Imperial College London

NERA ECONOMIC CONSULTING

Understanding the Balancing Challenge

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Imperial College Project Team:

Goran Strbac
Marko Aunedi
Danny Pudjianto
Predrag Djapic

NERA Project Team:

Sean Gammons
Richard Druce

Imperial College London
Department of Electrical and Electronic Engineering
South Kensington Campus
London SW7 2AZ
United Kingdom
Tel: +44 20 7594 6169
Fax: +44 20 7594 6282
www3.imperial.ac.uk/electricalengineering

NERA Economic Consulting
15 Stratford Place
London W1C 1BE
United Kingdom
Tel: +44 20 7659 8500
Fax: +44 20 7659 8501
www.nera.com

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Disclaimer

The views expressed in this report are those of the authors and not those of the Department of Energy and Climate Change (nor do they reflect Government Policy).

The analysis and information provided in this report is based on detailed modelling and reasonable assumptions. However, as with all analysis of this type there is always a margin for error and individuals must rely on their own skill and judgement when interpreting or making use of this report.

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Executive Summary

Objectives, modelling approach and assumptions

The GB electricity system faces very considerable challenges, including the changing GB generation mix and new patterns of demand. By 2020, according to UK Renewable Energy Roadmap[1], more than 30% of UK electricity demand will be met by renewable generation. To meet the Government's decarbonisation objectives, the electricity sector will also need to become increasingly decarbonised in the period 2030-2050. Integration of increased volumes of the low capacity value intermittent generation and less flexible nuclear and CCS plant, accompanied with significant increases in peak demand driven by electrification of transport and heat, [2] may lead to very significant reductions in the utilisation of generation infrastructure and electricity network assets leading to considerable increases in system integration costs. We refer to this increase in system integration costs as the "balancing challenge", and the key purpose of this report is to investigate how alternative balancing technologies may help mitigate this challenge.[3]

In this context, the objectives of this study are to:

- Assess the scale of the system balancing challenge over the period 2020-2050;
- Analyse the merits of, and the interaction between, alternative balancing technologies (interconnection, flexible generation, storage and demand side response) in minimising the costs of balancing the system in short and long-term; and
- Based on the outcomes of modelling, identify the key barriers to achieving the efficient deployment of and investment in alternative balancing technologies.

We apply a cost minimisation model to the European power system, including a representation of the interconnected GB, Irish and continental European electricity systems. The GB system includes models of transmission and distributed networks. Our model simultaneously optimises investment and short-term operation decisions for the entire European system on an hourly basis, also taking account of long-term system adequacy and security requirements.[4] The model includes a detailed representation of electricity demand, and the capability/availability of demand response technologies, based on detailed bottom-up models of individual demand sectors.

DECC's Carbon Plan scenarios allow us to formulate four development Pathways leading to the required decarbonisation of the power sector:

- Pathway A (Higher renewables; high energy efficiency: high demand electrification);

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1 HM Government, "The UK Renewable Energy Roadmap", July 2011.

2 Committee on Climate Change, "Building a low-carbon economy – the UK's contribution to tackling climate change", December 2008.

3 The projections of the supply-demand mix in GB electricity market out to 2050 based on DECC's Carbon Plan scenarios (HM Government, "The Carbon Plan: Delivering our low carbon future", December 2010) define the total energy production and demand on an annual level. In this work we assess the system integration cost associated with enforcing the operational feasibility of the system, i.e. balancing of demand and supply in real time, and enforcing security of supply requirements driven by stressed conditions when cold spells coincide with low renewable output conditions. Specifically, we focus on assessing the benefits of alternative balancing technologies (interconnection, flexible generation, storage and demand side response) in terms of their ability to reduce these system integration costs.

4 The system value of balancing technologies quantified in this report refers to the entire European system and not only to GB.

- Pathway B (Higher nuclear; lower energy efficiency: high demand electrification);
- Pathway C (Higher CCS; medium energy efficiency; low demand electrification); and
- Pathway D (Core Markal – balanced generation including bioenergy and marine; high energy efficiency)

We base assumptions for 2020-2030 on a balanced EMR scenario[5], and we carried out sensitivity analysis based on Pathway A.

Assessing the scale of balancing challenge

For each of the Pathway assumptions on generation and demand, the model schedules generation and makes investment decisions to ensure the feasibility of real-time operation while maintaining the acceptable levels of security of supply. As a 'business as usual' starting point, we allow the model to invest in only network and generation assets. Our assumptions on generation availability are based on the historical reliability performance of conventional generation, and our representation of system stress conditions assumes several days of low wind output coinciding with cold weather conditions. From this starting point, we assume no contribution from alternative balancing technologies (such as DSR or storage) beyond the capacities assumed to exist in 2020.[6] We refer to these model runs as *counterfactual* scenarios for each Pathway, and these represent the baseline scenario that we use as a reference to calculate the value of balancing technologies (through quantifying the reduced operating and capital expenditure that these alternative balancing technologies create). We further impose constraints on energy neutrality and self-security for the GB system, and progressively tighter carbon emission constraints towards 2050 in line with the Government's emissions targets.

Our analysis of the counterfactual cases reveals that, if there were no alternative balancing technologies available to the GB electricity system, the scale of the balancing challenge increases very significantly beyond 2030, with substantial investment needed in additional generation, transmission and distribution assets to ensure secure electricity supply, particularly in Pathways A and B that are characterised by extensive electrification of heat and transport and/or deployment of inflexible or intermittent generation. In Pathways A and B over 100 GW of additional generation capacity is needed if DSR, storage, flexible generation, or interconnection are not used to support system balancing, due to a significant increase in demand and the need to back up renewable generation. Furthermore, we observe that the distribution network investment required to accommodate the load growth driven by electrification of transport and heat increases significantly in the counterfactual scenarios[7], from £35bn in Pathway C by 2040 to more than £90bn in Pathway B by 2050. At the same time the system has a limited ability to absorb the high output from intermittent renewable technologies; in Pathway A up to 100 TWh (or about 30%) of renewable electricity may be curtailed in 2050. These results provide a baseline for assessing the balancing challenge once the balancing technologies are used to support the electricity system.

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5 This scenario meets the illustrative 100g/kWh CO_2 target in 2030 using central fossil fuel prices.

6 Interconnection, storage and demand side response are included in the original 2050 Pathways but have been removed in order to create the reference *counterfactual* Pathways.

7 Our model estimates that peak demand of the GB system will be between 129 GW (Pathway D) and 189GW (Pathway B)

In the next stage we allow the model to use alternative balancing technologies with the objective of reducing the short and long-term cost of system balancing (Figure E1). These technologies include: (i) demand-side response (DSR), (ii) flexible generation technologies, (iii) network solutions such as reinforcements and investment in interconnection, transmission and/or distribution networks, and (iv) the application of energy storage technologies.

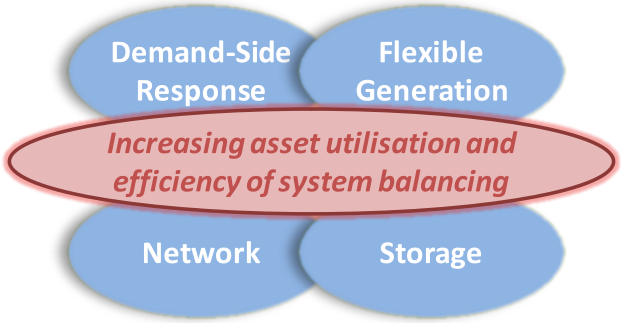

Figure E1. Balancing technologies

By comparing the performance of the system with various balancing technologies deployed, to the counterfactual scenarios, we quantify the benefits that alternative balancing technologies can bring in reducing system integration costs through enhancing both asset utilisation and the efficiency of real time demand-supply balancing.

We define a range of assumptions on the cost or availability of alternative balancing technologies based on information obtained from equipment manufacturers. However, our range of assumptions is not intended to be too extreme, and is defined such that each technology can play some role in balancing the system at the assumed cost. We do not consider the cost of DSR explicitly in the study given that the cost of the main enabling infrastructure (i.e. the smart meter rollout) will have already been incurred before 2020[8]; we therefore focus on the uncertainties surrounding its potential future uptake levels due to possible differences in the social acceptance of DSR schemes.

The scale of the balancing challenge in the balanced EMR scenario in 2020 and 2030 is relatively modest when compared to 2040 and 2050 Pathways (and 2030 Pathway A), due to the assumed increases in electrification and the penetration of intermittent renewables in these scenarios. Maximum system savings from balancing technologies in the balanced EMR scenario are £0.8bn/year in 2020 and £2.1bn/year in 2030; however, system benefits could reach £6.8bn/year if Pathway A is followed in 2030 rather than the balanced EMR scenario.

The maximum and minimum values of balancing technologies in 2050 (achieved when all balancing technologies are available at low costs or high cost, respectively) are greatest in Pathway A (£4.7bn-£14.9bn/year[9]), followed by Pathway B (£2.4bn-£7.0bn/year), D (£0.8bn-

8 Further infrastructure investment may be needed, i.e. the equipment to allow appliances to communicate with the smart meter, data and communications costs, IT system changes and costs associated with advertising and encouraging consumers to act. However, estimates of these costs are currently unknown and it was beyond the scope of this analysis to build this evidence base.

9 The savings may exceed £17bn/year, if the benefit of sharing security across interconnection is included.

£4.2bn/year) and C (£0.5bn-£3.8bn/year), as illustrated in Figure E2. The evolution of benefits created by using balancing technologies reflects the fact that the scale of the balancing challenge in the 2030-2050 horizon is considerable.

- Pathway A offers the most significant opportunities in terms of deploying balancing technologies, primarily because of very high levels of intermittent wind capacity;

- In Pathway B the scale of balancing challenge reduces (as it assumes less intermittent renewable output), even with higher demand and potential demand flexibility; and

- Pathways C and D offer less opportunities for balancing technologies, although there is still considerable room for their deployment when they are available at low costs. Pathway C has higher levels of CCS and the generation mix is therefore relatively flexible compared to alternative renewable generation, and features a lower level of demand electrification. Pathway D contains a much more balanced generation mix.

Maximum benefits in 2040 are lower than in 2050 for all Pathways, and except in Pathway C where the value drops between 2040 and 2050 due to its changing generation mix, minimum values are also lower in 2040 than 2050.

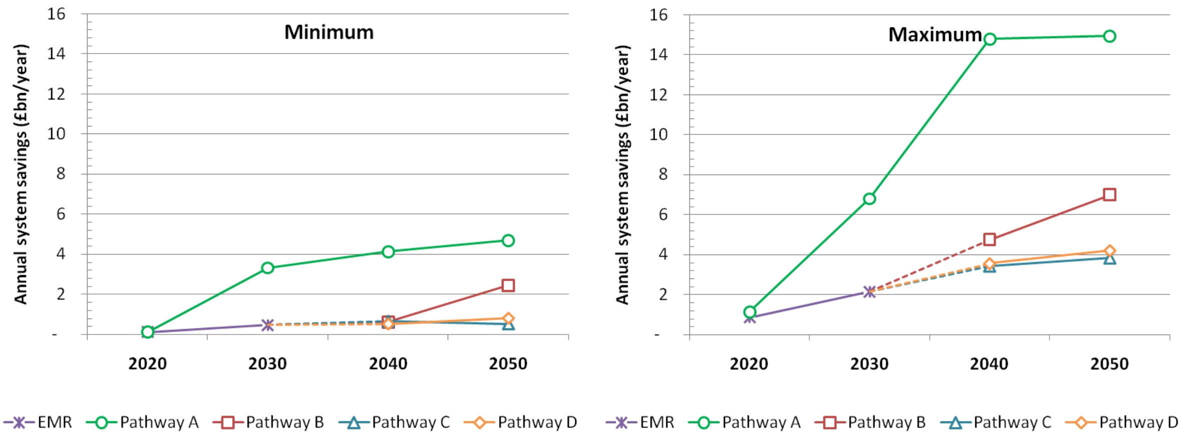

Figure E2. Minimum (left) and maximum (right) annual system savings from balancing technologies across Pathways and time

Given the lack of flexibility in the counterfactual scenario of Pathway A, the system is unable to accommodate the high penetration of renewable generation and we observe significant curtailment of renewables leading to the high value attributed to the balancing technologies in this Pathway. Given the need to comply with a carbon emission target of 50 g/kWh in 2050, if balancing technologies are not available, the model builds significant additional CCS capacity. Adding balancing technologies increases the ability of the system to absorb intermittent sources and hence costly CCS plant can be displaced from the generation portfolio, which leads to very significant savings in Pathway A (much larger than in other Pathways).

In Pathways A and B, which are characterised by considerable renewable curtailment in 2050, we observe that the majority of operating cost benefits from flexible technologies would materialise within GB. In Pathways C and D on the other hand, we notice a shift in OPEX savings from GB towards Europe. This follows from a far lower penetration of intermittent renewables in these two Pathways, while we assume that the renewable capacity in Europe is still substantial. In those cases the most efficient use of GB balancing technologies is to support efficient operation of the European system by reducing its OPEX through avoiding renewable curtailment.

Using alternative balancing technologies to address the balancing challenge

Across the Pathways analysed in this study, we observe substantial volumes of balancing technologies being deployed as part of the optimal solution, particularly in cases where we assume a given option is available at low cost.

Benefits of interconnection. Decisions regarding the deployment of interconnectors are highly sensitive to conditions prevailing in GB and the neighbouring markets. Our sensitivity studies indicate that the volume of interconnection may vary considerably; for example, assuming high uptake of DSR, or other flexibility in Europe, reduces interconnection levels between Great Britain (GB) and Continental Europe (CE). On the other hand, allowing interconnections to provide security of supply to GB increases the modelled amount of interconnection capacity significantly.

Applying our central assumption set (including self-security and energy neutrality), we observe that in all Pathways the quantity of interconnection that the model suggests is efficient does not vary materially across Pathways due to changes in the assumed cost of competing alternative flexible technologies. In general, a substantial level of interconnection is built to connect the GB system with Irish and continental European systems across all scenarios, when the interconnection is available at low cost (at least 20 GW is added in 2040 and at least 25 GW in 2050 across all four Pathways, of which around 10 GW is allocated to the GB-IE link, and the rest to the GB-CE link).

A key driver of interconnection investment between GB and Ireland, and between GB and Continental Europe, is the extensive development of wind generation we assume takes place in the Ireland. The model suggests that it is marginally more efficient for GB to become a transport hub for Irish wind output,[10] as total European system-wide costs increase if the Irish system is directly connected to the main European market. The system savings generated by deploying new interconnection capacity are dominated by savings in operating cost, which the interconnectors are able to reduce because of the improved capability of the system to absorb intermittent renewable output, reducing renewable curtailment (in our central assumption set, the interconnection is unable to produce any generation CAPEX savings due to the self-security assumption).

Benefits of flexible generation. We allow the model to choose the volume of more flexible generation to be deployed, for a given cost of enhanced flexibility, in order to minimise the overall system costs.[11] Over the range of cost assumptions we have examined, the model consistently suggests that some flexible generation is required to minimise system costs (about 5-10 GW in 2050 Pathways). This implies that a modest amount of these technologies is efficient across all Pathways, even at high costs.

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[10] The model estimates onshore network reinforcement within the GB transmission grid that would be needed to facilitate exporting Irish wind output to Continental Europe via GB.

[11] When considering additional generation flexibility, we modify the two key dynamic characteristics of thermal generation technologies: (i) reduced minimum stable generation, and (ii) improved ability to provide frequency regulation services.

The key benefit provided by flexible generation is a reduction in OPEX, and this occurs through two mechanisms: (i) additional generation flexibility improves the system's ability to absorb intermittent renewables; and (ii) flexible generators are more efficient i.e. incur less efficiency losses when providing reserve and response services to the system. However, in Pathway B, characterised by very high nuclear capacity, the saving in renewable curtailment enabled by flexible generation reduces electricity production from low marginal cost nuclear plant and hence produces lower total benefits.

Additional generation flexibility is not able to reduce generation capacity requirements on its own, as within the model this requirement is driven by security requirements ("backup" capacity). The impact on generation CAPEX savings is in fact negative due to additional investment into generation flexibility. When flexible generators are available at low cost (10% of baseline CAPEX), the optimal capacity chosen by the model is high – between 25 and 97 GW in 2050, suggesting it is a very efficient option, if available at low cost. We also observe that although some flexible generation capacity is efficient even at high cost, this amount tends to decrease as we approach 2050, largely because of the stronger competition from storage and DSR. As discussed below, these two options become increasingly attractive as they can assist in system balancing as well as offset distribution reinforcement costs,[12] which our model suggests increases rapidly towards 2050 as a result of increasing demand.

Benefits of storage. Our modelling suggests that storage technologies have a potentially important role to play in facilitating the transition to a low carbon power system. We allowed the model to build both bulk storage and distributed storage.[13]

Distributed storage is generally seen by the model to be more effective than bulk storage and is selected by the model in larger volumes, due to the additional ability of distributed storage to offset the need for distribution network reinforcement. At the same time, distributed storage can still contribute to the cost savings that bulk storage can deliver, i.e. OPEX savings through reducing wind curtailment and delivery of reserve and frequency regulation services, and generation CAPEX savings through providing security to the system, while trading off between them in an efficient manner on an hourly basis.[14] However, this conclusion is sensitive to the assumptions on costs of (and alternatives to) distributed storage as opposed to bulk storage. Additional sensitivities studied suggest it may be efficient to deploy a significant amount of bulk storage capacity if it is the only available alternative balancing option.

We find in some Pathways (such as Pathway A and Pathway B in 2050) that distributed storage gets built in considerable volumes (around 10 GW) even when it is available only at high cost. On the other hand, storage is far less competitive in Pathways C and D, given that these are characterised by lower demand growth (hence less opportunity to capture distribution CAPEX savings), lower renewables penetration (hence less opportunity to produce OPEX savings) and more flexibility in the baseline generation mix. Also, when storage is available at low cost, relatively high volumes of up to 30 GW are deployed in

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12 This benefit is not attainable by other balancing technologies analysed in this study.

13 In the model, the cost of distributed storage is between 20% and 33% higher than for bulk storage.

14 A comprehensive analysis of opportunities for energy storage applications in the future UK system is presented in the Carbon Trust report "Strategic Assessment of the Role and Value of Energy Storage Systems in the UK Low Carbon Energy Future", July 2012. Available at: http://www.carbontrust.com/resources/reports/technology/energy-storage-systems-strategic-assessment-role-and-value

Pathways A and B, as these feature a rapid increase in intermittent renewables (A) and/or an intensive growth of electricity demand (B).

Benefits of Demand-Side Response. In contrast to the other alternative balancing options, our model does not optimise the deployment of DSR based on assumptions regarding its cost. The high/low cases are defined by assumptions on availability and uptake of DSR. We considered penetration of DSR at 80% (high) and 10% (low), reflecting high and low acceptance levels of this technology. We therefore only examine the contribution that moving from low to high penetration of DSR can make to meeting the balancing challenge, i.e. minimising the costs of balancing the system.

In our models DSR provides both energy and ancillary services and using DSR does not involve any compromises on the services delivered by appliances (e.g. internal temperatures achieved by heat pumps or the ability of consumers to use their electric vehicles). There is considerable competition between distributed storage and DSR, as both provide similar services to the system; in particular, they are both able to mitigate the distribution network reinforcement required to accommodate increased electrification. Given that the deployment cost of DSR has not been considered, its performance in terms of reducing operating cost and primarily generation and distribution investment is highly beneficial to the system, as it can also help to avoid renewable curtailment or reduce generation and distribution capacity requirements. Application of smart voltage control in LV networks, and strategic asset replacement are alternatives to DSR and these would reduce the value of DSR (as well as of distributed storage).

Figure E3 provides a summary of the average system benefits provided by individual balancing technologies in cases when they are the only low-cost options, and all other options have high costs.

