020, with net benefits reaching £11bn per year in the case with the lowest storage cost (although this cost is still at the higher range of costs considered in 2020).

Unlike in 2030, the composition of net benefits is no longer dominated by OPEX savings, but is rather balanced between OPEX and generation CAPEX savings, and this occurs on a very similar scale for both bulk and distributed storage. Both savings components occur on a much larger scale than in 2030, largely due to significantly higher renewable curtailment, but also because of the impact of carbon emission constraints on the generation capacity. There is also a visible contribution to distribution CAPEX savings in the case of distributed storage, although its scale in 2050 is much smaller compared to the other two savings components than in 2030.

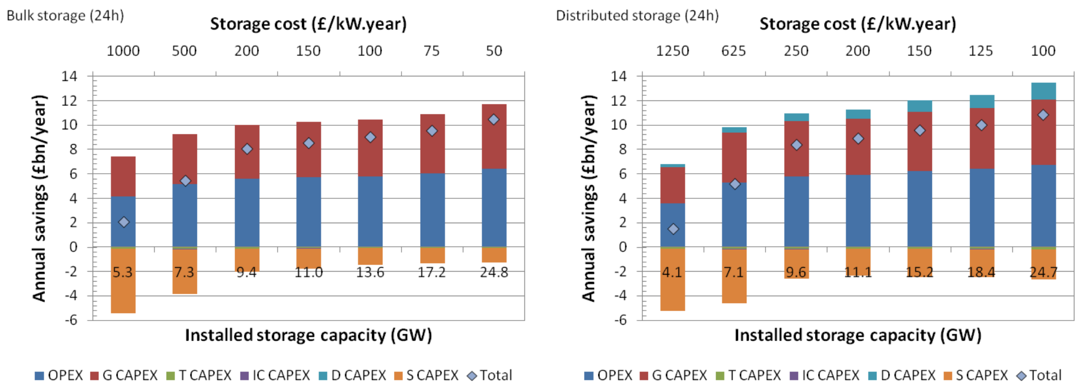


Figure 25: Annual net benefit of bulk and distributed storage in the Grassroots scenario in year 2050 (for 24-hr duration)

Figure 26 expresses the value of storage in 2050 per kW of storage capacity. The value is almost exclusively comprised of OPEX and generation CAPEX savings in roughly equal proportions. OPEX savings per kW of storage exceed £800/kW.year for the most expensive storage cases; this is double the amount observed in 2030, suggesting that the value of flexibility in the system increases greatly between 2030 and 2050. As in 2030, the value of storage for OPEX savings diminishes with higher storage volumes, given that the first GWs of storage capture the most valuable OPEX savings.

The optimal volumes of storage also increase considerably compared to the 2030 cases. For the least expensive storage, we notice that around 25 GW of storage is built, compared to about 15 GW in 2030. Also, even at very high storage cost levels (£1,000/kW.year for bulk and £1,250/kW.year for distributed) we observe a substantial amount of capacity (4-5 GW) being chosen by the model.

Generation CAPEX savings are much higher in 2050 than in 2030 cases, and can reach up to £700/kW.year, which is an order of magnitude higher than the investment cost of new CCGT or OCGT capacity. We also notice that the generation CAPEX savings component declines with higher storage volumes, unlike in 2030 when this component is broadly constant across the range of storage volumes, although it is smaller.

The reason for such high generation CAPEX savings is in the implications of the carbon emission constraint in the reference case. Because of the rigorous emission target (50 g/kWh) and a very high level of renewable curtailment in the reference case in 2050 (around 100 TWh annually), the only way to comply with the emission threshold is to add new and expensive CCS capacity to the system. When storage is added to such a system, curtailed renewable energy drops significantly, as elaborated previously. This means less CCS is needed to meet the emission constraint, i.e. that some of the CCS capacity can be replaced with much cheaper CCGT plants. This has the effect of producing large generation CAPEX savings in the system when adding new storage capacity. In addition to replacing marginal generation capacity for security purposes, as was the case in 2030 when it yielded around £50/kW.year, a kW of storage in the 2050 Grassroots pathway enables several kWs of CCS to be replaced with CCGT or OCGT, and hence creates substantially higher benefits for the system. This is obviously the consequence of the assumptions on the generation capacity and the emission constraint in 2050, and cannot be generalised for any pathway.

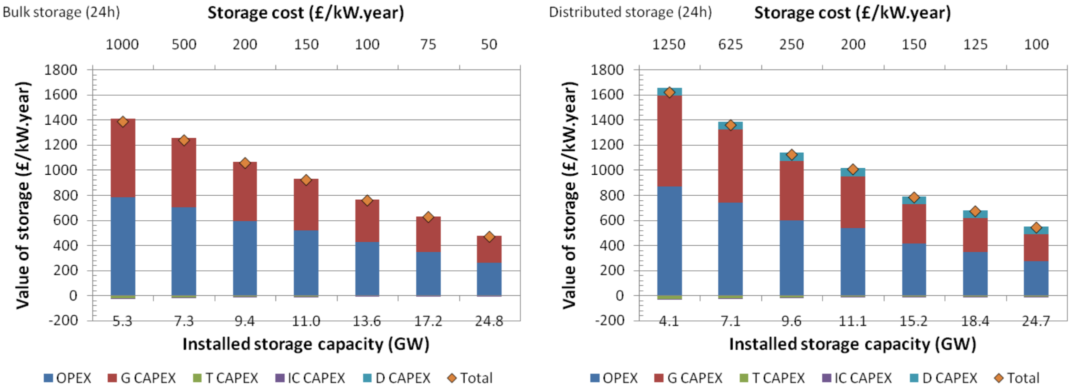


Figure 26: Value of bulk and distributed storage in Grassroots pathway in year 2050 (for 24-hr duration)

Figure 27 presents the average and marginal value curves for the two storage types in 2050. We observe a rapid decrease in the marginal value of storage up to 10 GW, which is roughly when all the additional CCS capacity added in the reference case has been replaced by cheaper generation. Beyond 10 GW the marginal value continues to drop but at a very slow rate, with the values similar in magnitude to marginal values observed in 2030. For smaller storage volumes however, the marginal and average values are much higher than in 2030, so that even at a very high cost of over £1,000/kW.year we see some 5 GW of storage being chosen by the model.

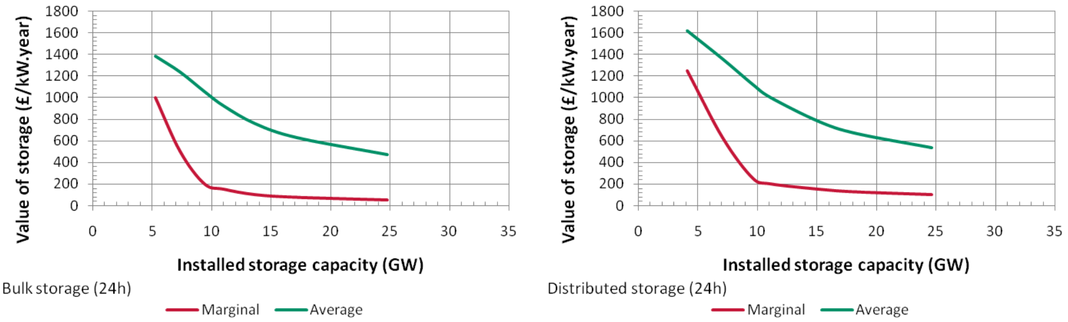


Figure 27: Average and marginal value of bulk and distributed storage in Grassroots pathway in year 2050 (for 24-hr duration)

The impact of storage on OPEX reduction is primarily driven by avoiding renewable curtailment; the effectiveness of storage in avoiding the need to curtail intermittent renewable output is illustrated in Figure 28, for the case of 24-hour bulk storage in Grassroots scenario in 2050. The scale of renewable curtailment in the reference case (100 TWh) is very high, accounting for about 30% of the total annual renewable electricity output. We observe that the storage in this case is even more efficient in reducing renewable curtailment, and in particular the first units of storage capacity. For instance, the first 5 GW of storage reduce the curtailed renewable output to only about 40% of the reference case value.

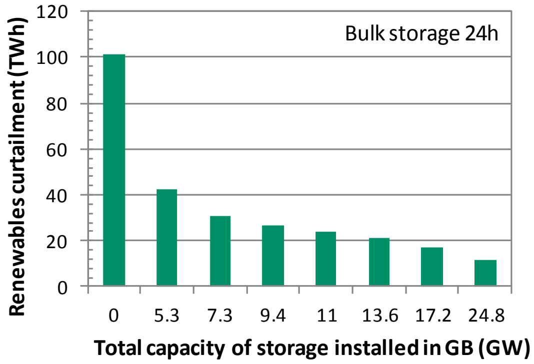


Figure 28: Impact of storage on renewable curtailment in Grassroots in 2050 (bulk storage, 24-hour case)

Figure 29 illustrates the optimal locations of bulk and distributed storage capacity in 2050. Similar as before, for small volumes of bulk storage the majority is placed in Scotland. However, after about 10 GW this trend changes so that an increasingly larger share of capacity is placed in England and Wales. This results in the Scotland's share of bulk storage capacity dropping to below 50% when storage capacity exceeds 20 GW.

Distributed storage location is again dictated by the higher demand levels in E&W compared to Scotland, which also represents better opportunities for saving distribution network reinforcement. Hence, more than 80% of distributed storage is located in E&W.

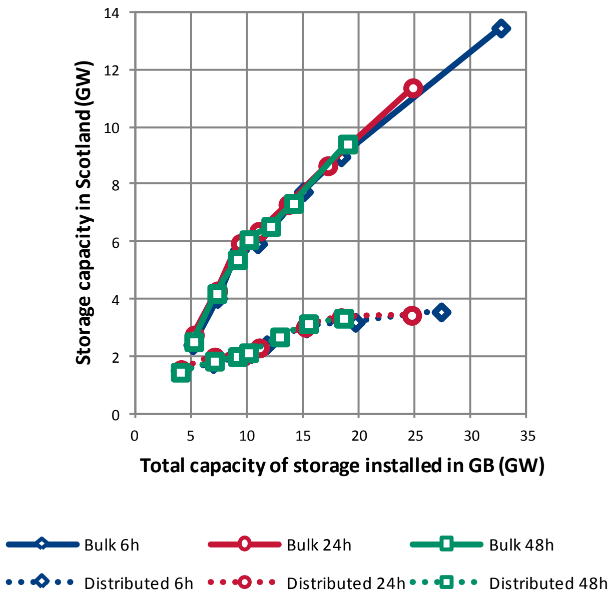


Figure 29: Share of total storage located in Scotland in 2050

A fundamental difference of the approach taken in this study over previous approaches to valuing storage is the whole systems approach. Several means by which the system costs can be reduced are considered in the modelling framework. These include, as introduced in Section 2.2, the capital expenditure for generation assets, investment in distribution, transmission and interconnect infrastructure, and system operation cost. The model chooses between these options to find cost-optimal system configurations and operation patterns. In doing so, complex trade-offs between these options are evaluated. For instance, a saving in one area may lead to increased cost in another, but so long as the aggregate benefit is greater than alternative solutions it may constitute a system optimal solution.

An overview of the constituent parts of the net system benefit and average value of storage across the 2020-2050 period is shown in Figure 30 and Figure 31.

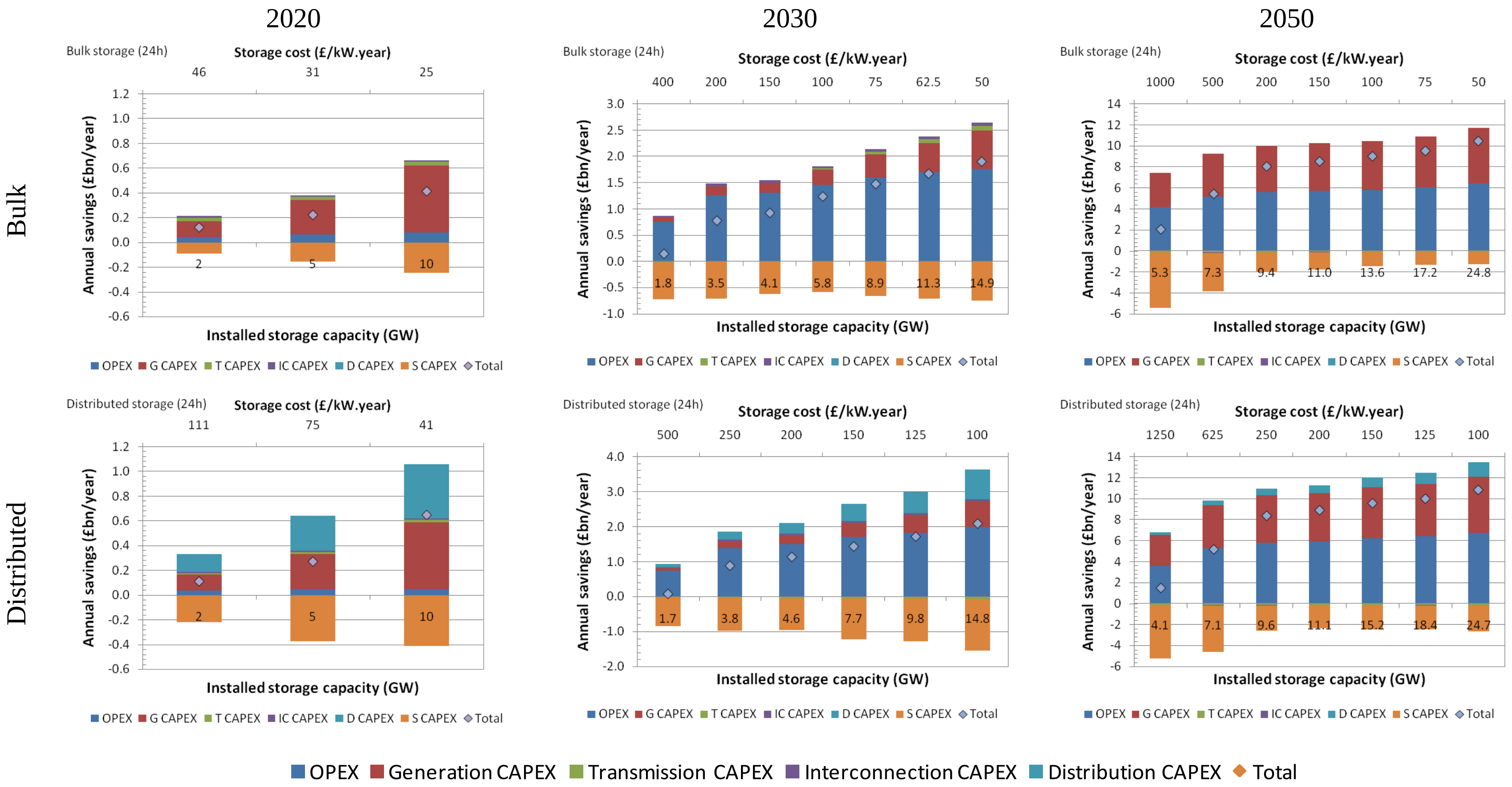


Figure 30: Net benefit of bulk and distributed storage from 2020 to 2050 (24-hour case)

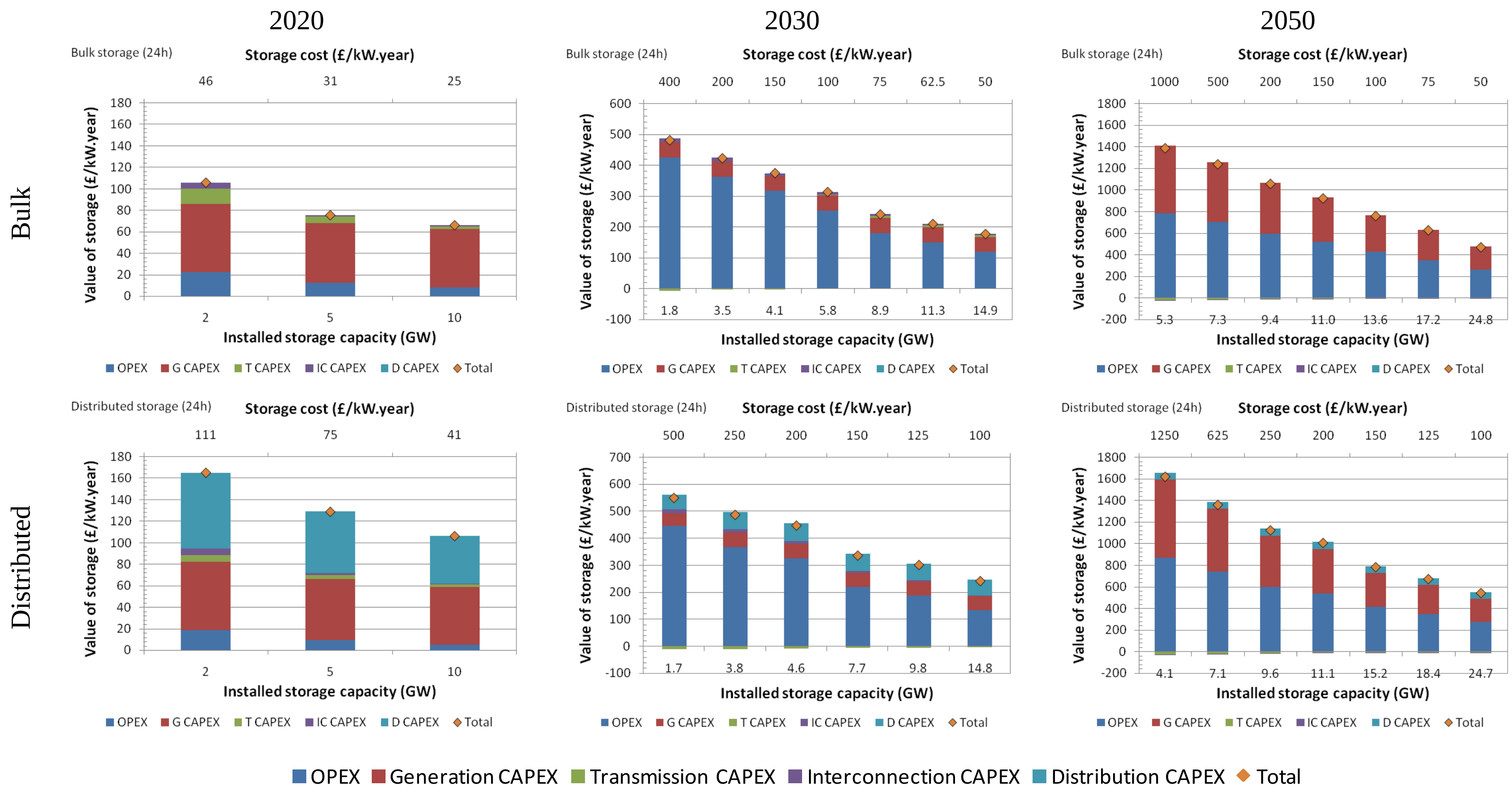


Figure 31: Composition of the value of bulk and distributed storage cases from 2020 to 2050 (24-hour case)

We notice that net system savings increase dramatically between 2020 and 2050 for a given cost of storage. For instance, in the case of bulk storage available at the cost of £50/kW.year, the achievable net benefits in 2020 are around £0.1bn, in 2030 this grows to around £2bn, while in 2050 we see a further rapid increase to over £10bn per year. Very similar levels of net benefits are observed for distributed storage with the cost of e.g. £100/kW.year.

In 2020 there is limited benefit of storage for reducing OPEX, and system benefit is dominated by CAPEX savings for generation and distribution capacity. In 2030 on the other hand OPEX savings are the dominant component, with generation and distribution CAPEX savings per kW of storage at a fairly constant level across the assumed range of storage cost. We also observe limited savings in transmission and interconnection CAPEX in 2030, which occur however only for bulk storage, while for distributed they do not occur. As discussed previously, this is the consequence of storage location: most bulk storage capacity is located in Scotland where it is able to balance the wind output locally and avoid the need for transmission reinforcement, while most distributed storage is located closer to large demand centres in the south. Distribution CAPEX savings appear to be broadly similar in both 2030 and 2050.

For year 2030 the value in the base case scenario is composed of the following main constituents: Operating expenditure (OPEX), due to avoided wind curtailment and improved scheduling of reserve plant, generation capital expenditure (G CAPEX), as a result of reduced peak loads, and in the case of distributed storage a third source of value stems from savings in distribution network reinforcement. Savings in generation capacity are stable across 2030 scenarios, since they displace a well defined peaking plant asset class of OCGT and CCGT plants with typical annualised investment costs of around £50/kW.

The same principle applies to distribution network savings. As these are a source of significant value, every kW of distributed storage installed is used to capture the maximum amount possible by displacing distribution network reinforcements. In the 3.8 GW distributed storage case for 2030 in Figure 31, the saving from storage is offset by an increase in transmission network investment. The cause for this counterintuitive effect is the presence of distributed storage south of Scotland. This storage is used to generate operational savings by absorbing wind energy installed in Scotland that would otherwise have to be curtailed. Additional transmission links between Scotland and England therefore provide additional value through further improved operational savings.

In 2050 there is a very high investment into high-cost storage (at the cost of £500-1,000/kW.year), which amounts to £4-5bn/year. This reduces considerably beyond 10 GW of storage, when we also see a slowdown in the growth of both OPEX and generation CAPEX savings. Very high generation CAPEX savings in 2050, especially for the first 10 GW of storage, are a direct result of the generation portfolio chosen in the baseline case (i.e. without considering storage). In order to comply with the carbon emission target of 50 g/kWh while facing massive renewable curtailment (reaching about 100 TWh in 2050 Grassroots scenario), the model chooses to add significant volumes of new CCS capacity to the system. Adding storage to the baseline configuration saves a major part of curtailed renewable output, which greatly reduces the need for CCS capacity. The effect of storage in that particular case is therefore not only the reduction in CCGT and OCGT capacity needed to maintain security, but also replacing some of the capital-intensive CCS units with much cheaper CCGT capacity (which has around 3.5 times lower annualised CAPEX than CCS). At the level of about 10 GW of storage most of the added CCS capacity has been replaced, and we therefore observe a slower increase in net benefits beyond this threshold.

Figure 32 illustrates in one chart how savings components evolve over time, for the example of distributed storage.

