Department for
Business, Energy
& Industrial Strategy

Appendix I: Electricity System Flexibility Modelling

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Contents

Summary

The UK government is committed to a target of net zero greenhouse gas emissions by 2050. This will require extensive decarbonisation of all sectors of the economy and the deployment of greenhouse gas removal technologies to remove any residual emissions.

Electricity will be increasingly important in supporting delivery of net zero, potentially providing around half of final energy demand as its use for heat and in transport increases. Understanding the ways in which the system can deliver more electricity whilst producing fewer carbon emissions, and the relative cost of doing so, is central to developing our energy strategy to support delivery of net zero. The Energy White Paper sets out an ambition for a fully decarbonised, reliable, and low cost power system by 2050, and to remain to course the system will need to be overwhelmingly decarbonised in the 2030s.[1]

The analysis in this paper is aligned to the modelling[2] published alongside the Energy White Paper and illustrative net zero demand scenarios included in the Energy and Emissions Projections.[3] The scenarios used in this analysis are just examples of many different possible pathways for the electricity system and should be treated as illustrative. Optimal pathways will continually be developed in light of the Climate Change Committee's advice, developments in technology and wider market developments. The analysis set out in this report was completed prior to announcements on the UK's sixth Carbon Budget (2033 to 2037).[4] Although the scenarios do not consider the impact of these decisions, they are still based on significant decarbonisation in the 2030s and therefore the strategic conclusions from this analysis remain relevant.

The electricity system needs to match generation and demand on a second-by-second basis to keep system frequency stable. System flexibility is the ability to adjust supply and demand to achieve that balance, and to help manage locational constraints on our networks. In the past, much of our flexibility has been provided by fossil fuels from turning up or down coal or gas fired power stations. To meet the UK's target to have net zero emissions by 2050, we will need to shift away from fossil fuels to use low carbon sources of energy. As we transition to more renewable energy, especially intermittent wind and solar generation, this will lead to greater variability in generation output, increasing the need for low carbon flexibility to manage the differences between generation and demand.

There are a range of technologies, on both the supply and demand-side that can be defined as low carbon flexibility. For the purposes of this analysis, we primarily consider flexibility provided

[1] BEIS (2020), Energy White Paper, https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future
[2] BEIS (2020), Modelling 2050: Electricity System Analysis, https://www.gov.uk/government/publications/modelling-2050-electricity-system-analysis
[3] BEIS (2020), Annex O: Net zero and the power sector scenarios, https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2019
[4] BEIS, Prime Minister's Office, 10 Downing Street (2021), UK enshrines new target in law to slash emissions by 78% by 2035, https://www.gov.uk/government/news/uk-enshrines-new-target-in-law-to-slash-emissions-by-78-by-2035

by demand side response (DSR), short-term electricity storage and interconnection.[5] We also test the impact of hydrogen-fired generation as an alternative source of low carbon flexibility. We do not explicitly model longer duration storage but expect this would result in a similar impact on the system as identified in our hydrogen modelling.

This paper sets out our analysis of the impact of low carbon flexibility in a decarbonised electricity system. The analysis helps us to understand the potential impact of flexibility on the system cost and carbon emissions, under different levels of demand. This assessment builds on the analysis published with the Energy White Paper, which showed the importance of flexibility in lowering system costs. This paper takes a closer look at the role that flexibility plays in the system, how different flexibility technologies interact with each other and the level of flexible capacity that might be needed as we transition to net zero.

A key challenge when determining how to decarbonise is the inherent uncertainty involved in modelling over such a long period. For electricity system flexibility, there are key uncertainties on how new technologies (e.g. electricity storage) will develop and the extent to which consumers will change their demand profiles in response to price signals. Our approach allows us to consider a wide range of different sources of uncertainty for the electricity system. As new issues emerge, we will continue to refine our analysis to understand their potential impacts. We explain the key assumptions and limitations of our modelling as well as considering areas for future research.

Our main findings from the analysis are:

- Increased flexibility from DSR, storage and interconnection, provides significant cost savings in a decarbonised electricity system. It is important for cost-effective integration of renewable generation, while meeting increased demand from electrified heat and transport. The impact of flexibility is greatest in a system with lower carbon intensities. We estimate the increased flexibility could save between £6-10bn per year in 2050 (2012 prices, undiscounted), at a carbon intensity of 5g/kWh.
- Hydrogen-fired generation could provide an alternative source of low carbon flexibility, reducing the impact of other flexible technologies. In scenarios with moderate levels of hydrogen, increased flexibility from other sources reduces system cost by around £4bn per year in 2050 at a carbon intensity of 5g/kWh. Low-carbon hydrogen could replace unabated gas fired generation providing system flexibility in periods of low renewable output. We have only modelled the impact of low-carbon hydrogen-fired generation, but technologies that can offer longer-term storage could have similar impacts.
- We tested the cumulative impact of flexibility using illustrative pathways from 2020 to 2050. In these pathways, increased flexibility reduced system costs by £30-70bn (2012 prices, discounted) with increased cost saving in the higher demand scenario.[6]

[5] In our modelling demand side response and storage is limited to intraday transactions.
[6] The impact of flexibility has increased since the estimate made for the 2017 Smart Systems and Flexibility Plan. Analysis commissioned from Carbon Trust and Imperial College in 2016 estimated saving of £17-40bn from deploying flexible technologies. This shows the increased important of system flexibility in reaching net zero.

- The largest cost saving from flexibility comes from a reduction in the capacity of low carbon generation needed to meet emissions targets. Increased levels of flexibility allow for better utilisation of renewable assets, reducing the level of curtailment of wind and solar. Without system flexibility more low-carbon capacity is required to ensure the same proportion of low-carbon generation.
- Flexibility could come from a range of sources. An integrated energy system with flexibility provided across power, heat and transport will be important to minimise costs. There is substantial potential for flexibility from storage, interconnection and from other parts of the energy system including: smart charging of electric vehicles, flexible use of heat pumps and hydrogen-fired generation.
- Sources of short-term flexibility, such as demand side response and short-term storage are broadly substitutable. These technologies have similar impacts on the system, flattening the daily electricity demand profile by shifting demand to times where generation is available, or shifting generation to times of high demand. A policy approach needs to consider system-wide flexibility rather than focus on individual technologies.
- In our illustrative scenarios, around 30GW of total flexible capacity in 2030, may be needed to cost-effectively integrate high levels of renewable generation. This is a substantial increase in deployment from the 10GW of flexibility on the system today.[7] Without these low carbon flexibility assets, we risk either inadequate energy security or having to build a more of new unabated gas in the same period.
- In 2050, around 30GW of combined short-term storage and DSR and 27GW of interconnection lead to the lowest system cost in the scenarios considered.[8] In our high flexibility scenario we assume around 15GW of storage (storage assets are assumed to have 4-hour duration, therefore 60GWh of storage capacity) and 15GW of DSR in 2050, but alternative combinations of DSR and storage would likely lead to similar outcomes.
- We have not explicitly modelled longer-duration storage, or the role that flexibility could play in managing locational network constraints.[9] If these aspects were considered, it is likely that additional flexibility could lead to lower system costs.
- These results are based on a set of illustrative pathways for the electricity system. The impact of flexibility and the most cost-effective deployment of flexible technologies in reality will depend on how the system develops. This analysis was completed prior to announcements on the UK's sixth Carbon Budget, so does not consider the impact of those decisions. However, results are still based on significant decarbonisation in the

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Carbon Trust and Imperial College London (2016), An analysis of electricity system flexibility for Great Britain, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/568982/An_analysis_of_electricity_flexibility_for_Great_Britain.pdf

[7] In 2020, there was around 10GW of flexibility on the system; 4GW of storage, 1GW of industrial and commercial DSR and 5GW of interconnection. National Grid ESO (2020), Future Energy Scenarios 2020, https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2020-documents

[8] DSR capacity is measured by the reduction in annual peak demand

[9] Analysis includes the network benefits associated with lower peak demand and less installed generation capacity, but not those associated with managing locational network constraints.