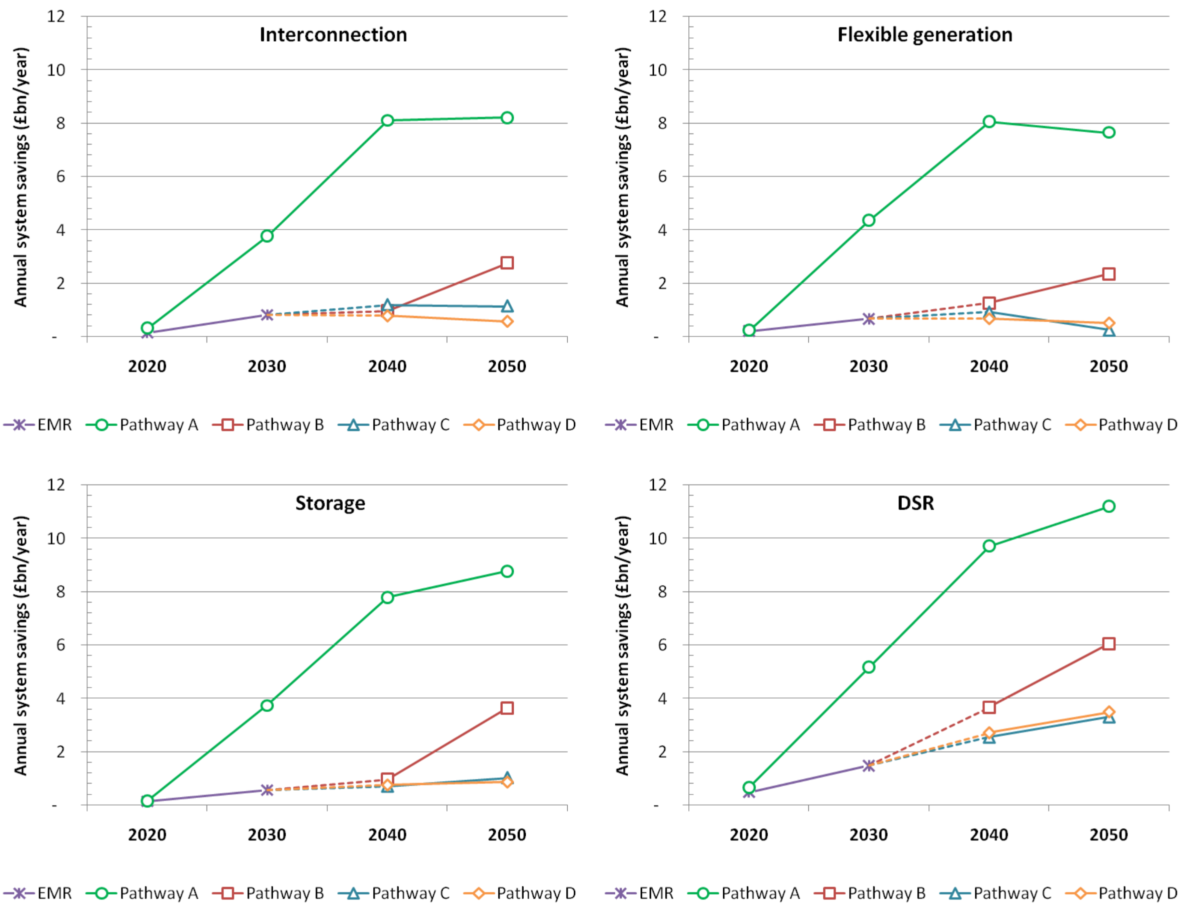

Figure E3. Average system savings from different balancing technologies when they are available at low cost while others have high costs (or low availability)

As set out above, the largest benefits are achieved in Pathway A and then in Pathway B. We also observe that all of the balancing technologies can contribute significantly to reducing the balancing challenge in low carbon systems, particularly in the more 'extreme' Pathways (A and B).

Practical implications for balancing technologies and further work

The scale of the balancing challenge beyond 2030, and before 2030 in Pathway A, is very considerable, and our modelling shows that the deployment of alternative balancing technologies may significantly reduce system integration costs. It is therefore important that appropriate market and regulatory frameworks are in place to facilitate a cost-effective evolution to a low carbon future.[15]

In this context, and in addition to the analytical modelling work, we have identified important economic themes that we see emerging from the modelling results in terms of the role of alternative balancing technologies, and have assessed some of the regulatory and market challenges that need to be overcome to ensure savings from deployment of these technologies

[15] The life span of electricity assets typically exceeds 30-40 years and it is hence important that investment decisions made at present are compatible with the requirements in 2030 and beyond.

are realised. DECC requested that we do not make policy recommendations, nor undertake a comprehensive assessment of the impact of all government policies on the balancing challenge, as this would require a longer, more in-depth, analysis.

Our work also highlights areas where the modelling may over or understate the potential for the deployment of alternative balancing technologies, which arise either because the model does not account for certain costs of deployment (e.g. the costs of participating in DSR schemes), or because the assumptions and/or methodology we applied limit their role in system balancing (e.g. the self-security and energy-sufficiency assumptions).

Finally, we identified a number of areas for potential further work to improve the robustness of our modelling results, including: valuing potential investments in alternative balancing technologies using a "real options" framework, market-based modelling allowing for competitive behaviour between companies and European countries, expanding our modelling through a more detailed representation of neighbouring European markets, and analysing the investment profile of distribution networks and how it is influenced by heat pumps, electric vehicles, DSR and embedded generation.

1. Background

1.1. Context

The GB electricity system faces very considerable challenges. By 2020, according to the GB Renewable Energy Roadmap[16], it is expected that more than 30% of GB electricity demand will be met by renewable generation. In order to achieve climate change mitigation objectives, the electricity sector should considerably reduce the carbon emission by 2030 with significantly increased levels of electricity production and demand driven by the incorporation of heat and transport sectors into the electricity system.[17]

The expected changes in both the supply and demand sides of the low-carbon system will lead to increases in overall system costs associated with both integrating the renewable sources on the supply side and integrating new transport and heating loads into the distribution network:

(i) Supply side driven system integration cost

The generation mix in low-carbon electricity systems is likely to include significant amounts of intermittent renewable generation (e.g. wind and solar), which is variable and difficult to predict and has a low capacity value, in combination with less flexible nuclear and CCS plant, leading to increased system integration costs associated with backup generation requirements and system balancing. The fundamental effects responsible for the additional system costs that are associated with low-carbon generation are:

a) *Degradation in utilisation of infrastructure (generation and electricity network assets).* Intermittent renewable generation can displace energy produced by conventional plant, but the ability of intermittent sources to displace the capacity of conventional plant will be limited, leading to increased generation capacity margins and reduced utilisation of conventional capacity (in other words, the capacity value of intermittent generation is significantly lower when compared with conventional generation).

b) *Reduced efficiency of system balancing.* The operating reserve requirements and need for flexibility at high penetration of intermittent renewable generation increase significantly above those in the conventional systems. The need for additional reserves and lack of flexibility may also decrease the ability of the system to absorb intermittent generation.

c) *Need for network reinforcement*. A very significant proportion of the new onshore and offshore wind generation will be located away from the demand centres and will hence require a very significant reinforcement or extension of the existing GB transmission network.

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16 HM Government, "The UK Renewable Energy Roadmap", July 2011.

17 Committee on Climate Change, "Building a low-carbon economy – the UK's contribution to tackling climate change", December 2008.

(ii) Demand side driven system integration cost

One of the major opportunities for decarbonising the GB heat and transport sectors is to shift some of this demand into the electricity system. The key concern is that this integration will lead to increases in peaks that are disproportionately higher than corresponding increases in annual electricity demand (even if radical energy efficiency measures are undertaken). This will potentially require significant reinforcement of the 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 a range of balancing technologies. These options are: (i) demand-side response (DSR), (ii) flexible generation technologies, (iii) network solutions such as reinforcements and investment in interconnection, transmission and/or distribution networks[18], and (iv) the application of energy storage technologies (Figure 1.1). The investigation of complementarity between different options as well as their competition is a central element of this work.

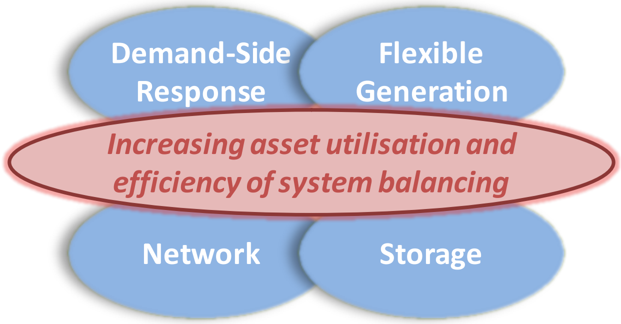

Figure 1.1. Balancing technologies

The most important references to previous work in the area of balancing the future low-carbon electricity system in GB include the modelling by Redpoint for the EMR,[19] and the work commissioned by the Committee on Climate Change.[20,21] All of these activities however only focus on the period up to 2030. On the other hand, DECC's 2050 Pathways[22] take a longer-term view of the evolution of the electricity system, but focus primarily on

18 We also estimate the benefits of the application of advanced distribution network technologies based on analysis carried out in the ENA study "Benefits of Advanced Smart Metering for Demand Response based Control of Distribution Networks", April 2010, and the ETI study assessing the impact of electric vehicles on UK distribution networks (April 2011).

19 Redpoint Energy, Trilemma UK, "Electricity Market Reform – Analysis of policy options", December 2010.

20 Redpoint Energy, "Decarbonising the GB power sector: evaluating investment Pathways, generation patterns and emissions through to 2030", A Report to the Committee on Climate Change, September 2009.

21 Pöyry Energy Consulting, "Impact of Intermittency", July 2009.

22 http://www.decc.gov.uk/en/content/cms/tackling/2050/2050.aspx.

annual energy balances, i.e. provide no explicit account of optimal balancing of the system. Here, we build on the work by looking at the long-term (2020-2050) and analysing balancing of the system in more detail.[23]

1.2. Objectives of this Study

The first objective is to assess the scale of the balancing challenge. To do this, we will use a relevant metric of the savings in electricity system costs that can be achieved through the adoption of a variety of alternative balancing technologies over the period to 2050. This is achieved by comparing the overall system cost across all sectors when we allow the model to deploy alternative balancing technologies efficiently, with a counterfactual scenario in which the model can only use conventional approaches to balancing the system, i.e. transmission, distribution and conventional generation investments.

The second key objective is to analyse the relative merits of the alternative balancing technologies in minimising the costs of balancing the system. We therefore model the optimal deployment of the alternative balancing technologies based on a range of plausible assumptions regarding their cost and availability. We also analyse the extent to which the availability of particular flexibility options is pivotal to achieving significant reductions in the costs of balancing the system.

Thirdly, to the extent that we can, and based on the outcomes of our quantitative modelling of the GB power system, we identify the key barriers to achieving the efficient deployment of and investment in alternative balancing technologies in reality, and identify possible areas that might require further consideration to incentivise optimal deployment of balancing technologies.

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23 In this report, “balancing” encompasses all actions needed to balance the system, ranging from second-to-second (ancillary services) to hour-to-hour and seasonal (back-up generation, etc) and securing the network.

2. Analysing the Balancing Challenge

2.1. Our Modelling Approach

We use a cost minimisation model for the entire European system, including a representation of the electricity systems of GB, Ireland and continental Europe. The model optimises investment decisions in GB at all levels of the power system (generation, transmission and distribution), generation investment decisions in the rest of the European system as well as the short-term operation of the entire European system on an hourly basis, including plant dispatch and scheduling of reserve and frequency regulation services to ensure sub-hour (seconds to minutes) balancing of the system. The model takes account of system adequacy and security requirements. Given that we optimise the entire European system (which also includes the GB system), all benefits presented and discussed in subsequent chapters refer to European-wide benefits; a varying proportion of these benefits can be attributed to GB, depending on the Pathway and year analysed.

A detailed representation of demand and the capability of demand response technologies, based on our bottom-up analysis and development of the demand profiles associated with residential and commercial sectors, are included in the model.

Considering snapshot years (2020, 2030, 2040 and 2050) the model optimises the volume and location of investment in the four alternative balancing technologies, based on assumptions regarding their costs and availabilities. It also makes optimal trade-offs between them, taking account of their assumed construction and operating costs and specific technical capabilities.

2.2. Pathways for Electricity Generation and Demand

2.2.1. Defining generation and demand backgrounds

We have based our projections of the supply-demand mix in the GB electricity market out to 2050 on DECC's Carbon Plan scenarios. These Pathways illustrate alternative generation mixes, and alternative demand-side developments, that lead to decarbonisation of the power sector. By basing our fundamental assumptions on these Pathways, we do not attempt to define the optimal development of the generation mix or the demand-side (e.g. the choice between nuclear, renewables and CCS to decarbonise the power system). Our objective is to analyse the role and value of the alternative balancing technologies assuming a range of rather different energy mixes, and taking these features of the future electricity system as given.

The four Pathways from the Carbon Plan that we analyse in this study are as follows:

- Pathway A (Higher renewables; high energy efficiency, high demand electrification)
- Pathway B (Higher nuclear; lower energy efficiency, high demand electrification)
- Pathway C (Higher CCS; medium energy efficiency; low demand electrification)

- Pathway D (Core Markal – balanced generation including marine and bioenergy; high energy efficiency[24])

These four Pathways are distinctly different in 2050 although we have assumed that they all start from a single 2020-2030 trajectory, which is based on the supply and demand profiles consistent with a balanced scenario from 2010 modelling for EMR[25], and the four Pathways then branch into alternative 2040 and 2050 trajectories. We have also analysed the case where period 2020-2030 is consistent with Pathway A rather than the balanced EMR scenario.

The key supply and demand-side characteristics of the four Pathways used in this study are shown in Table 2.1 below. For each Pathway, we depict the evolution of generation capacity between 2040 and 2050 on the left hand side, and the components of annual electricity demand for the same period on the right hand side. As the table describes in more detail, the Pathways have very different supply and demand-side assumptions, and changes in both affect the case for deployment of the alternative balancing technologies.

We use generation capacity and demand assumptions for the rest of Europe from recent Europe grid integration studies.[26] In line with the European CO_2 reduction targets, a significant contribution of renewable energy is assumed in Europe towards 2050.

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24 A central run produced using the MARKAL cost-optimising model. This run was recreated in the 2050 calculator: http://www.decc.gov.uk/en/content/cms/tackling/2050/2050.aspx (as of February 2012).

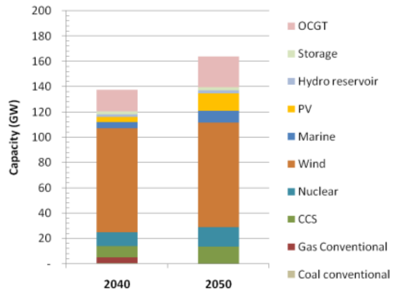
25 This scenario meets the illustrative 100 g/kWh CO_2 target in 2030 using central fossil fuel prices.

26 Modelling approach and future European generation and demand development scenarios, adopted in this study, have been used in a number of recent European projects to quantify the system European cross-border network infrastructure requirements and operation cost of integrating large amounts of renewable electricity in Europe. These 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 supported 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.

Table 2.1. Generation capacity and annual electricity demand across Pathways and time

<table>
<tr><th></th><th>Supply-side characteristics</th><th>Demand-side characteristics</th></tr>
<tr><td>Pathway A</td><td>

- Large penetration of RES (wind, solar, marine) – 108 GW in 2050
- Modest amounts of nuclear (16 GW) and CCS (13 GW) capacity
- Some backup generation capacity (24 GW) available to mitigate intermittency



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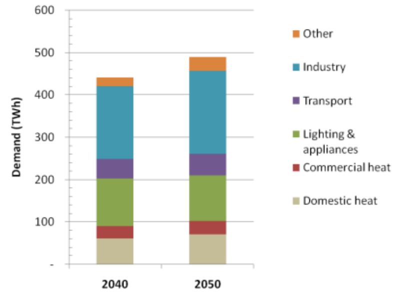
- Full electrification of heating (100%)
- Very high level of transport electrification (80%)
- Most ambitious energy efficiency targets (highest insulation levels and behavioural changes)



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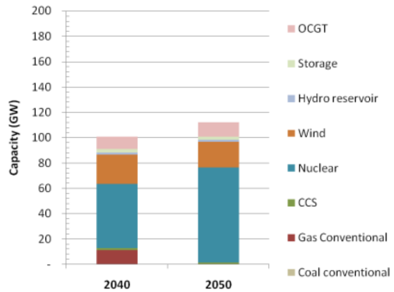
<tr><td>Pathway B</td><td>

- Large penetration of nuclear power (75 GW in 2050)
- Limited amount of RES (20 GW of wind) and CCS (2 GW)
- 11 GW of backup generation capacity



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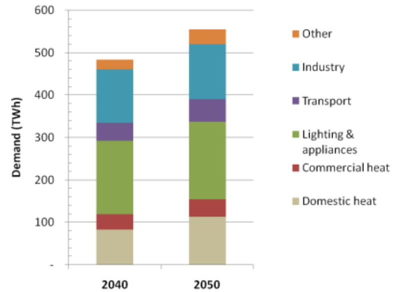
- High electrification of heating (88%)
- High level of transport electrification (60%)
- Modest energy efficiency – higher heating demand



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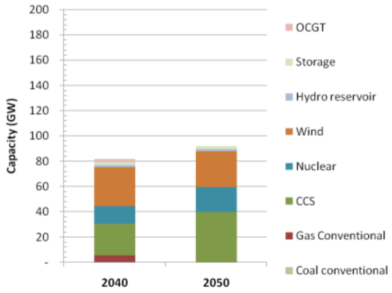
<table>
<tr><th></th><th>Supply-side characteristics</th><th>Demand-side characteristics</th></tr>
<tr><td>Pathway C</td><td>

Significant CCS capacity (40 GW in 2050)
Limited amount of nuclear (20 GW) and RES (28 GW of wind)
No additional backup capacity envisaged in 2050



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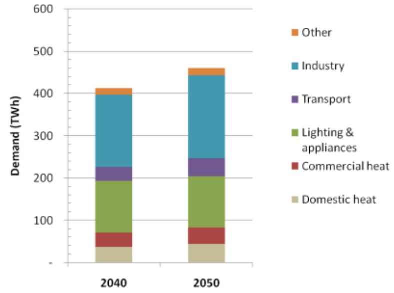
Moderately high electrification of heating (48% and 90% for residential and commercial, respectively)
High level of transport electrification (64%)
Moderately ambitious energy efficiency



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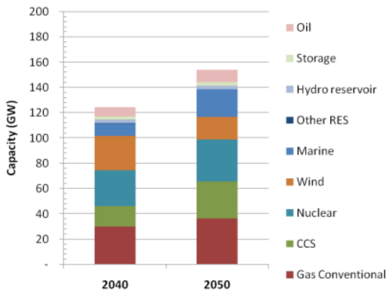
<tr><td>Pathway D</td><td>

Balanced capacity mix: 43 GW of RES in 2050 (out of which 22 GW is marine and only 18 GW wind); 33 GW of nuclear; 29 GW of CCS
Significant unabated gas (37 GW) and oil generation capacity (10 GW) still present in the system in 2050



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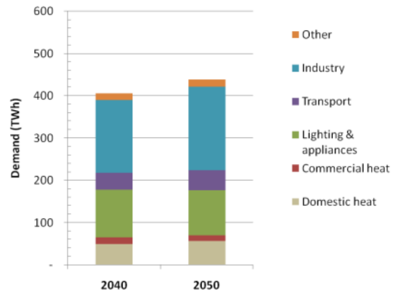
Moderately high electrification of heating (88% and 48% for residential and commercial, resp.)
High level of transport electrification (60%)
Moderately ambitious energy efficiency



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2.2.2. Ensuring a secure system

2.2.2.1. Hourly demand profiles

As noted above, the original Pathways presented in the Carbon Plan focus on annual energy balances, i.e. ensuring that sufficient energy is generated over the year to meet annual energy demand (with some implicit assumptions associated with uptake of demand side response). To investigate the value of flexible technologies to support balancing, we developed hourly demand profiles as inputs into the model using our bottom-up modelling of various demand categories (in particular for electrified heat and transport sectors).[27]

Our hourly demand profiles for charging of electric vehicles rely on a comprehensive database of light-vehicle driving patterns for the UK. We have categorised journeys into groups and identified the number of vehicles involved in a particular driving pattern. This allowed us to determine the corresponding distances travelled, start time and end time of each journey, as well as the energy needed for each journey. Start and end times of a particular journey provide information as to when the vehicle is on-road, while at other times the vehicle is stationary and potentially available for charging. Optimisation of charging hence does not impact on the ability of vehicles to carry out intended journeys.