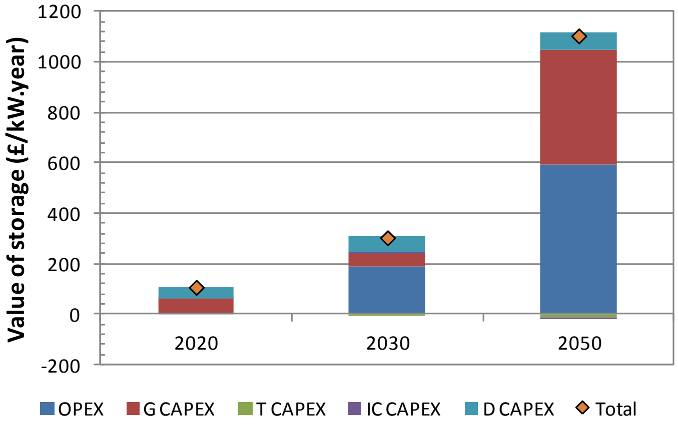


Figure 32: Increase in value and redistribution among beneficiaries (Grassroots pathway with 10 GW 24 hour distributed storage)

The scenarios discussed above result in a steady and significant increase in the value of storage over time, as shown in Figure 33.

In 2020 the increased penetration of renewables, primarily wind, imposes limited challenges associated with increased reserve requirements and the need for transmission network reinforcement between Scotland and northern England. Some of the corresponding costs can be avoided through deployment of storage.

Towards 2030 the value and size of the market for storage increases markedly. Additional operating costs savings can be achieved as a result increased intermittent generation from wind. Storage will also provide CAPEX related benefits. Given the growth in load expected towards 2030 due to electrification of transport and heat sectors, storage can reduce the need for peaking plant and reduce the expenditure associated with the reinforcements of distribution and transmission networks.

The highly carbon constrained scenarios for 2050 show very significant additional system cost savings, both OPEX and CAPEX related. Low cost unabated fossil fuel power stations are no longer available to provide peaking plant services in these scenarios. More costly CCS technologies have to be deployed and operated under technically and economically unfavourable low load factor conditions. The presence of storage, thus, captures a higher value by displacing such costly solutions leading to about half the value of storage now accruing from generation CAPEX savings, compared to 10-15% in 2030.

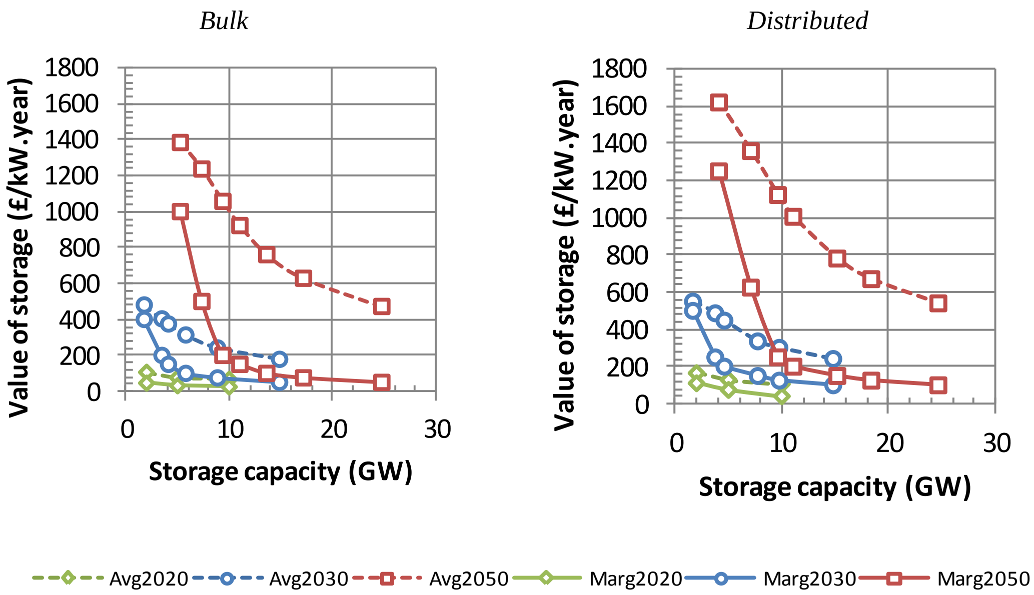


Figure 33: Average and marginal values for bulk and distributed storage, showing a marked increase in long-term value as well as a more pronounced drop in marginal value for the first 10 GW in 2050. (Results shown for base case 24 hour duration. 6 hour and 48 hour results can be found in the Appendix)

We observe that a flat objective function profile implies that relatively large changes in installed capacity of storage (when available at low cost) may result in relatively small changes in the overall costs. Although the accuracy and convergence criteria were tight, the shallow slope of the marginal value curve above 10 GW of installed storage capacity demands caution for the interpretation of results. This should be considered when making direct comparisons between results in this area.

3.2 Impact of competing balancing options

In this section we analyse the impact on the value of storage of the competition between storage and other balancing options in providing flexibility to the system. These alternative balancing options include interconnection, flexible generation and demand-side response. In general, these options will reduce the net benefit of storage, as indicated in Figure 34 and Figure 35, and will consequently undermine the value of storage, as shown in Figure 36 for bulk and Figure 37 for distributed storage technologies.

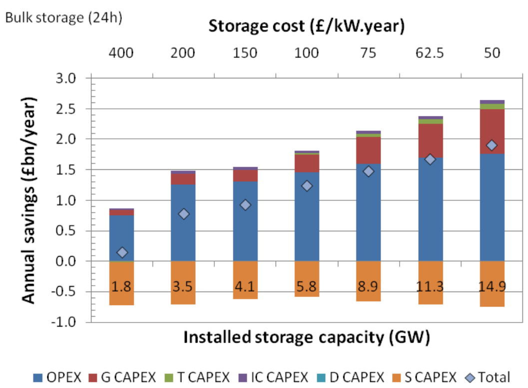
Alternative balancing options will also have an impact on the volume of storage that is optimal to build at a given cost level, as elaborated further in this section. It should be noted that the reference cases for different alternative balancing options, i.e. the characteristics of the system at the point before we start adding storage (reference case), can be considerably different hence affecting the value that storage can provide to the system.

The key trends with respect to the components of the value of storage observed in the baseline scenario include (charts (a) in Figure 34 to Figure 37):

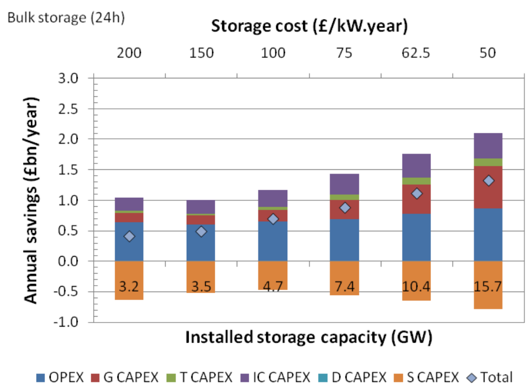
- For small levels of installed capacity of storage, the dominant source of benefits is OPEX savings that results from reduced renewable curtailment and displaced fuel. The first units of storage capacity are very efficient in saving RES energy that would otherwise be curtailed, while as the storage capacity increases, achieving significant saving in RES curtailment becomes increasingly difficult given that the residual occurrences of renewable curtailment tend to last longer.

- A relatively stable generation CAPEX savings component broadly equal to £50/kW.year, which corresponds relatively closely to the annualised investment cost of new CCGT or OCGT capacity. In other words, a given capacity of storage (bulk or distributed) displaces a similar amount of generation capacity in the system.
- Relatively modest transmission network and interconnection CAPEX savings due to the relatively low unit cost of new transmission capacity and the assumption that no new interconnection capacity between GB and the neighbouring systems is added post-2020 (hence very limited opportunity for any savings in interconnection CAPEX).
- A rather constant distribution network CAPEX savings component in the distributed storage case, in the amount of around £60/kW.year.

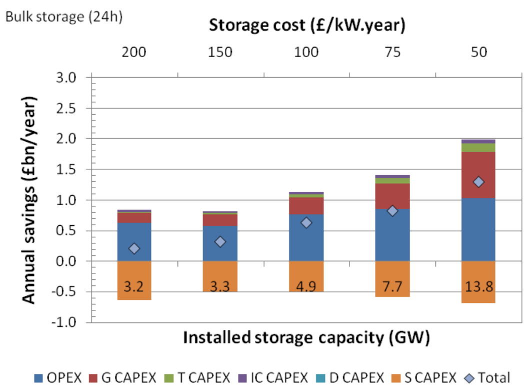
In Figure 34 and Figure 35 we present the impact of competing balancing options on the net benefits that bulk and distributed storage provide to the system for the assumed range of storage costs. Charts (b) to (d) represent the cases with interconnection, flexible generation and flexible demand, respectively.



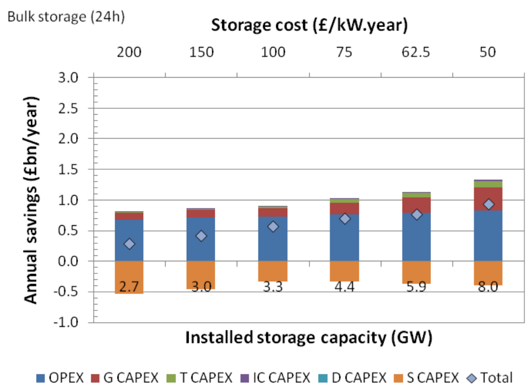
(a) *Bulk storage only*



(b) *Bulk storage in the presence of interconnection*



(c) *Bulk storage in the presence of flexible generation*



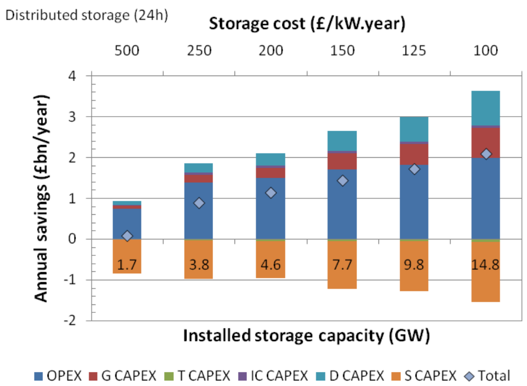
(d) *Bulk storage in the presence of demand-side response*

Figure 34: Net benefits of bulk storage in the presence of competing technologies

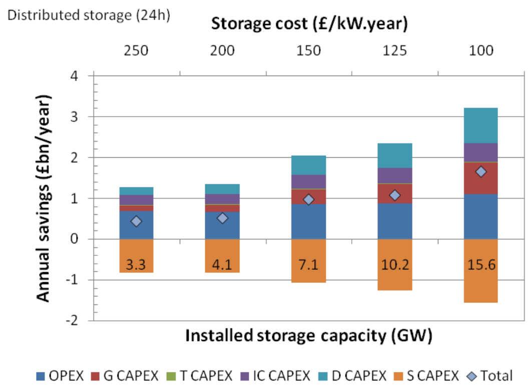
When comparing case (a) in Figure 34 with cases (b) to (d), where different options compete with storage in generating system benefits, we observe that the maximum net benefits (with the cheapest storage) reduce after introducing competing balancing options, by £0.6bn for interconnection, £0.4bn for flexible generation and £0.9bn for flexible demand.

Alternative balancing options significantly reduce the OPEX savings component, while DSR also significantly reduces generation CAPEX savings compared to the storage-only case.

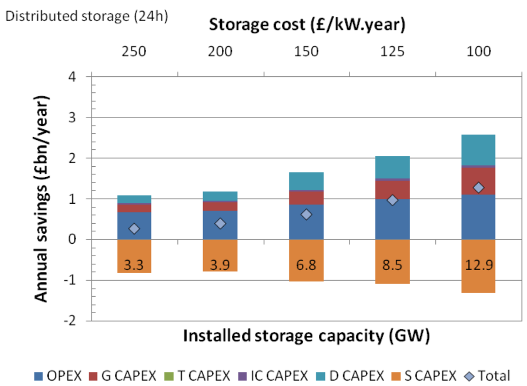
In the presence of interconnection there are considerable savings in interconnection CAPEX, and to a smaller extent transmission CAPEX; this is because storage reduces the need for interconnection capacity compared to the case without storage given that additional flexibility is now available within the UK.



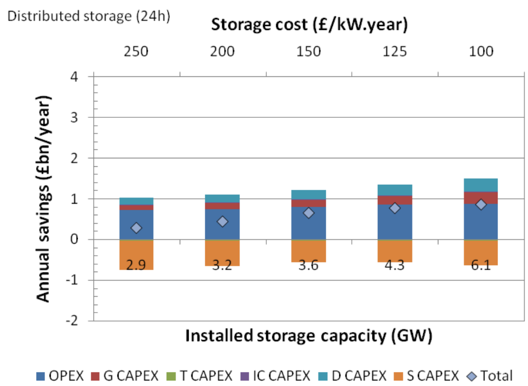
(a) Distributed storage only



(b) Distributed storage in the presence of interconnection



(c) Distributed storage in the presence of flexible generation

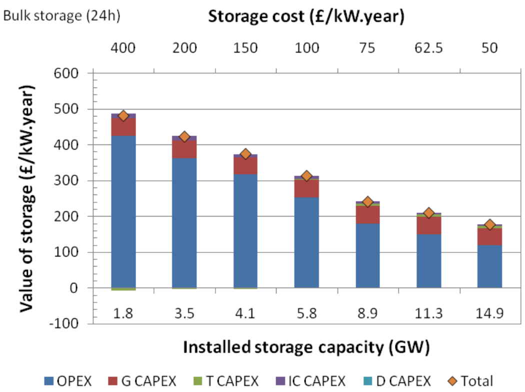


(d) Distributed storage in the presence of demand-side response

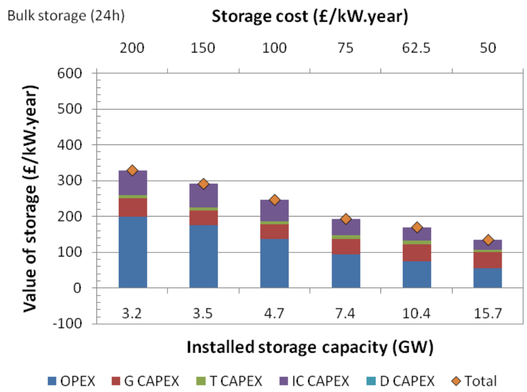
Figure 35: Net benefits of distributed storage in the presence of competing technologies

Charts (b) to (d) in Figure 35 suggest that the value of distributed storage diminished similarly to bulk storage after introducing competing balancing options. The distribution CAPEX savings component does not vary greatly except in the case of demand-side response, as a result of direct competition between DSR and distributed storage to capture benefits for distribution networks, in addition to other savings components.

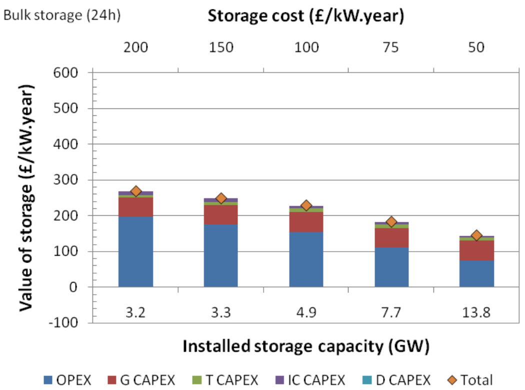
Figure 36 and Figure 37 present the impact of competing balancing options on the average value of bulk and distributed storage, expressed per kW of storage capacity.



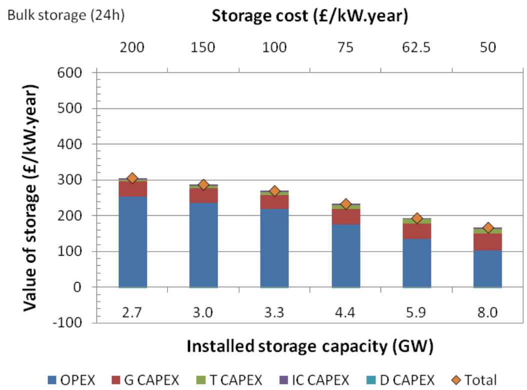
(a) Bulk storage only



(b) Bulk storage in the presence of interconnection



(c) Bulk storage in the presence of flexible generation

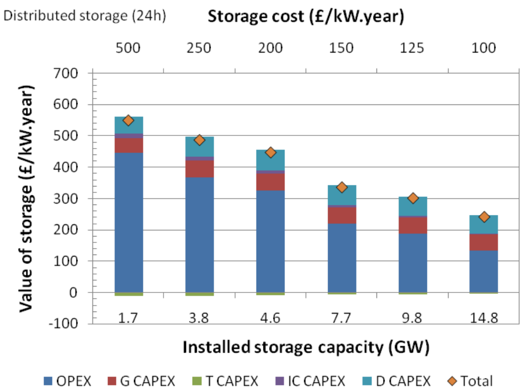


(d) Bulk storage in the presence of demand-side response

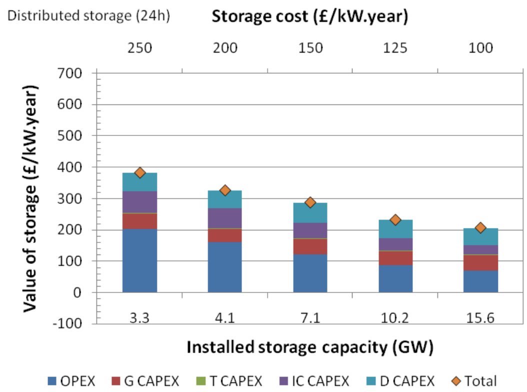
Figure 36: Value of bulk storage in the presence of competing technologies. Note that the installed capacity differs between scenarios.

We observe that in the presence of competing options the OPEX savings component drops to about a half of the reference case value (for a given storage size) when bulk storage is the only available flexible option, and this occurs regardless of whether storage is competing with interconnection, flexible generation or demand-side response. This is driven by the reduced level of renewable curtailment in the baseline cases that contain competing balancing options, leaving fewer opportunities for storage to capture OPEX savings by reducing renewable curtailment.

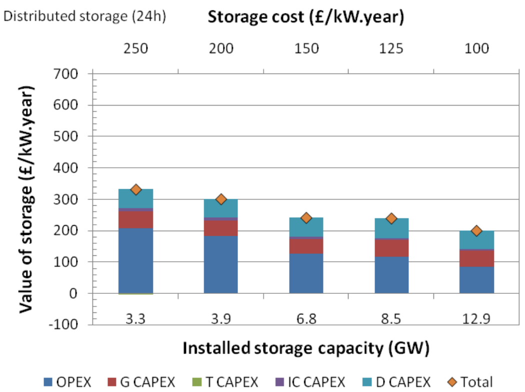
Generation CAPEX savings component does not appear to be particularly affected by the presence of other balancing options and is relatively stable at around £50/kW.year across the range of storage costs and volumes. On the other hand, when competing with interconnection, storage is capable of displacing the investment into new interconnections, although this benefit reduces in per kW terms with higher storage volumes. There is also a noticeable component of transmission CAPEX savings which becomes more substantial especially with interconnection and flexible generation.



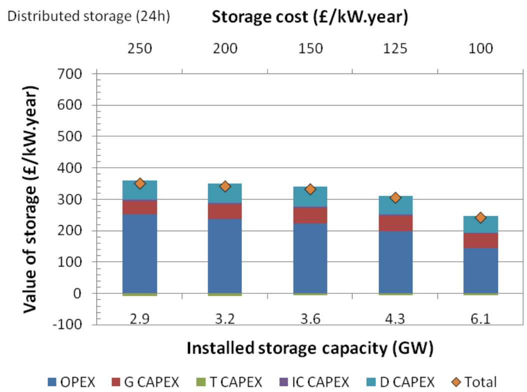
(a) Distributed storage only



(b) Distributed storage in the presence of interconnection



(c) Distributed storage in the presence of flexible generation



(d) Distributed storage in the presence of demand-side response

Figure 37: Value of distributed storage in the presence of competing technologies

Finally, with distributed storage we again observe similar trends in OPEX and CAPEX savings as for bulk, with the exception of the distribution CAPEX savings component, which is however not sensitive to the presence of other balancing options. An important change in terms of distribution CAPEX savings is that in the presence of flexible demand, the only competing technology also able to generate distribution investment savings, the deployed volumes of storage are several times lower than in the storage-only case. This is caused by the ability of responsive demand to flatten out the demand profile even before any distributed storage is added to the system, which results in the remaining cost saving opportunities being exhausted with less storage than before.

Because renewable curtailment is a key driver for OPEX savings, as well as for the overall value of storage, we present in Figure 38 the impact of adding new storage capacity on the level of curtailment across different scenarios (on the example of distributed storage of 24-hour duration). We observe that storage is generally rather efficient in saving RES curtailment (at 15 GW of storage the curtailment is below 5 TWh, which is less than 15% of the reference case value). The role of storage in improving the integration of renewables is discussed in more detail in Section 3.2.4.

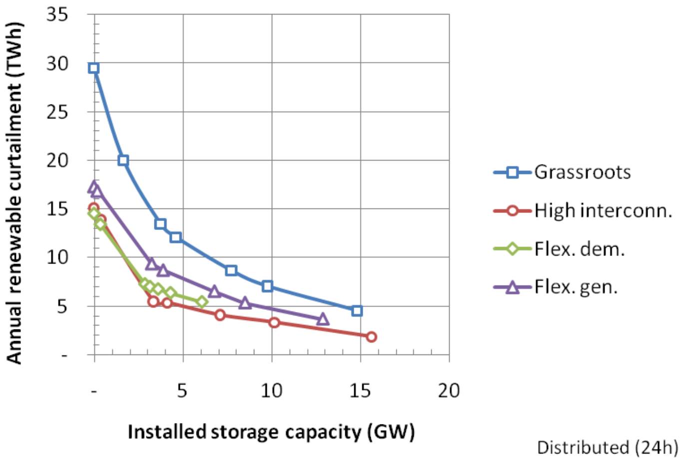


Figure 38: The impact of storage on UK renewable curtailment

3.2.1 Impact of interconnection

The impact of interconnection on the value and optimal volume of storage can be evaluated by observing and comparing charts (a) and (b) in Figure 36 and Figure 37.

The volumes of storage deployed for the assumed range of storage costs are similar before and after allowing for the expansion of interconnection capacity beyond the 2020 level, with the maximum storage capacity installed in the system of around 15 GW (for the lowest assumed storage cost level). The value of storage however decreases when interconnection competes with storage, and this occurs on a similar scale for both bulk and distributed storage across the assumed range of storage costs.