2030s. We would expect faster or deeper decarbonisation to bring forward the need for flexible technologies.

1. Modelling methodology

We used BEIS' model of the electricity sector, the Dynamic Dispatch Model (DDM) to explore the cost of the future electricity system in a single future year (2050) under a range of different flexibility scenarios.[10] Separately, we used BEIS' electricity Distribution Networks Model (DNM) to quantify the costs of reinforcing and maintaining Great Britain's electricity distribution network under these various scenarios up to 2050 – these costs are combined with the DDM's estimates and together provide a complete picture of future costs to the electricity system.[11] We tested flexibility scenarios against two demand levels and a range of deployment mixes that meet our UK net zero target by 2050. We subsequently tested different flexibility scenarios in full DDM and DNM runs (2020-2050).

To generate different deployment mixes, we identified plausible 2050 capacity ranges for those low-carbon technologies that are deployable at scale.[12] We also considered the potential role of hydrogen-fired generation, and in particular the extent to which it could replace unabated gas-fired peaking generation. We used the department's UK TIMES Model (UKTM) to identify two different electricity demand scenarios for the UK that reach net zero emissions across the whole economy by 2050.[13] The demand scenarios in this paper are aligned to the modelling[14] published alongside the Energy White Paper and illustrative net zero scenarios included in the Energy and Emissions Projections.[15]

We tested different levels of flexibility from short-term storage, interconnection, and DSR. DSR is provided from a range of different demand sources, including electric vehicles, heat pumps, smart appliances, and non-domestic consumers. The level of deployment of flexible technologies is imposed on the modelling, based on a range of feasible deployment levels. For DSR, our scenarios assume uptake of enabling factors, such as smart meters, half hourly settlement,[16] and time-of-use tariffs. There is a high degree of uncertainty in these scenarios,

[10] For further background information on the DDM please see: BEIS (2014), Dynamic Dispatch Model (DDM), https://www.gov.uk/government/publications/dynamic-dispatch-model-ddm

[11] The electricity transmission network consists of over 18,000 km of underground cables and overhead lines. The cost of reinforcing and maintaining these is calculated within the DDM. However, the electricity distribution network is much larger (~800,000 km of underground cables and overhead lines today) and requires the use of a separate model (the DNM) to quantify load related and non-load related distribution network costs for each scenario.

[12] Biomass with Carbon Capture and Storage (BECCS), which can provide negative emissions, is not considered in this analysis. This is because the amount of biomass that will be available, and the sector in which it is most efficiently used to meet net zero are both uncertain and under review as part of the work to develop a biomass strategy. Other renewable generation technologies such as hydro, wave and tidal may have a role to play in reaching net zero but are outside the scope of the current modelling.

[13] UKTIMES is a UK whole energy system optimisation model developed by University College London and BEIS More information can be found at https://www.ucl.ac.uk/energy-models/models/uk-times

[14] BEIS (2020), Modelling 2050: Electricity System Analysis, https://www.gov.uk/government/publications/modelling-2050-electricity-system-analysis

[15] BEIS (2020), Annex O: Net Zero and the power sector scenarios, https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2019

[16] Currently, most customers are settled on a 'non-half-hourly' basis using estimates of when they use electricity, based on a profile of the average consumer usage and their own meter reads (taken over weeks and months). A move to half-hourly settlement would make the settlement process more accurate and timely, aligned to how generators and suppliers trade electricity in the wholesale market. This will enable customers to respond to real-time price signals and provide the opportunity for customer to offer their flexibility into markets.

particularly on the consumer response needed for DSR, and our assumptions will therefore continue to be regularly reviewed and updated. Our modelling does not attempt to determine whether the market, or potential support mechanisms, would deliver this level of flexibility.

There are a number of limitations in our analysis, which should be understood before interpreting results:

- It is based on two illustrative net zero scenarios[17] – other scenarios, with potentially materially different power sector demands and profiles of carbon emissions to reach net zero in 2050 are possible. The impact and need for flexibility would be different in alternative scenarios.
- In our modelling, demand side response minimises the difference between demand and supply (net of intermittent generation). This approach reflects 'implicit DSR' – consumers changing behaviour in response to prices but not actively participating in markets (i.e. ancillary services or balancing). There are no costs associated with DSR, is it assumed to be free – but it is likely costs would be incurred outside the power sector, for example the capital cost of installing electric vehicle smart chargers or heat storage.
- All storage is 'intraday' meaning it cycles within a 24-hour period, as in the DDM all days are considered to be independent of each other.[18]. In our analysis new storage assets are assumed to 4- hour duration and operate predominately in wholesale and balancing markets. In practice a range of different storage assets will be needed, with storage also likely to be deployed to provide a range of grid services and helping alleviate local network constraints. If shorter duration assets (<4 hours) were deployed a greater power capacity (GW) would be required to reach the same storage capacity (GWh). We have not explicitly modelled longer-duration storage, but analysis demonstrated that moderate levels of low carbon hydrogen could reduce system cost and we expect that longer-duration storage would have similar impacts.
- Our DDM modelling includes a simplified representation of wholesale and balancing markets (including reserve and inertia). We recognise that may not reflect all business models for flexibility technologies that could exist in the future, including where a single provider may offer multiple services such as constraint management and frequency response.
- Analysis includes the network benefits associated with lower peak demand and less installed generation capacity but does not consider the role of flexible technologies in alleviating locational network constraints.
- Network costs from both the DDM (transmission) and DNM (distribution) are presented in estimated allowed revenue terms. Our estimated allowed revenue represent the costs

[17] For more detail on the two net zero scenario see: BEIS (2020), December 2020 Net Zero and the power sector scenarios, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/947439/energy-emissions-projections-2019-annex-o-net-zero-power-sector-scenarios.pdf

[18] Cycling is the process of charging and discharging a storage asset. For example, fully discharging a storage asset then fully re-charging it overnight would represent one cycle. In our modelling a storage asset must start and finish the day with the same amount of charge.

that network operators will be allowed to recover annually. In reality, allowed revenue will be decided by Ofgem as part of their RIIO price control framework. These estimates should be treated as more of an indication of how investment costs could be recovered over time as opposed to exact allowed revenue decisions through the RIIO process. They do not represent the total expenditure on investment in assets. The recovery of total expenditure investment in an asset via allowed revenue will be spread out over its lifetime (e.g. 45 years for distribution assets). Therefore, allowed revenue will look lower than any total expenditure estimates due to the discounting of future costs and also as any costs past 2050 are not considered as part of this analysis.

- The DDM’s transmission network costs (presented in allowed revenue terms) are based on the modelling of required transmission network lengths and flows alongside historic cost data to predict the cost of expanding and maintaining Great Britain’s electricity transmission network up to 2050. The modelling used here does not use power flow analysis across existing transmission network zones and boundaries and does not factor in constraints associated with specific locations or assets.
- For the purposes of this analysis, we have assumed that Distribution Network Operators (DNOs) only deploy conventional network reinforcements (additional underground cabling, installation of overhead lines, transformers etc.) to alleviate distribution network constraints. This allows us to isolate the impacts of the flexibility scenarios used in this analysis. There are a range of smart network solutions that DNOs/DSOs could potentially be deployed in the future, which could defer the need for large and expensive conventional reinforcements.[19]

The next sections of this report reflect our 3-stage methodology for assessing the impact of flexibility:

1. **Flexibility parameter testing**: First we assess the impact of changing flexibility assumptions while keeping low carbon capacity fixed. This methodology allows us to assess the marginal impact of adding flexible technologies to a given deployment mix. We use this analysis to identify appropriate ranges of flexibility to be carried forward to the next stages of analysis.

2. **Impact of flexibility in 2050**: We use the results from parameter testing to create 9 flexibility scenarios, made up of different short-term storage, DSR and interconnection levels. We test these scenarios against a range of deployment mixes and two demand levels. The results estimate the overall impact of flexibility in 2050, providing system cost saving at different carbon intensities.