Our hourly profiles of demand for electricity for heating are based on typical temperature variations within an average year,[28] including a cold period of several days that characterises a typical cold spell in a 1-in-10 winters. Our bottom-up models for electrified heating based on heat pumps (with appropriate proportions of air and ground source heat pumps as specified in Pathways) take into consideration the changes in performance of a given type of heat pump driven by the fluctuations in outdoor temperature.[29] Optimisation of the operation of the heat pumps and heating, ventilation and air conditioning (HVAC) systems does not involve any compromise on the comfort levels, and relies on the assumed existence of dedicated heat storage in individual buildings.[30] We further assume that the cold spell coincides with significantly reduced wind output. We take this approach to stress-test the resilience of the system to cold and low wind conditions that may occur during the winter in the UK.

2.2.2.2. Secure generation capacity mix

Taking as given the assumptions in the Pathways on the mix of installed generation capacity, and the composition of the demand side supported by our bottom-up profiles calibrated to match annual energy demand specified in the Pathways, the model first enforces the

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[27] The Carbon Plan specifies annual electricity consumption in TWh for each type of load (electric heating, electric vehicles, industrial, commercial, etc). We transform the annual electricity consumption quantities into hourly demand profiles, which we then use as inputs into our modelling.

[28] An average, "normal" year, with respect to space heating requirements, is the one in which minimum and maximum annual temperatures are in line with long-term historic averages.

[29] The Coefficient of Performance (COP) for air-source heat pumps can typically vary between 3 during mild weather to about 1.5 during very cold spells (when heating requirements are normally the highest).

[30] Our assumption on heat storage installed in households/businesses is based on a fixed hot water tank size that is considered acceptable for installing into buildings. This average size tank has been estimated at around 150 litres. Given that the assumptions on building insulation levels and consumer behaviour differ considerably between different Pathways, the same tank generally provides a higher duration (more than 3 hours) in Pathways with improved insulation and lower internal temperature settings (e.g. Pathway A), while in Pathways with poorer insulation and only minor changes in consumer behaviour such as Pathway B this might account for less than 2-hour duration.

feasibility of the real time operation of each of the Pathways while maintaining the acceptable levels of security of supply. The model achieves this through investing in network and generation assets within a ‘business as usual’ context. In this analysis we assume no contribution from alternative balancing technologies (such as DSR or storage) beyond the capacities assumed to exist in 2020. We refer to these cases as *counterfactual* scenarios for each Pathway, and these hence represent the baseline scenario that we use as a reference to calculate the value of balancing technologies (through quantifying the reduced operating and capital expenditure that these alternative balancing technologies create).[31]

2.2.2.3. Additional system-level constraints

When calculating the additional investment in generation technologies and network reinforcements, we require that the model adhere to additional constraints, which are discussed below.

- *Energy balance and security constraints.* Although we model the GB alongside neighbouring markets, we impose the constraint that GB is *energy-neutral*, i.e. that its annual electricity imports are equal to exports. Assuming energy neutrality is essential for maintaining the consistency with the Carbon Plan Pathways. We further assume that GB is *self-secure*, i.e. GB generation capacity needs to be sufficient to meet peak demand, with sufficient reserve margin within GB; this assumption implies that no contribution from interconnectors to system security can be expected.[32] In maintaining security, we have assumed the level of system reliability indices is consistent with historical levels of security of supply.[33] We have however also carried out sensitivity studies to understand the impact of relaxing the self-security constraints on the cost of making the system secure and the value of alternative balancing technologies in supporting the system.

- *Carbon cost and emission constraints.* Our model meets the security requirement at minimum costs while meeting CO_2 emissions constraints from the power sector of 100 g/kWh in 2030, 75 g/kWh in 2040 and 50 g/kWh in 2050. We also impose a minimum price on CO_2 emissions of £27/tonne in 2020, and £70/tonne in 2030 and beyond.[34]

Table 2.2 presents the generation capacity (left) necessary to maintain historic levels of security of supply (under the assumptions discussed above). The table also presents daily demand profiles (right) associated with maximum and minimum demand in 2050, obtained based on our bottom-up demand modelling discussed in Section 2.2.2.1. When compared with Table 2.1, we observe a considerable increase in generation capacity across the Pathways, with the most significant additions occurring in Pathways A and B (100 GW and 125 GW in 2050 respectively). This is due to the combination of generation and demand

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31 Interconnection, storage and demand-side response are included in the original 2050 Pathways but have been removed in order to create the reference *counterfactual* Pathways.

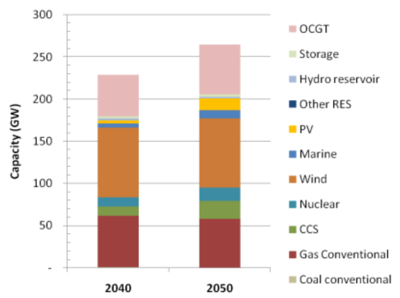
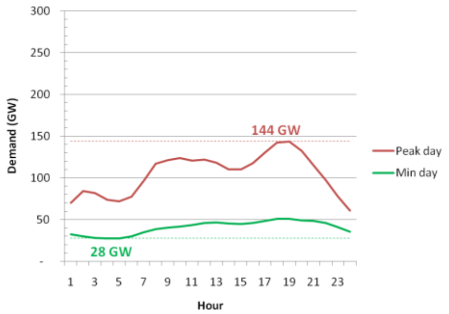
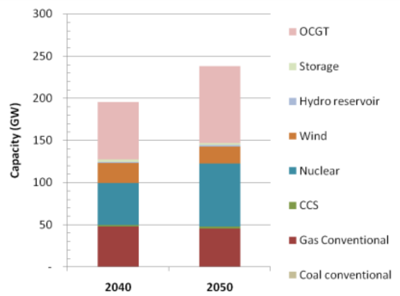
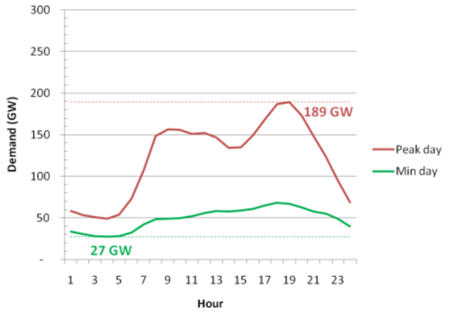
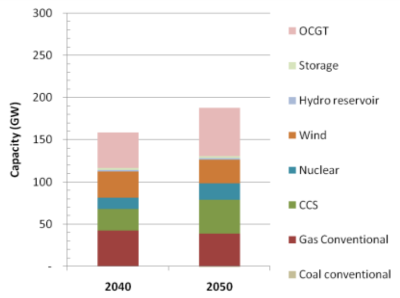
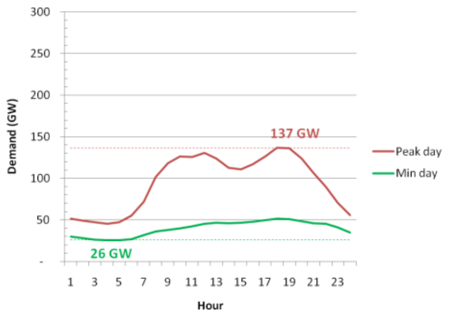
32 We also impose a self-security constraint for the European electricity system.

33 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.

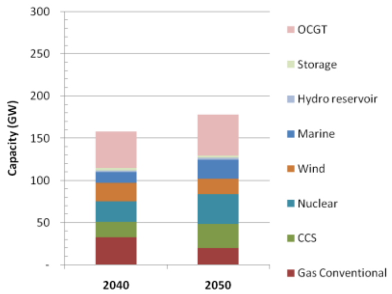
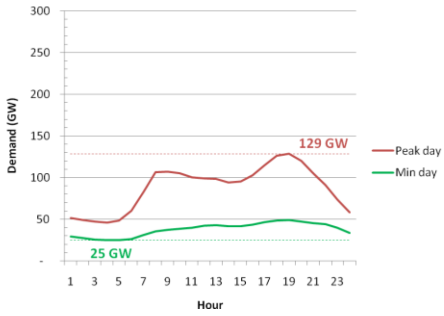
34 Source: DECC’s latest provisional Traded Carbon Price Projections for use in HMG appraisal, published alongside the updated Energy Model Projections and Fossil Fuel Price Assumptions in Autumn 2011. We have used the values for energy modelling with Carbon Price Floor. £70 per tonne of CO_2 is the 2030 carbon price in real 2009 prices (the same value in real 2011 prices is £74.2/tonne).

backgrounds, where a large quantity of generation with low capacity value[35] is not able to meet the considerable hourly demand fluctuations under the assumption of a high level of heat and transport electrification, and in particular is not able to meet the peak demand in a colder than average winter at an acceptable level of security of supply. On the other hand, the minimum demand profile illustrates the likely need for curtailing intermittent renewable generation in a given Pathway (especially the ones featuring large renewable capacity such as Pathway A).

Table 2.2. Counterfactual scenarios (excluding balancing technologies): secure generation capacity and maximum and minimum demand profiles

	Secure generation capacity	**Maximum and minimum demand profiles (2050)**
Pathway A		
Pathway B		
Pathway C		

35 Although wind generation is expected to displace energy produced by fossil fuel plant, its ability to displace capacity of conventional generation will be very limited. For instance, if the capacity value of a wind generation is 10% this means that upon installing 30 GW of wind capacity it may be possible to retire 3 GW of conventional capacity without compromising the reliability performance of the system.

	Secure generation capacity	Maximum and minimum demand profiles (2050)
Pathway D		

2.3. Counterfactual Scenarios

The starting point for our analysis is to analyse the counterfactual scenario for each of the four Pathways in which we allow the model to invest in additional power generation capacity (OCGT, CCGT and CCGT+CCS) (see Table 2.2) and transmission and distribution reinforcements as appropriate to maintain security of supply and carbon constraints. The cost of developing a secure power system using these conventional balancing technologies provides a benchmark, which enables us to evaluate the benefits of deploying alternative balancing technologies. In other words, the difference in the total system cost between the counterfactual scenario and the scenarios where we allow the model to deploy alternative balancing technologies defines the scale of the balancing challenge.

The figures below show the results of the four counterfactual scenarios, and illustrate the scale of the balancing challenge:

- To secure the system using conventional approaches (i.e. without any contribution from new storage, interconnection or DSR), significant investment in additional generation capacity is required. Figure 2.1 shows that the additional generation capacity in some Pathways exceeds 100 GW in 2050, and is above 70 GW in both 2040 and 2050 for all Pathways except for Pathway D.[36]

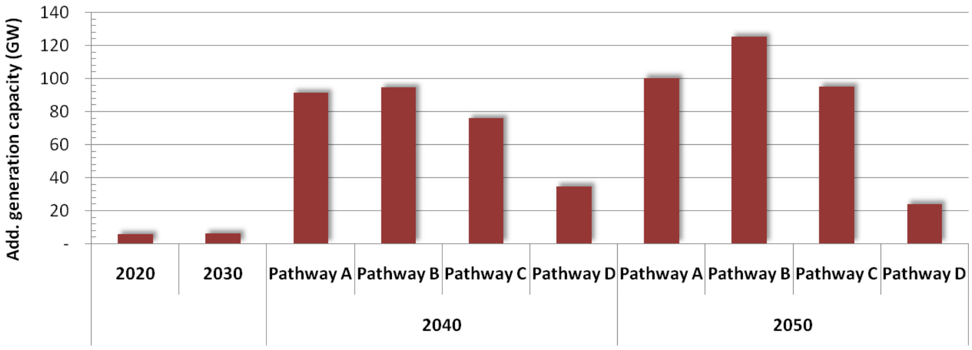


Figure 2.1. Additional generation capacity across Pathways and time

[36] The model optimises the location of the additional generation plant needed to maintain security of supply among the 5 regions; however, as it is assumed that this generation will be connected to the transmission system, this generation cannot offset the need for distribution network reinforcements driven by increased demand.

- Additional investment is also required in transmission and distribution networks (Figure 2.2). Electrification of heat and transport sectors will require significant distribution network reinforcements, particularly visible in Pathways A and B, where the annualised distribution network investment needed by 2050 reaches £4bn and £6bn per annum, respectively.[37] In this context, the cost of transmission reinforcements, driven by both changes in generation mix and demand, is relatively modest.

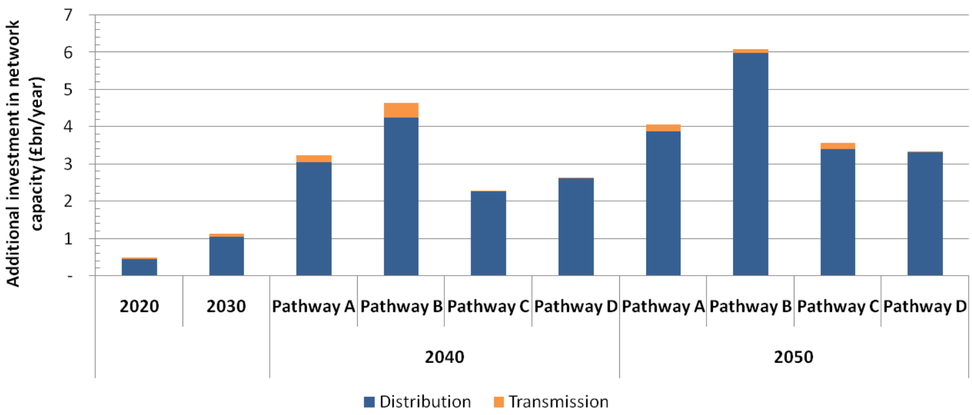


Figure 2.2. Additional investment in network capacity across Pathways and time

- Without the alternative balancing technologies, the system has a limited ability to absorb renewable electricity generation, and a large proportion of intermittent renewable generation may need to be curtailed in order to balance the system.[38] As illustrated by Figure 2.3, the scale of renewable curtailment is significant in Pathways that feature large renewable capacity, such as Pathway A where between 20% and 30% (or between 60 and 100 TWh) of renewable output is curtailed in the counterfactual scenario.

The scale of the balancing challenge increases significantly between 2030 and 2040, assuming the balanced EMR scenario in 2020-2030. This is driven by the assumptions of rapidly increasing penetrations of renewable electricity, and the additional demand due to accelerated electrification of heat and transport sectors. However, if another Pathway was followed in 2030, such as Pathway A, we would observe significantly higher renewable curtailment already in 2030 (around 12%), as indicated in Figure 2.3.

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37 Annualised network investment in this context refers to the annualised equivalent of investment into distribution network reinforcement needed to accommodate the projected increase in peak demand resulting from increased electrification. A similar interpretation holds for transmission investment. Annualised values are obtained based on parameters elaborated later in Table 2.4.

38 For example, minimum demand in Pathway A in 2050 is 28 GW, while there is 108 GW of renewable generation capacity installed. Hence, when windy conditions occur in off-peak periods, a significant quantity of wind generation capacity may have to be curtailed to ensure supply does not exceed demand. Also, wind might need to be curtailed because of maintaining the system security of supply through provision of reserve and response.

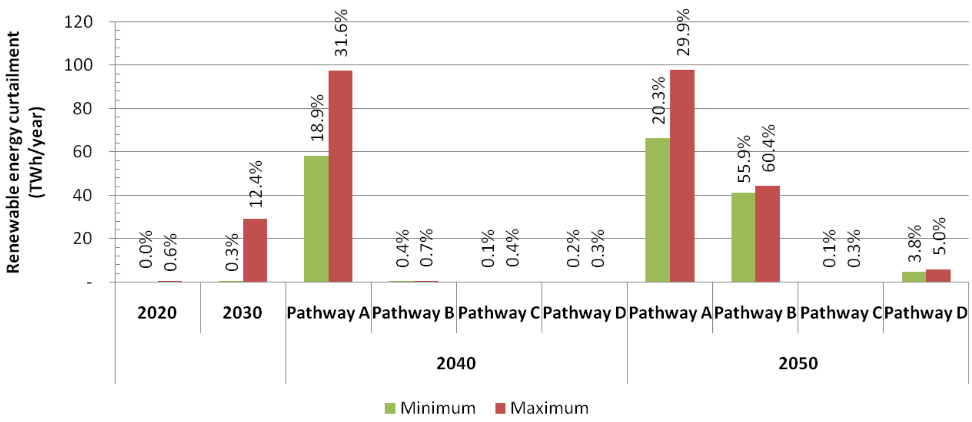

Figure 2.3. Renewable energy curtailment across Pathways and time (percentages indicate the share of available renewable energy that is curtailed)[39]

2.4. Alternative balancing technologies

In the next stage we analyse a range of scenarios where we allow the model to use the alternative balancing technologies to secure the system at least-cost. By comparing these scenarios to the counterfactuals set out above, where alternative balancing technologies are not available, we quantify the benefits these can bring in minimising the electricity system costs.

The range of scenarios analysed is designed to illustrate both the array of uncertainty that exists regarding the cost of these technologies and the potential for their deployment, but also the market arrangements and operational practices that may influence the system integration cost and hence the value of alternative balancing technologies.

However, the range of cost and availability assumptions is not defined to be extreme. The assumptions on high and low cost/availability of alternative balancing technologies are chosen such that each of the balancing technologies considered can play some role in balancing the system. In reality, therefore, if the costs of a particular alternative balancing option turn out to be much higher than assumed, the efficient volumes of that option would be at a smaller level than indicated by our modelling, and vice versa.

As well as the costs of construction and operating the alternative balancing technologies, we factor in the risk associated with each option through the use of market-based discount rates to annualise costs.[40] However, in practice there is little evidence on the returns required by investors in relatively new technologies such as storage, and the prevailing commercial arrangements in the power sector in the period to 2050 will affect investors' perception of

[39] The range of sensitivities analysed for each of the Pathways, as described in Section 2.5 below, defines the minimum and maximum values. For renewable curtailment, the key sensitivities include the accuracy of wind forecasting and the integration of wind into providing response and reserve services. Maximum curtailment values correspond to less accurate wind forecasting and limited participation of wind in providing reserve and response.

[40] See Table 2.4 for an overview of the assumptions on the lifetime and cost of capital for a range of generation and network assets.

risk. These issues will be crucial to decisions on deployment, although we do not consider them further here.

Table 2.3 summarises our cost and availability assumptions for the range of alternative balancing technologies considered in this study. The assumed costs are held constant (in real terms) across all years considered in the study.

Table 2.3. Cost and availability of alternative balancing technologies assumed in the study

Flexible option	Cost level	Value
Flexible generation	Low	10% over investment cost
	High	50% over investment cost
Storage*	Low	£75/kW/yr (B), £100/kW/yr (D)
	High	£125/kW/yr (B), £150/kW/yr (D)
Interconnection	Low	£96/MW/km/yr
	High	No new interconnections beyond those planned by 2020
Demand-side response	Low	80% penetration of available demand
	High	10% penetration of available demand

* B = Bulk, D = Distributed

We define our assumptions on the cost of adding additional flexibility to power generation capacity as percentage increase in baseline investment cost. Our consultations with equipment manufacturers suggest that a 10% and 50% increase in investment cost represent plausible lower and upper bounds on the costs of increasing generators' flexibility. Key flexibility parameters considered in this study include: (i) Minimum Stable Generation (MSG), which is assumed to reduce by 25% with more flexible generation, and (ii) the capability to provide frequency regulation, where flexible generators are able to provide 100% of their reduced output as frequency response, compared to 40% for generators with standard flexibility.

For bulk and distributed storage, our cost assumptions are defined to ensure it is economic for these technologies to play a role in balancing the system in both the high and low cost scenarios.[41] In reality, there is considerable uncertainty regarding the future costs of electricity storage, and the costs of developing storage capacity may turn out to be higher than we assume, making storage investments less economic for supporting balancing of the system (and vice versa). We assume bulk storage is less expensive than distributed storage to reflect the likely impact of economies of scale.[42]

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[41] We have expressed the range of investment costs for 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 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.