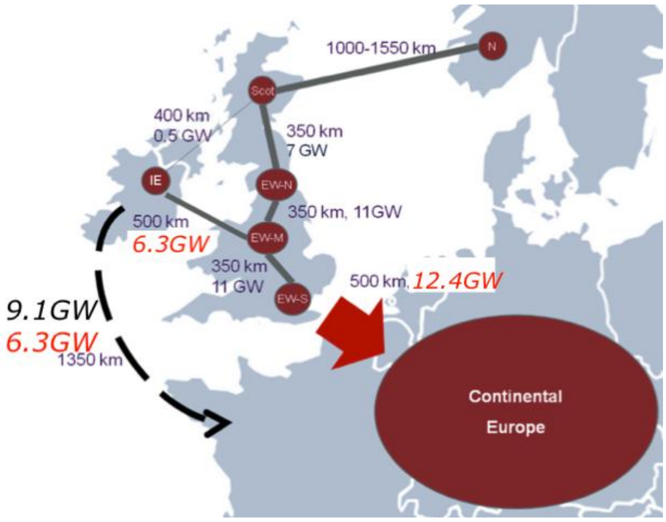


Figure 39: Interconnection capacity expansion beyond 2020. In the constrained case 9.1 GW are built between Ireland and continental Europe. In the expansion case (red figures) additional capacity between GB, Ireland and continental Europe is built. This indirect connection allows for the direct link between Ireland and continental Europe to be reduced.

In the reference case, i.e. when there is no new storage capacity in the system, if the construction of new GB interconnection capacity is restricted beyond the 2020 level, the model only chooses to build 9.1 GW of interconnection between Ireland and continental Europe. When GB interconnection is allowed to expand, however, the optimal solution is to build 6.3 GW of new interconnection capacity between Ireland and GB, and 12.4 GW between GB and continental Europe, while the direct IE-CE link is reduced to 6.3 GW. This allows the system to take advantage of abundant Irish wind resources, and transport this energy, combined with the UK wind output, further to the rest of Europe. In effect, the GB becomes a hub for Irish and British wind, facilitating its transport to Europe in a cost-efficient way.

Allowing the construction of new interconnection capacity is beneficial for the system because it significantly reduces the amount of curtailed renewable electricity generation in the UK from 29.4 TWh to 15.1 TWh annually. This also suggests there will be less scope for storage to be used to reduce the system operating cost through reductions in renewable curtailment. The operating cost savings component is indeed lower in cases with increased interconnection capacity, by about 50% compared to the baseline (Grassroots) case. This is also confirmed by Figure 38, where curtailment levels (and the corresponding reductions) are significantly lower for the High interconnection scenario.

As an example, if we observe the second bar in charts (a) and (b) in Figure 36, which correspond to a similar volume of bulk storage (about 4 GW) being added to the system, we notice about £320/kW.year of storage value generated through reduced operating cost in case without new interconnections, while an equivalent size storage in the presence of interconnection would generate only about £150/kW.year, i.e. less then half of the base case value. A similar trend is observed for distributed storage as well.

Generation CAPEX savings achieved by deploying storage are not significantly affected by adding new interconnection capacity, which follows from the fact that the assumed self-security constraint does not take into account any contribution of interconnection to the security of supply (unlike the contribution from storage). The generation CAPEX component of savings amounts to around £50/kW.year, suggesting that a given amount of storage capacity replaces a similar amount of generation capacity in the system.

Distribution CAPEX savings generated by distributed storage is not sensitive to the level of interconnection, i.e. they are broadly at the same value of £60/kW.year as in the baseline scenario.

Part of the reduction in OPEX savings generated by storage is compensated by savings in interconnection CAPEX, which decrease in per kW terms with larger storage capacity. For instance, about 15 GW of bulk storage would displace about 5.6 GW of interconnection capacity between GB and CE, and 1.9 GW between IE and CE, while the capacity of the GB-IE link increases by 1.9 GW. The total savings however are still visibly lower than in the baseline (Grassroots) scenario across the range of storage costs and volumes considered in the study.[31]

As an illustrative example of the interaction between storage and interconnection, Figure 40 indicates how adding storage to the system affects the optimal additions to the capacity of GB interconnectors. It shows that adding storage in GB reduces the need for new interconnection capacity between GB and mainland Europe, while on the other hand it slightly increases the capacity of the GB-IE link. This can be explained by the fact that with increased storage capacity there is less need to rely on the flexibility from Europe which is provided via the interconnection line, while on the other hand GB storage improves the ability of the GB system to absorb both British and Irish wind, hence suggesting to build more GB-IE capacity

[31] Note that the cost of interconnection is related to its length, given that cable installation costs are significant and that the distance between IE and continental Europe is larger than between IE and GB.

and simultaneously reduce the capacity of the costly IE-CE connection as part of the optimal solution.

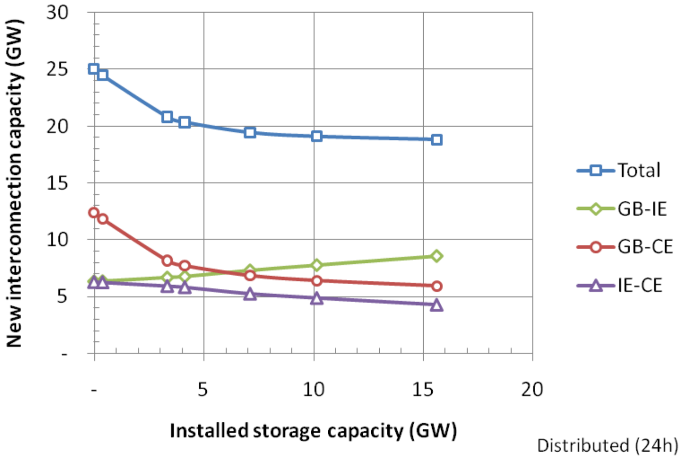


Figure 40: The impact of storage on new GB interconnection capacity

3.2.2 Impact of flexible generation

The impact of flexible generation on the value storage and volumes deployed can be observed by comparing charts (a) and (c) in Figure 36 and Figure 37. Improved generation dynamic parameters (reduced minimum stable generation and improved frequency regulation capabilities) contribute significantly to reduced RES curtailment (from 29.4 TWh in the baseline scenario to 17.3 TWh with flexible generation scenario) reducing the scope for storage for further operating cost reductions.

Generation capacity added to the system in the reference case is similar in both baseline and flexible generation scenarios, the only difference being that slightly less OCGT and slightly more CCGT is being added, given that flexible CCGT can provide system services (reserve and response) accompanied with less energy delivery, causing in turn less renewable generation to be curtailed. We again observe a fairly stable reduction in generation and distribution CAPEX per unit of storage capacity.

Also, the range of storage volumes deployed in the presence of flexible generators reduces slightly (in the order of 10-15%) for the assumed range of storage cost values, when compared to the baseline scenario.

3.2.3 Impact of flexible demand

The impact of flexible demand on the value and optimal volumes of storage can be observed by comparing charts (a) and (d) in Figure 36 and Figure 37. The volumes of storage deployed with a high penetration of flexible demand are significantly reduced compared to the baseline case. The maximum capacity of bulk storage (corresponding to the lowest cost case) reduces from 15 GW to 8 GW, while for distributed storage this reduction is even greater, from 15 GW to only 6 GW. This suggests that the installed capacity of storage is highly sensitive to the presence of competition from flexible demand.

When comparing reference cases (with no storage added) between the baseline and flexible demand scenarios, we observe that flexible demand on its own reduces system peak demand from around 104 GW to 87 GW, which brings substantial benefits in terms of reduced generation capacity (about 17 GW less is added compared to the baseline case). The resulting (net) demand profile with active flexible demand is therefore considerably flatter than in the baseline scenario. Also, in the flexible demand reference case the RES curtailment is reduced to 14.5 TWh, compared to 29.4 TWh in the baseline (Grassroots) scenario. Finally, given that demand-side response is active at the LV level of distribution networks, and generates significant peak reductions, it is able to bring substantial benefits in terms of reduced need for network reinforcement; in the reference case, the savings compared to the baseline case amount to £800m per annum.

All of these impacts of responsive demand indicate that there is an intensive competition between flexible demand and storage (in particular distributed storage), given that demand response has the potential to bring substantial benefits in various segments of the electricity system – OPEX (through reduced RES curtailment), generation CAPEX and distribution CAPEX – which are also the targets for cost reduction by using storage. This is further illustrated by the optimal volumes of storage installed in the system – lower installed capacities indicate there is less scope for the application of flexibility provided by storage, given that a large part of flexibility benefits have already been captured by flexible demand.

Lower levels of RES curtailment when flexible demand is present in the system, as illustrated in Figure 38, explain the drop in the OPEX savings component of the value of storage when compared to the baseline scenario. Reduction in OPEX savings is again about a half of the baseline value.

We observe little change in the generation and distribution CAPEX savings compared to baseline levels across the range of storage costs considered in the study.

Flexible demand differs from other competing options in its capability to alter, i.e. flatten the resulting demand profile in order to reduce capacity requirements in the system (in particular for generation and distribution assets), and is in that respect the most direct competitor to storage. Therefore the potential for CAPEX reduction by deploying storage is exhausted more quickly than in the absence of demand flexibility. In other words, in a system with much less peaky demand, the combined benefits of an additional unit of storage in terms of reducing demand peaks and operating cost become reduced.

3.2.4 Performance of storage in the presence of competing flexible options across time

The presence of storage can lead to significant system savings, as shown in Figure 41. Even at the higher cost estimates storage generates positive net benefits, ranging from £750m to £1.9bn per annum in the base case for 2030. Reduction in technology costs can increase the net benefit, especially in 2030. By 2050 net benefits are substantially higher with £10 to £13bn per year worth of savings for the base case. In relative terms the difference in net benefit between high cost and low cost assumptions becomes smaller in 2050.

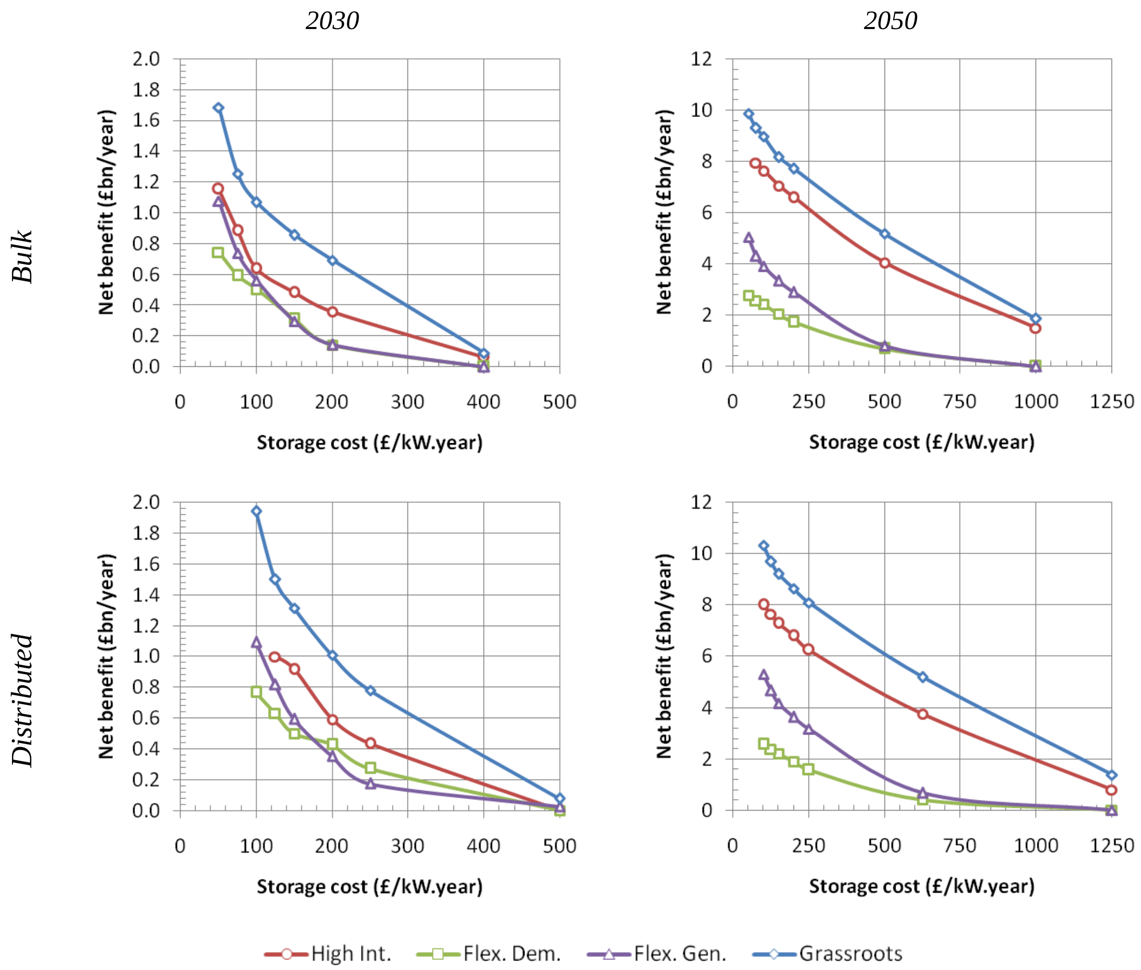


Figure 41: Net benefit of storage across scenarios (6 hour duration. For 24 hours see Appendix)

An additional net benefit in the order of £500m per year appears feasible from the 2030 results if storage costs can be reduced from the high to the lower cost estimates in this study (see Table 4).

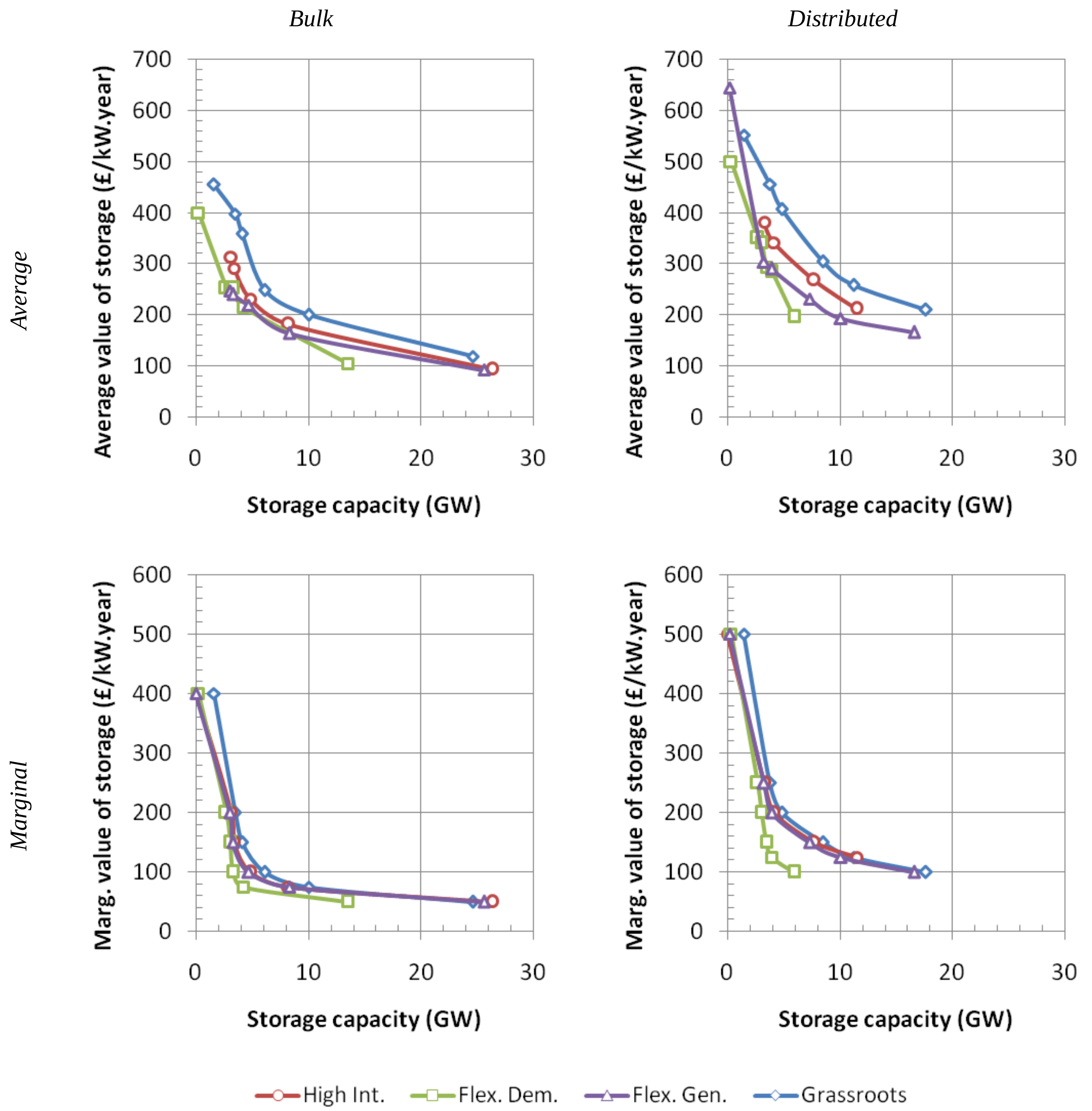


Figure 42: Average and marginal values for bulk and distributed storage in 2030 across different scenarios. The marginal value is stable for most scenarios with the exception of flexible demand, which results in significantly reduced levels of deployment. (Results shown for 6 hours storage duration; for 24 hour and 48 hour results see the Appendix)

The sensitivity of the value of storage to the presence of alternative solutions is shown in Figure 42. All cases originate from the base case scenario, which is in turn subjected to specific changes in the level of interconnection with neighbouring energy systems, flexibility in generation, and the flexibility from the demand side. The average values again show that all scenarios with competing options reduce the average value of storage compared to the baseline Grassroots case.

The effect on the marginal values is shown in the lower half of Figure 42. These show how much storage would be invested in at a given cost within an economically efficient system. The marginal values differ only slightly between the different scenarios, with the notable exception of flexible demand.

For high storage costs assumption between 4 and 6 GW of storage are installed across these scenarios. With lower technology costs this can increases to between 16 and 22 GW with 6 hours duration for three of the four scenarios. Neither flexible generation nor interconnection significantly change the quantity of storage installed at given costs. This means that storage, although it overlaps in its functionality with interconnection and flexible generation, can act sufficiently complementary with these technologies to maintain a high marginal value. In other words, storage, interconnection and flexible generation are not mutually exclusive solutions, i.e. building interconnection capacity does not remove the role for storage. This is different in the case of flexible demand.

Figure 43 shows the decline in the effectiveness of storage in avoiding renewable curtailment. As the level of storage deployment increases, the amount of energy that can be 'saved' per unit of storage reduces. The cause for this decline is the reduction in value that can be generated from curtailment energy. The first few units of curtailed wind that are saved need to be stored for only short periods of time before displacing costly generation, whereas the last few units may occur at times when the next discharge opportunity is further into the future and avoiding curtailment does not constitute good use of capacity.

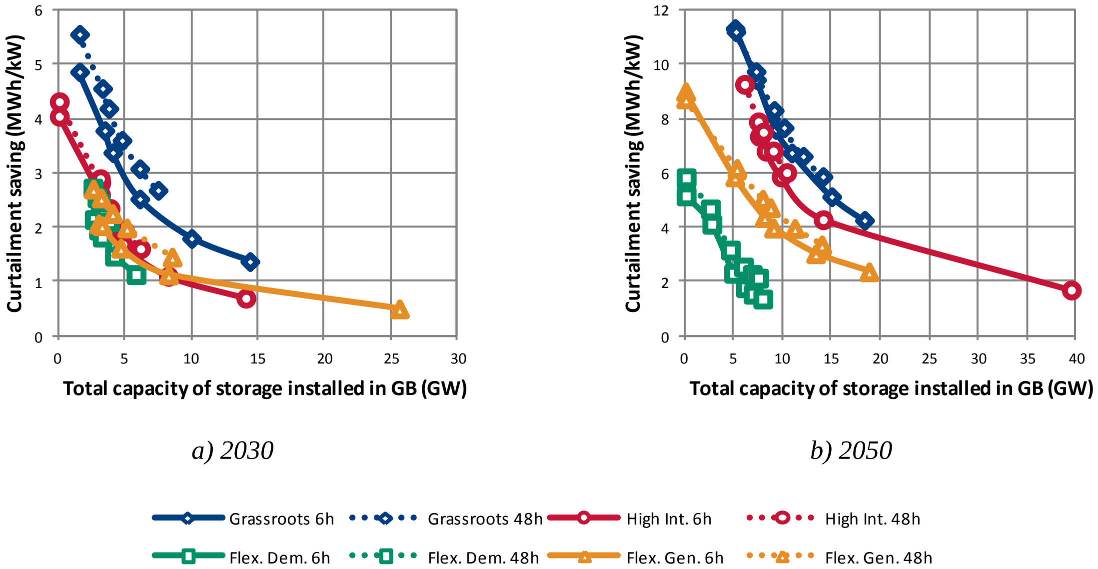


Figure 43: Effectiveness of curtailment. Initially high effectiveness reduces with level of deployment in 2030 and 2050. In 2050 the effectiveness is higher overall.

Some of the avoided curtailment is lost due to the round trip efficiency of storage. It is important to note, however, that not all avoided curtailment necessarily passes through storage. By providing reserve capacity and the resulting improved scheduling of plant, storage enables more wind energy to be delivered at the time of generation. In such instances the round trip efficiency of storage does not directly affect the amount of avoided curtailed that displaces other plant.

Storage duration beyond 6 h only brings about minor improvements in the effectiveness of avoiding wind curtailment, as shown in Figure 43a. A more significant impact results from changes to scenario assumptions. Interconnection and flexible demand can negatively affect the ability of storage to operate with curtailed wind energy. The strongest contender is again the flexible demand scenario. 5 GW of storage, which were capable of shifting 17.5 TWh in 2030, reduce their turnover of otherwise curtailed energy to 6 TWh, when competing with a flexible demand side.

In 2050, when wind energy is more abundant and curtailment both more common and more costly (due to the cost of abated energy), storage plays a bigger role and becomes more effective at avoiding curtailment. Figure 43b shows the curtailment saving of roughly twice the amount of energy per unit installed. Still, added storage duration changes these figures only marginally, whereas interconnection, flexible generation and flexible demand compete even more strongly with storage. 5 GW of storage lose 80% of their ability to absorb excess renewables in the presence of a flexible demand side, falling from close to 60 TWh to less than 11 TWh.

The reduction of curtailment, and therefore the increase in value of energy generated from wind could lead to an improvement in the investment landscape for intermittent renewables and create virtuous circles in technology deployment as part of a low carbon transition. Further work in this area, exploring the positive feedback between storage and investment in renewables, should be encouraged.

The underlying causes of the differences in value between pathways and scenarios will be discussed in more detail in the following section.

3.3 Pathway comparison

The generation mixes for all scenarios are shown side by side in Figure 44. We observe different trends in role of storage. In 2050 Grassroots pathway, storage directly affects the capacity of CCS, while in Nuclear and CCS pathways, storage impacts the capacity of CCGT and OCGT plant.