3. **Impact of flexibility from 2020-50**: We identify low-cost deployment mixes under different flexibility scenarios from our 2050 analysis and test illustrative pathways from

[19] Distribution System Operator (DSO) transition – refers to the potential transformation of today’s Distribution Network Operators (DNOs) from passive to active network managers. DSOs would have access to real-time network monitoring data and are able to dynamically manage, reconfigure and balance their networks so that there is less need to deploy large and expensive distribution network reinforcement assets. The analysis in this paper does not factor in the additional flexibility benefits that could materialise from a DSO transition.

2020-2050 needed to reach these levels. The results estimate the cumulative benefits of a more flexible system during the transition to net zero.

2. Flexibility parameter testing

In this section we test a broad range of feasible flexibility scenarios to identify appropriate ranges to take forward to the next stage of the analysis (section 3). We identify the impact of changing flexibility assumptions while keeping low carbon capacity fixed. Scenarios are tested against two deployment mixes: 'high renewables' (5GW nuclear, 15GW CCS, 160GW wind, 80GW solar), and 'balanced' (20GW nuclear, 30GW CCS, 120GW wind, 40GW solar). These deployment mixes are purely illustrative and are used to test whether flexibility has similar impacts in systems with different generation technologies and carbon intensities.

2.1 Short-term storage

Figure 1 shows the impact of different levels of short-term storage capacity on system cost and emissions intensity. We tested storage capacity between 0-100GW. *In these scenarios all storage is assumed to be 4-hour duration and is additional to the (c3GW) pumped hydro storage currently deployed*. Storage reduces system cost and emissions intensity by lowering renewable curtailment and reducing need for peaking generation. Benefits start to diminish at 20-30GW, beyond this level the additional cost of storage outweighs the system benefits. The results are consistent across both deployment mixes. These scenarios assume no DSR, we further test the interaction between storage and DSR in section 2.4.

Figure 1*: Impact of short-term storage on system cost and emissions in 2050.*

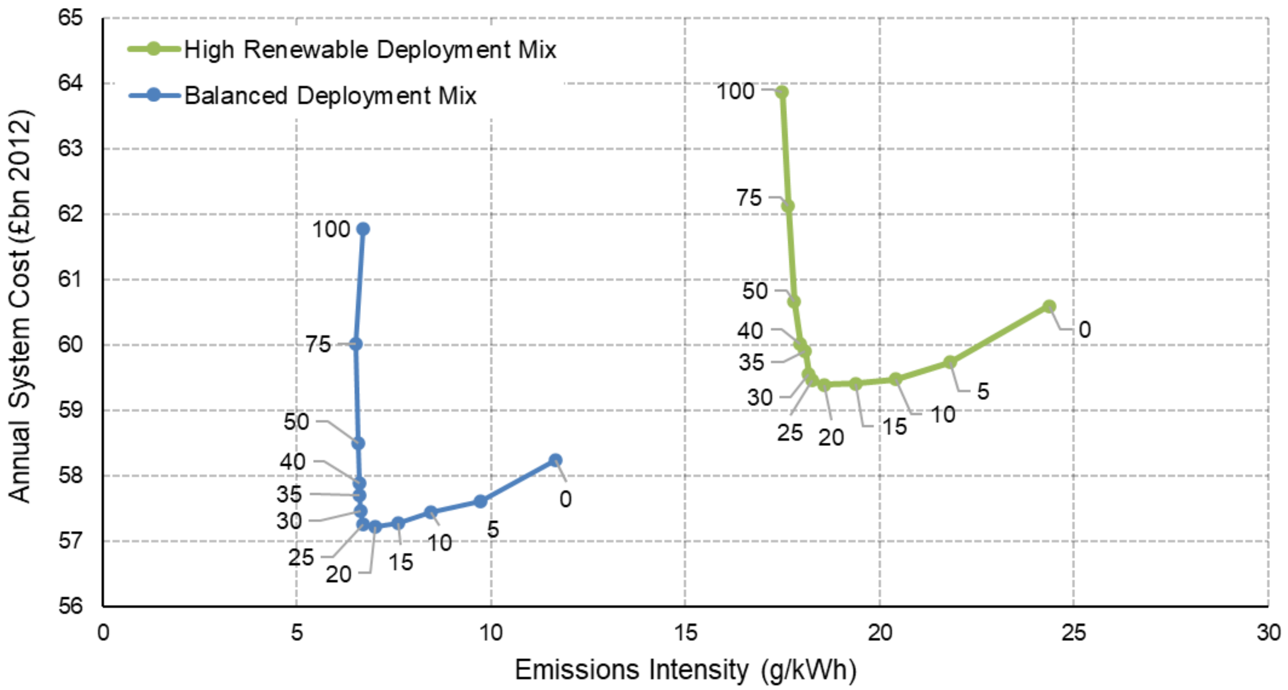


Figure 1 shows the system cost and emission intensity of systems with different deployments of storage-term storage. Each dot represents a different model run, the amount of storage in each deployment mix is shown in the data labels (0-100GW). Results are shown for two illustrative deployment mixes: balanced and high renewables.

2.2 Sources of demand side response

Figure 2 shows the cumulative amount of demand shifted across the year and the impact on peak demand, under different assumptions.[20] We find that smart charging of electric vehicles and heat pumps combined with heat storage provide the largest potential for DSR.

Smart charging of electric vehicles has the largest impact on peak demand. We split electric vehicle demand into a number of sub-categories (see Annex I.1), the highest potential for flexibility is likely to come from residential off-street charging. This is because it represents the largest amount of controllable load and is especially valuable as it moves demand away from the evening peak. Compared to the central smart charging assumption (‘Electric vehicles – central flex’), additional flexibility from electric vehicles does not reduce peak demand, as the system peak is now in the morning, where electric vehicle demand is already low.

In our baseline, we assume all buildings have heat storage installed that is used for hot water demand. Our scenarios test the potential flexibility from additional heat storage (buildings have heat storage used for space heating demand) and pre-heating (allowing heat demand to be brought forward by one hour to proxy the potential for thermal storage provided by building fabric). We find that ‘pre-heating’ provides less demand flexibility than additional heat storage, although further analysis is needed to consider the interaction between these technologies.

Domestic DSR (via smart appliances) and non-domestic DSR (industrial and commercial consumers) provided a small amount of demand shifting in our modelling. Smart appliances represent a relatively small amount of controllable load, therefore provide less potential for DSR. The peak of non-domestic demand is often not correlated to overall system peaks, therefore in our modelling shifting non-domestic demand has less opportunity for flattening overall demand profiles.

[20] Demand reduction in one period resulting in an increase in demand in another period (i.e. the overall level of demand remains constant).

Figure 2*: Peak reduction and annual demand shifted from different demand sources in 2050*