[42] Current cost estimates of storage technologies vary within a very broad range. For instance EPRI's 2010 report quotes prices for megawatt-scale storage between £620 and £3,170/kW, and £810-7,120/kW for kilowatt-scale applications ("Electricity Energy Storage Technology Options: A White Paper Primer on Applications, Costs and Benefits", Electric Power Research Institute, December 2010). It has to be noted that most of the technologies included in these cost ranges have not yet reached the commercial application phase for electricity grid management purposes. In addition to the

The cost of interconnection infrastructure has a relatively low level of uncertainty, although the financing cost may be different depending on whether the corresponding investment is merchant or regulated. A number of planned transmission projects quote similar levels of unit cost, on which we base our low-case cost assumption. However, reflecting the possibility that the large-scale deployment of new interconnection may be restricted by other factors, such as market arrangements or supply chains, in the high-cost case we prevent the model from developing new interconnection capacity beyond the levels assumed to be in place by 2020.[43]

We have analysed two cases on DSR: high availability/uptake of DSR (low-cost DSR) and low availability/uptake of demand side response (high-cost DSR). The percentages of 80% and 10% are chosen to reflect either high or low participation of demand in providing flexible services to the system. It should be noted that 80% and 10% do not refer to the entire system demand in a given year; these figures rather quantify the proportion of the demand, which has the potential to be flexible, that is actually willing to participate in system management. Demand categories assumed to be potentially flexible include: electrified space and water heating in residential and commercial sectors, electrified transport demand, and demand for smart wet appliances in the household sector. These categories together account for a varying proportion of total system demand, with their share increasing towards the 2050 horizon in line with the assumptions on electrification in different Pathways. Flexible demand also contributes to the provision of reserve and frequency regulation services as appropriate.[44] In assessing the flexibility provided by these demand categories, we make use of our detailed bottom-up models, which enable us to quantify the contribution of flexible demand to system management without compromising services provided to end customers. We do not associate any specific cost with the deployment or use of DSR in the model, due to the very significant uncertainty in future costs, and customer acceptance rates.[45] This may mean that we overestimate the value of DSR at the expense of other balancing technologies.

2.5. Other Drivers of the Balancing Challenge

In Section 2.2 we set out our four supply and demand cases (4 Pathways), and in Section 2.4 we set out our high/low cost and availability assumptions for the balancing technologies. In addition we have also investigated the sensitivity of our results to a number of other factors that affect the value of the alternative balancing technologies in GB:

- *Level of DSR uptake in Europe.* In some of our sensitivity studies we considered the impact of a high uptake rate of DSR in the European system, which could potentially affect the value of the balancing technologies in the GB. We assume similar DSR penetrations as GB, i.e. the high DSR scenario in Europe entails 80% of DSR penetration.

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uncertainty around investment cost, it is also difficult to estimate the cost of capital and economic lives applicable to different technologies.

43 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. The report envisages 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) and 0.5 GW between GB and Ireland (East-West). In addition, there is the Moyle interconnector between Scotland and Northern Ireland with a capacity of 0.5 GW.

44 For example, in the case of Electric Vehicles, provision of frequency regulation is based on rapid reduction of charging for short period of time (of a proportion of the vehicle fleet), rather than injecting power back power to the grid.

45 As we describe further in Chapter 4, the main cost associated with DSR deployment is the roll-out of smart metering infrastructure, which the government has already mandated. However, there are a range of additional infrastructure and commercial costs that would be needed – but a detailed investigation of these costs was beyond the scope of this study.

- *Wind forecasting error improvements and contribution of wind generation to reserve provision.* The presence of intermittent renewable generation will increase the requirements for reserve and frequency regulation services. The need for these services is directly driven by wind output forecasting errors and this will significantly affect the ability of the system absorb wind energy. It is expected that the 4 hour ahead forecasting error of wind, being at present at about 15% of installed wind capacity, may reduce to 10% post-2020 and then further to less than 6%, may have a material impact of the value of flexibility options. Furthermore, wind generation could contribute to providing balancing services in future, particularly when wind output needs to be curtailed, which may have visible beneficial effects in Pathways with a high contribution from renewables. We therefore test the effect of these factors on the value of alternative balancing technologies in our sensitivity analyses.
- *GB as a hub for Irish wind.* The concept of GB becoming a hub for the transport of Irish wind energy towards continental Europe seems *prima facie* an economically sound proposition from a European system perspective, given the significant increase in Irish wind capacity and the distances involved in connecting Ireland to mainland Europe directly rather than via the GB. Given the uncertainty associated with this proposition we examine the impact that the decision to either reinforce or not reinforce the interconnection capacity between Ireland and GB would have on deployment and benefits of alternative balancing technologies.
- *Benefits within and outside the GB.* It is important to note that the benefits of balancing technologies deployed in GB (or at its borders) are generally seen not only within the GB system, but also in continental Europe (CE) and Ireland (IE). The split between GB-based and (European) system-wide benefits is very dependent on the underlining characteristics of the generation and demand mix. Furthermore, the balance of the level of flexibility between the CE and the GB system is a driver for the geographical split of benefits of balancing technologies. For instance, if flexible generation is deployed in GB only, but there is a lack of flexibility in Europe, the model builds interconnection in order to reduce the system costs in Europe (e.g. through reduced wind curtailment). Conversely, when there is a high uptake of demand-side flexibility in Europe and Ireland, the benefits of interconnection may be higher in GB, suggesting that European DSR is supporting balancing in GB. Given that our analysis optimises the overall European system, the generation OPEX benefits expressed in Section 3 are European system-wide, with varying proportions of benefits located within GB. For individual Pathways, we discuss the case-specific allocation of benefits between GB and rest of the system.

2.6. Other Assumptions

We take projections of fossil fuel prices from the central scenario in DECC's 2011 Fossil Fuels Price Projections[46]. 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

[46] DECC's IAG Guidance for Policy Appraisal: Guidance tables 1-24: supporting the toolkit and the guidance, available at: http://www.decc.gov.uk/en/content/cms/about/ec_social_res/iag_guidance/iag_guidance.aspx.

£98/bbl in 2050 in real terms (based on 2011 prices), while gas and coal prices remain constant in real terms beyond 2020 and 2030 (70 p/therm and £71/tonne respectively).[47]

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,[48] 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.[49] Interconnection in our analysis is assumed to have the same cost parameters as transmission reinforcement.[50] We take distribution network reinforcement costs from the assumptions made by Ofgem during the latest distribution price control review (a more detailed overview of our assumptions on distribution asset costs is provided in the Appendix, Table A4).

As shown in Table 2.4, 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.[51]

Table 2.4. Assumptions on investment cost, lifetime and cost of capital for generation, transmission and distribution assets

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).
** Figures for distribution assets not provided because of the variety of distribution asset types (lines, cables, transformers etc.) that were considered in modelling. More detail is provided in the Appendix.

Although the modelling framework adopted in this study is comprehensive and includes all key segments of the electricity system, there are certain limitations. The model performs a

47 The impact of high fuel cost on the value of storage is analysed in the Carbon Trust report "Strategic Assessment of the Role and Value of Energy Storage Systems in the UK Low Carbon Energy Future", July 2012.

48 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.

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

50 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.

51 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.

cost-based optimisation at a pan-European level[52], and does not simulate the operation of various market segments of the electricity market in different jurisdictions. In other words, the model assumes a perfectly efficient and fully integrated European market in future years; the actual market arrangements might differ from this. A further limitation is that only one generation mix is assumed in Europe, which is harmonised with the European emission reduction targets; a significantly different generation portfolio would generally result in different values for the benefits and volumes interconnection from what is presented in this study.

52 This is discussed further in Section 4.

3. Meeting the Balancing Challenge

Figure 3.1 provides an overview of the balancing challenge across different Pathways over time scales considered.

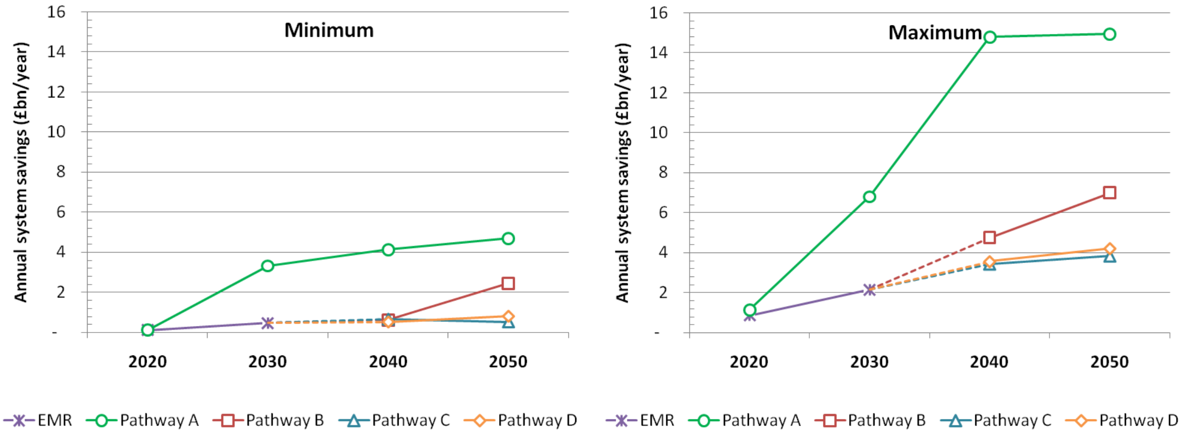

Figure 3.1. Minimum and maximum system savings with combinations of balancing technologies across Pathways and time

The value of balancing technologies, i.e. the scale of the balancing challenge is clearly the greatest in Pathway A, followed by Pathways B, D and C. The maximum system benefits that could be achieved in 2050 if all balancing technologies are available at low cost ranges from about £15bn/year in Pathway A and £7bn/year in Pathway B, to around £4bn/year in Pathways C and D. Even when balancing technologies are available at high cost, the benefits in Pathway A are substantial, while in other Pathways the scope for high cost flexible balancing options is reduced. We further note that the timing of when the balancing challenge becomes important is heavily Pathway-dependent: the 2030 benefits in Pathway A are significantly higher than 2040 benefits in any of the other three Pathways.

We start by presenting the range of modelling results for 2020 and 2030 that we obtain for the two Pathways analysed (balanced EMR scenario and Pathway A) and across all cost/availability scenarios. We then present results for 2040 and 2050 separately for each of the four Pathways (A to D). Finally, we then summarise our findings for different alternative balancing technologies across Pathways and the time horizon covered in our analysis.

3.1. The Balancing Challenge in 2020 and 2030

As already indicated in Figure 2.1 to Figure 2.3, the scale of the balancing challenge in 2020 and 2030 is small when compared to 2040 and 2050, due to the assumed increases in electrification and the penetration of intermittent renewables that occurs post-2030.

Figure 3.2 presents the savings that the deployment of alternative balancing technologies could deliver to the system in 2020. The chart on the left represents the balanced EMR scenario, while the one on the right represents Pathway A in 2020.

Different bars in these charts represent different cost/availability scenarios for balancing technologies. For example, the first bar (referring to "Interconnection") shows the available cost savings compared to the counterfactual if interconnection is at "low cost/high availability" scenario, while all other technologies exhibit "high costs/low availability"; this particular case results in annual savings to the system of £0.2bn per annum in the balanced EMR scenario. Similarly, the next three bars refer to cases where flexible generation, storage and DSR are available at low cost, respectively, while all other balancing technologies have high costs.

The last two bars on the right refer to the cases where all options are available either at high cost/low availability ("All high") or at low cost/high availability ("All low"). We use a similar chart layout to describe the benefits of balancing technologies throughout this chapter.

Figure 3.2 (and the equivalent figures presented later in the report for other years and Pathways) breaks total system benefits into several components: (i) GB generation CAPEX savings,[53] (ii) interconnection CAPEX,[54] (iii) GB transmission CAPEX, (iv) GB distribution network CAPEX, (v) system-wide generation operating costs (OPEX), which are reported net of the inefficiencies associated with operating storage, and (vi) CAPEX associated with new storage capacity deployed in GB. These components can be positive, indicating savings, or negative indicating costs.

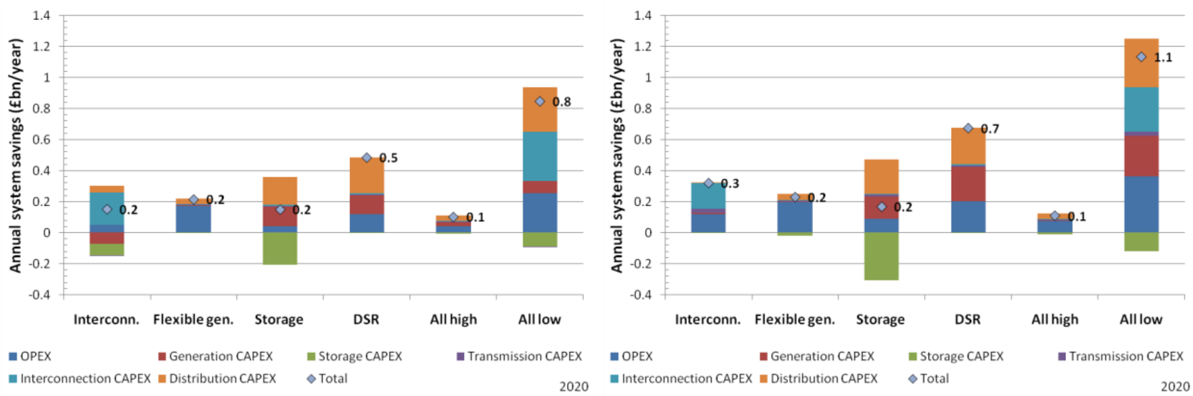

Figure 3.2. System benefits of alternative balancing technologies in 2020 for the balanced EMR scenario (left) and Pathway A (right)

The rightmost bars in Figure 3.2 show that maximum potential cost savings in 2020, assuming the most favourable situation for all options, vary between £0.8bn per annum in the balanced EMR scenario to £1.1bn per annum in Pathway A. This suggests that the scale of the balancing challenge in 2020 is limited, with limited scope for the application of alternative balancing technologies. Reasons for this include a relatively modest penetration of intermittent renewable generation and a low level of heat and transport electrification, which combined with a relatively flexible generation portfolio (similar to today) means there is limited need for additional flexibility in the system.

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[53] Generation CAPEX savings also take into account the investment into additional generation flexibility as one of the alternative balancing technologies.

[54] Changes in interconnection CAPEX include both interconnectors from GB towards Ireland or mainland Europe, as well as direct interconnection between Ireland and continental Europe. Investing into new British interconnectors, although requiring additional investment to build the interconnection capacity, can reduce the necessary investment into the IE-CE interconnection compared to the counterfactual scenario.

Figure 3.3 presents the volumes of balancing technologies deployed as part of the optimal solution for the two alternative system configurations in 2020.

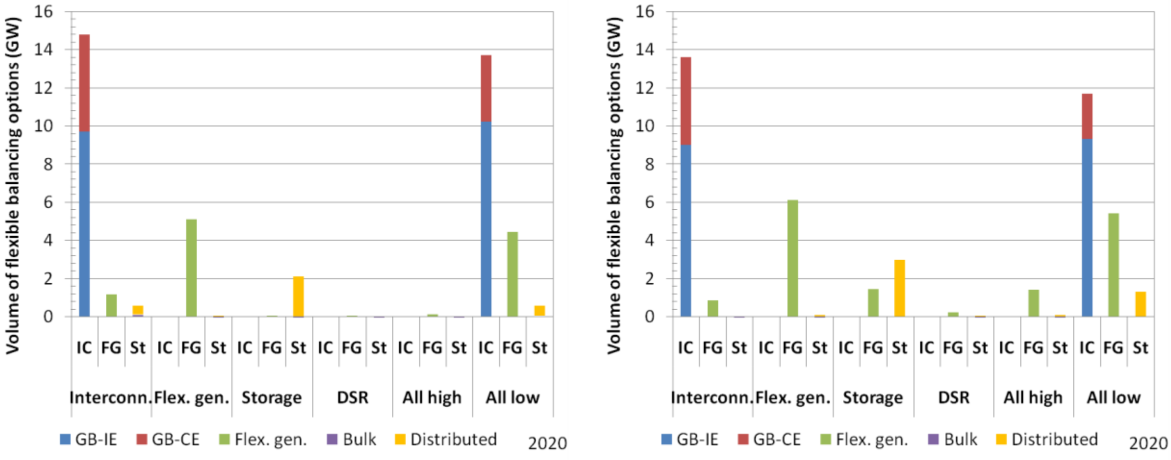


Figure 3.3. Optimal volumes of alternative balancing technologies in 2020 for the balanced EMR scenario (left) and Pathway A (right)

Six groups of bars presented in Figure 3.3 correspond to the six scenarios represented in Figure 3.2, i.e. the first four are for each of the balancing technologies in turn (with the option in question available at low cost/high availability while all others are at high cost/low availability), and in the last two either all have low or high costs (high/low availability respectively). Within each group there are three bars that represent the optimal deployed volume of three balancing technologies: interconnection (IC), flexible generation (FG) and storage (St) (DSR is not depicted as it is difficult to express in GW terms[55]). Interconnection and storage capacities are further separated into components – interconnection into the connections towards Ireland or mainland Europe, and storage into bulk or distributed capacity. We now discuss the role and benefits of individual balancing technologies in the two scenarios presented above.

Benefits of Interconnection. We observe that the model builds between 12 and 15 GW of new interconnection capacity, as it is cost-effective to combine the integration of Irish and GB wind generation (in order to make savings in OPEX as indicated in Figure 3.2). We observe that the investment in GB-IE and GB-CE interconnections in fact reduces the overall cost of interconnection in the region, due to savings made through avoiding investment in directly interconnecting Ireland and CE (in Figure 3.2, we note that investment in the new interconnection with GB produces net savings in interconnection in the region). This makes GB a hub for Irish and GB wind and OPEX savings are mostly driven by reduced curtailment of wind generation in Ireland (i.e. outside GB). We however note that this investment will bring relatively modest net benefits of up to £400m/year.

[55] DSR actions are a complex function of the flexibility characteristics of each demand category, with typically large variations in daily, weekly and seasonal cycles, as well as inter-temporal constraints determining how much energy can be shifted between different times of day. Therefore, even when knowing the energy and (uncontrolled) peak demand in flexible demand categories, the level of flexibility i.e. the amount of energy that can be shifted will generally fluctuate widely across time, unlike the other balancing technologies considered in this study.

Benefits of Flexible Generation. We note that the model installs 4-6 GW of flexible generation capacity only if it is available at low cost, as indicated in Figure 3.3 (otherwise very little gets built). Note that generation CAPEX savings are negative in this case as investment is undertaken to make generators more flexible (Figure 3.2). This is cost-effective as large enough savings are made in OPEX, although the net benefits created are very small.

Benefits of Storage. We observe that 2 GW of storage is built in 2020 in the balanced EMR scenario and 3 GW in Pathway A, when it is available at low cost (and other balancing technologies are high cost), and smaller amounts otherwise. The difference in the deployment of new storage capacity is driven by higher renewable capacity in Pathway A, which provides opportunity for storage to offset CAPEX associated with backup generation. Distributed storage is built to also mitigate distribution network reinforcement driven by the peak demand increase. We note that the operation of storage (to achieve these CAPEX savings) neutralises the benefits in OPEX reduction due to inherent inefficiency losses. Overall however, we observe that the savings achieved are of the same magnitude as the investment in storage needed to achieve these, and hence the resulting net benefits are not significant.

Benefits of Demand-Side Response. We note that DSR brings benefits in reducing OPEX (supporting more efficient operation of the system with increased amount of intermittent generation), while simultaneously offsetting the need for backup generation (generation CAPEX savings) and mitigating the distribution network reinforcement requirements, more significantly in Pathway A than in balanced EMR scenario. The savings that can be attributed to DSR are between £500m/year (balanced EMR) and £700m/year (Pathway A). It is important to note that OPEX benefits achieved through DSR are achieved by marginally enhancing the utilisation coal over gas generation (due to the marginal differences in production costs).

Benefits of combined alternative balancing technologies. When all balancing technologies are available at low cost, savings are between £0.8bn/year and £1.1bn/year, of which the generation and distribution CAPEX savings are achieved in GB. OPEX savings are however shared between GB, Ireland and mainland Europe, while CAPEX savings associated with interconnection are seen outside GB (reduced investment in IE-CE interconnection).

Figure 3.4 presents the benefits of deploying alternative balancing technologies in 2030. The benefits in 2030 are again presented for the balanced EMR scenario (left) and Pathway A (right). The layout of the charts is the same as in Figure 3.2.