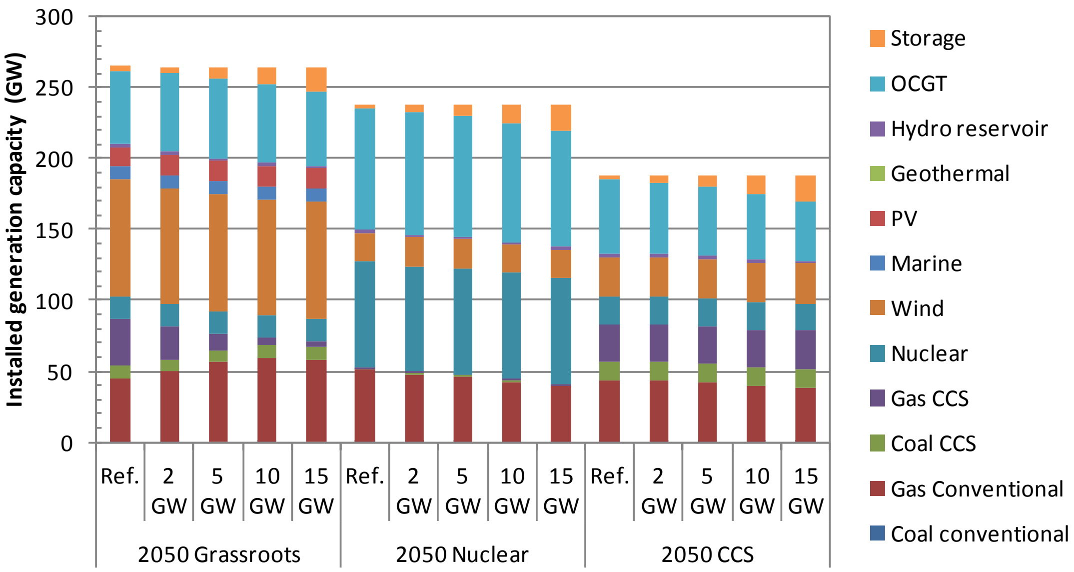


Figure 44: Generation mixes in 2050 Grassroots, Nuclear and CCS pathways

As is further evident from Figure 44, the total installed capacity does not change in any of these scenarios as a result of adding storage. For every GW of storage installed, the equivalent capacity of conventional generation can be avoided without adverse effects on system security. The capacity credit for storage is therefore high (ca. 100%), even for relatively modest durations of several hours as the duration of peaks is relatively short. In case of a flatter demand profile, there will be a stronger link between the storage duration and its ability to displace generation capacity and contribute to security of supply.

In Figure 45 we observe that the net benefits are significantly reduced in the non-renewable generation dominated pathways. Whereas in Grassroots 10 GW of bulk storage saves over £8bn/year (£1,000/kW.year) in 2050, in Nuclear pathway this results in net savings of less than 1£bn/year (£220/kW.year) and in CCS less than £0.2bn/year (£60/kW.year), as illustrated in Figure 45.

The results show that the OPEX savings in Grassroots are more than 3 times higher compared to the OPEX savings in the Nuclear pathway, while the level of renewable curtailment in CCS pathway is negligible and this reduces the opportunity for energy arbitrage and hence the respective value of storage in terms of OPEX savings is low. In Grassroots pathway, savings in renewable curtailment facilitated by energy storage will substitute the electricity output CCS and other fossil fuel power plant.

As the difference between the marginal cost of renewable and cost of coal/gas fired plant is relatively large, this drives up the value of saving renewable curtailment in Grassroots. In the Nuclear pathway, the absolute levels of renewable curtailment are much smaller when compared to the Grassroots pathway. Furthermore, saving in renewable curtailment enabled by storage will also increase electricity production from low marginal cost nuclear plant. Thus, the (average) value of saving renewable curtailment in this pathway is rather low (Figure 46).

In Grassroots, in order to meet the carbon emissions target of 50 g/kWh and to supply electricity demand efficiently while ensuring security of supply, additional capacity of gas CCS is needed in the base case, as the renewable curtailment is very significant. When new energy storage is added into the system, by reducing renewable curtailment, storage also reduces the need for expensive low carbon CCS, as more renewable generation gets absorbed by the system. As CAPEX of CCS is about 3.5 times higher than the CAPEX of CCGT, this drives up the value of savings in generation CAPEX.

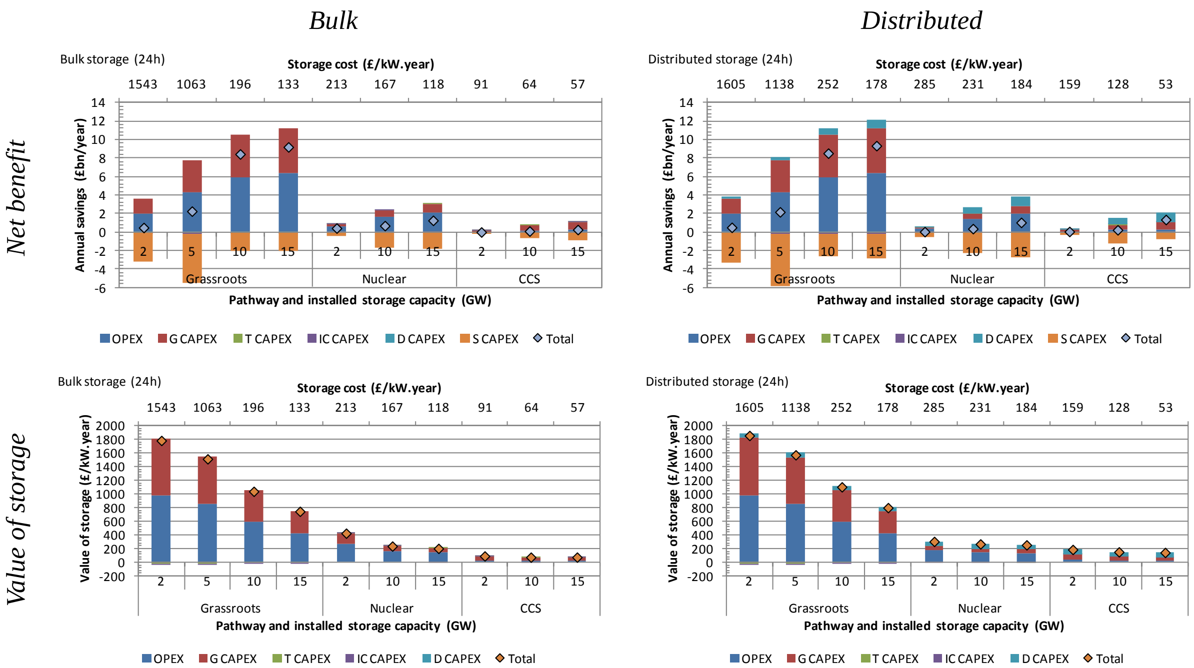


Figure 45: Net benefit and value of storage in Grassroots, Nuclear and CCS pathways in 2050

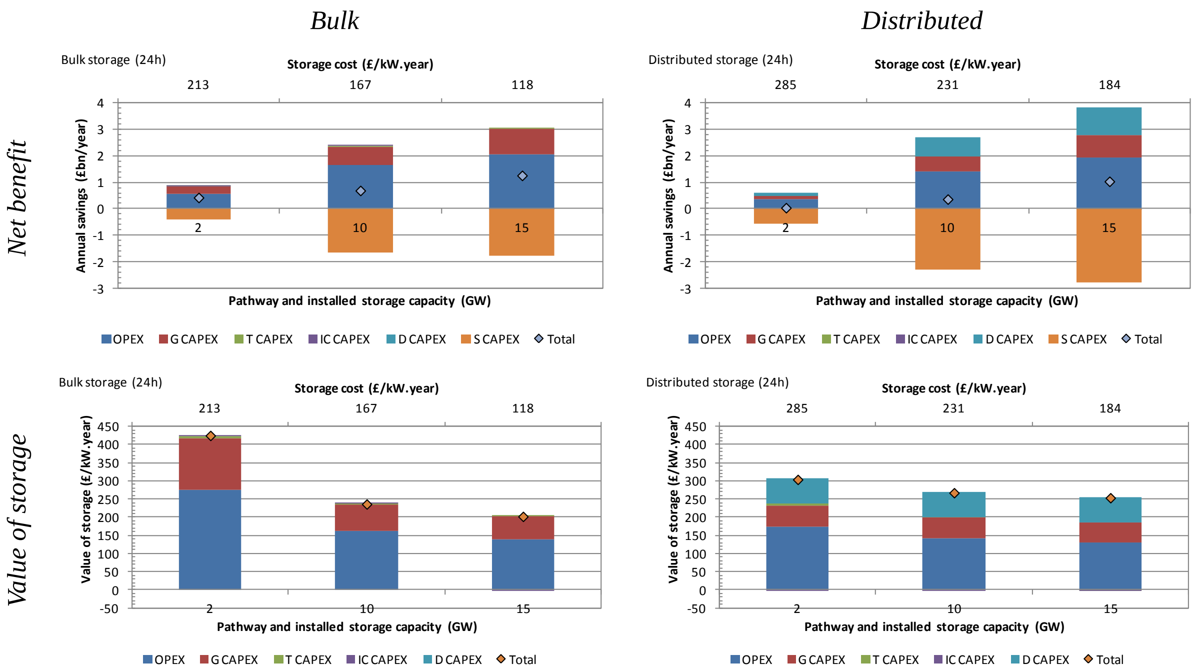


Figure 46: Net benefit and value of storage in Nuclear 2050 pathway

It is interesting to observe in Figure 44 how storage can reduce the need for CCS capacity by a multiple of its own capacity. For example, 2 GW of storage can displace 10 GW of CCS, which is the consequence of the strong link between CAPEX savings and reduced renewable generation curtailment (OPEX savings) in this pathway. In CCS and Nuclear pathway, however energy storage substitutes conventional gas capacity. Thus, adding storage can only reduce capacity of CCGT and OCGT and may facilitate small shift between CCGT and OCGT plant, which will marginally increase the generation CAPEX savings.

In the CCS pathway as presented in Figure 47, most of the value of bulk storage comes from the savings in generation CAPEX. In this case, adding storage cannot facilitate the shift from low-carbon CCS to conventional plant due to emission constraints. Therefore storage can only reduce capacity of conventional gas plant (CCGT and OCGT). Consequently, the generation CAPEX savings is much lower than in the Grassroots scenario.

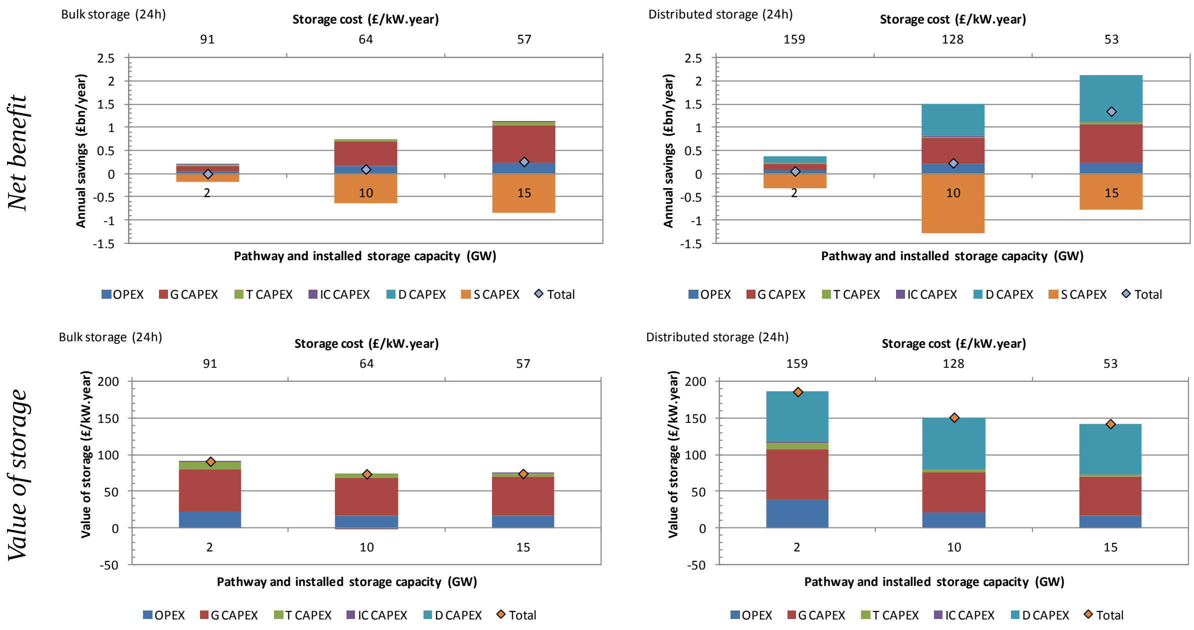


Figure 47: Net benefit and value of storage in CCS 2050 pathway

Observations from the pathway comparison

From the above discussion, we can conclude the following:

- Value of storage in terms of OPEX savings will be driven by the opportunities to perform energy arbitrage, particularly from saving renewable generation that would otherwise be curtailed. This is also facilitated by reducing the need for part-loaded plant needed to provide various reserve services. This value will however tend to be low when the capacity of low marginal cost plant increases (Nuclear pathway).
- Value of storage with respect to generation CAPEX savings will be determined by the opportunity to reduce high CAPEX generating plant that may be required due to its low carbon characteristics such as CCS in Grassroots pathway.
- Similarly, the value of distributed storage with respect to distribution network CAPEX savings will be driven by the opportunity to reduce peak demand (i.e. by discharging during peak conditions).
- Emissions constraints will improve the value of storage.

Given the UK government's objectives of building sustainable and low carbon generation system in the future, the value of energy storage is likely to shift from OPEX savings to CAPEX savings. A hypothetical generation system consisting only wind and storage can be used to illustrate this key point. In this system, the savings in OPEX enabled by energy storage is practically zero. However, storage will be able to displace significant amounts of wind capacity. In this extreme system the CAPEX savings are the key value of storage. Examples with other technologies with low short-run marginal costs, such as nuclear, will lead to similar trends.

3.4 Value of storage for providing ancillary services

3.4.1 Frequency response services

System frequency is a continuously changing variable that is determined and controlled by the careful balance between system demand and generation. If demand is greater than generation, the frequency falls below 50 Hz while if generation is greater than demand, the frequency rises above 50 Hz. As the demand is continuously changing so the frequency varies by small amounts but larger frequency changes occur when there are significant imbalances of power, such as a loss of large generating plant. In order to maintain a secure and stable system operation, the balance between demand and generation must be continually maintained such that the system frequency is retained within narrow limits around 50 Hz.[32]

Automatic frequency regulation services are required for the management of frequency immediately after a sudden loss of generation. These services are generally provided by synchronised generators specially selected to operate in frequency sensitive mode (while running part loaded) and by load reductions from some industrial customers. These Frequency Response services[33] maintain the system frequency profile over time scale from seconds to several tens of minutes. Beyond these timescales, the system operator would call upon Reserves that are used to re-establish the original level of Frequency Response services in the system, so that any subsequent loss of generation can be dealt with. These Reserve requirements are met by (slower) part-loaded plant and by non-synchronised plant, such as standby generators, flexible demand and storage that can start generating quickly upon receiving the instruction (Standing Reserve Service). Finally, the system operator will re-establish the original levels of Reserves by scheduling another generator to replace the lost plant (Replacement Reserves) and this process would normally be completed within several hours (driven by the time needed to start up a coal-fired unit or a CCGT).

Provision of Response Services is associated with running part-loaded plant, with the consequence of reduced efficiency of plant operation. This leads to additional fuel consumption with corresponding cost and CO_2 implications. In the context of Renewable Energy Strategy, it is important to recognise that in a system with significant contribution from variable and difficult to predict wind generation, the presence of less flexible nuclear plant may challenge the ability of the system to absorb wind power, particularly during high wind and low demand conditions. One of the reasons is the need to increase the amount of Response and Reserve services to deal with uncertainty in wind output. Hence, the application of storage, but also various forms of dynamic-demand or variable speed generation technologies (i.e. wind generation) may be used to enhance the system capabilities to absorb more renewable energy. In the context of this work, we carried out investigations to quantify the value of Frequency Response services that fast storage technologies, such as flywheels or super-capacitors may be able to provide.

As indicated above, frequency regulation services are provided via fast responsive generating plants equipped with governors (controlling devices), which respond automatically to the changes in system frequency. Provision of short-term frequency regulation services is more

[32] Under normal operating conditions, the system frequency should not change for more than ±0.2 Hz around nominal value, while for sudden loss of generation greater than 1,000 MW, the system frequency should not fall below 49.2 Hz and should be restored to 49.5 Hz within 1 minute. We take into account that the capacity of the largest generating plant in future, such as new nuclear, will increase from 1,320 MW to 1,800 MW.

[33] There are two types of Response Services: Primary Response is used to contain the frequency drop while Secondary Response is utilised to allow the containment unit to return to its pre-disturbance conditions once the system frequency is restored to the operational limits. Some large demand consumers provide the service via the operation of low frequency relays when there has been a sudden and significant mismatch between demand and generation causing the system frequency to fall rapidly and sufficiently low to trigger the low frequency relays.

demanding and costly than providing slow operating reserve. This is because part loaded generators can only deliver, in the form of frequency regulation service, a proportion of the headroom created by part load operation. As indicated in Figure 48, the amount of frequency regulation that a generator can provide (R_{max}) is generally significantly lower than the headroom created from part-load operation (P_{max} – MSG).

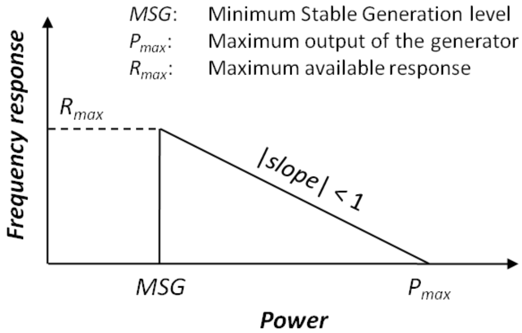


Figure 48: Provision of frequency regulation from conventional generation

Imperial's short-term stochastic generation scheduling model was used to quantify the value that fast storage technologies may be able to provide in reducing generation operating costs. System frequency regulation requirements are set at 1,800 MW, in line with the expected rating of the largest generating unit post-2020. We simulated year-round system operation to evaluate the savings in operation costs for the main Grassroots pathway, and cases with high interconnection and with low fuel costs.

We observe that the value of fast storage is largest in the base case and that interconnection will not reduce its value considerably. The savings come from a significantly reduced need to run generation part-loaded and an enhanced capability of the system to absorb renewable generation. However, changes in fuel prices will have a major impact on the value of storage, as the savings in generation operating costs are the major driver of value of fast storage. We also observe that the presence of flexibility of conventional generators has a major impact on the value of fast storage, which is presented in Figure 49.

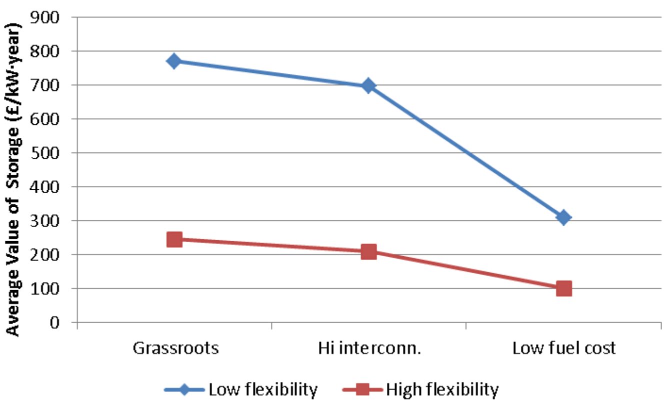


Figure 49: Value of frequency regulation provided by fast storage in the presence of competing options

Under an extreme case of flexible generation being able to use the entire headroom from part load operation for provision of frequency regulation the value of fast storage reduces to £230/kW in the Grassroots pathway, and to £100/kW under the assumption of low fuel cost.

3.4.2 Simultaneous contribution to frequency response and system balancing

As indicated above, storage can contribute to an increased ability to absorb intermittent renewable generation by providing frequency response, in addition to other benefits analysed in previous sections such as energy arbitrage, reserve provision and reducing the generation capacity requirements for security purposes.

We have therefore undertaken a set of case studies to quantify the benefits of providing frequency response simultaneously with other aspects of storage operation. In these studies we assume that storage can provide frequency regulation at the level of 10% of its installed capacity. Figure 50 summarises the savings in renewable curtailment contributed by bulk and distributed storage in cases with and without frequency response provision. The avoided renewable curtailment is illustrated for a range of installed capacities of storage corresponding to the assumed range of annualised investment costs of storage.

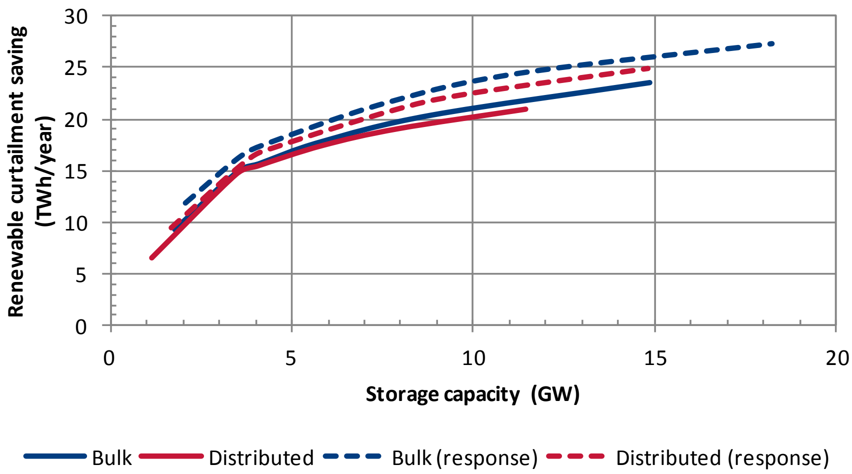
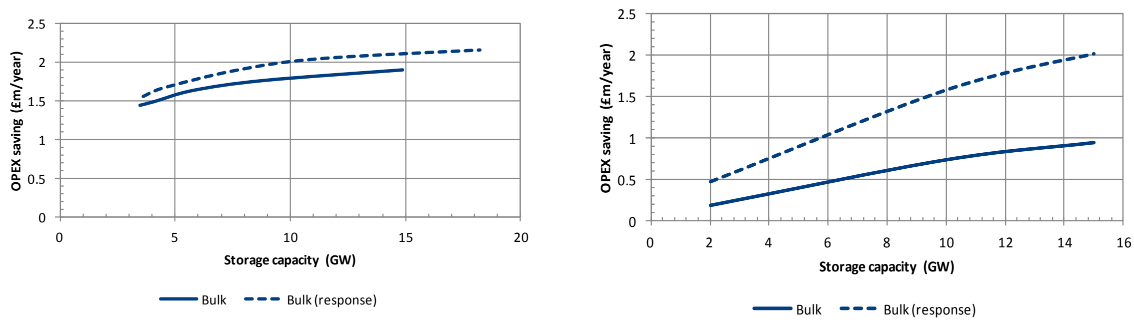


Figure 50: Savings in renewable curtailment contributed by bulk and distributed storage with and without frequency response provision

As expected, if storage is able to provide frequency response, the savings in operating cost is higher than without frequency response provision. Furthermore, we also observe that for the same installed capacity bulk storage provides larger benefits in terms of avoided renewable curtailment than distributed storage. This is the result of trade-offs that distributed storage makes between savings in RES curtailment and reduced distribution CAPEX in order to achieve maximum total savings.