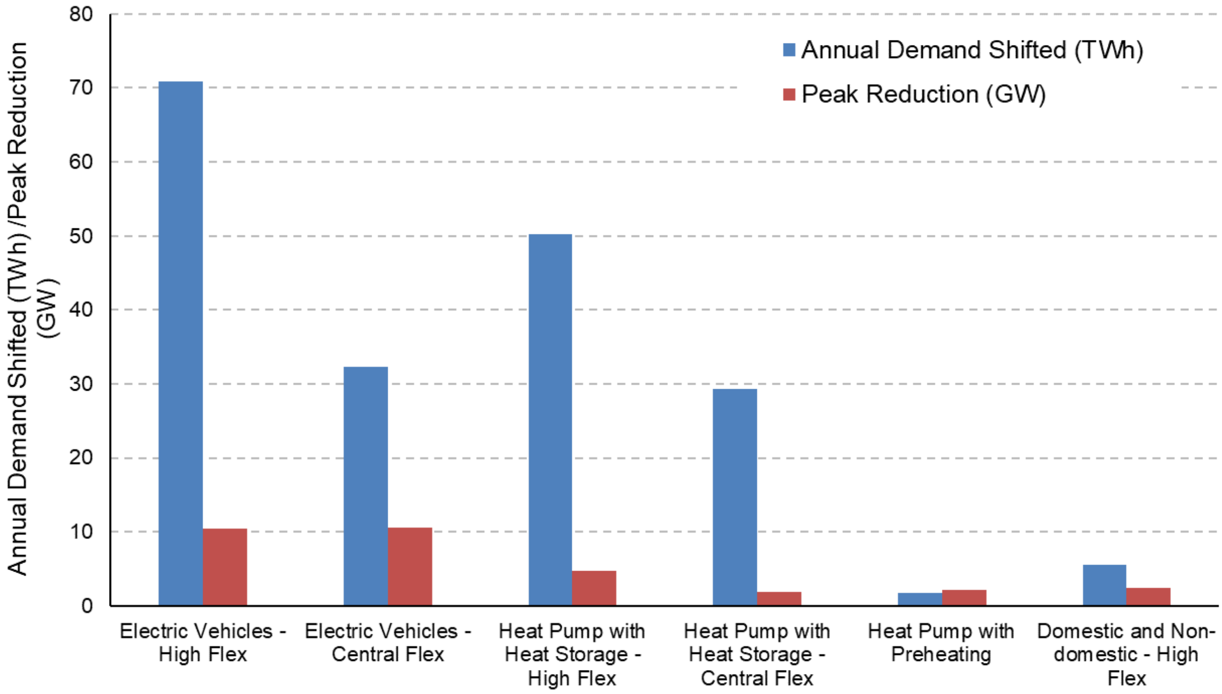


Figure 2 shows the volume of demand shifted across the year (blue bars) and the reduction in peak demand (red bars). The results are shown for illustrative flexibility assumptions for a range of different demand sources. The results for domestic DSR (via smart appliances) and non-domestic DSR (from industrial and commercial consumers) are combined in our scenarios.

2.3 Interconnection

Figure 3 shows the impact of different levels of interconnection capacity on system cost and emissions intensity. We tested 3 levels of interconnection capacity broadly based on the potential pipeline of projects; 9.8GW (existing projects and projects under construction), 17.9GW (based on known pipeline projects at advanced stages of development) and 27GW (stretch scenario based on pipeline projects at early stages of development) against two illustrative capacity mixes.[21] Greater capacity of interconnection reduces system cost and emissions intensity by reducing the need for peaking generation (through increased imports) and lowering renewable curtailment (through increased exports). For the scenarios we tested we did not find a ‘tipping point’ where additional interconnection capacity provided no system value.

[21] Assumptions were set in early 2020, the pipeline of projects may have subsequently changed.

Figure 3*: Impact of interconnection capacity on system cost and emissions in 2050.*

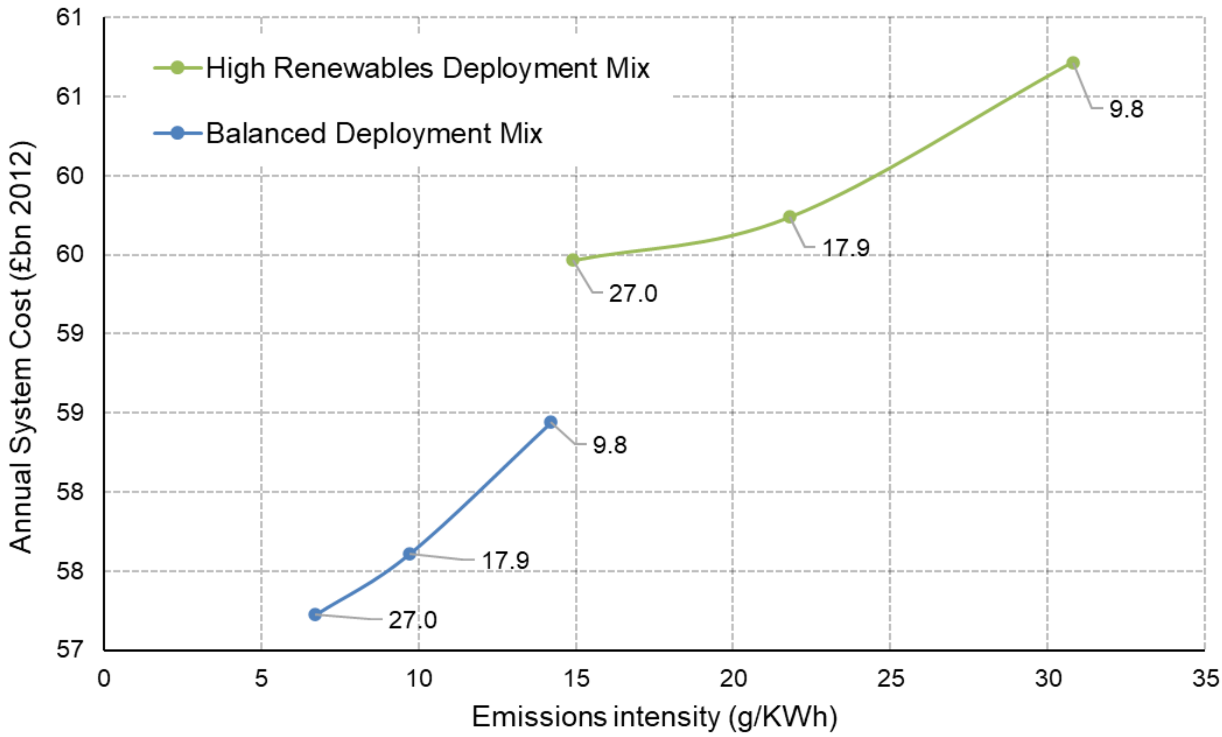


Figure 3 shows the system cost and emission intensity of systems with different deployments of interconnection capacity. Each dot represents a different model run, the amount of interconnection in each deployment mix is shown in the data labels (9.8GW, 17.9GW, 27GW). Results are shown for two illustrative deployment mixes: balanced and high renewables.

2.4 Interaction between flexibility technologies

To assess the interaction between different flexibility technologies we tested the impact of one technology assuming different levels of the other technologies. For example, in Figure 4 we show the impact of storage deployment under different levels of DSR. We find that the system benefits of storage are affected by the level of DSR available. In a system with minimal levels of DSR, between 20-30GW of storage leads to the lowest cost and emissions intensity. However, in a scenario with high levels of DSR, 5-10GW leads to the lowest cost, beyond this level the additional cost of storage outweighs the system benefits. We conclude that there is a high degree of substitutability between DSR and short-term storage. Higher levels of DSR flatten the daily demand profile meaning that there is a smaller arbitrage opportunity available for storage, resulting in storage providing less system benefit. This result indicates that a policy approach needs to consider system-wide flexibility rather than focus on individual technologies. The cost-effectiveness of different flexibility technologies should be considered and greater progress in one area could diminish the need for the other.

Figure 4*: Impact of short-term storage on system cost and emissions in 2050, under different levels of demand side response.*