We note that that the benefits that might be achieved from deploying flexibility options in a number of scenarios are significantly higher than in 2020. Furthermore, we also observe that the differences in potential cost savings from deploying balancing technologies in the two Pathways (balanced EMR and Pathway A) are much more significant when compared to the differences between these two scenarios in 2020. This is driven by the fact that the balanced EMR scenario contains significantly lower assumptions on the level of wind generation and electrification of demand than Pathway A by 2030. The balancing challenge is therefore much more significant in Pathway A than in the balanced EMR scenario.

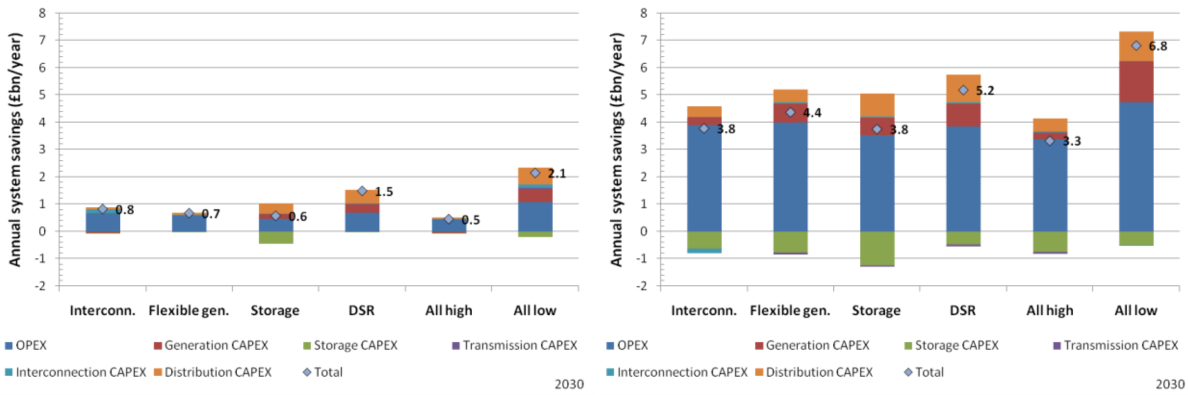


Figure 3.4. System benefits of alternative balancing technologies in 2030 for the balanced EMR scenario (left) and Pathway A (right)

Maximum benefits, achieved for the “All low” cost case in Figure 3.4 show that maximum potential cost savings in 2030 range from £2.1bn per annum in the balanced EMR scenario to £6.8bn per annum in Pathway A. As a result, from Figure 3.5 we observe that all balancing technologies are generally deployed in larger volumes in Pathway A than in the balanced EMR scenario. We will now discuss the role and benefits that individual balancing technologies can make in addressing the growing balancing challenge.

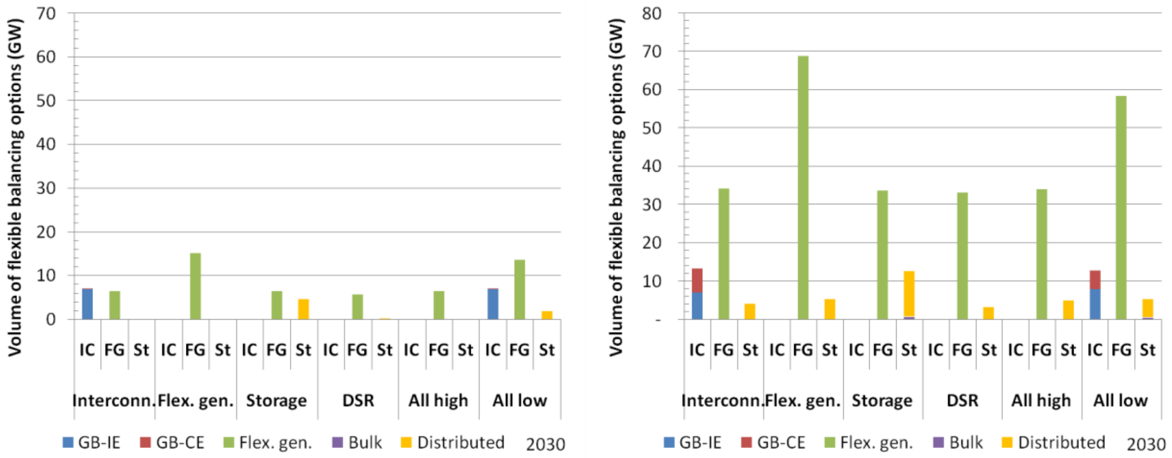


Figure 3.5. Optimal volumes of alternative balancing technologies in 2030 for the balanced EMR scenario (left) and Pathway A (right)

Benefits of Interconnection: Capacities of interconnection added between GB and IE systems are very similar for both Pathways in 2030 (7-8 GW). The new capacity of GB-CE interconnection on the other hand differs significantly; while around 5-6 GW is built in Pathway A, virtually no new capacity is added in the balanced EMR scenario. This is driven by lower renewable capacity in GB and enhanced capability of the system to absorb Irish wind within GB without the need to directly export surplus wind towards mainland Europe. We also note that in the balanced EMR scenario the investment in interconnection is focused on reducing OPEX expenditure by about £0.6bn/year (a significant proportion of this benefit is achieved outside GB through enhancing the capability of the system to absorb intermittent generation in Ireland). In addition, the overall cost of interconnection in the region is reduced, due to savings made through avoiding investment in interconnecting Ireland to CE directly. New interconnection capacity in Pathway A brings OPEX savings of almost £4bn/year, although the investment in interconnection results in a small increase in overall interconnection cost in the region. It is important to stress that in Pathway A, interconnection contributes significantly to reducing curtailment of renewable generation in GB (from 28 TWh in the counterfactual to 1 TWh) and hence almost all OPEX savings are achieved in GB. Given that the value of interconnection is driven by the reduction in renewable generation curtailment and corresponding savings in OPEX, improved wind forecasting errors and enhanced reserve management practices that involve wind generation providing balancing services would be expected to reduce the benefits of interconnection.

Benefits of Flexible Generation. We note that between 6 and 15 GW of flexible generation is added in the balanced EMR scenario in all cases, whilst in Pathway A more than 33 GW is chosen when it is available at high cost, about 70 GW when it is the only low-cost option and 60 GW when all options are available at low cost. In Pathway A, flexible generation achieves similar OPEX benefits to the case with interconnection, although renewable curtailment is reduced to about 7 TWh (rather than 1 TWh as in the case with interconnection). The additional OPEX savings are achieved through providing frequency regulation services at lower cost and enhancing the operating efficiency of the CE system by enabling load factors of base load plant, such as CCS, to be increased. Overall, a large majority of the OPEX savings in this case are achieved outside GB.

Benefits of Storage. About 5 GW of storage is built in the balanced EMR scenario and about 13 GW in Pathway A, when it is the only option available at low cost; smaller amounts are constructed otherwise in the balanced EMR scenario, whilst in Pathway A up to 5 GW is chosen when available at high cost. The deployment of the higher capacity in Pathway A is driven by greater renewable penetration (a similar effect is observed in 2020) and an increased level of electrification of transport and heat sectors. In addition to providing savings in OPEX through more efficient intermittency management, storage offsets CAPEX associated with backup generation, and distributed storage mitigates distribution network reinforcement driven by an increased peak demand. We note that between 3 and 5 GW of distributed storage is installed in Pathway A even when storage is available at high costs.

Benefits of Demand-Side Response. Savings in operating costs achieved by enhancing the ability of the system to absorb intermittent generation dominate the benefits of DSR. Additional contribution of DSR is in offsetting the need for backup generation and reducing the distribution network reinforcement requirements. When compared with storage, DSR reduces generation CAPEX more, and it also achieves larger OPEX savings due to lower losses associated with re-distributing demand across time. The volume of system benefits generated by DSR when it is the only low-cost option in the balanced EMR scenario is £1.5bn/year while the benefits increase to 5.2bn/year in Pathway A (note that no cost is associated with the deployment of DSR).

Benefits of combined alternative balancing technologies. When all balancing technologies are available at low cost, potential savings are significant: £2.1bn/year in balanced EMR and £6.8bn/year in Pathway A. In line with our modelling approach, all generation and distribution CAPEX savings are achieved in GB. OPEX savings however are shared between GB, Ireland and mainland Europe, while CAPEX savings associated with interconnection occur outside GB (reduced investment in IE-CE interconnection).

Table 3.1 provides a summary of the benefits and volumes for the balancing technologies for the balanced EMR scenario and Pathway A in 2020 and 2030.

Table 3.1. Summary of benefits and volumes of alternative balancing technologies for the balanced EMR scenario and Pathway A in 2020 and 2030

EMR – Interconnection*	2020		2030	
Baseline	£0.2bn	(9.7+5.0) GW	£0.8bn	(6.9+0.0) GW

* Capacity (GW) = (GB-IE + GB-CE)

EMR – Flexible generation	2020		2030	
Baseline	£0.2bn	5.1 GW	£0.7bn	15.0 GW

EMR – Storage	2020		2030	
Baseline	£0.2bn	2.1 GW	£0.6bn	4.5 GW

EMR – DSR	2020		2030	
Baseline	£0.5bn	n/a	£1.5bn	n/a

EMR – All options	2020		2030	
High cost	£0.1bn	n/a	£0.5bn	n/a
Low cost	£0.8bn	n/a	£2.1bn	n/a

PATHWAY A – Interconnection*	2020		2030	
Baseline	£0.3bn	(9.0+4.6) GW	£3.8bn	(7.0+6.2) GW

* Capacity (GW) = (GB-IE + GB-CE)

PATHWAY A – Flexible generation	2020		2030	
Baseline	£0.2bn	6.1 GW	£4.4bn	68.9 GW

PATHWAY A – Storage	2020		2030	
Baseline	£0.2bn	3.1 GW	£3.8bn	12.5 GW

PATHWAY A – DSR	2020		2030	
Baseline	£0.7bn	n/a	£5.2bn	n/a

PATHWAY A – All options	2020		2030	
High cost	£0.2bn	n/a	£3.3bn	n/a
Low cost	£1.1bn	n/a	£6.8bn	n/a

3.2. Pathway A

The results of Pathway A are presented in slightly more detail than for other Pathways. Descriptions of subsequent Pathways are kept briefer, primarily focusing on changes as compared to Pathway A.

As a first step, we present a high-level overview of the system benefits achieved by individual balancing technologies, as well as portfolios of balancing technologies that are either all at low cost, or all at high cost. This is followed by a more detailed discussion of the role and benefits of individual balancing technologies.

Figure 3.6 and Figure 3.7 present the system benefits generated by balancing technologies in various cost and availability scenarios for Pathway A in 2040 and 2050.

The layout of the figures presenting system benefits differs from the layouts of Figure 3.2 and Figure 3.4. Given the very high penetration of intermittent renewable capacity in Pathway A, we distinguish between "Base" and "Imp" cases, which refer to sensitivities related to wind management:

- "Base" represents the "Baseline" case where wind provides no reserve or response services, and wind forecasting errors are at expected 2020 levels (standard deviation of wind forecasting error of around 10%).
- "Imp" represents the "Improved" case where wind generation is providing reserve and response services (when constrained off), and wind forecasting errors are reduced by 20% as compared to forecasting errors improvements expected to be achieved by 2020.

The four pairs of bars on the left refer to different balancing technologies, and show the range of cost savings available compared to the counterfactual if a particular option has low cost or high availability, while all other options exhibit high costs or low availability. In the last pair of bars (denoted by "All options") "High" refers to the case where all flexible technology options have high cost/low availability, while "Low" includes all flexible technology options at low cost/high availability. In addition to the two sensitivities behind the "Base" and "Imp" values, we also discuss the impact of other sensitivities (which are described in Section 2.5) on the value of the balancing technologies.

The potential savings in Pathway A are generally largest in the “Base” case, i.e. when we assume the current level of wind forecasting error and no contribution of wind generation to the provision of balancing services. The potential savings are lower in the “Imp” case, where we assume that wind generation contributes to the delivery of balancing services, and improvements are made in the accuracy of predicting the output of intermittent generation.

The Figures suggest that the scale of the balancing challenge in 2040 and 2050 is potentially very significant, with benefits in 2040 being only slightly lower than in 2050.[56] Savings in annual operating cost are rather similar for “Base” cases in 2040 and 2050, with around £8bn/year of OPEX saved compared to the counterfactual scenario. This is due to similar levels of renewable capacity assumed in the system in 2040 and 2050 for Pathway A. We observe that the key driver for OPEX savings is avoided renewable curtailment (98 TWh of RES output is curtailed in the “Base” case, and 63 TWh in the “Imp” case in 2050 counterfactual scenario).

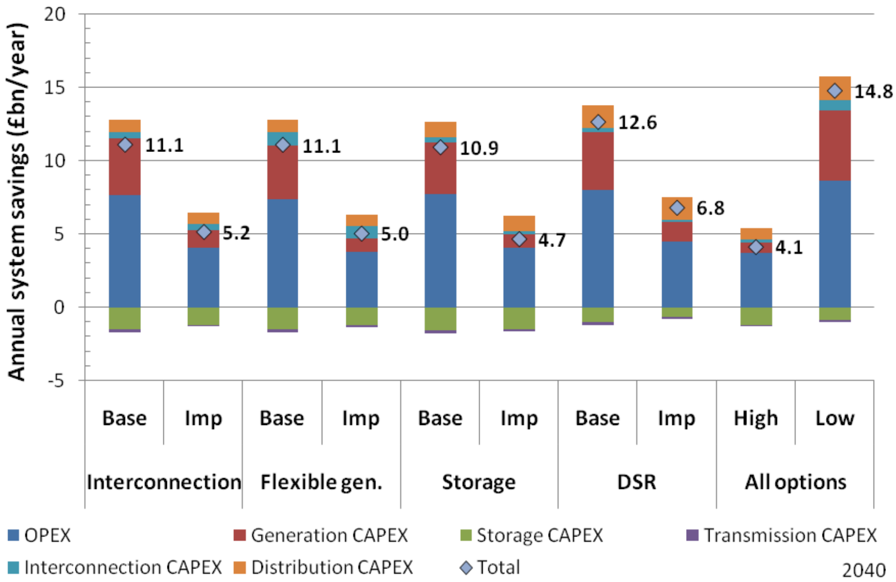


Figure 3.6. Minimum and maximum annual system benefits in Pathway A (year 2040)

56 We note that differences between “Base” and “Imp” savings are higher in 2040 than in 2050, i.e. the value of flexible options in 2040 will be more sensitive to the system parameters related to wind management.

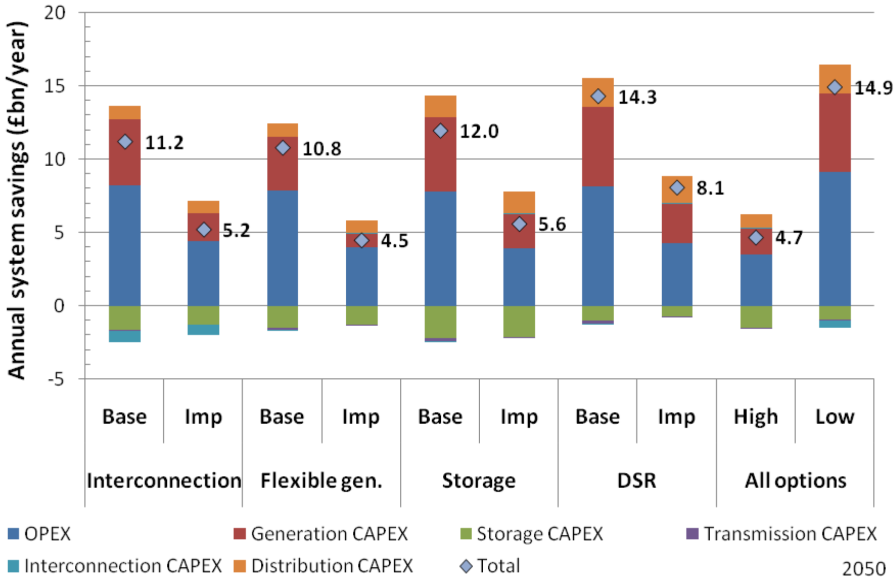


Figure 3.7. Minimum and maximum annual system benefits in Pathway A (year 2050)

We further observe that the OPEX benefits in Pathway A are predominantly achieved in GB. In contrast to the assumption that the level of renewable generation does not change between 2040 an 2050, in Continental Europe and Ireland we assumed a gradual increase in RES capacity forecasted out to 2050; hence there is less need for flexibility in Europe in 2040 compared to 2050, and the European system provides flexibility to support the balancing of the GB system by reducing its OPEX. On the other hand, in the "Imp" cases in 2050, where there is substantial need for flexibility in CE due to increased renewable capacity, a part of OPEX savings is achieved outside GB by using the flexible balancing options deployed within GB to support the integration of renewables in Europe.

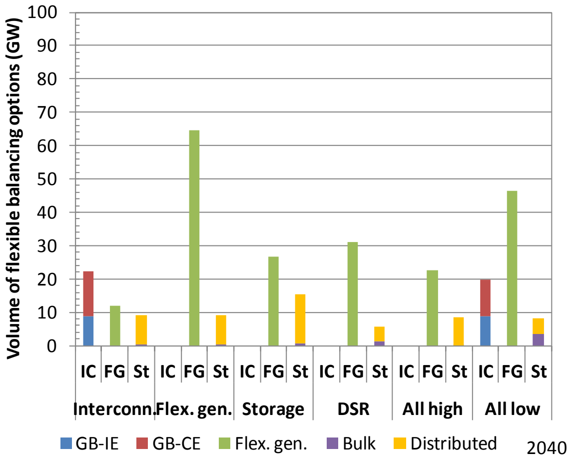
In our model we only allow GB balancing technologies to alter generation, transmission and distribution capacity within GB. All of the corresponding CAPEX savings are therefore achieved exclusively within GB.

Generation CAPEX savings in Pathway A are to a large extent driven by the carbon constraint imposed in all Pathways in 2040 and 2050. In the counterfactual scenario, a significant amount of additional CCS capacity is necessary to keep emissions below the assumed limit, given that 20-30% of renewable generation may need to be curtailed. This additional CCS capacity is around 28 GW in "Base" and 10 GW in "Imp" cases in both 2040 and 2050 (less CCS capacity is needed in the "Imp" case due to lower wind curtailment). Given that balancing technologies generally reduce wind curtailment, these also eliminate the need to meet the carbon target by adding capital-intensive CCS capacity (especially in the "Base" case). We observe a reduction in generation CAPEX by deploying storage and DSR, as these balancing technologies reduce the overall requirements for backup generation capacity. Slightly more generation CAPEX is saved in 2050 than in 2040 (£5bn/year as opposed to £4bn/year), which is driven by higher peak demand in 2050 as a result of greater electrification of demand.

Distribution CAPEX savings can only be achieved by deploying DSR and distributed storage, given that these two technologies impact the peak demand of the distribution networks. We observe that distribution CAPEX savings tend to be higher when one or both of these two balancing technologies are available at low cost (high availability).

Net expenditure for interconnection CAPEX, which includes interconnectors with GB as well as the direct IE-CE link, is relatively low or even represents a net benefit to the system despite a substantial investment in new interconnection capacity when it is available. This is because the reinforcement of GB-IE and GB-CE capacity typically offsets a significant part of investment into the more costly IE-CE capacity.

Figure 3.8 illustrates the efficient volumes of balancing technologies added to the system across the range of scenarios and sensitivity studies in 2040 and 2050. The first four bar groups refer to the scenarios where each of the four individual balancing technologies has low cost or high availability, while all others have high cost (or low availability). The values shown in those four bar groups represent the average deployed volumes of balancing technologies across the "Base" and "Imp" cases studied for a given scenario, with "IC" denoting interconnection capacity, "FG" flexible generation and "St" storage (DSR is again not plotted for the reasons explained earlier). The last two bar groups represent the average deployed volumes in scenarios where all options have high cost or low availability ("All high"), or all options have low cost or high availability ("All low").