Further studies were carried out to understand the value of storage when providing frequency response services in different pathways. We expect that considering the increase in renewable penetration in the future and the possibility of having less flexible plant, the value of these services may become more significant. As demand for frequency response services is system-specific, we have carried out this analysis for Grassroots and Nuclear pathways, as in these scenarios the value of the frequency response service is expected to be significant. The studies consider several levels of storage deployment, and the results are summarised in Figure 51.



(a) Grassroots *(b) Nuclear*

Figure 51: Comparison between the value of providing frequency response in Grassroots and Nuclear pathways

In all generation systems, enabling storage to provide frequency response will improve the OPEX savings. The savings come from reduction in renewable energy curtailment and the reduction in engaging out of merit generation driven by frequency response requirement. However, the benefits vary among these systems. In Grassroots pathway, the increase in OPEX savings due to the provision of frequency response services is relatively smaller compared to the respective increase in Nuclear pathway. This is expected, considering the share of nuclear plant in Nuclear pathway's generation mix (30%) and the assumption taken in this study that nuclear plant does not provide frequency response services itself.

3.5 Further sensitivity analyses on the value and role of storage

3.5.1 Impact of storage efficiency

All results presented so far assume a round-trip efficiency of storage of 75%. In practice storage technologies can vary widely in their efficiency and we simulate this via the following three efficiency levels: 50%, 75% and 90%.

Figure 52 illustrates the differences resulting from these efficiencies, for bulk and distributed storage in 2030 and 2050. The first point to note is that with low deployment (i.e. high technology costs) the added value and increased level of deployment is only slight in all cases. This may be surprising, since the difference between 50% and 90% efficiency is significant in technology terms. In the environment which these storage applications find themselves in, the efficiency is however of secondary importance. Wind energy that otherwise has to be curtailed has a marginal value of close to zero and is available in abundance. How efficiently it is converted is therefore less critical, so long as sufficient energy is available to displace high cost generation and assets.

This picture changes if the costs of storage drop and deployment increases. Now more valuable sources of electricity begin to be used for charging and increasingly less costly energy is displaced during discharging. Thus the efficiency with which the conversion takes place begins to matter and 90% efficient storage is deployed more than twice as much as 50% efficient storage at identical cost. The effect is most pronounced for distributed storage in 2050.

As pointed out previously, the marginal value curve for low storage costs is very flat and slight differences in assumptions can result in disproportionately big changes in deployment level. The wide range in storage capacity for low marginal value must therefore be treated with caution.

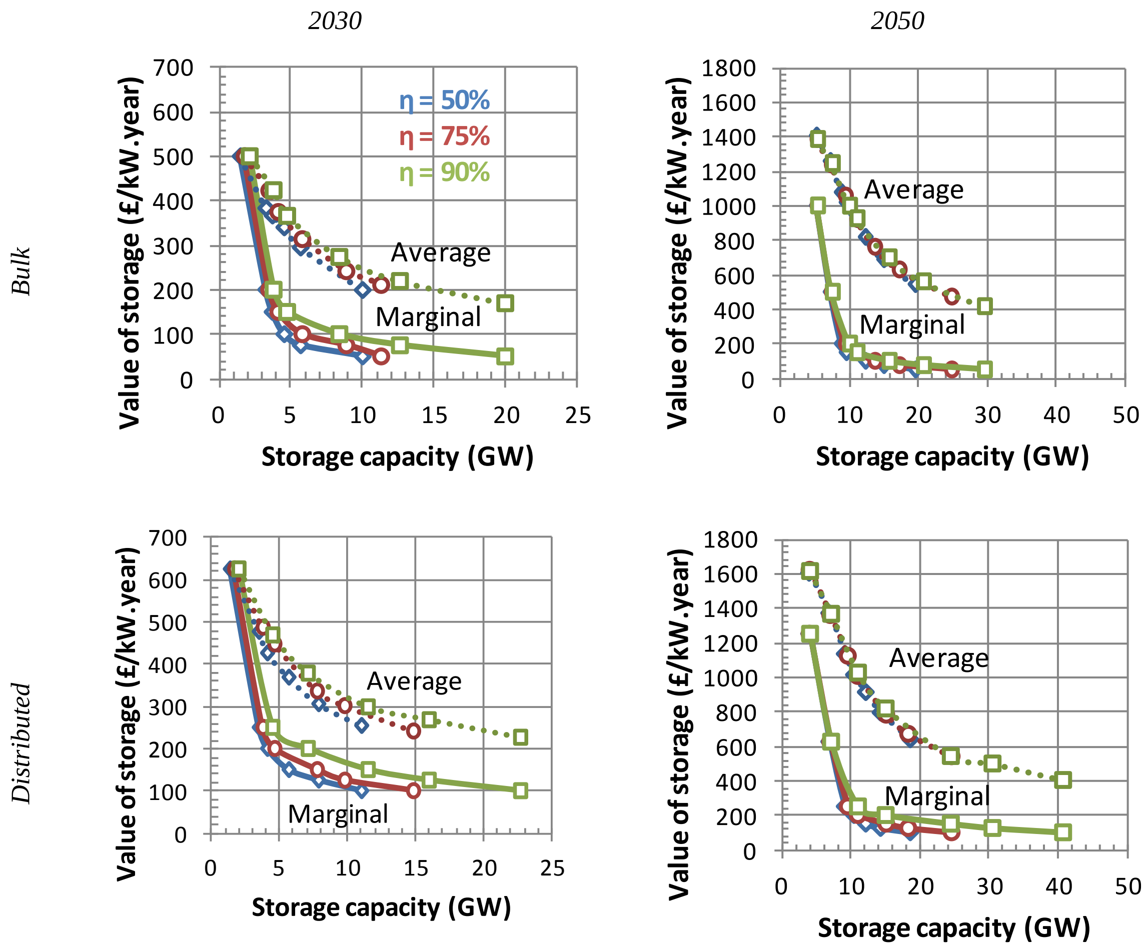


Figure 52: Impact of efficiency on installed capacity and average value. Efficiency leads to larger deployment in low cost cases, while the average value is not affected significantly. (Cases shown for base case with 24h storage duration)

3.5.2 Value of additional storage duration

Our studies on the value of storage with different durations reveal that additional storage duration, although adding value to the storage installation, does not result in wider deployment. To the contrary, with 24 hour storage the marginal value reduces faster and the maximum bulk storage deployment reduces from 25 GW to 15 GW compared to the 6-hour case. For distributed storage this effect is a lot less pronounced, reducing by only 2.5 GW from 17.5 GW.

The explanation for this counterintuitive effect is that storage with longer durations can capture more value with smaller installed capacity. 1 GW with 24 GWh capacity can create more system savings than 1 GW with 6 GWh. Hence, all additional capacity is left with less of the system saving potential remaining and the marginal value drops faster. In other words, because longer durations are more valuable, less storage capacity is needed.

A consequence of the increased value of the first few units is that marginal and average values are further apart for longer storage durations. Policy makers should therefore consider the additional value of longer storage durations, which the marginal value at high capacities may not reflect.

The modelling framework does not assign an explicit cost to the energy capacity. Instead energy capacity is coupled to the installed capacity via the storage duration. The value of additional energy can thus be established by comparing the value for a given amount of storage capacity with different storage durations. The 10 GW system shown in Figure 53 initially has a storage duration of 1 hour (= 10 GWh). The first additional hour of storage duration leads to the highest additional value, with further increases leading to diminishing returns.

Distributed storage initially gains significantly from an increase in storage duration. At a capital cost for energy capacity of less than £34/kWh.year distributed storage delivers greater value with two hours duration compared to one. To make further increases in duration viable the cost has to be significantly lower, falling to less than £1/kW.year for storage durations in excess of 6 hours.

Bulk storage has to meet lower cost targets for storage durations below 6 hours. As with distributed storage, for long storage durations to become viable, low cost solutions are needed with cost targets approaching around £1/kWh.year.

The discrepancy between the value of energy capacity for bulk and distributed storage suggests that distribution network savings, which account for the difference between the two storage types, can be gained with relatively short storage durations. More than 3 hours storage duration appears not to yield significant added benefits to distribution networks.

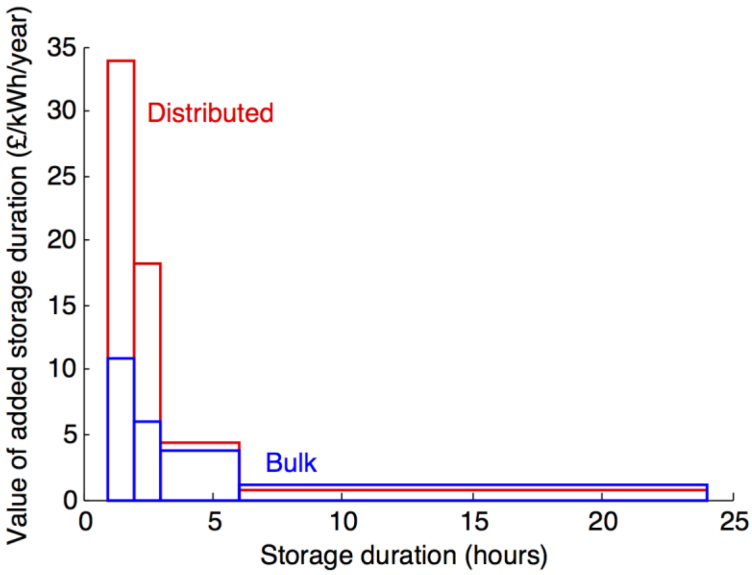


Figure 53: Value of adding energy capacity (duration) to a 10 GW of storage in the base case scenario for 2030.

3.5.3 Impact of scheduling methodology

In Section 1.6 we introduced the methodology employed in this study for scheduling systems stochastically. Figure 54 presents the difference in the value of storage being evaluated using conventional deterministic scheduling and the stochastic scheduling approach.

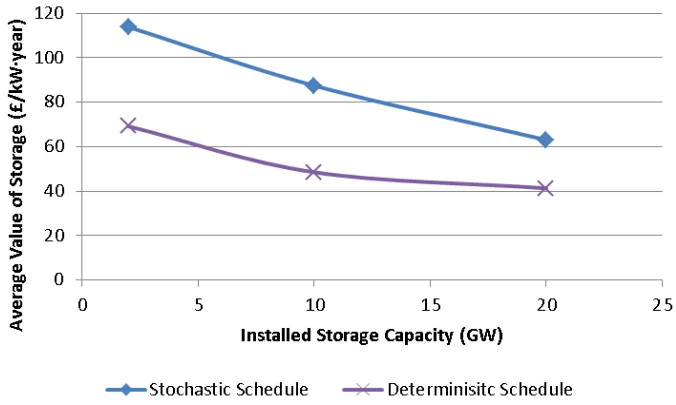


Figure 54: Difference between stochastic and deterministic scheduling. Improved scheduling can yield over 75% increase in the value of storage.

It is clear that it will be very important to optimally allocate the storage resource between providing reserve and conducting energy arbitrage. Stochastic scheduling optimisation is therefore superior as it optimises the allocation of the storage resources dynamically, depending on the system conditions. In fact, scheduling operation of generation using traditional deterministic approaches may significantly reduce the value of storage, as exogenous allocation of storage resource across multiple system conditions will be suboptimal. Therefore, optimising the balance between reserve provision and energy arbitrage through stochastic scheduling approaches will be particularly critical for relatively modest amounts of storage. For example, for 2 GW of storage, stochastic scheduling increase the value of storage by more than 75%, while for the installation of 20 GW of storage this would be around 50%.

In addition, there will be storage technologies that could provide frequency regulation services by altering the mode of their operation as a function of system frequency, over short timescales from seconds to tens of minutes (flywheels, super capacitors, pump-storage schemes equipped with variable speed drives, etc). In the stochastic scheduling model, we assess the value of these technologies by reducing the need for conventional generation to supply the response services.

3.5.4 Impact of forecasting error

Uncertainty over changes in wind output over the next hours necessitates the presence of reserve capacity. In the above examples storage generates its largest share of value from operational savings, which include such reserve services. Here, we assume improved certainty in forecasting wind. Figure 55 shows the best and worst assumed cases for the wind forecasting error.

The improved wind forecasting results in less reserve plant requirements. Furthermore, wind generation itself is assumed to provide frequency regulation services.

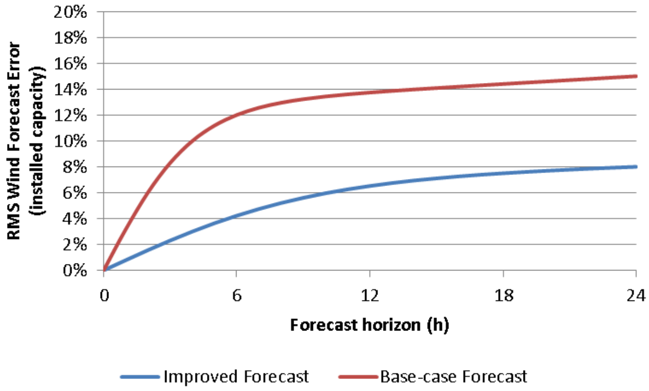


Figure 55: Wind error assumptions for stochastic scheduling

As a result the value of storage reduces substantially. Operational savings, previously worth more than £180/kW.year for 10 GW of bulk storage now provide less than £50/kW.year of value. This discrepancy is a measure of the value of reliable forecasting, which directly competes with the ability of storage to provide reserve capacity.

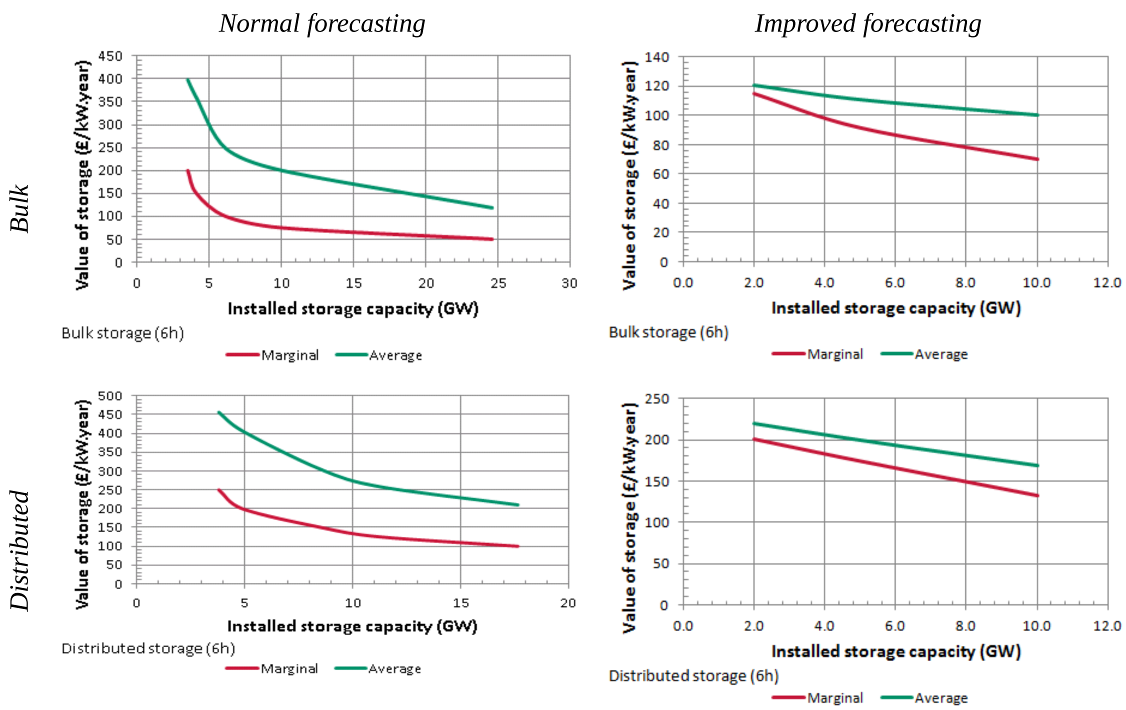


Figure 56: The impact of improved wind forecasting on the average and marginal values of bulk and distributed storage

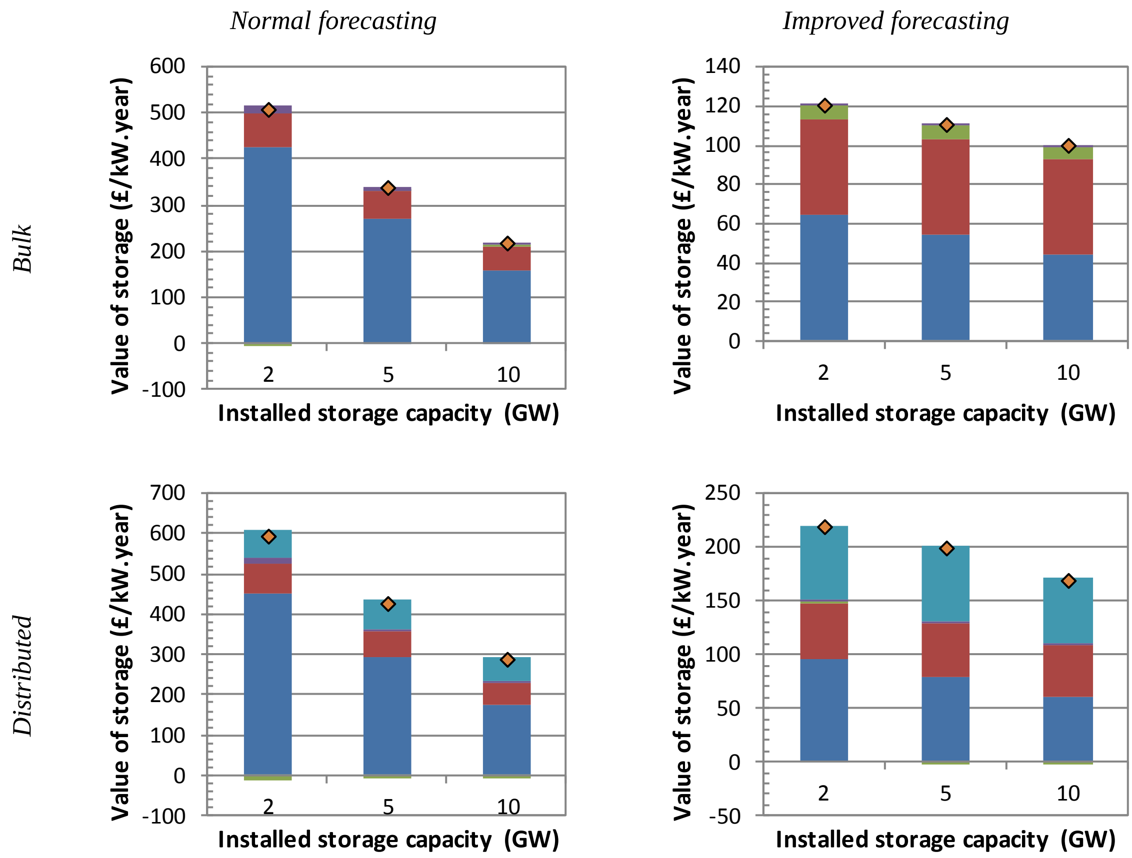


Figure 57: The impact of improved wind forecasting on the components of the value of bulk and distributed storage

3.5.5 Impact of high fuel cost

We have further investigated the impact of increased fuel and carbon prices on the value of storage compared to the baseline assumptions on fuel and carbon prices. Figure 58 illustrates the effect of fuel price increase for the example of 24-hour duration of storage in year 2030.

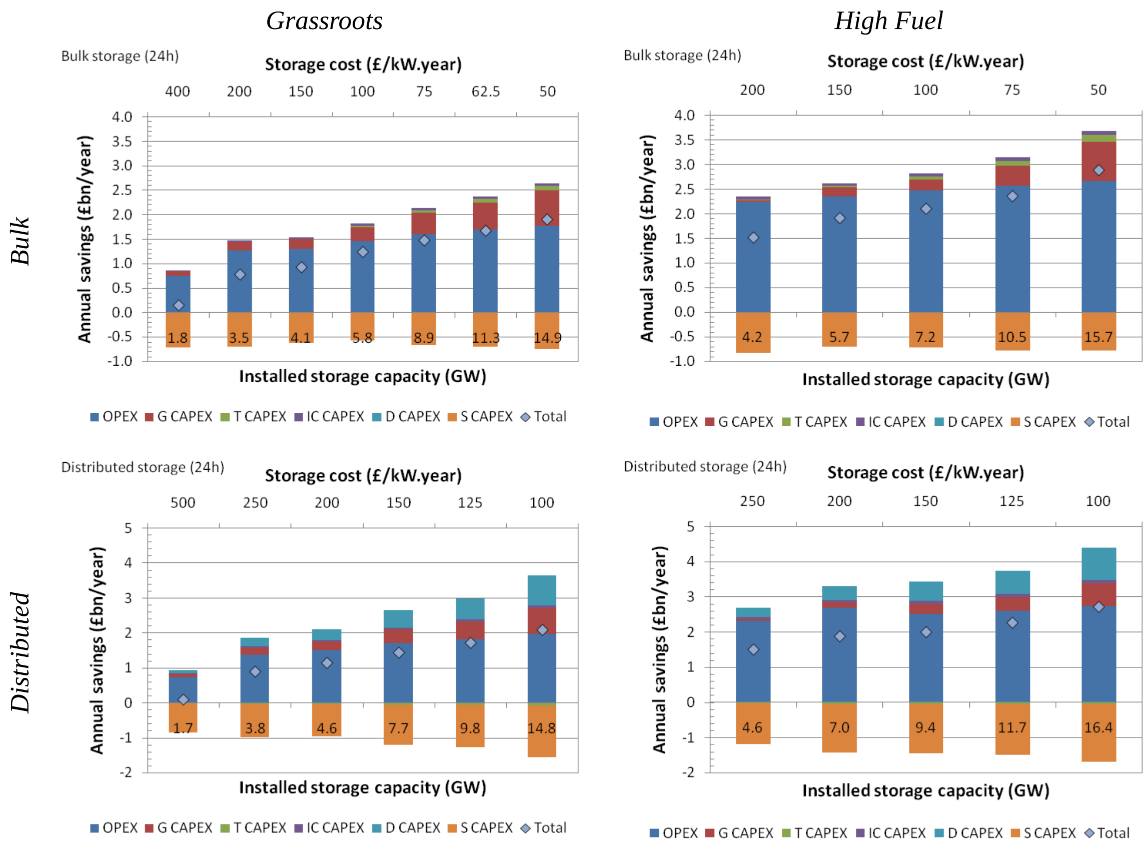


Figure 58: Comparison of net benefits of bulk and distributed storage in 2030 between Grassroots and High Fuel scenarios (24 hour duration)

When compared to the Grassroots cases, High Fuel cases are characterised by slightly larger storage volumes for the same storage cost level, and an even more dominant role of OPEX savings in the overall benefits. Given that the opportunity cost of renewable curtailment is reflected in the increased generation of conventional thermal plants, and their operating cost are higher due to more expensive fuel, there is an even greater incentive in the system to avoid renewable curtailment. The use of storage is therefore much more driven by preventing RES curtailment than by avoiding generation CAPEX (which is not assumed to change compared to the Grassroots cases). Because generation investment becomes relatively less heavy as a cost category than operating cost, storage responds to this change in circumstances by allocating its activities to the area which generates more benefits, and in this case this means an even stronger emphasis on reducing RES curtailment. We also notice that net benefits increase by between £0.5bn and £1bn compared to the Grassroots values.