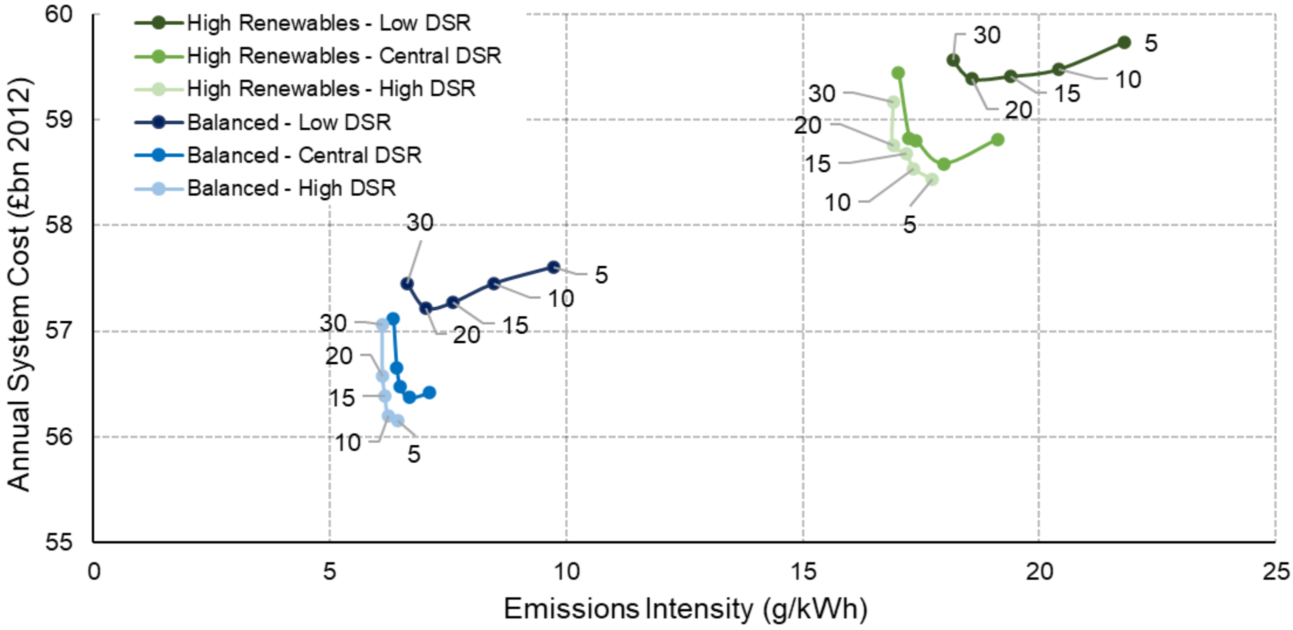


Figure 4 shows the system cost and emission intensity of systems with different deployments of storage capacity, and DSR. Each dot represents a different model run, the amount of storage in each deployment mix is shown in the data labels (5-30GW). Storage deployment is tested under 3 levels of illustrative DSR assumptions, shown in the different shaded dots. Results are shown for two illustrative deployment mixes: balanced and high renewables.

We also tested the interaction between interconnection capacity and both DSR and storage. We found limited substitutability between these technologies; the impact of additional interconnection capacity was similar under scenarios with low or high DSR and storage. We conclude that interconnection plays a different role in the system to DSR and storage in our scenarios. Higher levels of storage and DSR flatten the demand profile and maximise the utilisation of renewables within a day. Their main benefit to the system is on days where there are *both* periods of surplus and deficit renewables generation, for example storing a surplus in overnight periods for use in the evening peak. Higher interconnection capacity allows for greater imports when domestic renewable output is low reducing the reliance on unabated gas, and greater exports when domestic renewables output is high resulting in less curtailment. As such, interconnection can provide system benefits where there is *either* surplus or deficit renewable generation across the entire day.

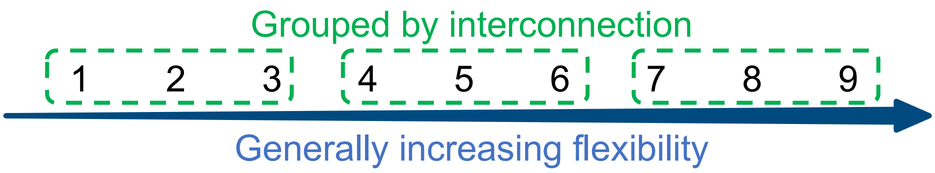
3. Impact of flexibility in 2050

3.1 Creating flexibility scenarios

We use the findings from the parameter testing to generate a sensible range of flexibility scenarios in 2050. Due to the substitutability between DSR and storage, we combine these technologies into a single set of assumptions. We test 3 different levels of combined DSR and storage, and 3 different levels of interconnection, for a total of 9 flexibility scenarios. Figure 5 outlines the different flexibility scenarios, further detailed on the assumptions used can be found in Annex I.1. We tested flexibility scenarios against two demand levels and a range of deployment mixes that meet our UK net zero target in 2050. The results estimate the overall impact of flexibility in 2050 at different carbon intensities.

Figure 5*: Summary of the 9 flexibility scenarios tested:*

	5GW Storage Low DSR	10 GW Storage Central DSR	15GW Storage High DSR
9.8GW Interconnection	1	2	3
17.9GW Interconnection	4	5	6
27GW Interconnection	7	8	9



3.2 Role and value of increased system flexibility

Table 1 shows the minimum system cost under each of the flexibility scenarios, for both high and low demand levels at different carbon intensities. Increased flexibility reduces system cost in all scenarios. At a 5g/kWh carbon intensity with high demand, the difference between the least flexible scenario and the most flexible scenario is about £10bn per year in 2050, or with low demand, about £6bn per year.

The impact of flexibility on system cost is greater at lower carbon intensities. At higher carbon intensities, unabated gas generation is still able to provide some system flexibility. At lower carbon intensities there is less room for any unabated gas generation, therefore low carbon flexibility becomes essential for integrating renewable generation.

Table 1: Illustrative impact of flexibility on annual system cost in 2050 under alternative scenarios.

Demand	Emissions (g/kWh)	Minimum annual system cost (£bn 2012)								
		Low IC Low DSR/Stor	Low IC Cen DSR/Stor	Low IC High DSR/Stor	Cen IC Low DSR/Stor	Cen IC Cen DSR/Stor	Cen IC High DSR/Stor	High IC Low DSR/Stor	High IC Cen DSR/Stor	High IC High DSR/Stor
		1	2	3	4	5	6	7	8	9
High	5	71.8	67.7	66.1	65.8	63.9	62.8	64.2	62.5	61.9
High	10	65.3	63.1	63.0	63.1	60.8	60.4	61.2	59.6	59.3
High	25	61.3	60.2	59.9	59.7	58.9	58.8	59.5	58.6	58.6
Low	5	58.5	56.5	56.2	55.9	54.4	54.0	54.8	53.1	52.6
Low	10	55.7	54.1	53.5	53.5	51.9	51.9	52.3	51.2	50.9
Low	25	52.8	52.1	51.9	51.9	51.2	51.1	51.8	50.8	50.8

Demand	Emissions (g/kWh)	Savings relative to lowest flex scenario								
		Low IC Low DSR/Stor	Low IC Cen DSR/Stor	Low IC High DSR/Stor	Cen IC Low DSR/Stor	Cen IC Cen DSR/Stor	Cen IC High DSR/Stor	High IC Low DSR/Stor	High IC Cen DSR/Stor	High IC High DSR/Stor
		1	2	3	4	5	6	7	8	9
High	5		4.1	5.8	6.1	8.0	9.1	7.6	9.3	9.9
High	10		2.2	2.3	2.2	4.5	4.9	4.1	5.7	6.0
High	25		1.1	1.4	1.6	2.4	2.5	1.8	2.7	2.7
Low	5		2.0	2.3	2.6	4.1	4.5	3.7	5.4	5.9
Low	10		1.6	2.2	2.2	3.8	3.8	3.4	4.4	4.8
Low	25		0.7	0.9	0.9	1.5	1.7	1.0	1.9	2.0

The shading in Table 1 shows the relative system cost (green lower cost, red higher cost), and the relative impact of flexibility (green higher impact, red lower impact) in each scenario.

Figure 6 shows the change in annual system cost relative to the lowest flexibility scenario, split by cost category (results are presented for the high demand level). The largest system costs savings from increased flexibility are from reduced capital costs, primarily from a reduction in low carbon capacity. Increased system flexibility reduces the curtailment of wind and solar by flattening the demand profile and storing generation until periods where it can be utilised. Maximising the utilisation of renewables reduces the need to 'overbuild' low carbon capacity. In other words, without system flexibility more low-carbon capacity is required to ensure the same proportion of low-carbon generation.

There is also a reduction in network costs. Increased flexibility lowers peak demand on the system allowing network investment to be deferred or avoided, lowering the cost of network reinforcement. There are smaller cost reductions in operating and balancing costs, as better utilisation of renewables displaces more expensive generation. Higher flexibility scenarios typically have greater interconnection costs as increased interconnection capacity and less excess renewable generation leads to higher net imports. These imports displace more expensive domestic generation also contributing to lower operating costs.

Increased system flexibility also allows for a greater range of deployment mixes to meet low carbon intensities. For example, at very low levels of system flexibility, low carbon intensities (5g/kWh and below) can only be achieved with significant nuclear and gas CCUS capacity. The better utilisation of renewables capacity through increased system flexibility means that less alternative low carbon capacity is needed to reach low carbon intensities.