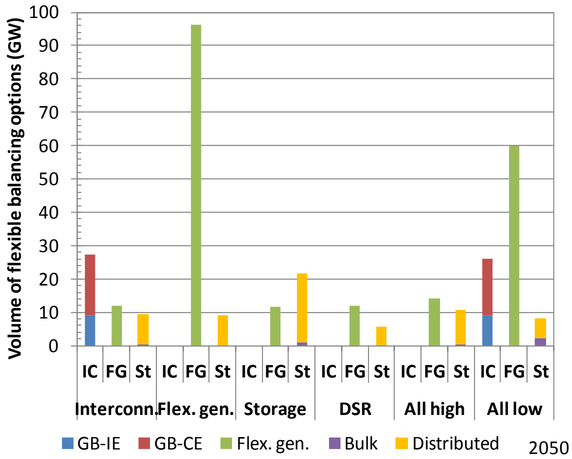


Figure 3.8. Optimal volumes of alternative balancing technologies in Pathway A in 2040 (left) and 2050 (right)

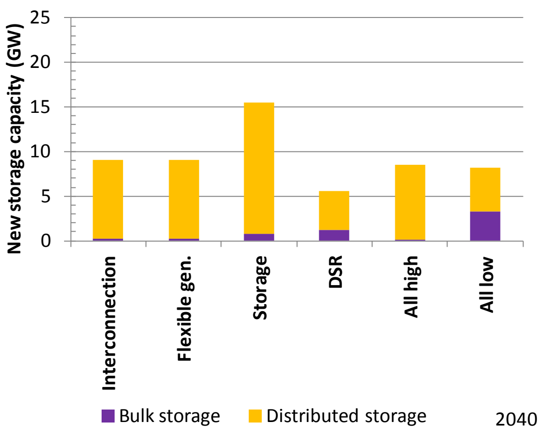
The optimal deployed volumes of flexible generation generally reduce between 2040 and 2050, except if the cost of generation flexibility is low, in which case we observe a slight increase in capacity. The interconnection capacity increases by about 5 GW between 2040 and 2050, while storage capacity increases only by a small amount when it is the only low-cost balancing option.

Based on the above figures and the corresponding study results we observe the following:

- ***Benefits of storage.*** Depending on the scenario and the assumed cost of storage, the model builds a wide range of capacities of distributed storage (6-22 GW). The results show that the optimal deployment of distributed storage is particularly sensitive to the availability of DSR, as well as the cost of storage itself. It is less dependent on the costs and availability of interconnection and the cost of flexible generation. If distributed storage is the only alternative balancing option available, then the model deploys 10-20% more than when other options are available.

Figure 3.9 illustrates the efficient volumes of distributed and bulk storage added to the system across the range of scenarios and sensitivity studies in 2040 and 2050. The scenarios presented are the same as in Figure 3.8, i.e. the first four bars refer to the scenarios where each of the four individual balancing technologies has low cost or high availability, while all others have high cost (or low availability), and the last two bars represent the average deployed storage volumes in scenarios where all options have high cost or low availability ("All high"), or all options have low cost or high availability ("All low").

The charts in Figure 3.9 show that the optimal volume of distributed storage does not change significantly between 2040 and 2050 in Pathway A, as the levels of renewable generation are very similar. More storage is built in 2050 (22 GW as opposed to 15 GW) when storage is available at low cost due to increases in the level of electrification of demand and as a result higher requirements for distribution network reinforcement, which distributed storage is able to offset.



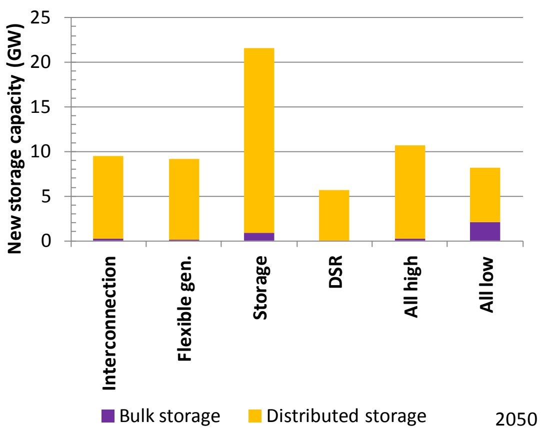


Figure 3.9. Deployment of storage in Pathway A (2040 and 2050)

The deployment of *bulk storage* (in GW terms) occurs at lower levels than distributed storage, at the storage cost levels assumed in this study. The reason for this is that distributed storage has a similar capability to support balancing the system, but also offsets the need for distribution network reinforcements. In the scenarios where all four alternative balancing technologies are available at low cost, the model builds only modest amounts (<3 GW) of bulk storage, although distributed storage is assumed to be between 20% and 33% more expensive than bulk. Nevertheless, we note that different assumptions i.e. larger cost differentials between bulk and distributed storage could provide markedly different results in this respect.

In cases when bulk storage is the only available alternative balancing option, assuming the same cost levels as before, the volumes of bulk storage deployed would increase considerably for 2050 as shown in Figure 3.10 below.

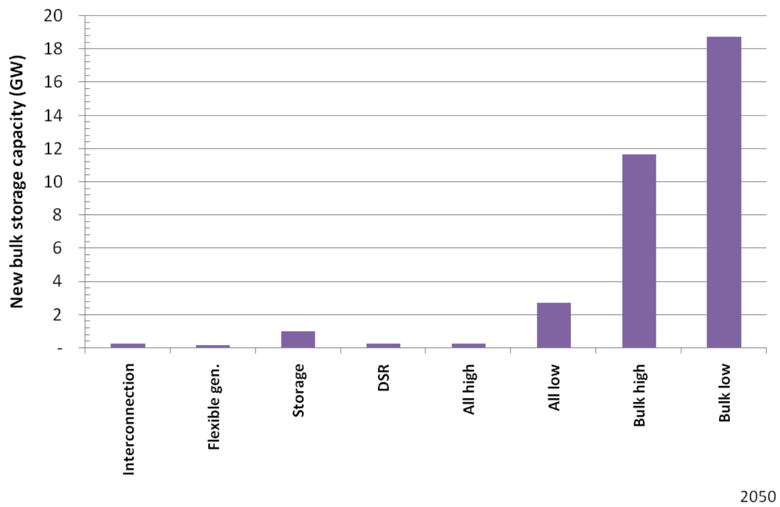


Figure 3.10. Deployment of bulk storage in Pathway A (2050) including the case when it is the only available option

The first six bars in the figure refer to the same scenarios as in Figure 3.9, i.e. they show the average deployed capacities of bulk storage when each of the options are low cost while others have high costs, and when either all options have high costs or all options have low costs. The additional two bars represent the cases when bulk storage is the only available flexible option (i.e. there is no competition from distributed storage and other balancing technologies), and is available either at high cost ("Bulk high"), or at low cost ("Bulk low"). We observe that in these two cases the deployment of bulk storage increases significantly, to between 12 GW (for high-cost bulk storage) and 19 GW (for low-cost bulk storage).

Competition with DSR. If there is a low penetration of DSR and if storage is available at low cost, the model builds a large quantity of distributed storage (ca. 22 GW). If DSR is widely available and storage is expensive, the model only builds around 6 GW. If DSR penetration is low and storage is expensive, the model builds around 10 GW of distributed storage.

Geographical allocation. Distributed storage is deployed across all areas of the country to offset distribution reinforcements. Largest volumes of distributed storage capacity are installed in semi-urban networks, as these networks dominate the overall distribution network reinforcement costs (due to their design and cost characteristics) when the local peak demand increases. On the other hand, a significant proportion of additional bulk storage investment takes place in Scotland, where it is used to absorb high outputs of renewable generation and partially offset the levels of transmission investment between England and Scotland.

- ***Benefits of flexible generation.*** Our modelling shows that the key drivers of optimal investment in flexible generation are the extent of interconnection between GB and neighbouring markets, the cost of providing flexible generation, and the flexibility already available, both in GB and in the neighbouring systems. Optimal volumes of flexible generation chosen across the range of scenarios analysed are shown in Figure 3.11 for the same cases as in Figure 3.9.

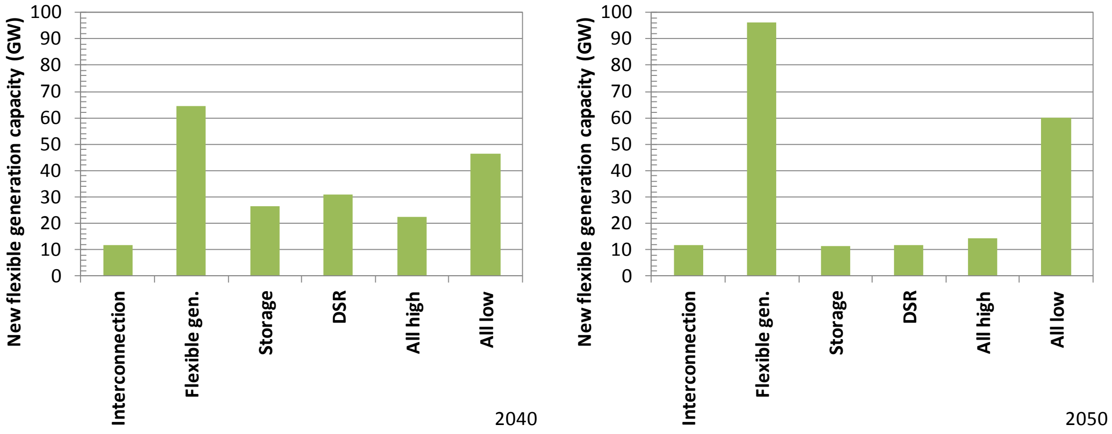


Figure 3.11. Deployment of flexible generation in Pathway A in 2040 (left) and 2050 (right)

When comparing flexible generation deployment in 2040 and 2050, we observe that if flexible generation is only available at a high cost, the optimal volume drops in 2050. This results from increased competition from DSR and storage when these options are available or are at low cost, both options become more attractive as the electrification of demand increases in 2050. If however flexible generation is less expensive, we observe an increase in its deployment in 2050 due to the increased contribution of nuclear with a reduced ability to provide frequency regulation services.

Impact of cost of flexibility. In all scenarios, the model builds at least about 10 GW of flexible generation in 2050, and an even higher amount in 2040, even if it comes at high cost (50% of CAPEX). If the cost of flexible generation is lower (10% of CAPEX), the model builds significantly more capacity, but the quantity is sensitive to the amount of interconnection and other assumptions. The average deployed quantity of flexible generation in that case ranges from 60 GW (when all balancing technologies have low cost or high availability) to 96 GW (when flexible generation is available at low cost, but all other options have high cost).

Impact of availability of other balancing technologies. The optimal level of flexible generation investment does not depend very significantly on the availability of DSR and the cost of storage. This is driven by a very high renewable curtailment in the counterfactual scenario (about 100 TWh), which DSR can mitigate only to a limited extent outside of winter period (due to the impact of heating's contribution to DSR via heat pumps), and storage cannot displace flexible generation cost-effectively at the assumed cost levels. The deployed volume of flexible generation in this Pathway on the other hand depends on the availability of interconnection; in the case when no new interconnection is available, the flexible generation capacity is approximately 50% higher than in the presence of new interconnections. If flexible generation is the only available alternative balancing option, the model decides to make virtually all non-nuclear thermal plant flexible, but only if it is available at low cost (10% of CAPEX).

In cases when wind generation does not provide balancing services and the flexibility of thermal generation is improved, the volume of flexible generation installed increases significantly. In the low-cost scenario for all balancing technologies, the model chooses to build 60 GW of flexible generation capacity in GB in 2050, which then plays a major role (alongside other options) in reducing the renewable energy curtailment in GB from

98 TWh in the counterfactual scenario to only 9 TWh per annum, also supporting the balancing of the CE and Irish systems.

Impact of wind contribution to reserve, restricted interconnection to Ireland and high DSR uptake in Europe. Flexible generation, when available at low cost in Pathway A, attains its minimum benefits when wind generation contributes to the provision of balancing services and wind forecasting errors are low, in which case 97 GW of flexible generation is installed in GB. The bulk of benefits come from operating cost savings as a result of reduced renewable curtailment. Maximum benefits of flexible generation are observed in the case when wind forecasting errors remain high. The installed flexible generation capacity in that case is 95 GW. Presence of demand-side flexibility in Europe and Ireland has an impact on the role of flexible generation. Instead of 95 GW, the model chooses only about 29 GW of flexible generation, given that the needs for flexibility in Europe are fulfilled by European DSR (a similar trend is observed as with the optimal interconnection capacity between GB and CE).

- ***Benefits of interconnection.*** The model shows that across the range of scenarios on the cost and availability of other balancing technologies, and for a given set of system-level assumptions, it is efficient to build a similar quantity of interconnection between GB and neighbouring markets, as illustrated in Figure 3.12 for the period 2040-2050. The meaning of bars in the figure is the same as in Figure 3.9. In line with our assumptions, no new interconnection capacity is built in the middle four bars, as these refer to cases where no expansion of interconnection was allowed beyond the 2020 level. We observe that the optimal capacity of interconnection increases by about 5 GW between 2040 and 2050, but its capacity is not very sensitive to the cost or availability of other balancing technologies.

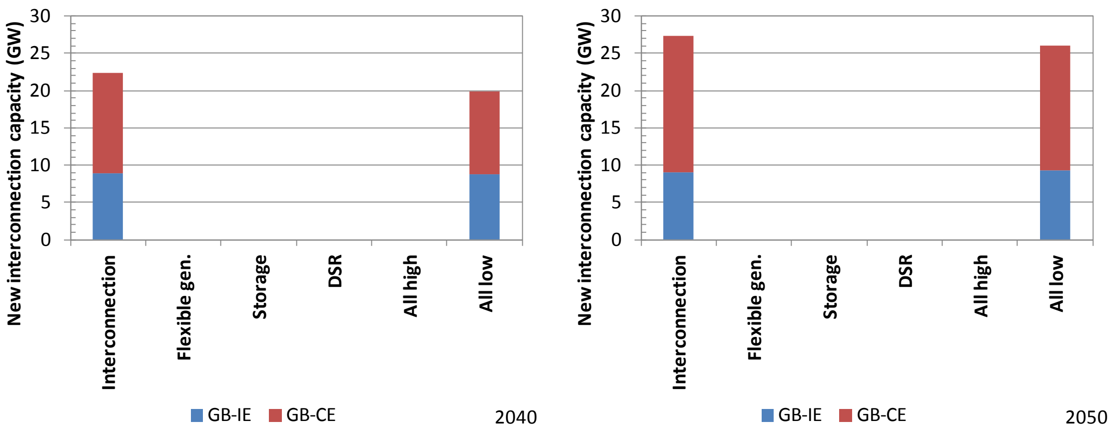


Figure 3.12. Deployment of interconnection in Pathway A (2040 and 2050)

The interconnection volume deployed however depends considerably on the assumptions related to the system sensitivity drivers identified in Section 2.5, and their impact is elaborated below.

Wind generation contribution to providing balancing and wind forecasting. In the scenario where interconnection is the dominant flexible option, the minimum benefits ("Imp" case in Figure 3.6 and Figure 3.7) occur if we assume that wind generation contributes to the delivery of balancing services and if wind forecasting is improved. The majority of benefits in this case arise from savings in operating cost, as a result of avoided renewable curtailment. As interconnection is assumed to not contribute to system security (the "self-security" constraint), generation CAPEX savings are modest and are the result of small quantities of storage and DSR offsetting peak. The optimum installed capacity of interconnectors from the whole-system perspective in this case is 9 GW between GB and Ireland, and 18 GW between GB and Continental Europe (CE). The high levels of interconnection with CE are partly a result of GB acting as an export/import hub for Irish wind imported by GB. Even if interconnection is the only available flexible balancing option, the model still only builds roughly the same amount (around 27 GW).

The lack of sensitivity to the costs or availability of other balancing technologies suggests that interconnection represents a robust solution to the balancing challenge for this case, regardless of how other balancing technologies evolve in the future in terms of their cost and availability. Nevertheless, note that this applies to the particular scenario considered here; decisions regarding the deployment of interconnectors are sensitive to conditions prevailing in GB and the neighbouring markets, and may vary considerably under a different set of assumptions.

If however wind generation does not contribute to the provision balancing services and wind forecasting errors do not reduce (beyond 2020 projection) ("Base" case in Figure 3.6 and Figure 3.7) renewable curtailment in GB increases from 63 to 98 TWh in the counterfactual scenario in 2050 (when no balancing technologies are deployed). The total new interconnection capacity in the scenario with the low-cost balancing technologies remains broadly similar as before (27 GW). However, annual system benefits in this case increase from £5.2bn to £11.2bn per annum as a result of saving more wind compared to the relevant counterfactual scenario, and the displacement of expensive CCS capacity installed in the counterfactual scenario in order to meet the carbon emission targets.

Emergence of GB as hub for Irish wind energy. In all cases where the installation of new interconnection capacity is allowed post-2020, the model, optimising from the (European) whole-system perspective, chooses to reinforce the GB-Ireland interconnectors, as well as the interconnection between GB and CE. Given that GB is assumed to be energy-neutral, this has a consequence of transporting part of the excess wind energy from Ireland through GB (following the assumption that a significant expansion of Irish wind capacity will take place), where it is combined with the GB wind resource and exported further to CE. In order to test the strength of the economic case for the proposition of GB becoming a hub for British and Irish wind energy, we have investigated the assumption that GB does not pursue such policy, i.e. that GB interconnection capacity to Ireland does not increase beyond 2020. The analysis suggests that only slightly more capacity is added to the GB-CE border (19 GW instead of 18 GW), while overall system benefits remain virtually unchanged at £11.2bn. The impact on renewable curtailment across the system is also modest. Instead of connecting Ireland with GB, the model builds a stronger IE-CE interconnection in order to transport Irish wind energy. These figures imply that although there are system benefits in connecting Ireland to CE via GB, the economic advantages of that proposition may not be significant.

High uptake of DSR in Europe. We have further found that the presence of additional flexibility in Europe and Ireland in the form of DSR reduces the need for new interconnection capacity between GB and CE. The GB-CE capacity in the "Base" case reduces from 18.5 GW to 7.3 GW in the low interconnection cost scenario, and if all balancing technologies are available at low cost, the capacity drops from 16.8 GW to

4 GW. At the same time the capacity of the GB-IE interconnection slightly increases (from 9 GW to 9.7 GW in the low interconnection cost case, and from 9.3 GW to 9.5 GW when all balancing technologies have low costs). Lower GB-CE interconnection capacity results directly from significantly reduced flexibility needs in Europe given the assumption that significant DSR resource is already available. This however has little impact on the overall system benefits (which increase by about £0.1bn as a result of high DSR uptake in Europe), while GB benefits on the other hand increase to a level exceeding system benefits, suggesting that European DSR is now supporting balancing within GB. This is different to the "Base" and "Imp" cases where GB's balancing technologies provide flexibility to Europe and Ireland, making GB-based benefits somewhat smaller than the system total. The impact on the internal GB transmission reinforcement has been found to be marginal.

Transmission reinforcement with interconnection constrained at the 2020 level. If we prevent the model from developing new interconnection capacity, the model builds different patterns of onshore reinforcement within GB. For example, when the model is allowed to choose how much interconnection to build, some onshore reinforcements take place primarily to transport Irish wind to continental Europe. The model also builds slightly more Scotland-England reinforcement where interconnection is not permitted.

Impact of self-security constraint. Another finding from our analysis is that if the self-security constraint is relaxed, i.e. if the interconnection capacity is allowed to contribute to security of supply (shared security), the efficient volume of interconnection would increase significantly, from 26.1 GW in the "Base" case to 39.6 GW in the low interconnection cost case (out of which 16.7 GW is added between GB and Ireland, and 22.9 GW between GB and Continental Europe). Generation CAPEX savings increase significantly as a result of interconnection displacing generators both in GB and in the rest of Europe. The amount of interconnection capacity added is again found to be rather insensitive to the cost and availability of other balancing technologies: moreover, if all balancing technologies are available at low cost, the optimal GB-CE interconnection capacity is even higher than in the low interconnection cost case (27.9 GW), while GB-IE capacity reduces to 15 GW. Also, the aggregate system benefit of balancing technologies, when they all have low cost or high availability, increases from £14.9bn to £17.2bn per annum, primarily as the results of the total GB generation capacity reducing by about 50 GW.

Combined effect of shared security and high DSR uptake in Europe. We carried out a further sensitivity analysis for 2050 to assess the additional value of interconnection when it is allowed to contribute to supply adequacy (shared security), combined with a high uptake of DSR outside the GB system. In this case, we find that the GB-CE capacity reduces to 10 GW, which is significantly lower than in the case when self security constraint is relaxed and low uptake of DSR in European system (22.9 GW), but higher than in the case of high DSR uptake in Europe and self security constraint enforced (7.3 GW). The optimal GB-IE capacity for the same case is 12.1 GW, which is again higher than in the high DSR uptake case, and even higher than in the "Base" case. We observe similar trends when all balancing technologies are available at low costs. System benefits with relaxed self-security and high DSR uptake in Europe total £15.7bn per annum (when all balancing technologies are available at low cost), which is higher than the case with European DSR only (£15bn), but lower than in the system with relaxed security and no DSR in Europe (£17.2bn).