Figure 59 illustrates the impact of high fuel prices on the average value of storage for the same cases as in Figure 58. Unlike the Grassroots case studies, we no longer observe a relatively constant contribution of generation CAPEX savings per kW of storage capacity. With high fuel prices and low storage capacity, the storage is almost exclusively used to save operating cost i.e. avoid renewable curtailment whenever possible (although for distributed storage there is a relatively consistent distribution CAPEX savings component similar to Grassroots level, but which is an order of magnitude smaller than OPEX savings). As storage capacity increases, the most favourable opportunities to save renewables have been used already, so the OPEX savings component diminishes, and generation CAPEX savings gradually increase to a value observed in the Grassroots cases. For both distributed and bulk storage, we observe visibly higher average values of storage than for the same storage cost in the Grassroots scenario.

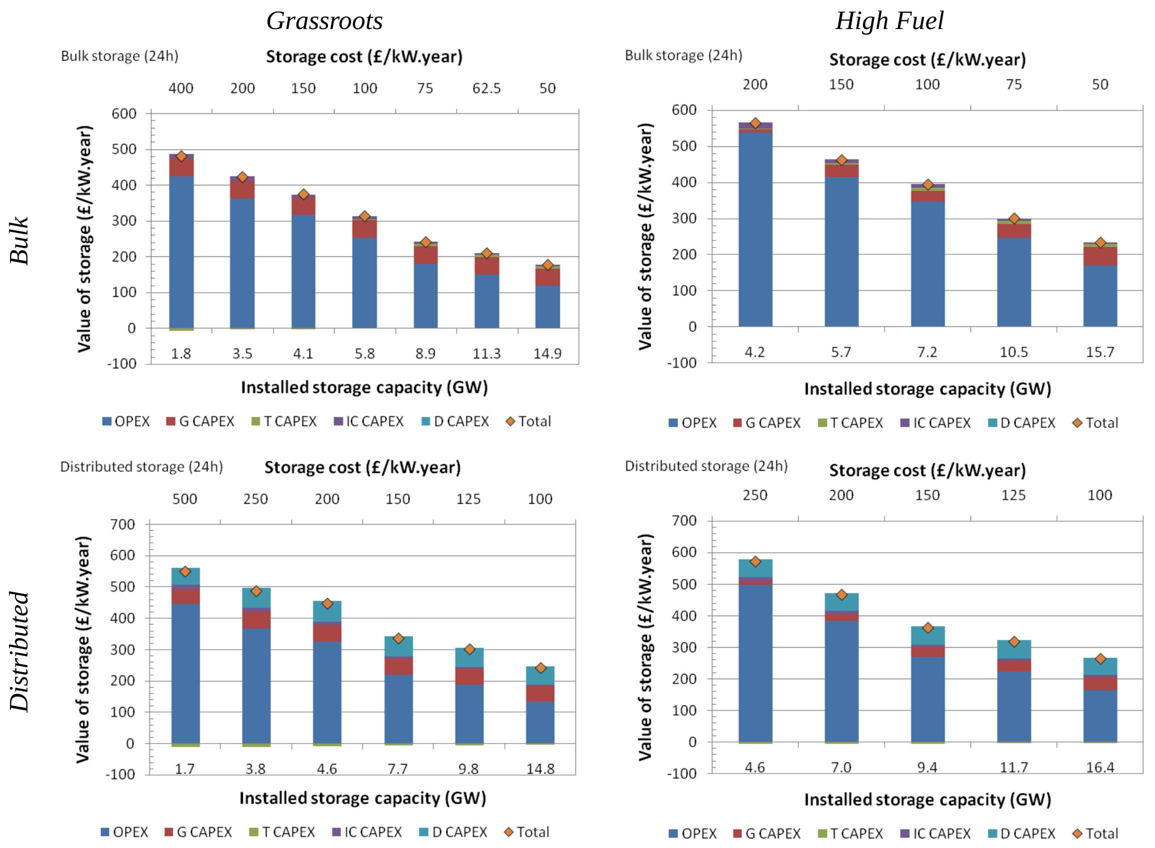


Figure 59: Comparison of average values of bulk and distributed storage in 2030 between Grassroots and High Fuel scenarios (24 hour duration)

We finally provide a comparison between average and marginal value of storage in Grassroots and High Fuel cases in Figure 60, for the 6-hour example of bulk and distributed storage and for years 2030 and 2050. We observe that marginal value curves do not differ significantly (especially in 2050) except for smaller storage volumes, and that high fuel cost expectedly produces higher values for a given volume of storage.

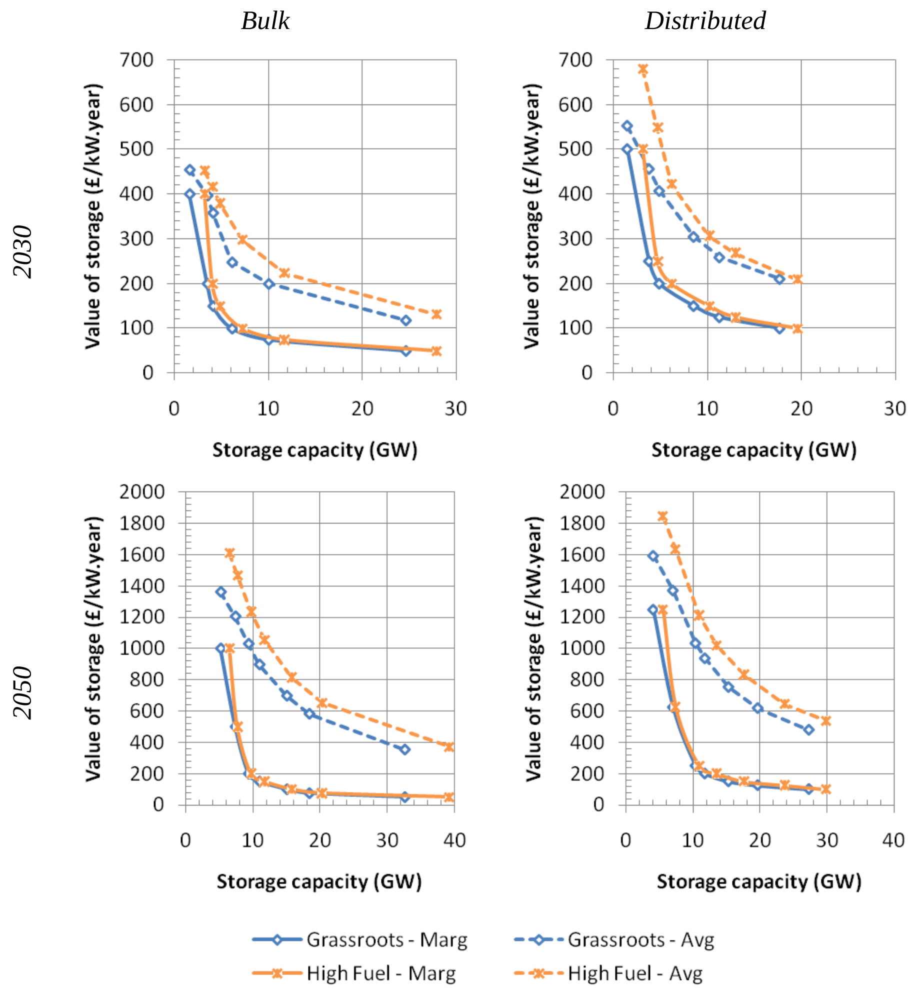


Figure 60: Comparison of average and marginal values for bulk and distributed storage in 2030 and 2050 between Grassroots and High Fuel scenarios (6 hour duration)

4 Overview of energy storage technologies – current status and potential for innovation

4.1 Introduction

In this section of our report we seek to briefly introduce the current status of current candidate technologies for grid-scale energy storage, and comment on the prospects for innovation in these and other technologies that may emerge over time. In particular it is essential to note that the duty cycles imposed on the energy storage will vary depending on the design and control of the power system, and on the scale and location of the storage itself, and as such it is unlikely that only one storage technology will be required. It is much more likely that a portfolio of technologies will be required, suited to a range of applications. This is illustrated in the two duty cycles illustrated in Figure 61, which show the hourly usage patterns for two types of storage systems, a more distributed system with 6 hours of energy storage, and the other representing the use of bulk storage with 48 hours of storage capacity. The difference in the number of cycles that the storage system has to manage, and the differing degrees of state of charge, is evident. The more distributed storage system requires the ability to both cycle more frequently, and to operate over a wider state of charge range.

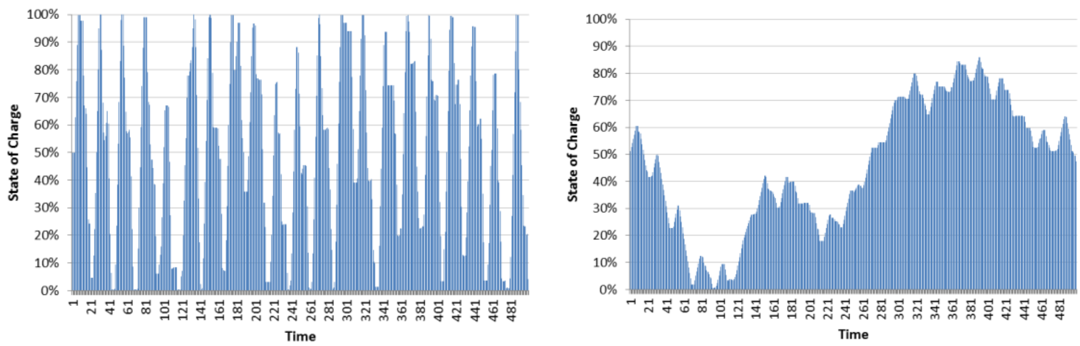


Figure 61: Two predicted patterns of storage use in a future low carbon grid, showing state of charge against time in hours. The curve on the left illustrates the pattern of use for a more distributed storage system, with 6 hours of storage capacity, while the curve on the right shows the pattern of use for a more bulk storage system, with 48 hours of storage capacity.

Table 5 introduces the range of current candidate energy storage technologies. Our best estimates of typical performance characteristics are given, including output DC voltage, power, energy, capacity, discharge time, discharge and charge rate (in term of the C rate), and the round trip efficiency, though it must be noted that the actual numbers for round trip efficiency will depend on factors such as the C rate used, the operating history of the unit, and the state of charge range applied.

Table 5: Current energy storage technologies

Storage technology	DC Voltage	Power rating	Energy at Grid	Capacity	Discharge time	Discharge rate	Recharge time	Recharge rate	Roundtrip efficiency	URLs
	[V]	[MW]	[kWh]	[kAh]	[h]	[C]	[h]	[C]	[%]	
Li-ion batteries -Altairnano System (lithium nanotitanate)	831	1	250	0.301	0.25	4.000			86-93 (no power conversion sys)	Altairnano ESS
Li-ion batteries -A123 System (lithium nanophosphate)	960	2	500	0.521	0.25	4.000	0.25	4.00	90	A123Systems ESS
Advanced Lead Acid		50	200000		4	0.250			85-90	EPRI
Sodium sulphur batteries- NGK	128	0.05	360	2.813	7.2	0.139	8.64	0.12	77-85	Overview of NGK NaS battery
ZEBRA battery		10	80000		8				80-85	
Flywheels- Beacon Power	831	20	5000	6.014	0.25	4.000			90	Beacon Power
PEM Fuel Cell- Pearl Hydrogen	60	0.005							50 (discharge only)	Pearl Hydrogen
PEM Electrolyser- Proton Energy	831	0.007							60 (charge only)	
redox flow batteries- ZnBr ZBB Energy	350	0.25	500	1.429	2	0.500			75	ZBB Energy
redox flow batteries-Vanadium Cellstrom	48	0.01	100	2.083	10	0.100			80	Cellstrom
compressed air		100	400000		4	0.250			80	
superconducting magnetic energy storage		0.2	0.6		0.003	333.333			95	
double layer capacitors- EPRI	585	0.1	0.278	4.8E-04	0.00278	359.712	0.0278	35.97	80-93	EPRI
Pumped hydro energy storage		2000	24000000		12	0.083			75-85	
Cryogenic energy storage		200	800		4	0.250	12	0.08	57-74	Highviews Power Storage
Pumped Heat Electricity Storage		2							72-80	Isetropic Ltd

An important issue where data is very limited is that of the lifetime of grid-scale storage technologies in practical applications, and how this relates to the duty cycle and means of control. For example, in automotive applications it is known that the lifetime of Li-batteries can be increased by only operating them over a portion of their full charge range, but this has implications for battery size and cost.[34] Given that grid-scale storage technologies will require much longer lifetimes and sustain many more cycles than storage technologies for transport, albeit with more relaxed targets for energy density, it is essential that more information is gathered on the relationship between duty cycle, control strategies, and storage technology choice and design, through future research and demonstration programmes.

4.2 *Storage technology overview*

This section of the report provides a brief overview of the technologies introduced in Table 5. Table 6 provides data on the estimated total installed costs of storage technologies, taken from the comprehensive EPRI report of 2010 "Electricity Energy Storage Technology Options: A White Paper Primer on Applications, Costs and Benefits". All costs are in US$. The reader is referred to that report for additional information on the assumptions supporting the cost analysis. Note that the EPRI report distinguishes between costs for specific energy storage applications – the table below takes the low and high cost values from the range of applications discussed in the EPRI report. Costs are provided for two broad classes of storage technology, a 'MW' scale covering 1 to 1,400 MW and 0.25 to 14,000 MWh, and a 'kW' scale covering 1-50 kW and 7 to 250 kWh.

Table 6: Estimate of total installed costs. Based on EPRI 2010

MW scale		
	Total cost $/kW	Cost $/kWh
Li-ion batteries	1085-4100	900-6200
Advanced Lead Acid	950-4600	625-3800
Sodium sulphur batteries	3100-4000	445-555
Flywheels	1950-2200	7800-8800
redox flow batteries- ZnBr	1450-2015	290-1350
redox flow batteries-all Vanadium	3000-3700	620-830
compressed air - underground	1000-1250	60-125
compressed air - above ground	1950-2150	390-430
Pumped hydro energy storage	1500-4300	250-430
kW scale		
	Total cost $/kW	Cost $/kWh
Li-ion batteries	1250-11000	950-3600
Advanced Lead Acid	1600-3725	400-950
redox flow batteries- ZnBr	1450-6300	725-2250

Lithium-ion batteries

Lithium and lithium-ion batteries are known for their good power and energy densities, and to have reasonable cycle life provided they are not operated over a wide state of charge range.

[34] Element Energy, "Cost and performance of EV batteries", report for the Committee on Climate Change, March 2012.

With recent advances in the development of safer nanometric materials for battery electrodes it has become possible to build modular stationary systems for energy storage and load levelling. A123 Systems has developed nanosized iron phosphate cathodes and cells utilising this material. The company has also manufactured electrical energy storage units with 500 kWh of energy and 2 MW of power based on these cells.[35] Since 2008, A123 Systems has deployed over 20 MW (or ten units) of grid-connected energy storage units.

Altairnano have developed a nanometric battery anode based on lithium titanate. In a similar manner to A123 Systems, the company also manufactures both individual cells and energy storage units. Having 250 kWh energy and able to deliver 1 MW power, these storage units can be assembled into larger systems. One 1 MW/250 kWh unit has been operating since 2008[36].

Advanced lead-acid batteries

Lead-acid chemistry is the most mature rechargeable battery technology and widely used for various applications such as automotive, UPS, telecommunications and others. Though significantly inferior in terms of power density to lithium-ion, lead-acid batteries are used for large-scale energy storage. A 1 MW/1.5 MWh lead-acid system by GNB Industrial Power and Exide has been operating for 12 years and was replaced in 2008. Other lead-acid energy systems have been deployed in sizes of 10 to 20 MW. Advanced lead-acid batteries are being developed to improve cycle life and durability. Storage systems utilizing these advanced batteries are expected to start field testing in few years.[37]

Sodium-sulphur (NaS) batteries

Developed and manufactured by NGK Insulators, NaS batteries utilize molten sodium, sulphur and ceramic separator as anode, cathode and conductive electrolyte respectively. To operate, the battery temperature is held in the range of 300-350 °C. The energy storage module based on the NaS battery can provide 360 kWh energy and 50 kW power.[38] There are more than 300 NaS energy facilities worldwide, with the largest facility rated at 34 MW. This battery technology has a good reputation for cycle life, however a fire at a NaS battery facility in September 2011, which led to the release of highly toxic hydrogen sulphide gas, has raised concerns about the safety case of this technology, and currently production and operation of these batteries has been stopped pending further investigation of the fire.

ZEBRA Battery

The ZEBRA or Sodium-Nickel Chloride battery utilizes a molten sodium anode, molten sodium aluminium chloride electrolyte and nickel cathode. Similarly to NaS, it needs elevated

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[35] A123 Systems Energy Storage Solutions: http://www.a123systems.com/products-systems-smart-grid-stabilization.htm

[36] Altairnano Energy Storage System: http://www.altairnano.com/profiles/investor/fullpage.asp?f=1&BzID=546&to=cp&Nav=0&LangID=1&s=0&ID=10697

[37] "Electricity Energy Storage Technology Options: A White Paper Primer on Applications, Costs and Benefits", Electric Power Research Institute, December 2010.

[38] Akihiro Bito, "Overview of the Sodium-Sulfur Battery for the IEEE Stationary Battery Committee", Power Engineering Society General Meeting, pp. 1232-1235, June 2005.

temperature to operate, in range of 260-360 °C. Initially developed for EV applications, ZEBRA batteries offer a potentially attractive solution for stationary energy storage, offering very low levels of self-discharge and good lifetimes, though there are concerns that energy is required when the battery is not in use to maintain its operating temperature. There are limited grid applications to date, but a 400 kW unit is under development in the USA. The values in Table 5 are therefore only projections.[39]

Flywheels

Flywheels can be viewed as kinetic or mechanical batteries. Flywheel energy storage works by boosting a rotor (flywheel) to a very high speed and keeping the energy in mechanical/rotational form. The energy is converted back by slowing down the flywheel. A single flywheel energy storage unit manufactured by Beacon Power can deliver 100 kW power and store 25 kWh. Such units can be built from modules into large energy storage units for frequency regulation. For example, the first known operating Smart Energy Matrix Frequency Regulation Plant comprised 20 such units, with an output energy of 5 MWh at a power of 20 MW.[40] Flywheels offer rapid response times and very large numbers of charge cycles, but must be housed in robust containment and require high engineering precision components which currently results in a relatively high cost.

PEM Fuel Cells and Electrolysers

PEM Fuel Cells generate electricity from hydrogen and oxygen/air while the electrolysers produce hydrogen and oxygen from water and electricity. Individual fuel cell and electrolyser units can be assembled into bigger modules to generate more electricity and hydrogen. However, in order to store the energy there is a need to have hydrogen storage, for example as compressed gas. The overall efficiency is currently around 30% for the combined fuel cell and electrolyser system. A possible method to increase round trip efficiency would be a move towards steam electrolysis which has much greater efficiency, but this is not currently a commercially available technology.

Redox flow batteries

A redox flow battery is an electrochemical device that can accumulate (charging mode) and deliver (discharging mode) energy via reversible reduction-oxidation reactions of electrolytes either in liquid or gaseous form that are stored in separated storage tanks. As such, power is decoupled from the energy storage capacity since the power is determined by the number of cells and their size, while the energy capacity is purely a function of the volume and concentration of electrolyte. Redox flow batteries are regarded as being able to operate to high levels of depth of discharge but have lower energy densities. Various redox couples have been tested such as Fe/Cr, Zn/Cl, Zn/Br, H/Br, V/V, S/Br and others. However, only Zinc-Bromine (Zn/Br) and all-vanadium (V/V) redox batteries have currently reached commercialisation. For example, ZBB have produced an energy storage unit that can deliver 25 kW power and store up to 50 kWh of energy. Combined into large modules, such units can store 500 kWh energy, with the potential to be up-scaled even further to 6 MWh.[41]

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[39] Shin-ichi Inage, “Prospects for Large-Scale Energy Storage in Decarbonised Power Grids”, working paper, International Energy Agency, 2009.

[40] Beacon Power Flywheels. http://beaconpower.com/products/smart-energy-25.asp

[41] ZBB Flow Batteries. http://www.zbbenergy.com/products/flow-battery/

Cellstrom is one of the few companies that manufacture all vanadium redox flow cells. Their energy storage unit with 10 kW power and 100 kWh energy can be modularly up-scaled to deliver 40 kW/400 kWh of power and energy[42]. Zinc-Bromine and all-vanadium redox batteries have been already developed for applications such as solar energy fuelling stations, telecommunications, and remote area utility power.

Compressed Air Energy Storage (CAES)

CAES uses electricity to compress air and store it in an over- or underground reservoir. The electricity is produced when the compressed air is expanded and directed through a turbine. Underground CAES storage systems are most cost-effective with storage capacities up to 10 GWh, while overground units are typically smaller and more expensive, with capacities on the order of 60 MWh. There are two operating first-generation CAES systems: one in Germany and one in Alabama. Improved second-generation CAES systems have been defined and are currently being developed.[43] CAES system are currently regarded as having longer lifetimes than battery technologies, but have a lower round trip efficiency and can require a fuel stream. Underground CAES requires suitable geographic sites.