Figure 6*: Cost saving relative to lowest flexibility scenario, split by cost category (high demand, 5g/kWh carbon intensity)*

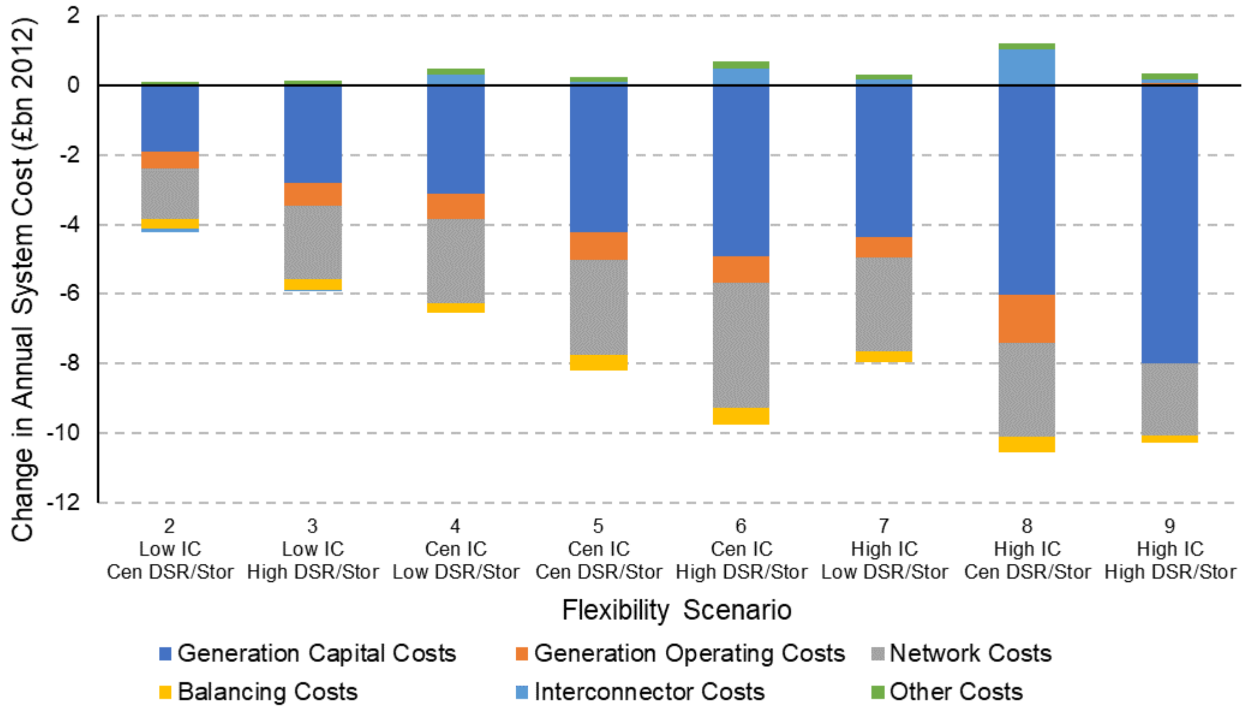


Figure 6 shows the change in annual system cost in each flexibility scenario compared to the lowest flexibility scenario (scenario 1). Results are shown for the minimum cost deployment mix that meets a 5g/kWh carbon intensity in the high demand scenario. Costs are split by category; 'network costs' include both transmission and distribution network costs, 'other costs' include carbon costs and unserved energy costs

3.3 Impact of hydrogen-fired generation

We considered the potential for hydrogen-fired generation to be an alternative source of low carbon flexibility. There is a high degree of uncertainty around the volume of hydrogen that might be available for the power sector in 2050 and its price. We consider a scenario where the total amount of hydrogen-fired generation is constrained to 20TWh or less, and hydrogen is twice as expensive as natural gas. We assume that this hydrogen is made by steam methane reformation with Carbon Capture and Storage (sometimes labelled as "blue" hydrogen) and include the residual carbon emissions in our overall power sector carbon emissions.

Table 2 shows the minimum system cost under each of the flexibility scenarios, now for systems that include hydrogen-fired generation. The inclusion of hydrogen-fired generation diminishes the savings from other sources of flexibility. The difference between the least flexible and the most flexible scenario is up to £4bn per year with a 5g/kWh carbon intensity. Hydrogen significantly reduces the cost of reaching low carbon intensities in our low flexibility scenarios. For example, in the lowest flexibility scenario, the inclusion of hydrogen-fired generation reduces the cost of reaching 5g/kWh by around £5bn per year. Systems with hydrogen see relatively smaller benefits from increased storage, DSR and interconnection because hydrogen provides an alternative source of low-carbon flexibility.

We calculated the impact of deploying hydrogen "off model", making the simplifying assumption that it would only displace natural gas generation, with no other impact on the generation mix. In reality, there will be a complex interaction between the price of hydrogen and its place in the merit order, and how it competes with other sources of flexibility.

Table 2: Illustrative impact of flexibility on annual system costs in 2050 under alternative scenarios, system including hydrogen-fired generation.

		Minimum annual system cost (£bn 2012)									Savings relative to lowest flex scenario								
Demand	Emissions (g/kWh)	LowIC Low DSR/Stor 1	Low IC Cen DSR/Stor 2	Low IC High DSR/Stor 3	Cen IC Low DSR/Stor 4	Cen IC Cen DSR/Stor 5	Cen IC High DSR/Stor 6	High IC Low DSR/Stor 7	High IC Cen DSR/Stor 8	High IC High DSR/Stor 9	LowIC Low DSR/Stor 1	Low IC Cen DSR/Stor 2	Low IC High DSR/Stor 3	Cen IC Low DSR/Stor 4	Cen IC Cen DSR/Stor 5	Cen IC High DSR/Stor 6	High IC Low DSR/Stor 7	High IC Cen DSR/Stor 8	High IC High DSR/Stor 9
High	5	66.4	64.5	64.2	64.7	63.3	62.5	63.8	62.5	62.2		1.8	2.1	1.6	3.1	3.9	2.6	3.9	4.2
High	10	63.9	62.6	62.3	62.6	61.6	60.9	61.8	60.8	60.8		1.3	1.6	1.4	2.3	3.0	2.1	3.1	3.2
High	25	63.6	62.6	62.3	62.3	61.3	60.9	61.8	60.8	60.8		1.0	1.3	1.3	2.3	2.8	1.8	2.8	2.9
Low	5	57.4	55.7	55.5	55.4	54.3	54.1	54.9	53.7	53.6		1.7	1.9	2.0	3.1	3.3	2.5	3.7	3.8
Low	10	54.3	53.6	53.3	53.3	52.7	52.5	53.2	52.3	52.1		0.6	1.0	1.0	1.5	1.8	1.1	2.0	2.2
Low	25	54.2	53.6	53.2	53.3	52.7	52.5	53.2	52.3	52.1		0.6	0.9	0.8	1.4	1.7	1.0	1.9	2.1

The shading in Table 2 shows the relative system cost (green lower cost, red higher cost), and the relative impact of flexibility (green higher impact, red lower impact) in each scenario.

In this analysis we have not explicitly included any longer-duration storage, but we expect that longer-term storage could have similar impacts to hydrogen-fired generation. Longer duration storage could store excess renewable generation in one period, then generate electricity in periods of low renewable output. This would result in a similar impact on the system as assumed in our hydrogen modelling. Periods where unabated gas generation would have otherwise been needed to meet demand, could instead be met by output from long duration storage. Further analysis is needed to understand the scale and characteristics of long duration storage that would be needed in a decarbonised system.

4. Impact of flexibility from 2020-50

4.1 Creating illustrative pathways

In the next stage of the analysis, we assess the impact of increased flexibility as we transition to net zero. Instead of running the DDM in its single year (2050) mode, we run the model for all years between 2020 and 2050. This allows us to understand the role of flexibility in a changing system and consider the cumulative costs and benefits.