- ***Benefits of Demand-Side Response.*** Given that the deployment cost of DSR has not been considered, its performance in terms of reducing operating cost and investment is highly beneficial to the system. Minimum and maximum value of DSR are attained in the same cases as with storage, the minimum with low wind forecasting error ("Imp" case), and the maximum in the opposite ("Base") case.

  In contrast to the other options, our model does not optimise the deployment of DSR based on assumptions regarding its cost. The high/low cases are defined by assumptions on penetration (80% vs. 10%). We therefore only examine the contribution that moving from low to high penetration of DSR can make to meeting the balancing challenge, i.e. minimising the costs of balancing the system. In our models DSR provides both energy and ancillary services. The exercise of the DSR does not involve any compromises on the services levels delivered by appliances involved in delivering flexibility.

  Competition with distributed storage. Our analysis indicates that DSR competes most strongly with distributed storage. Absolute levels of benefits are even higher than for storage, as there is no cost associated with DSR deployment. The level of investment in storage (storage CAPEX) is the lowest when DSR is present. This competition exists because these two options are the only ones to be able to achieve savings in distribution network reinforcement.

  Impact of high DSR uptake in Europe. Our sensitivity analysis which focused on the impact of high DSR uptake in Continental Europe and Ireland suggests that the value achieved by DSR in GB is not significantly affected by the presence of DSR outside the GB system. This is partly a result of the fact that only DSR within GB is assumed to be able to reduce generation capacity requirements and distribution network investment in the GB system; European DSR is therefore limited to reducing OPEX and transmission and interconnection CAPEX. Furthermore, the contribution of European DSR in supporting GB system balancing is limited given that the interconnection capacity between GB and the neighbouring systems is limited to 2020 levels in the case when DSR is the only low-cost (i.e. high-availability) balancing technology.

  Although our modelling shows the benefits available from increasing DSR penetration, the level of deployment that is optimal will depend on the costs associated with increasing the uptake i.e. acceptance rates of DSR.

- ***Benefits of combined alternative balancing technologies.*** The overall savings available from the use of alternative balancing technologies, based on our range of assumptions on the costs or availability of each technology, are between £5bn and £15bn per annum in 2050, and between £4bn and £15bn per annum in year 2040.

  These savings arise because of reduced expenditure on generation CAPEX (largely caused by not having to build expensive CCS capacity for peak demand, in order to meet the carbon emission targets), lower operating costs driven primarily by reduced wind curtailment, and reductions in investments in transmission and distribution network capacity. Renewable energy curtailment, for instance, reduces from between 63 and 98 TWh in the 2050 counterfactual scenario to between 6 and 14 TWh if different combinations of balancing technologies are used. We observe that in Pathway A, when all balancing technologies are available at low cost, the total system savings are dominated by savings in OPEX and generation CAPEX. We also find that the majority of benefits in this Pathway are generated within GB.

- ***Additional sensitivity analyses.*** In order to test the robustness of our findings to the uncertainty of particular input assumptions, several additional sensitivity studies have been carried out for Pathway A (with the high-level implications potentially applicable to other Pathways). They include:

  The impact of alternative heat pump operation. There is currently considerable uncertainty regarding the operation patterns of heat pumps in the highly electrified heating sector projected for the future; one possibility is that operation of heat pumps would be similar to the present gas boilers or micro CHP; on the other hand, heat pumps may have lower power ratings and hence operate, during very cold days, for longer periods of time.

  Our analysis demonstrates that if heat pumps had lower power ratings, peak demand would be reduced by about 16 GW (or 11%) in 2050, but this would also result in increased energy consumption during very cold days due to the extended operation of heat pumps in order to maintain the same comfort levels i.e. the indoor temperature at acceptable levels,[57] although the increase in energy consumption would not be critical at an annual level. Given that the resulting peak demand is lower, the requirements for backup generation and distribution network reinforcement will be lower in the counterfactual case. We also observe that due to a flatter demand profile the energy content of storage facilities would need to increase from hours to several days' worth of energy content. This would have significant implications on the target cost of storage.

  Our analysis shows that the reduction in benefits from deploying a portfolio of balancing technologies due to lower ratings of HPs, when compared to the corresponding counterfactual, ranges from £2.5bn in the minimum benefit case (i.e. when all options have high cost or low availability) to £5bn in the maximum benefit case (all options at low cost or high availability).

  The impact of high storage efficiency. The optimal deployment of distributed storage would increase if the cycle efficiency of storage improves.[58] Our model suggests that about 50% more distributed storage capacity is built if the efficiency increases from 75% to 95%. Similar to distributed storage, the optimal volume of bulk storage increases if storage efficiency improves; for the case when efficiency improves from 75% to 95% we observe that the amount of bulk storage increases very significantly. Highly efficient storage (both bulk and distributed), when combined with other balancing technologies, increases the total system savings by about £0.5bn.

  The impact of smart voltage control in Low Voltage distribution networks. Reinforcements of the distribution network can be driven either by thermal constraints or voltage constraints. In many representative networks analysed in this study (e.g. semi-urban

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57 This would lead to increased energy consumption during those periods, i.e. the daily energy consumption would be higher than in the case of heat pumps with higher ratings.

58 Cycle efficiency of storage refers to the percentage of energy which, upon charging into storage, is extracted when storage is discharged again (in one charge-discharge cycle). For example 75% cycle efficiency, if 1 MWh of energy is charged into empty storage, when that energy is recovered from storage, only 0.75 MWh is obtained due to losses in the charging and discharging processes.

networks) we observe that voltage limitations become binding before thermal limits are reached. Resolving voltage constraints can be carried out either by circuit reinforcements or by installing voltage control devices. Our previous analyses demonstrated that the application of smart voltage control in distribution networks (in-line voltage regulators in low-voltage networks) could potentially reduce the cost of necessary reinforcement by about 30%.[59] This would reduce the benefits from deploying distributed storage and DSR as the scope to contribute to avoiding network reinforcement would be considerably reduced. This could have a further effect of shifting the balance between bulk and distributed storage towards more bulk capacity being built.

Table 3.2 provides a summary of benefits and volumes of balancing technologies reported in this section, along with the results of additional sensitivity analyses conducted for this Pathway. We note that although there is considerable difference in system benefits from deploying flexible balancing technologies between the "Baseline" and "Improved" cases, the deployed volumes of balancing technologies differ only slightly. This can be explained by much higher marginal benefits generated by the first units of capacity of balancing technologies in the "Baseline" case, which is characterised by very high levels of renewable curtailment. After a certain volume of balancing technologies has been added, their marginal benefits converge to similar values as in the "Improved" case, which results in similar capacities being deployed, but the cumulative benefits (which also include the benefits of the first units of capacity) remain at a significantly higher level than in the "Improved" case.

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[59] ENA and 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.

Table 3.2. Summary of benefits and volumes of alternative balancing technologies for Pathway A in 2040 and 2050

PATHWAY A – Interconnection*	2040		2050	
Baseline	£11.1bn	(8.9+13.6) GW	£11.2bn	(9.0+18.5) GW
Improved	£5.2bn	(8.9+13.3) GW	£5.2bn	(9.0+18.2) GW
Additional sensitivity studies (Baseline)`				
Interconnection providing security	n/a	n/a	£13.9bn	(14.3+21.1) GW
High uptake of European DSR	£10.3bn	(7.9+8.1) GW	£11.3bn	(9.7+7.3) GW
Interconnection providing security + European DSR	n/a	n/a	£11.7bn	(11.6+9.5) GW
Restricted interconnection with IE	n/a	n/a	£11.2bn	(0.0+19.5) GW
European DSR and restricted link to IE	n/a	n/a	£11.0bn	(0.0+6.6) GW

* Capacity (GW) = (GB-IE + GB-CE)

PATHWAY A – Flexible generation	2040		2050	
Baseline	£11.1bn	64.1 GW	£10.8bn	94.9 GW
Improved	£5.0bn	65.2 GW	£4.5bn	97.5 GW
Additional sensitivity studies (Baseline)				
High uptake of European DSR	£10.2bn	49.0 GW	£11.2bn	28.9 GW

PATHWAY A – Storage	2040		2050	
Baseline	£10.9bn	15.8 GW	£12.0bn	22.1 GW
Improved	£4.7bn	15.2 GW	£5.6bn	21.1 GW
Additional sensitivity studies (Baseline)				
High uptake of European DSR	£10.9bn	20.4 GW	£11.7bn	22.5 GW

PATHWAY A – DSR	2040		2050	
Baseline	£12.7bn	n/a	£14.3bn	n/a
Improved	£6.8bn	n/a	£8.1bn	n/a
Additional sensitivity studies (Baseline)				
High uptake of European DSR	£13.0bn	n/a	£13.9bn	n/a

PATHWAY A – All options	2040		2050	
High cost	£4.1bn	n/a	£4.7bn	n/a
Low cost	£14.8bn	n/a	£14.9bn	n/a
Additional sensitivity studies (Low cost)				
Interconnection providing security*	n/a	n/a	£18.5bn	n/a
High uptake of European DSR**	£14.0bn	n/a	£15.0bn	n/a
Interconnection providing security + European DSR***	n/a	n/a	£15.4bn	n/a
Restricted interconnection with IE****	n/a	n/a	£14.9bn	n/a
European DSR and restricted link to IE*****	n/a	n/a	£14.6bn	n/a

* Optimal interconnection capacity in 2050 increases from 26.1 to 36.3 GW.
** Optimal interconnection capacity in 2050 reduces from 26.1 to 13.5 GW.
*** Optimal interconnection capacity in 2050 reduces from 26.1 to 15.9 GW.
**** Optimal interconnection capacity in 2050 reduces from 26.1 to 18.3 GW (GB-CE only).
***** Optimal interconnection capacity in 2050 reduces from 26.1 to 2.6 GW (GB-CE only).

3.3. Pathway B

In this section we highlight the findings associated with Pathway B, primarily focusing on the changes compared to the results of Pathway A. Figure 3.13 and Figure 3.14 present the system savings across different scenarios on cost and availability of balancing technologies for Pathway B in 2040 and 2050, using the same layout as in Figure 3.2. Given that the penetration of intermittent renewables in Pathways B, C and D is much lower than in Pathway A, our studies show that wind forecasting error and wind contribution to reserve provision in these three Pathways only have a minor impact on the overall system benefits. We therefore present only the results referring to the "Base" sensitivity in Pathways B, C and D.

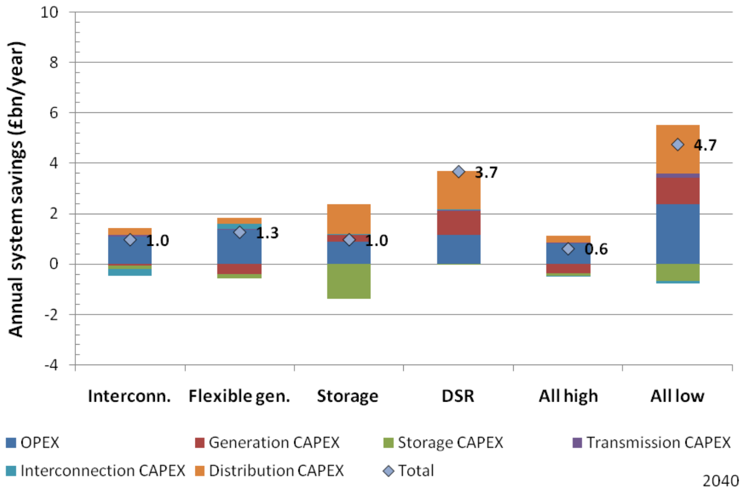

Figure 3.13. System benefits in Pathway B (year 2040)

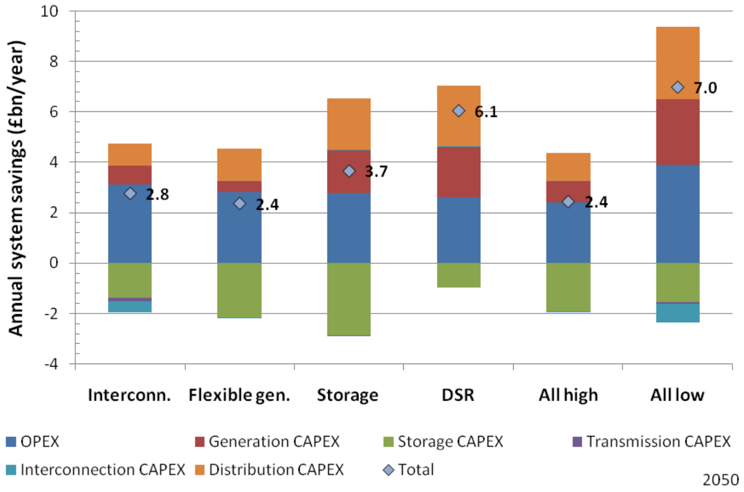

Figure 3.14. System benefits in Pathway B (year 2050)

We observe that OPEX savings across different cost scenarios for balancing technologies are substantially higher in 2050 than in 2040 (by £1-2bn/year), as a result of much higher renewable curtailment in the 2050 counterfactual scenario (45 TWh vs. only 0.6 TWh in 2040). We further note that OPEX savings in 2040 are not very significant when storage is the only low-cost option, given that the marginal cost of nuclear output is relatively low, there is much less benefit in saving wind curtailment. As in Pathway A, we observe that the majority of OPEX benefits in Pathway B are located within GB across the range of scenarios on balancing technologies for both 2040 and 2050.

Generation CAPEX savings are much higher in 2050. This is because of the increased deployment of storage and DSR, which are also able to displace significant generation capacity, while also generating distribution CAPEX savings due to higher levels of demand electrification in 2050.

Distribution network CAPEX savings are also visibly higher in 2050 than in 2040, especially when DSR or storage (or both) are available at low cost. This follows from the fact that the increase in demand in Pathway B is the most significant across all Pathways, requiring substantial distribution network reinforcement, which DSR and distributed storage can mitigate.

Minimum benefits when all options have high costs are equal to £2.4bn per year in 2050 and £0.6bn in 2040. The maximum benefit achieved in the case when all options are available at low costs is £7bn in 2050 and £4.7bn in 2040. The overall level of benefits in the Pathway B is visibly lower than in Pathway A, largely due to reduced renewable curtailment in the counterfactual.

System benefits in year 2040 for Pathway B (Figure 3.13) show a similar trend as in 2050, but on a considerably smaller scale, given that the balancing challenge in 2040 is expected to be less severe due to lower electrification levels.

Figure 3.15 illustrates the efficient volumes of balancing technologies added to the system in Pathway B across the range of scenarios and sensitivity studies in 2040 and 2050. The same layout is used as in Pathway A.

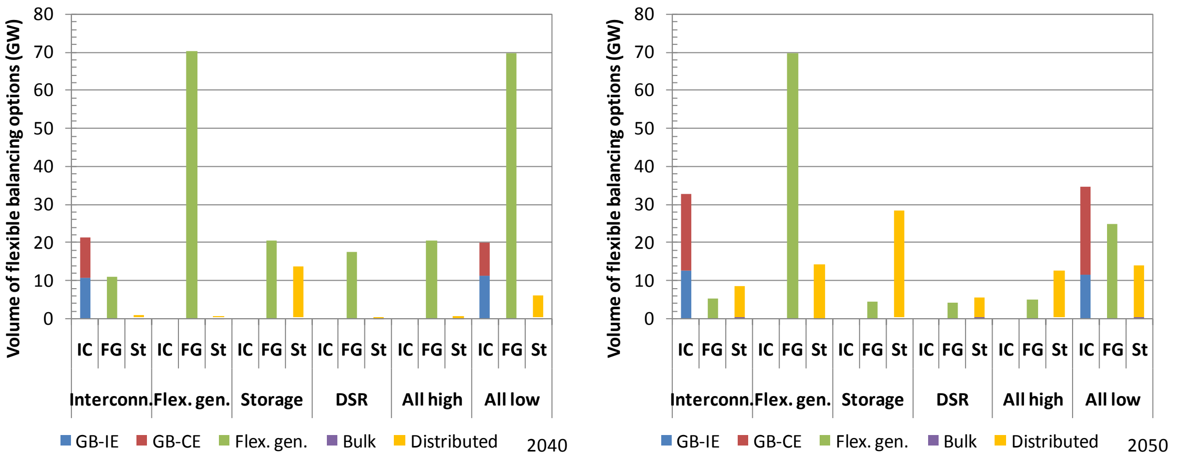

Figure 3.15. Optimal volumes of alternative balancing technologies in Pathway B in 2040 (left) and 2050 (right)

The optimal deployed volumes of flexible generation reduce considerably between 2040 and 2050, except when flexible generation is the only low-cost option. The interconnection capacity increases by some 10-15 GW between 2040 and 2050, and storage capacity increases by a similar amount. The increase in storage capacity, especially distributed storage, is driven by very high electrification levels projected for 2050 in Pathway B (peak demand in 2050 is around 190 GW, as opposed to 150 GW in 2040).

- *Benefits of Storage*. Under our assumptions on the cost of storage, the model chooses to build less bulk than distributed storage capacity in this Pathway (different cost assumptions on storage may generally result in different outcomes). This is illustrated in Figure 3.16 with bars representing the average volumes of storage built in 2040 and 2050 when only one option has low cost and others have high costs, or if all are available at low or high cost. In the case where storage is the option that has low cost, both bulk and distributed storage have low costs. Most of the storage capacity is built as distributed storage to gather the benefits of avoided cost to the distribution networks.[60] We also observe that the volume of distributed storage increases considerably between 2040 and 2050, largely as a result of increased demand electrification which increases the total GB peak demand from about 150 GW in 2040 to about 190 GW in 2050.

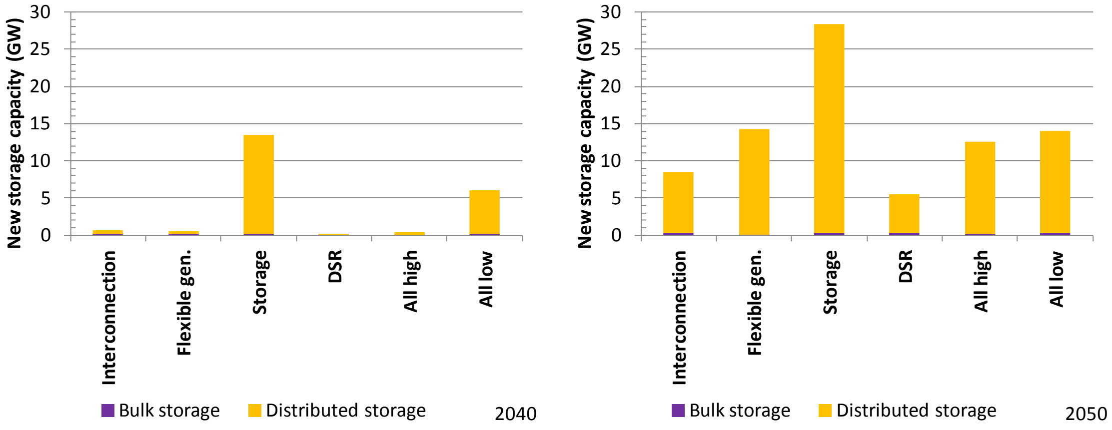

Figure 3.16. Deployment of storage in Pathway B (2040 and 2050)

In 2050, around 5 GW distributed storage is constructed when DSR level is high and storage has high costs; 28 GW of distributed storage is built if it has low cost and DSR uptake levels are low; 8-14 GW is built in other cases. In 2040 we observe 13 GW of distributed storage being built if it is the only low-cost option, while around 6 GW is chosen if all options have low cost (only very small amounts are chosen in other cases).

The composition of benefits of storage is much more balanced between operating cost savings, generation and distribution CAPEX than for instance interconnection or flexible generation. Distribution network savings tend to be more pronounced than in Pathway A due to larger assumed electricity demand for Pathway B. Also, because of the ability to provide distribution network savings, the volume of storage varies far less across the range of sensitivities analysed in this study (unlike for instance flexible generation).