Superconducting Magnetic Energy Storage (SMES)

A superconducting magnetic energy storage system stores energy in a magnetic field created by the flow of electric current in a superconducting inductor. The superconducting inductor must be cryogenically cooled below its superconducting critical temperature. Energy is added or extracted from the magnetic field of the inductor by increasing or decreasing the current in the inductor. At steady state, the superconducting inductor does not dissipate energy and therefore the energy may be stored almost indefinitely. SMES devices are still under development. A 24 kV SMES magnet has been tested at Florida State University, as a research system.[44] This technology offers high cycle life and rapid response, but currently has a relatively low energy density and high cost, and requires energy to constantly cool the magnet.

Electrolytic Double Layer Capacitors (EDLC)

EDLC (supercapacitors) store energy in the form of separated charges at porous electrodes divided by electrolytic solution. Due to their high power density but relatively low energy density, EDLCs are well suited to voltage and frequency stabilisation. EDLC storage technology is slowly being deployed. For example, a demonstration project of 300 kWh/100 kW uninterruptible power supply system using electrochemical capacitors for bridging power was carried out by EPRI Power Electronics Application Center in 2003.[45] This technology offers high cycle life and rapid response, but currently has a relatively low energy density and high cost, and suffers from a relatively high rate of self discharge when compared to other electrochemical energy storage technologies.

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[42] Cellstrom flo battery. http://www.cellstrom.at/cellcube-FB-10-100-ene.56.0.html?&L=1

[43] “Electricity Energy Storage Technology Options: A White Paper Primer on Applications, Costs and Benefits”, Electric Power Research Institute, December 2010.

[44] Ibid.

[45] “Challenges of Electricity Storage Technologies”, A Report from the APS Panel on Public Affairs Committee on Energy and Environment, May 2007.

Pumped Hydro Energy Storage (PHES)

PHES is the most established utility scale energy storage technology, utilising electricity to pump water from a low to high reservoir. When electricity is needed, water is released from the high to low reservoir via a turbine to generate electricity. PHES has the highest capacity of the energy storage technologies known and tested. PHES can be practically sized up to 4,000 MW and operate at around 75%, to a maximum of 85%, efficiency. PHES is currently the most widely implemented storage technology world-wide, representing around 99% of the global grid scale energy storage capacity. In the US alone there are 38 plants providing 19 GW of power.[46] The major disadvantage of this technology is that it is geographically constrained with limited potential for new sites, especially in the UK.

Cryogenic Energy Storage (CES)

CES uses liquefied air or liquid nitrogen which can be stored in large volumes at atmospheric pressure. Its energy generation is very similar to CAES. CES comprises three discrete modules for charging, discharging and storage. Currently such a system is under development by the UK company Highview Power Storage, who have a 350 kW demonstration plant in place.[47] The technology is not geographically constrained and builds on existing supply chains for most of the system components. Round trip efficiency is lower than some storage cycles should this be a concern, though this can be raised by appropriate thermal integration.

Pumped Heat Energy Storage (PHEES)

PHEES uses two large containers of mineral particulate (gravel for example). Electricity is used to pump heat from one vessel to the other, resulting in the first container cooling to around -160 °C and the second container warming to around 500 °C. The specially designed heat pump machine can be thermodynamically reversed to operate as an engine and the electricity is recovered by passing the heat from the hot container back through the machine to the cold container, while the machine drives an electrical generator uses liquefied air or liquid nitrogen which can be stored in large volumes at atmospheric pressure. Such a system is currently being developed by Isentropic Ltd.[48]

4.3 Potential for innovation in energy storage technologies

There are a number of important unknowns in grid scale energy storage, in particular relating to the cost and lifetime of energy storage technologies when applied to real duty cycles within the power network, across a range of power and energy scales, and as a function of location within the network. As such it is essential to demonstrate and evaluate a range of storage technology types to understand how the duty cycle and control strategy impact the performance and lifetime of the storage systems, and in turn how the characteristics of the storage system influences the most optimum design and control of the network, for lowest overall cost and carbon emissions. This learning will offer significant opportunities for

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[46] "Electricity Energy Storage Technology Options: A White Paper Primer on Applications, Costs and Benefits", Electric Power Research Institute, December 2010.

[47] Highviews Power Storage. http://www.highview-power.com/wordpress/?page_id=5

[48] http://www.isentropic.co.uk/

innovation within the range of storage technologies, providing opportunities for improved materials and components to emerge in the medium term which improve the performance and lifetime of current technologies. In the longer term breakthroughs are expected in storage materials, components and systems which offer significantly reduced cost and longer lifetimes, for example in alternative redox flow battery chemistries, in very large footprint supercapacitors and batteries, in new heat/cold storage materials, and in sodium ion batteries (which reduce the dependence on lithium resources), etc.

5 Summary of findings and recommendations for further work

Key high-level findings

The following high-level observations can be drawn from the analysis carried out in this study:

- The values presented in this report tend to be higher than previous studies suggest. This is a direct result of the whole-system approach employed here that includes savings in generation capacity, interconnection, transmission and distribution networks and savings in operating cost. These savings all contribute towards the value of storage, but their relative share changes over time and between different assumptions.
- In the Grassroots pathway, the value of storage increases markedly towards 2030 and further towards 2050. Carbon constraints for 2030 and 2050 can be met at reduced costs when storage is available. At a bulk storage cost of ca. £50/kW.year, the optimal volume deployed grows from 2 GW in 2020 to 15 and 25 GW in 2030 and 2050 respectively. The equivalent system savings increase from modest £0.12bn per year in 2020 to £2bn and can reach over £10bn per year in 2050.
- The value of storage is the highest in pathways with a large share of RES, where storage can deliver significant operational savings through reducing renewable generation curtailment. In nuclear scenarios the value of OPEX is reduced as the value of energy arbitrage between renewable generation and nuclear is lower. CCS scenarios yield the lowest value for storage.
- A few hours of storage are sufficient to reduce peak demand and thereby capture significant value. The marginal value for storage durations beyond 6 hours reduces sharply to less than £10/kWh.year. Additional storage durations are most valuable for small penetration levels of distributed storage.
- Distributed energy storage can significantly contribute to reducing distribution network reinforcement expenditure.
- In the Grassroots pathway, storage has a consistently high value across a wide range of scenarios that include interconnection and flexible generation. Flexible demand is the most direct competitor to storage and it could reduce the market for storage by 50%.
- Bulk storage should predominantly be located in Scotland to integrate wind and reduce transmission costs, while distributed storage is best placed in England and Wales to reduce peak loads and support distribution network management.
- Higher storage efficiencies only add moderate value of storage. With higher levels of deployment efficiency becomes more relevant.
- Operation patterns and duty cycles imposed on the energy storage technology are found to vary considerably, and it is likely that a portfolio of different energy storage technologies will be required, suited to a range of applications.
- There remain a number of important unknowns with respect to the technologies involved in grid-scale energy storage, in particular relating to the cost and lifetime of storage technologies when applied to real duty cycles within the electricity network.
- By indicating the cost target levels for storage at which it may become competitive in the future, this study helps identify which technologies offer the potential for innovation and development in order to further reduce their cost.

- The “split benefits” of storage pose significant challenges for policy makers to develop appropriate market mechanisms to ensure that the investors in storage are adequately rewarded for delivering these diverse sources of value.

Policy implications and future work

Strategic importance:

- The time scales and rate at which the value of storage increases pose a strategic challenge. The long-term value will not be very tangible to market participants in 2020, yet a failure to deploy storage in a timely manner may lead to higher system costs in 2030 and beyond. Strategic policies may be needed to ensure markets can deliver long-term system benefits.

Technology support:

- We have shown that cost reduction can lead to significant increases in net benefit.
- Future work should include a potentially large spectrum of storage technologies with the objectives to deliver: lower cost; higher cycle life; longer calendar life; lower maintenance; improved safety; enhanced environmental compatibility; higher volumetric energy density; higher round-trip energy efficiency and easier integration. In addition, novel control strategies that can incorporate technology-specific constraints of the energy storage system will be needed, which is fundamental if the value of energy storage and its competitiveness are to be maximised. Furthermore, the question of the optimal design of the power electronics interface and control of the operation of tens of thousands of individual cells within a grid-scale storage system has not yet been resolved.

Policy and market development:

- This work provides quantitative assessments that should inform energy storage technology developments and related innovation policy in order to further reduce their cost. The method of cost minimisation used in this work is equivalent to assuming that investment decisions are taken in a perfectly competitive market, while in reality, market failures, such as the impact of externalities, inefficient pricing or natural monopoly, mean the least-cost level of deployment might not take place in practice.
- This analysis also clearly demonstrates that storage can bring benefits to several sectors in electricity industry, including generation, transmission and distribution, while providing services to support real-time balancing of demand and supply and network congestion management and reduce the need for investment in system reinforcement. These “split benefits” of storage pose significant challenges for policy makers to develop appropriate market mechanisms to ensure that the investors in storage are adequately rewarded for delivering these diverse sources of value.
- Further work is needed to understand how different market and policy frameworks would impact the deployment of alternative grid-scale energy storage technology solutions
- It is not clear whether government policies should incentivise the development and deployment of novel storage technologies, and if so, what sort of mechanisms should be considered, e.g. ranging from subsidies to direct procurement.

Option value:

- The value of storage cannot be generalised. It is location, time and context-specific. Although the absolute value of storage differs significantly between different scenarios and pathways, storage provides savings across a wide range of possible futures and may thus provide a hedging option within a balance portfolio of technologies. The option value of storage should be considered in future studies to assess the case for storage in this capacity.

Appendix

Grassroots pathway – generation and demand backgrounds

The DECC Grassroots pathway forms the basis for our analysis. We derive hourly demand profiles from the annual energy demand defined by the Grassroots pathway in different categories. This hourly time series is central to the operation of storage and it further informs the resource adequacy of the generation portfolio. The day with the highest peak load and the day with the lowest demand point are shown in Figure 62 for years 2020, 2030 and 2050. The peak loads of these profiles necessitate additional peaking capacity to be added to the generation mix specified in the Grassroots scenario to ensure supply adequacy. This additional capacity is in line with a loss of load expectation (LOLE) of less than 4 h at a value of lost load (VoLL) of £10,000/MWh.

When quantifying the demand profiles for electricity-based heating, we assume a year with normal (average) temperature variations, including a cold period of several days that characterises a typical cold spell in a 1-in-10 winter. Our bottom-up models for electrified heating based on heat pumps (with appropriate proportions of air and ground source heat pumps as specified in the key assumptions of the Grassroots scenario) take into consideration the changes in the performance of a given type of heat pump driven by the fluctuations in outdoor temperature. We further assume that the cold spell coincides with a period of significantly reduced wind output, in order to stress-test the resilience of the system to cold, still conditions that may occur periodically during winter in the UK.

The generation mix of the Grassroots scenario and the reinforced capacity used in this study are also shown in Figure 62.

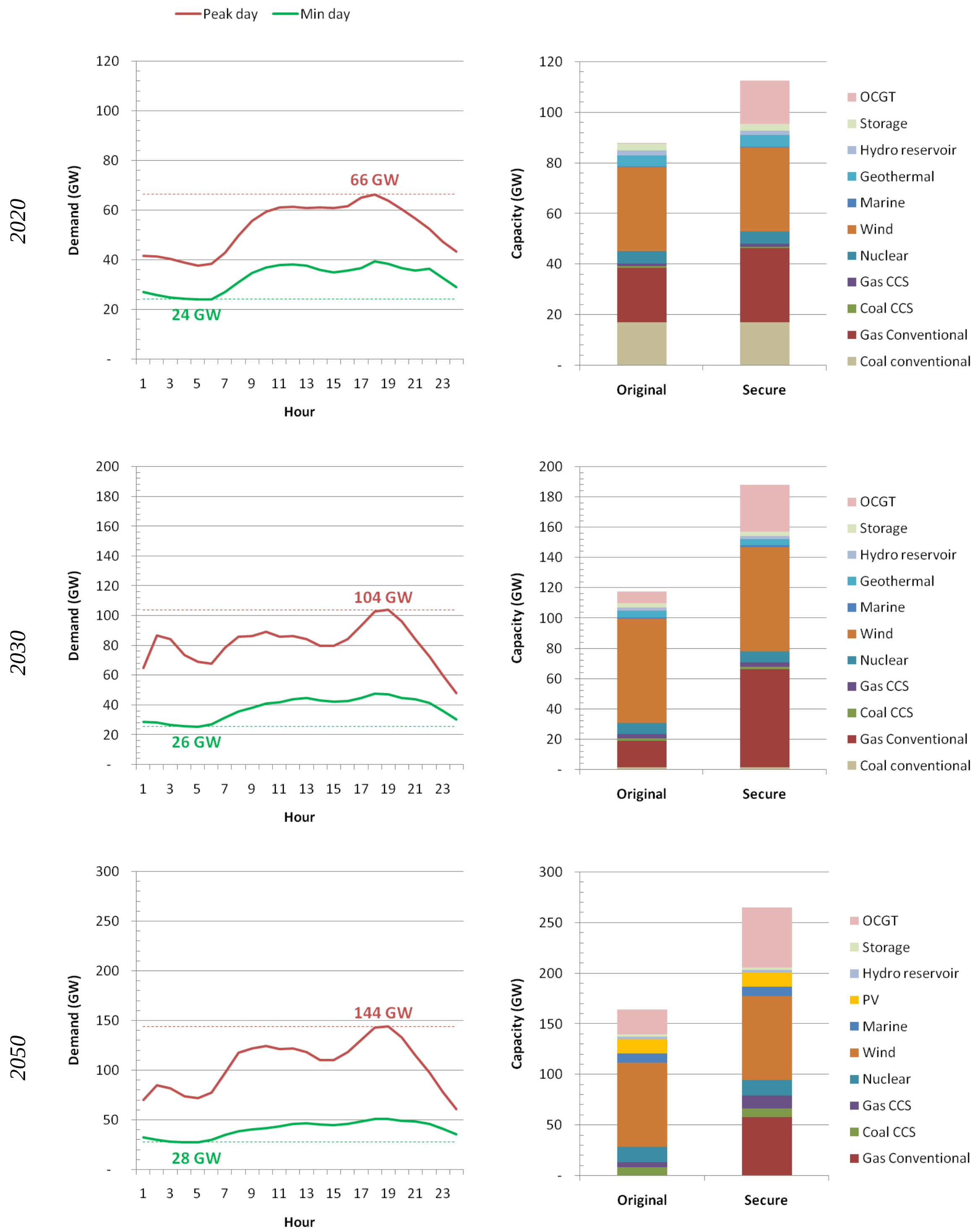

Figure 62: Minimum and maximum loads resulting from decomposing the Grassroots pathway demand into time series with hourly resolution (left). Right: capacity mix for the Grassroots pathway in 2030 and 2050 alongside the reinforced mix used in this study (plotted on the same scale as demand).

Average and marginal values of storage in 2030 and 2050

Bulk

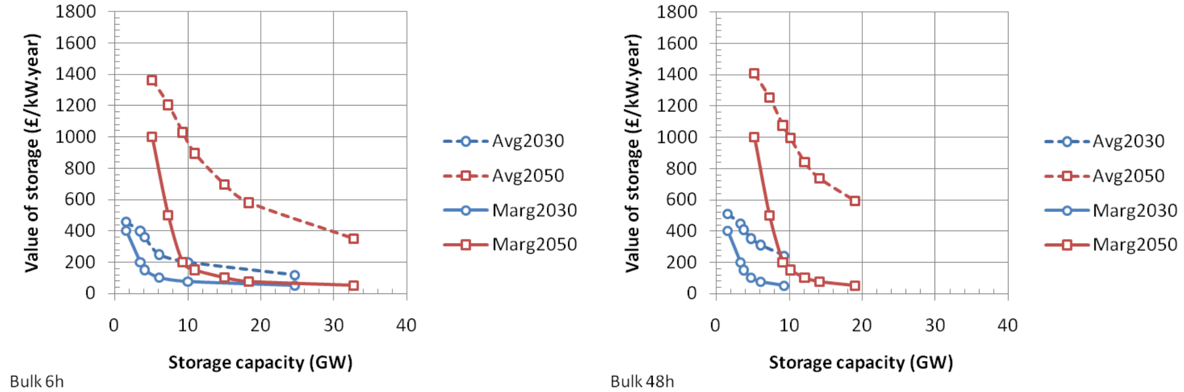

Figure 63: Average and marginal values of bulk storage in years 2030 and 2050 of the Grassroots pathway, for durations of 6 and 48 hours. Optimal volumes in 2050 are significantly higher than in 2030 for a given storage marginal value. Except in the case of very low storage cost, there is little difference in optimal volume between 6-hr and 48-hr cases.

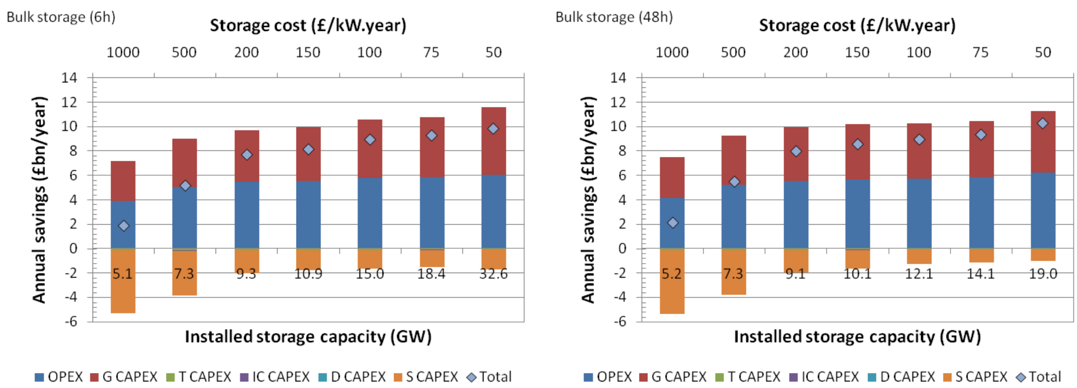

Figure 64: Composition of net benefits of bulk storage in year 2050 of the Grassroots pathway, for durations of 6 and 48 hours. System benefits are dominated by operation cost reduction and generation CAPEX savings in similar proportions, which are partially offset by storage investment cost. Values for the 48-hr case tend to be slightly higher than for 6 hours.

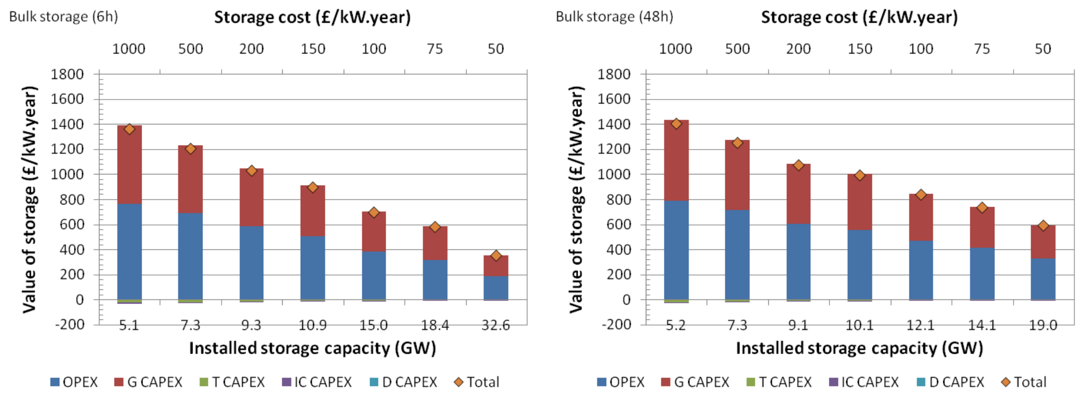

Figure 65: Composition of the value of bulk storage in year 2050 of the Grassroots pathway, for durations 6 and 48 hours. System benefits per kW of storage are evenly distributed between savings in operation cost and generation CAPEX. Values for the 48-hr case tend to be slightly higher than for 6 hours.

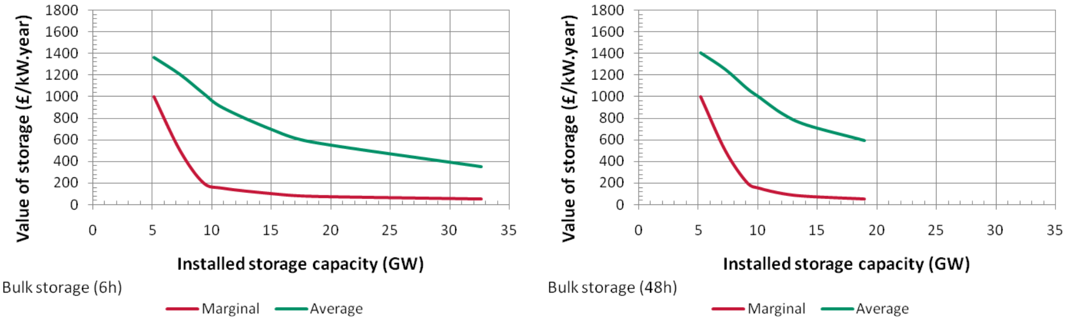

Figure 66: Average and marginal value of bulk storage in year 2050 of the Grassroots pathway, for durations of 6 and 48 hours. Marginal values for the 6-hr and 48-hr cases tend to be very similar except for very low storage cost.

<u>*Distributed*</u>

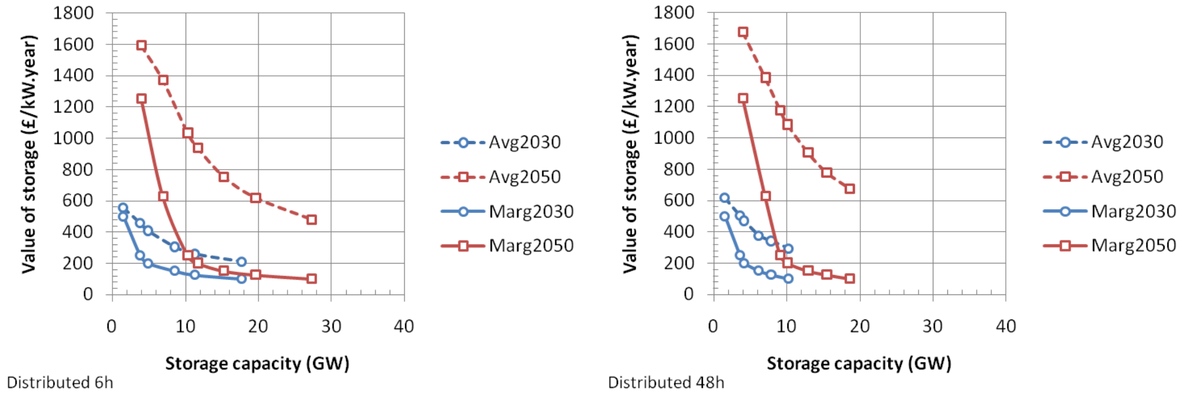

Figure 67: Average and marginal values of distributed storage in years 2030 and 2050 of the Grassroots pathway, for durations 6 and 48 hours. Optimal volumes in 2050 are significantly higher than in 2030 for a given storage marginal value. Except in the case of very low storage cost, there is little difference in optimal volume between 6-hr and 48-hr cases.