We selected 3 flexibility scenarios to cover the full range of our 2050 runs; scenario 1 (now called ‘Low’), scenario 5 (now called ‘Central’), and scenario 9 (now called ‘High’). The scenarios were run for both high and low demand levels.[22] We identified low carbon deployment mixes that were low cost for reaching 5g/kWh emissions targets in 2050. Scenarios with increased flexibility require less low carbon capacity. To make it easier to interpret modelling results, we chose deployment mixes with the same levels of nuclear and gas CCUS (30GW of each), and only changed the level of renewable capacity. Modelling limitations and uncertainty over the timing of hydrogen deployment mean we have not included hydrogen-fired generation in these scenarios. Table 3 sets out the deployment mixes we used in the analysis. For the purposes of modelling we assume the low carbon capacity deploys broadly linearly between now and 2050.[23] The capacities used here are illustrative and are just examples of many different possible pathways for the electricity system.

Table 3: Deployment mixes (GW) in 2050 for illustrative flexibility and demand scenarios

Demand Scenario	High Demand			Low Demand		
Flexibility Scenario	High	Central	Low	High	Central	Low
CCUS	30	30	30	30	30	30
Nuclear	30	30	30	30	30	30
Onshore Wind	30	20	45	20	20	10
Offshore Wind	60	80	120	40	45	80
Solar	10	30	10	30	30	30
Interconnectors	27	18	10	27	18	10
Storage[24]	15	10	5	15	10	5
Demand Side Response	High	Central	Low	High	Central	Low

[22] For more detail on the two net zero demand scenarios see: BEIS (2020), Net Zero and the power sector scenarios, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/947439/energy-emissions-projections-2019-annex-o-net-zero-power-sector-scenarios.pdf

[23] Renewable capacity deploys between 2026 and 2050, nuclear and CCS capacity deploys between 2030 and 2050.

[24] This figure excludes existing pumped hydro storage capacity.

4.2 Cumulative impact of flexibility

The results mirror our findings from the 2050 analysis, such that increased system flexibility provides significant reductions in system costs. Table 4 shows the cost saving relative to the low flexibility scenario, broken down by cost category. In these pathways, increased flexibility reduces cumulative system costs by around £30bn in the low demand scenario, and around £70bn in the high demand scenario (2012 prices, discounted).

The impact of flexibility is greater in later years when the carbon intensity of the system is lower. The majority of the system cost saving comes between 2040-2050. This supports the finding from the 2050 analysis that flexibility becomes more important to cost-effectively meet very low carbon intensities, when flexibility provided from unabated gas is not available. This also helps to explain why the benefits of our high flexibility scenario are only marginally higher when compared to the central flexibility scenario. The benefits from future years are more heavily discounted in our appraisal methodology, so the impact on total cost saving is reduced.

Table 4: Saving relative to low flexibility scenario (£bn, 2012 price base, discounted)

Demand Scenario	High Demand		Low Demand	
Flex Scenario	Central	High	Central	High
Generation capital costs	-36	-44	-19	-20
Generation operating costs	-6	-6	-1	0
Network costs	-21	-26	-13	-17
Balancing costs	-4	-5	-1	-1
Interconnectors	3	7	5	10
Other costs	0	1	0	0
Total	-64	-72	-29	-29

The largest savings come from the generation capital cost reductions associated with needing to build less low carbon generation. From the late 2020s, increased flexibility reduces the curtailment of renewable generation, allowing carbon intensities to be met with less low carbon capacity. Figure 7 illustrates the level of curtailment in each of our scenarios. For example, in the high demand case, the low flexibility scenario results in around 40% of renewable generation being curtailed in 2050, this is reduced to around 20% in the central flexibility scenario and 10% in the high flexibility scenario.

There are also savings from lower transmission and distribution network costs. Demand side response shifts demand from peak periods to lower demand periods, reducing peak demand and improving the utilisation of the existing network. This allows network investment to be deferred or avoided, lowering the cost of network reinforcement. There are smaller cost reductions in generation and balancing costs.

Higher flexibility scenarios have two impacts on interconnector flows. First, higher interconnector capacity increases the potential for both imports and exports, and second, the reduction in renewable capacity reduces the amount of excess renewable generation there is to export over the interconnections. Overall, the higher flexibility scenarios lead to higher net imports. The additional cost of imported electricity is included in the interconnection cost category. In all scenarios, we see interconnectors becoming net exporters (a higher volume of exports than imports across a year).

Figure 7: Renewable generation and curtailment across all scenarios

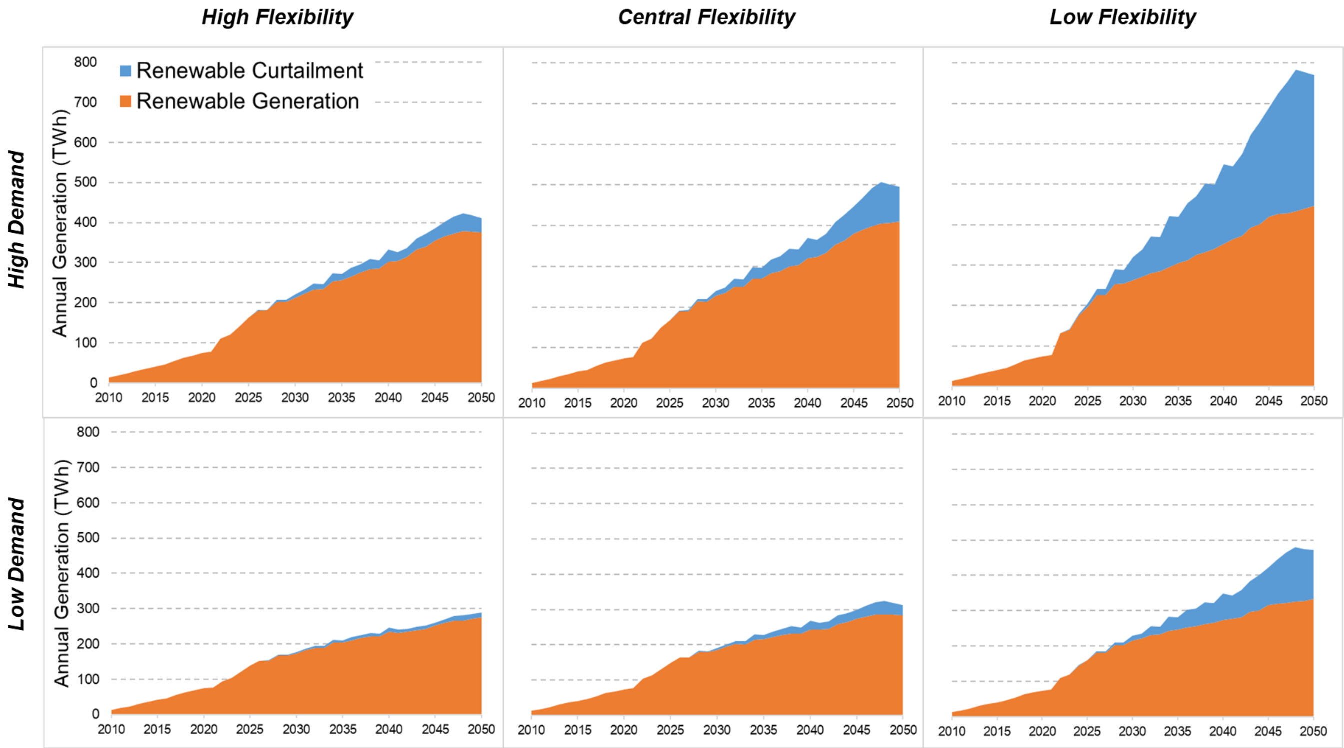


Figure 7 shows the annual utilised renewable generation (in orange) and curtailed renewable generation (in blue) in each of the flexibility scenarios. Renewable generation is made up of solar and wind generation. Results are shown for both low and high demand scenarios.

4.3 Deployment of flexible technologies

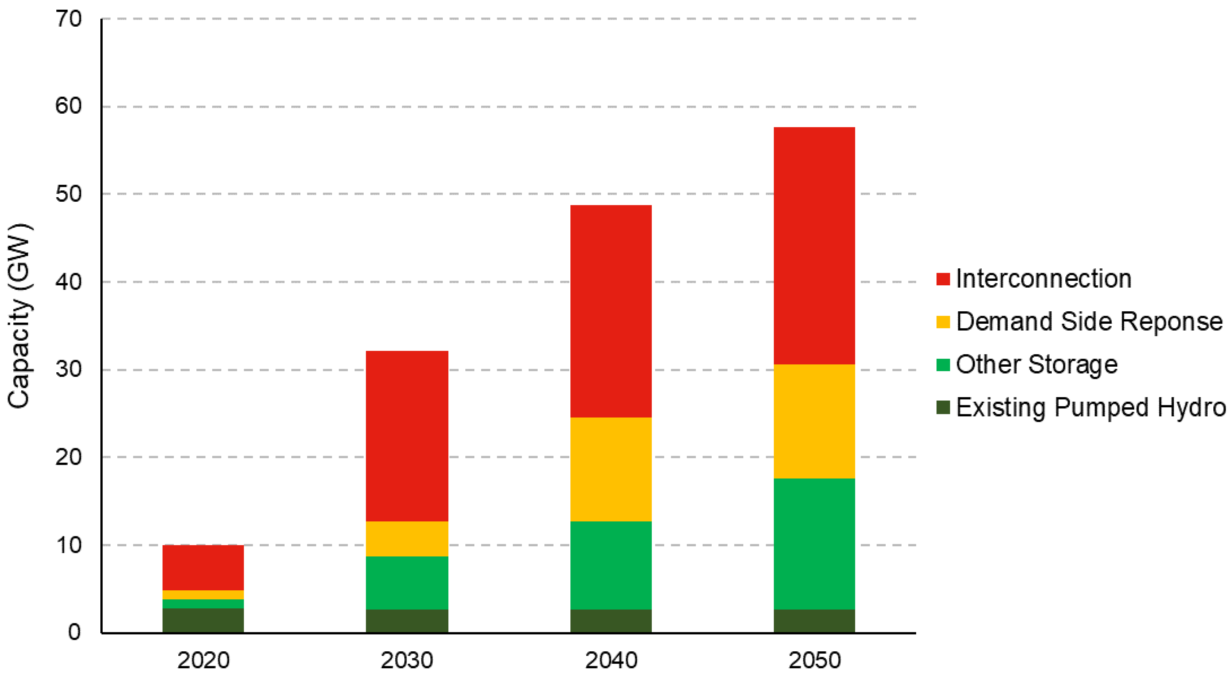
The illustrative pathways described above also demonstrate the potential scale of low carbon flexibility needed to cost-effectively integrate high levels of renewable generation as we transition to a decarbonised electricity system. The scenarios used in this analysis are just examples of many different possible pathways for the electricity system to contribute towards our net zero target. The actual need for flexibility will depend on how the electricity system develops, including the electricity demand profile and technology mix. This means that the optimal level of flexibility could differ from the levels demonstrated in this analysis. However, we expect the requirement for low carbon flexibility to be significant in all decarbonisation pathways, with substantial increases in deployment needed from current levels.

Our 2050 analysis showed that around 30GW of combined short-term storage and DSR and 27GW of interconnection lead to the lowest system cost in 2050 in the scenarios considered. In our high flexibility scenario we assume around 15GW of storage and 15GW of DSR, but alternative combinations would likely lead to similar outcomes. This level of storage and DSR is enough to largely flatten the daily demand profile in 2050, maximising the use of renewable generation across the day. Increased interconnection capacity reduces system cost by reducing the need for peaking generation (through increased imports) and lowering renewable curtailment (through increased exports).

Figure 8 shows the deployment of flexibility capacity from 2020 to 2050 in our high flexibility scenario. We use a set of assumptions to create a feasible trajectory that reaches the 2050 deployment discussed above. The interconnector trajectory is based on the pipeline of projects, it reaches the ambition of around 18GW of interconnection by 2030, then assumes a broadly straight line trajectory between 2030 and 2050. The level of DSR is calculated from the reduction in annual peak demand in our model (the difference between demand before any DSR is applied and after DSR is applied). As electric vehicles and heat pumps with heat storage provide the greatest opportunity for DSR, the level of DSR corresponds to the assumed rollout of these technologies. In addition to the existing pumped hydro storage, we assume a straight-line trajectory of ‘other’ short-term storage between 2020 and 2050, reaching around 5GW in 2030 and 10GW in 2040.

This illustrative pathway demonstrates that the need for flexibility will rapidly increase as variable renewable generation replaces fossil fuel sources, and heat and transport is electrified. Around 30GW of total flexible capacity in 2030, and 60GW in 2050, may be needed to cost-effectively integrate high levels of renewable generation. This is a substantial increase in deployment from the 10GW of flexibility on the system today. We expect the pipeline of interconnectors to contribute the most to increased flexible levels in 2030, but there will also need to be increased deployment of short-term storage and DSR. In 2040 and 2050 there is a substantial increase in all flexible technologies.

Figure 8: Illustrative deployment of flexible technologies, high flexibility scenario[25]



25 ‘Other storage’ includes existing battery projects and new deployments. All new storage assets are assumed to be 4-hour duration and could be a range of technologies including new battery and pumped hydro projects.

5. Next steps

Our analysis finds that increased flexibility, provided through short-term storage, DSR and interconnection, provides significant cost savings in a decarbonised electricity system. It is important for cost-effective integration of renewable generation, while meeting increased demand from electrified heat and transport.

We outline some of the limitations associated with our analysis in section 1, future work will develop this analysis to improve our evidence base:

- Analysis is based on two illustrative net zero pathways. As the pathway to net zero becomes clearer the analysis will be refined to understand the impact on electricity system flexibility. For example, this analysis was completed prior to announcements on the UK's sixth Carbon Budget, so does not consider the impact of those decisions. We would expect faster decarbonisation of the electricity system to bring forward the need for flexibility.
- We have not explicitly modelling longer-duration storage in this analysis. Further analysis is needed to understand the scale and characteristics of long duration storage that would be cost-effective in a decarbonised system.
- There are other sources of flexibility, such as vehicle-to-grid, that have not been included in this analysis. As new technologies become available and are commercially deployed, we will need to consider their impact on the system and the interaction with existing technologies.
- We calculated the impact of deploying hydrogen "off model", making the simplifying assumption that it would only displace natural gas generation, with no other impact on the generation mix. Further analysis will consider the interaction between hydrogen-fired generation and other sources of flexibility.

Annex I.1: Detailed flexibility assumptions

Flexibility Technology	Low	Central	High	Comment
Domestic/Non-domestic (% of half-hourly demand than can shift to a different half-hour)				
Domestic (Smart Appliances)	0	3	3	Demand can shift 4 hours
Non-domestic	0	10	10	Demand can shift 4 hours
Electric vehicles (EVs) (% of half-hourly demand than can shift to a different half-hour)				
EVs – Res. Off Street	0	70	90	Demand can shift 4–8 hours
EVs – Res. On Street	0	20	50	Demand can shift 4–8 hours
EVs – Destination	0	0	70	Demand can shift 4 hours
EVs – Depot	0	70	90	Demand can shift 1–2 hours
EVs – Rapid	0	0	0	No demand shifting
Heat (pre-heating and heat storage)				
Heat (Domestic and Non-domestic)	All buildings are assumed to have sufficient storage for hot water demand (equivalent to ~200L water cylinder in the average dwelling) and no flexibility for space heating demand.	90% of demand can be brought forward through 'pre-heating'	c20% of buildings are assumed to have additional storage (equivalent to 200L for the average dwelling) for shifting space heating demand. We assume no 'pre-heating' in this scenario	Pre-heating: Demand can shift 1 hours Heat Storage: Demand can shift 24 hours
Storage (GW)	5	10	15	All storage is assumed to have 4 hour duration. Capacity is additional to existing pumped hydro storage (c3GW)
Interconnection (GW)	9.8	17.9	27	

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