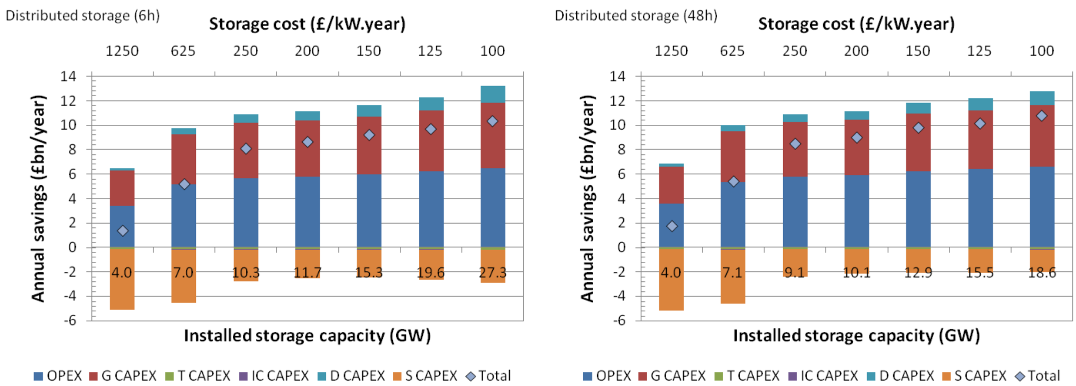

Figure 68: Composition of net benefits of distributed storage in year 2050 of the Grassroots pathway, for durations of 6 and 48 hours. System benefits are dominated by operation cost reduction and generation CAPEX savings in similar proportions, with a relatively smaller contribution from distribution CAPEX savings. Storage investment cost is plotted as negative benefit, resulting in net system benefit ('Total'). Values for the 48-hr case tend to be slightly higher than for 6 hours.

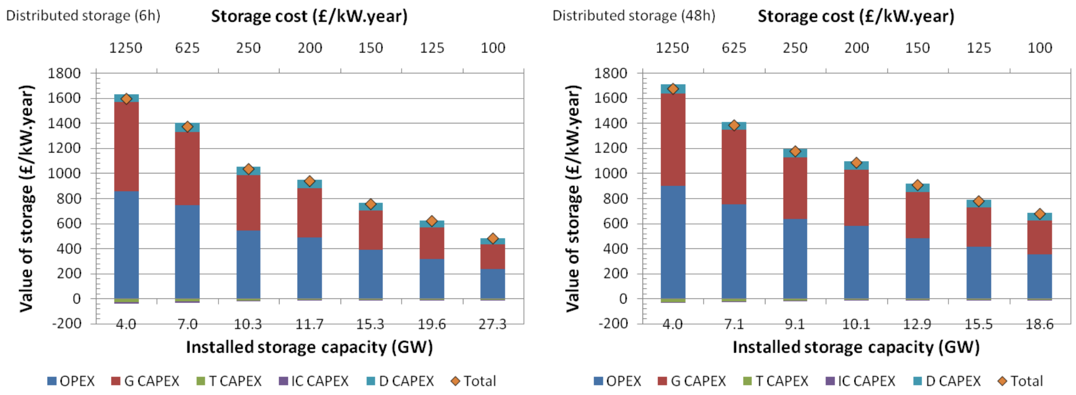

Figure 69: Composition of the value of distributed storage in year 2050 of the Grassroots pathway, for durations of 6 and 48 hours. System benefits per kW of storage are dominated by savings in operation cost and generation CAPEX, with proportionally much smaller contribution from distribution CAPEX savings. Values for the 48-hr case are higher than for 6 hours.

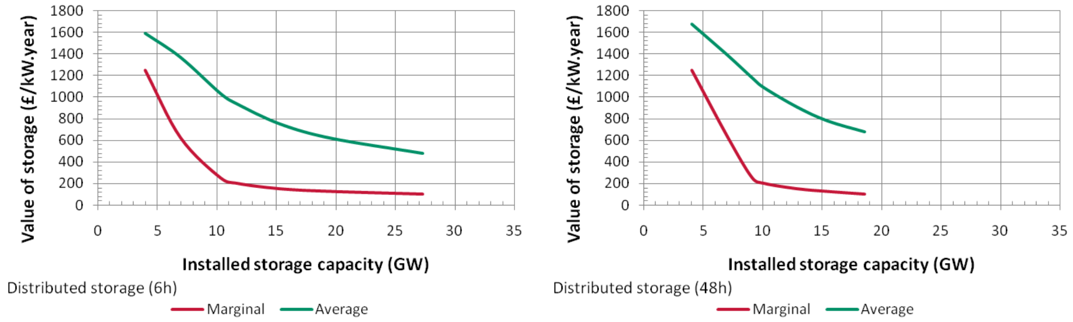

Figure 70: Average and marginal value of distributed storage in year 2050 of the Grassroots pathway, for durations of 6 and 48 hours. Marginal values for the 6-hr and 48-hr cases tend to be very similar except for very low storage cost.

Pathway comparison

CCS

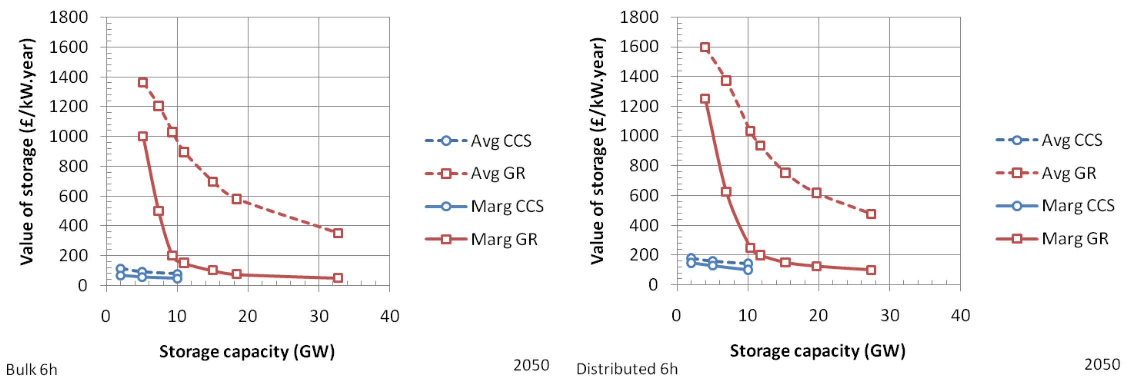

Figure 71: Value of storage for 2050 in Grassroots and CCS pathways (cases shown for 6 h duration). Values in the CCS pathway are only a small fraction of values in the Grassroots scenario.

Impact of competing balancing options (2050)

Bulk

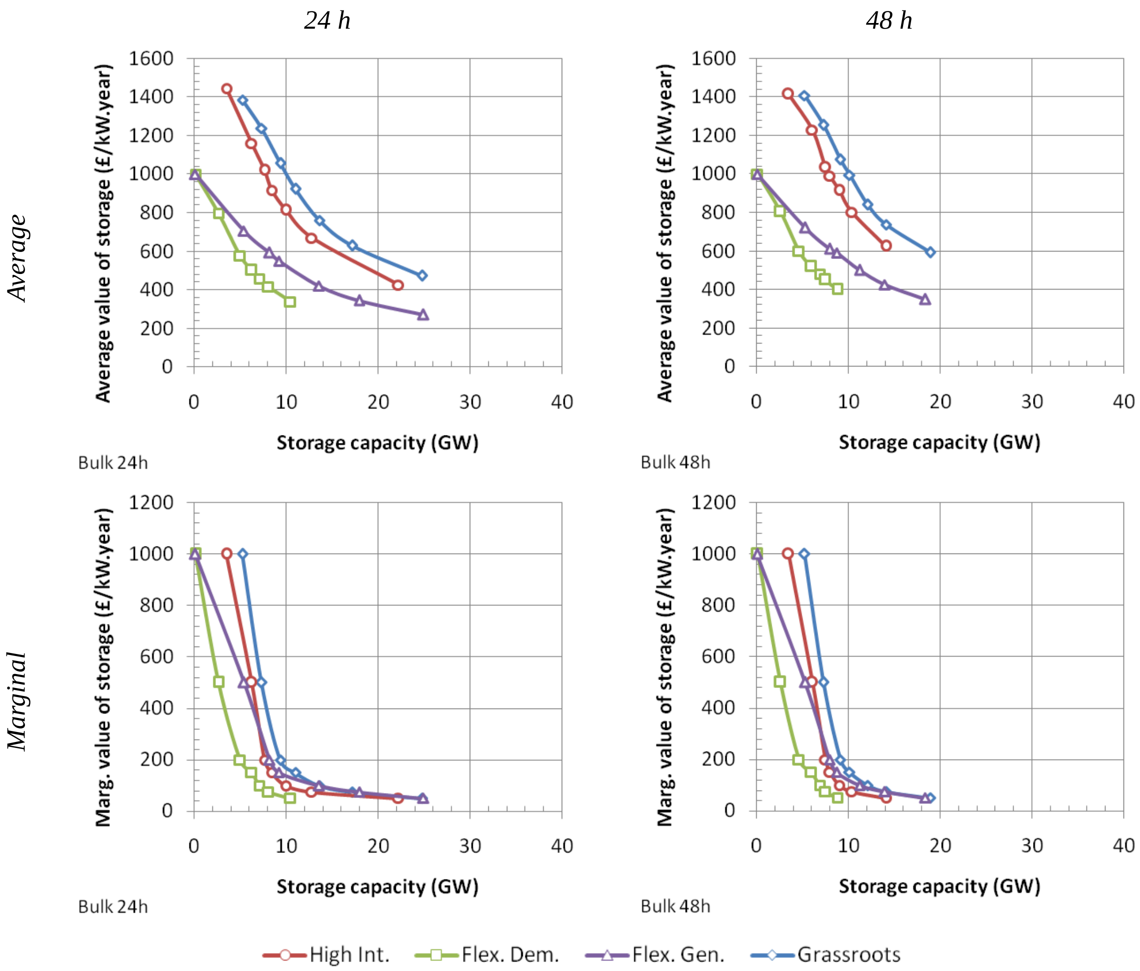

Figure 72: Average and marginal values of bulk storage for year 2050 of Grassroots pathway, for a range of flexible balancing options competing with storage (24-hr and 48-hr duration). Competing options reduce the value of storage and consequently the optimal volumes chosen for construction.

Distributed

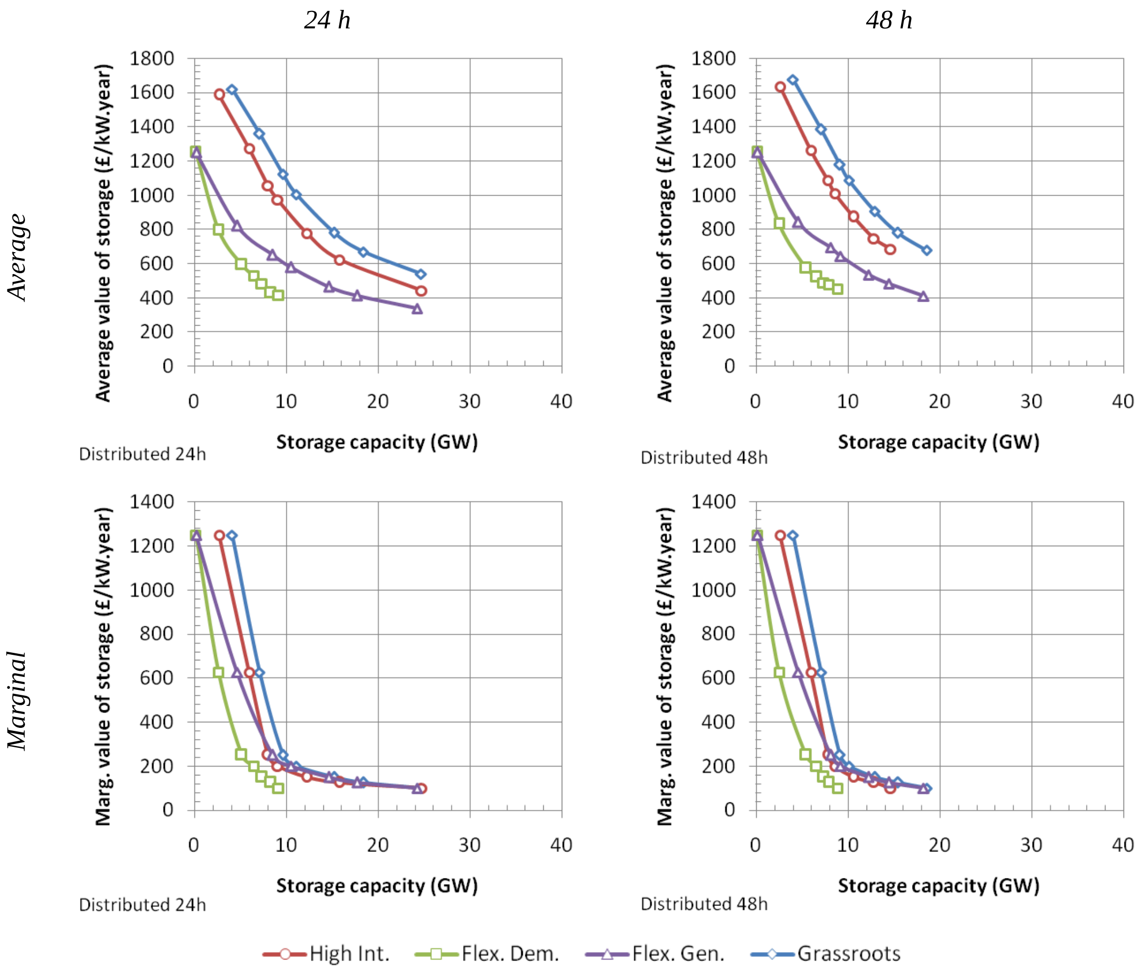

Figure 73: Average and marginal values of distributed storage for year 2050 of Grassroots pathway, for a range of flexible balancing options competing with storage (24-hrand 48-hr duration). Competing options significantly reduce the value of storage (flexible demand in particular) and the optimal volumes of storage.

Storage duration

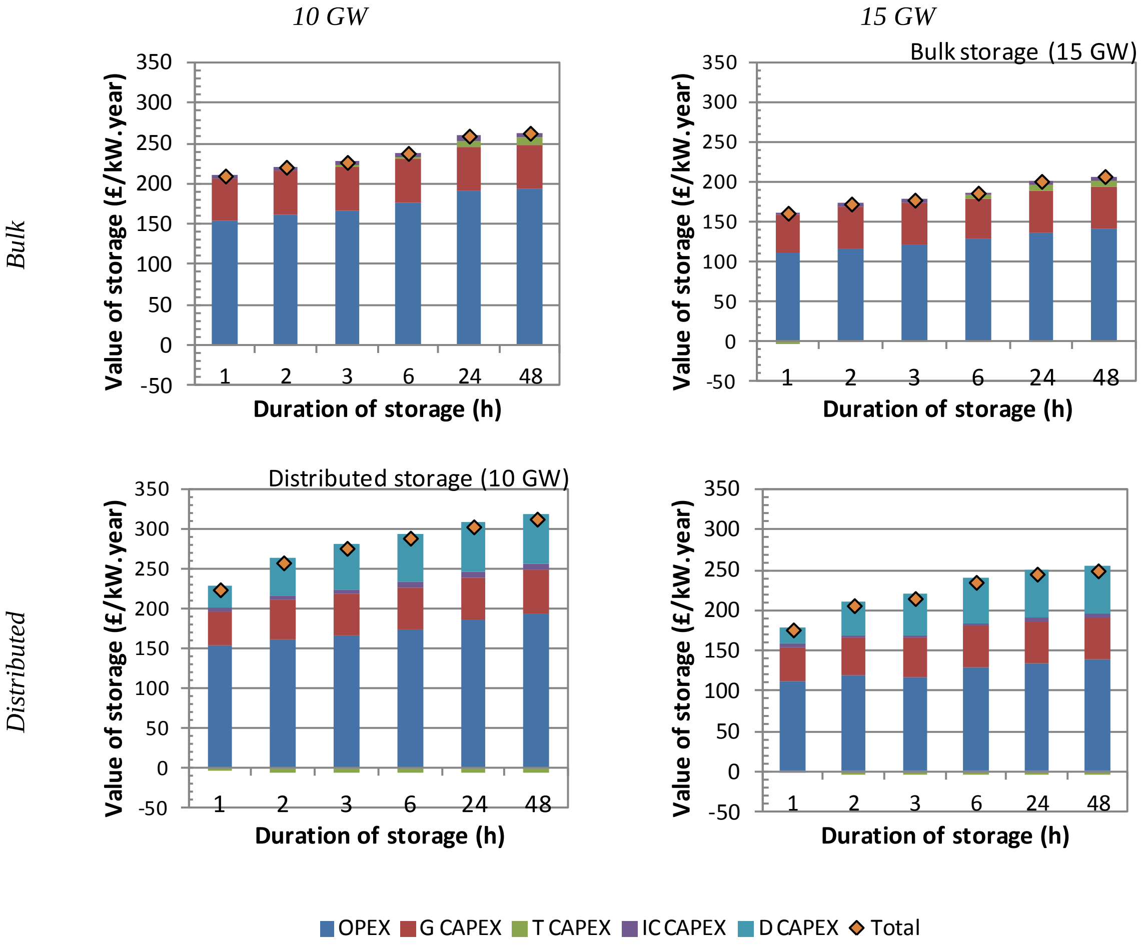

Figure 74: Impact of storage duration on its value. Values shown include bulk and distributed storage, with fixed volumes of 10 GW and 15 GW. Longer duration adds to the value of storage.

Forecasting Error

Results shown in Section 3.5.4 combine the effect of ‘best case’ wind forecasting errors and the ability of wind turbines to provide regulation services. The results shown here are for cases where wind does not provide regulation services. The difference from the results in Section 3.5.4 is slight (less than £10/kW.year). It is therefore the forecasting error that is primarily responsible for the reduction in values shown in Section 3.5.4.

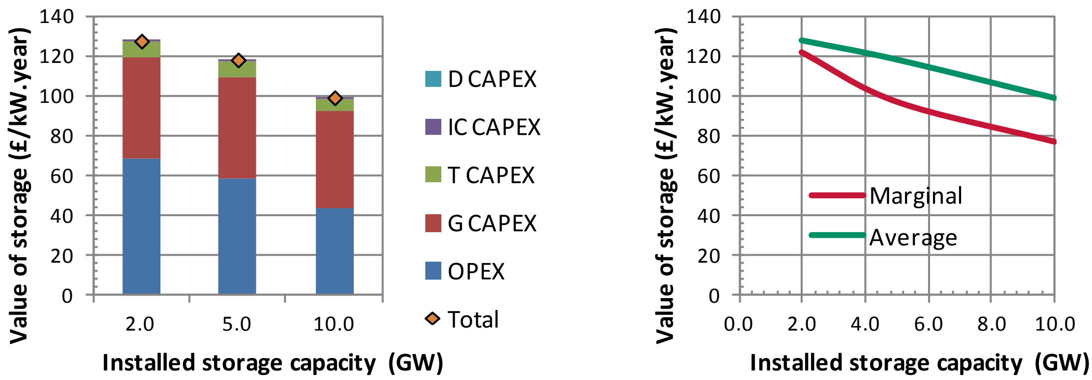

Figure 75: Value of bulk storage for the 'best case' wind forecasting, when wind does not provide regulation services. Results shown are for the Grassroots pathway, year 2030.

Generation and fuel costs

We take projections of fossil fuel prices from the central scenario in DECC's 2011 Fossil Fuels Price Projections. Given that these projections only cover the period up to 2030, we extrapolated the trends exhibited before 2030 in the period between 2030 and 2050. Following that approach, oil prices increase from £77/bbl in 2020 and £84/bbl in 2030 to £98/bbl in 2050 in real terms (based on 2011 prices), while gas and coal price remain constant in real terms level beyond 2020 and 2030 (70 p/therm and £71/tonne respectively). We carried out a set of sensitivities to investigate the impact of high fuel prices on the deployment of alternative balancing options and the associated system benefits.

We take our assumptions on the cost of developing and operating new generation capacity from the 2011 update of DECC's Electricity Generation Cost Model,[49] using "medium, n-th of a kind" costs. We estimated investment costs for new transmission assets based on long-term strategy documents for transmission network development.[50] Interconnection in our analysis is assumed to have the same cost parameters as transmission reinforcement.[51] We take distribution network reinforcement costs from the assumptions made by Ofgem during the latest distribution price control review.

We annualise the costs of investment in generation, transmission and distribution assets using typical asset lives from the Electricity Generation Cost Model (and other sources for non-generation assets), and values for the Weighted-Average Cost of Capital (WACC), taken from a recent study prepared for the Committee for Climate Change.[52]

We express the range of investment cost of storage capacity in our analysis through annualised values only, i.e. we have not assumed any particular values for the cost of capital (WACC) and the economic life of storage facilities, both of which are highly uncertain at

[49] Parsons Brinckerhoff, "Electricity Generation Cost Model – 2011 Update", prepared for the Department of Energy and Climate Change, August 2011. Available at: http://www.pbworld.com/pdfs/regional/uk_europe/decc_2153-electricity-generation-cost-model-2011.pdf.

[50] Electricity Network Strategy Group: "Our Electricity Transmission Network: A Vision For 2020", March 2009.

[51] We also took into account the cost of additional equipment on both sides of an interconnection, by adjusting the distances involved in expanding the interconnection capacity.

[52] Oxera, "Discount rates for low-carbon and renewable generation technologies", prepared for the Committee on Climate Change, April 2011. Available at: http://www.oxera.com/cmsDocuments/Oxera%20report%20on%20low-carbon%20discount%20rates.pdf.

present. Different interpretations of our annualised values for a particular storage technology would yield different capitalised values, but this would not affect the results of our analysis that are based on annualised cost.

Distribution and transmission network costs

Table 7: Assumptions on distribution network costs

Equipment	Overhead network	Underground network
LV cable or OH line	£30/m	£98.4/m
LV inline voltage regulator	£1k	£2k
HV/LV PMT or GMT	£2.9k	£13.2k
HV cable or OH line	£35/m	£82.9/m
EHV/HV GMT	£377.9k	£377.9k
Other costs (EHV lines, admin, etc.)	10%	10%

The assumed transmission network cost is £1,500/MW.km.