- *Flexible generation*. Figure 3.17 illustrates the average volume of flexible generation in 2040 and 2050, installed across our sensitivity studies for various assumptions on cost and availability of balancing technologies (using the same layout as in Figure 3.16).

[60] We have carried out an additional case study where bulk storage is added as the only available flexible option, and the results indicate a higher level of deployment than when facing competition from distributed storage. At high storage cost, about 3.5 GW of new bulk storage capacity is built.

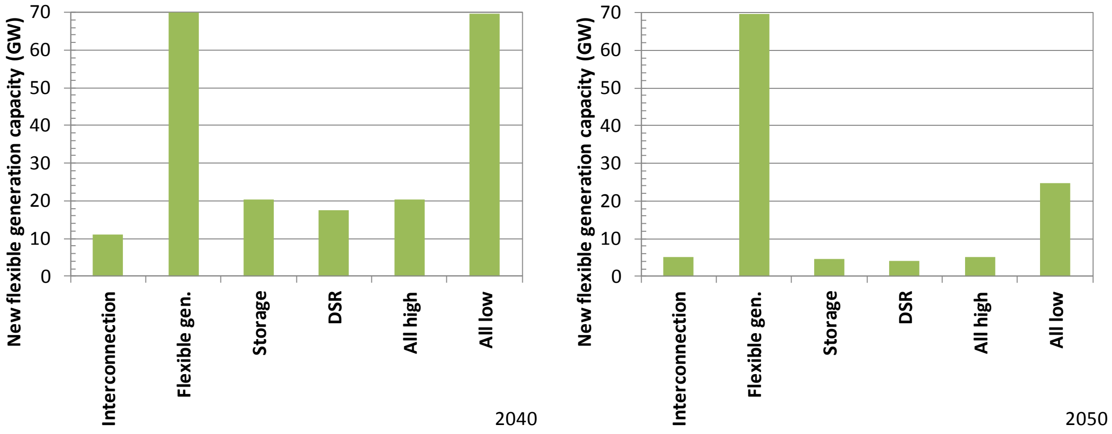

Figure 3.17. Deployment of flexible generation in Pathway B (2040 and 2050)

Given that the marginal cost of nuclear output is relatively low, there is much less benefit in saving wind curtailment, hence the value of flexibility for reducing operating cost is lower than in Pathway A.[61] There is therefore much tighter competition here between flexible generation and other options in providing system savings. In particular, we note that increased volumes of storage and DSR reduce the volume of flexible generation. This effect is more pronounced in 2050 than 2040, because of the expanded DSR potential due to increased demand, and increased opportunities for storage to increase the efficiency of the high nuclear-based system capacity while simultaneously capturing the benefits from avoiding significant distribution network reinforcement cost. In 2050, less than 5 GW of flexible generation is built when this option is characterised by high costs.

When available at low cost, flexible generation attains the annual system benefit of £2.4bn in 2050 and £1.3bn in 2040, with about 70 GW of flexible generation installed in GB. The majority of benefits come from operating cost savings as a result of reduced renewable curtailment.

- *Benefits of Interconnection.* Similar to previous figures, Figure 3.18 presents the average volumes of interconnection deployed between GB and its neighbours in 2040 and 2050, calculated across the range of sensitivities analysed in this study (there is again no new interconnection capacity in high interconnection cost cases[62]).

[61] In Pathway A the saved wind curtailment displaces gas and CCS generation, which has a higher operating cost than nuclear plant.

[62] High interconnection cost cases assume 2020 levels of interconnection capacity.

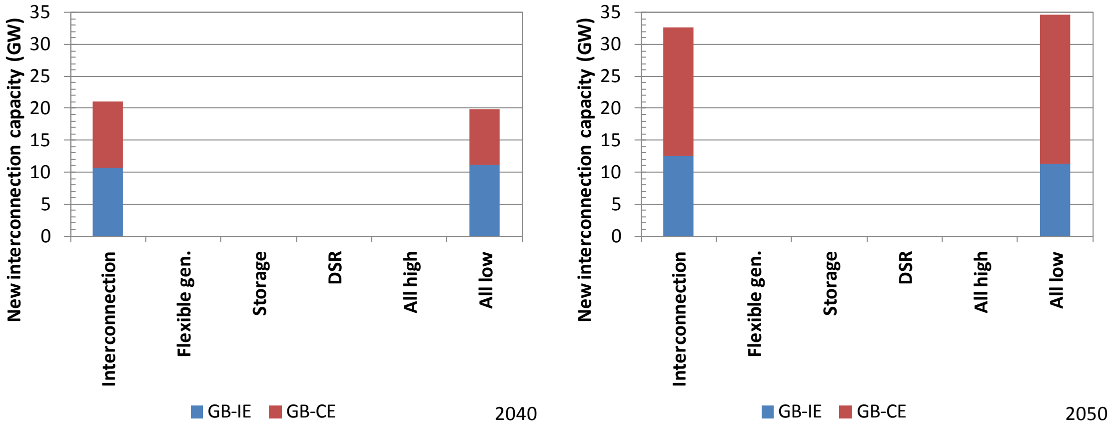

Figure 3.18. Deployment of interconnection capacity in Pathway B (2040 and 2050)

There is a notable increase in optimal capacity between 2040 and 2050, which is the result of a greater balancing challenge; a large amount of less flexible nuclear generation (75 GW) is combined with very high and rather peaky demand. It is interesting to note that the interconnection capacity also increases when all flexibility options are available. This is because the operation of DSR and storage is driven by peak demand reductions in order to minimise distribution network reinforcement costs, which in turn would lead to increased renewable generation curtailments that are efficiently avoided by increasing capacity of interconnection.

In the scenario where interconnection is the dominant flexible option, the majority of benefits arise from savings in operating cost, i.e. avoided renewable curtailment. Because the interconnection is assumed not to contribute to system security, generation CAPEX savings are modest and are the result of storage and DSR appearing as part of the portfolio. Installed capacity of interconnectors in this case is 13 GW between GB and Ireland, and 20 GW between GB and CE.

The greatest value achieved by deploying interconnection is obtained for the sensitivity study where the self-security criterion is relaxed, i.e. when interconnections are allowed to contribute to the security of supply. The operating cost component of savings changes very little from the minimum benefit case, but generation CAPEX savings increase significantly as a result of interconnection displacing generators both in GB and in the rest of Europe. The volumes of interconnection increase considerably at the same time: 18 GW is installed between GB and Ireland, and 48 GW between GB and CE. This is driven by the fact that Pathway B is characterised by very high peak demand (190 GW), which in the counterfactual case requires the construction of significant additional generation capacity to ensure security of supply. If interconnection is allowed to contribute to security, given that its investment cost is generally lower than the cost of generation capacity, the interconnectors reduce generation capacity requirements on both sides of the link. In this case of shared security, when interconnection is available at low cost and all other options at high cost, the generation capacity requirement in GB reduces by 78 GW compared to the counterfactual self-secure case, and by about 65 GW compared to the self-secure case with low-cost interconnection. Our analysis shows that relying on interconnection for security brings more than £3.5bn of additional net savings compared to the self-secure case for the assumed generation and demand background for the European and Irish systems, so that the total system savings reach £6.5bn annually. The savings are achieved despite a large investment in interconnection capacity, because of saved generation CAPEX that is a multiple of interconnection investment.

We also observe a major impact as a result of a high penetration of DSR in Europe on the optimal levels of interconnection. With DSR active outside GB only about 3.1 GW of new interconnection capacity is installed between GB and CE in 2050, while the GB-IE capacity remains close to 12 GW (i.e. self-security criterion is enforced). The substantial additional flexibility in CE is now sufficient to efficiently balance the CE system without relying on flexibility from GB provided via the GB-CE interconnection link. The overall system savings on the other hand increase to £3.2bn annually in 2050, compared to the "Base" low interconnection cost case (£2.9bn).

Our further sensitivity analysis suggests that the existence of additional flexibility in Europe and Ireland in the form of DSR may affect the volumes of interconnection installed to displace generation capacity for the purpose of providing security of supply. The optimal GB-CE capacity in this case is 9.7 GW, much lower than in the shared security case (47.6 GW), but higher than in the case with enforced self-security and high DSR uptake in Europe (3.1 GW). Similarly, the GB-IE capacity is chosen at a level between the shared-security case and high European DSR uptake case: 16.6 GW as opposed to 17.9 GW and 12.1 GW, respectively. The total system savings resulting from shared security reduce significantly with an increased DSR penetration in Europe, to the level of £3.5bn annually (which is still higher than £3.2bn savings in the high European uptake case).

- *Demand-Side Response*. The benefits of DSR are found to be considerable. Absolute levels of benefits are higher than for storage, as no cost has been assumed for DSR deployment, and the level of investment in storage is the lowest when DSR is present due to their direct competition, especially with respect to savings in distribution network investment. Composition of benefits of DSR is also rather balanced, with distribution CAPEX, generation CAPEX and OPEX savings each contributing about a third of the total benefit.

Table 3.3 provides a summary of benefits and volumes of balancing technologies reported in the figures in this section, and the results of all additional sensitivity analyses conducted in this Pathway.

Table 3.3. Summary of benefits and volumes of alternative balancing technologies for Pathway B in 2040 and 2050

PATHWAY B – Interconnection*	2040		2050	
Baseline	£1.0bn	(10.7+10.3) GW	£2.8bn	(12.7+19.8) GW
Additional sensitivity studies (Baseline)				
Interconnection providing security	n/a	n/a	£6.5bn	(15.0+46.2) GW
High uptake of European DSR	£1.0bn	(11.7+0.0) GW	£3.2bn	(12.1+3.1) GW
Interconnection providing security + European DSR	n/a	n/a	£3.5bn	(16.6+9.7) GW
Restricted interconnection with IE	n/a	n/a	£2.1bn	(0.0+22.4) GW

* Capacity (GW) = (GB-IE + GB-CE)

PATHWAY B – Flexible generation	2040		2050	
Baseline	£1.3bn	70.0 GW	£2.4bn	69.5 GW
Additional sensitivity studies (Baseline)				
High uptake of European DSR	£0.7bn	31.7 GW	£2.5bn	10.5 GW

PATHWAY B – Storage	2040		2050	
Baseline	£1.0bn	13.9 GW	£3.7bn	28.9 GW
Additional sensitivity studies (Baseline)				
High uptake of European DSR	£0.8bn	16.3 GW	£3.4bn	28.2 GW

PATHWAY B – DSR	2040		2050	
Baseline	£3.7bn	n/a	£6.1bn	n/a
Additional sensitivity studies (Baseline)				
High uptake of European DSR	n/a	n/a	£6.3bn	n/a

PATHWAY B – All options	2040		2050	
High cost	£0.8bn	n/a	£2.5bn	n/a
Low cost	£4.7bn	n/a	£7.0bn	n/a
Additional sensitivity studies (Low cost)				
Interconnection providing security*	n/a	n/a	£11.2bn	n/a
High uptake of European DSR**	£3.5bn	n/a	£7.4bn	n/a
Interconnection providing security + European DSR***	n/a	n/a	£7.4bn	n/a
Restricted interconnection with IE****	n/a	n/a	£6.2bn	n/a

* Optimal interconnection capacity in 2050 increases from 35.4 to 59.5 GW.
** Optimal interconnection capacity in 2050 reduces from 35.4 to 10.8 GW.
*** Optimal interconnection capacity in 2050 reduces from 35.4 to 14.9 GW.
**** Optimal interconnection capacity in 2050 reduces from 35.4 to 26.0 GW (GB-CE only).

3.4. Pathway C

Figure 3.19 and Figure 3.20 present the potential savings across different portfolios of balancing technologies for Pathway C in 2040 and 2050, using the same layout as for Pathway B.

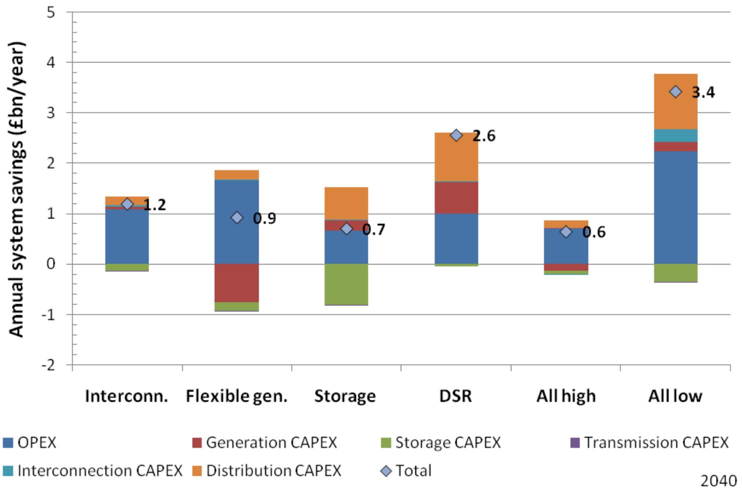

Figure 3.19. System benefits in Pathway C (year 2040)

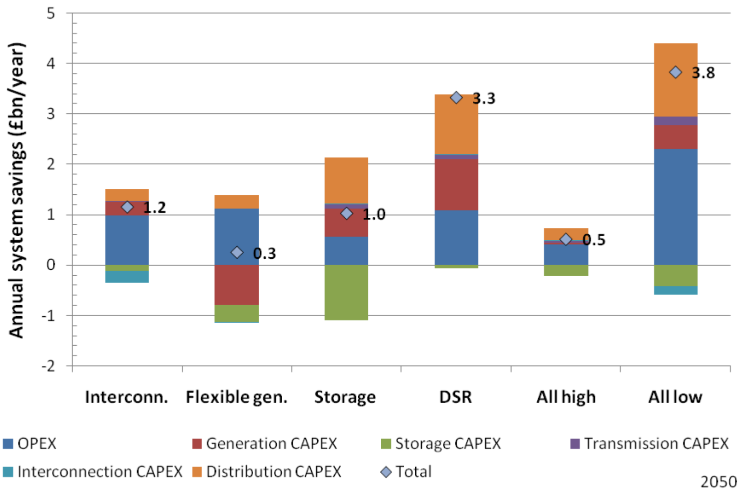

Figure 3.20. System benefits in Pathway C (year 2050)

Unlike the previous two Pathways, in Pathway C there is a general tendency for the majority of OPEX benefits in the system to be generated outside GB (generation, transmission and distribution CAPEX savings are still confined to GB borders). This is driven by a lower benefit of reduced OPEX in GB, as there is much less renewable capacity installed and the level of electrification is lower than in Pathways A and B. Also, there is a similar magnitude of the balancing challenge in 2040 and 2050 (2050 features less renewable generation, but a higher rate of demand electrification). The optimal solution therefore involves using balancing technologies in GB to reduce European OPEX (e.g. by avoiding renewable curtailment); given that CE scenarios involve a significant contribution of renewable generation. OPEX savings in Europe are sometimes even achieved at the expense of negative OPEX savings in GB, in order to maximise the efficiency of the operation of the entire interconnected GB-IE-CE system. A minor exception to this trend is the case where DSR is the only low-cost option, in which case most OPEX savings occur in GB, where DSR helps by increasing the load factors of more efficient plants. Another finding from our studies is that if additional flexibility is present in the CE system in the form of large DSR penetration, the benefits provided to the European system almost completely vanish, and the volumes of balancing technologies reduce accordingly.

Distribution CAPEX savings are low unless DSR or distributed storage is available at low cost. We also note that the avoided distribution network reinforcement cost increases between 2040 and 2050 due to increasing demand.

Balancing technologies in Pathway C achieve a visibly lower overall level of savings compared to Pathways A and B. The key driver for this is a relatively low level of electrification and limited renewable capacity installed in GB. System benefits in year 2040 for Pathway C show a very similar trend as in 2050, with some options and combinations even resulting in higher benefits (installed wind capacity in 2040 is higher than in 2050, while 2040 electrification levels are lower).

Figure 3.21 shows the optimal volumes of balancing technologies added to the system in Pathway C across the range of scenarios and sensitivity studies carried out for 2040 and 2050 (with the same layout used as in previous Pathways).

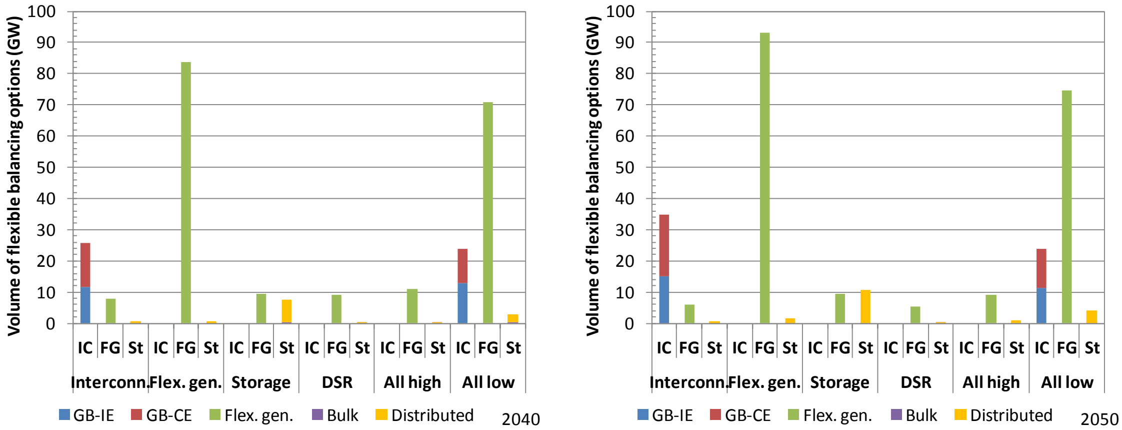

Figure 3.21. Optimal volumes of alternative balancing technologies in Pathway C in 2040 (left) and 2050 (right)

The optimal deployed volumes of flexible generation do not change significantly between 2040 and 2050. The interconnection capacity increases by about 7 GW between 2040 and 2050 (when interconnection is the only option available at low cost), while storage capacity broadly remains the same in both years.

- *Benefit of Storage*. As shown in Figure 3.22, which presents average optimal volumes of storage deployed across our sensitivity studies, the deployed volume of storage, when it is the only low-cost option, includes almost exclusively distributed storage, suggesting it is more cost-efficient than bulk storage at our cost assumptions. The volume of bulk storage in 2050 amounts to less than 1 GW, whilst up to 11 GW of distributed storage gets installed. The composition of benefits of storage is dominated by generation and distribution CAPEX savings, and a significant contribution from operating cost savings.

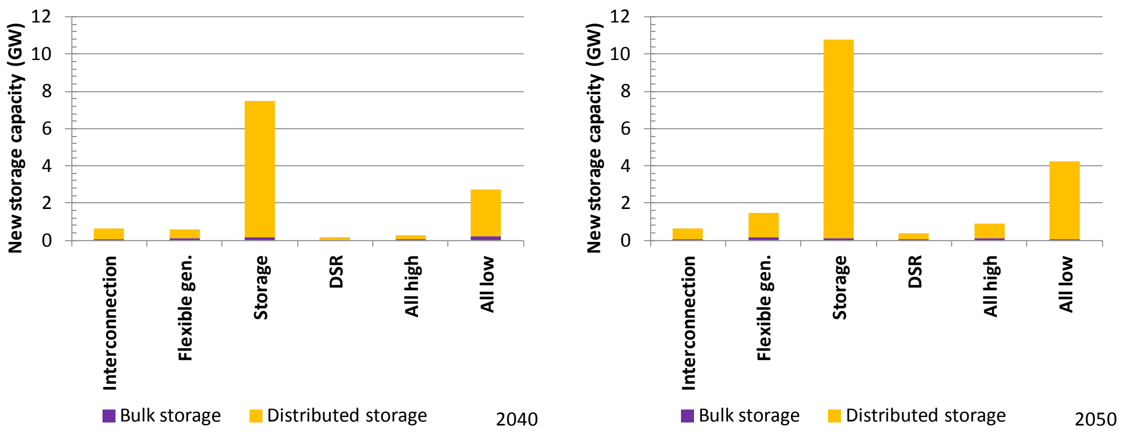

Figure 3.22. Deployment of storage capacity in Pathway C (2040 and 2050)

Deployment of distributed storage, as in other Pathways, is sensitive to its cost and the levels of DSR uptake. If the storage cost is low, around 11 GW of storage is built in 2050, while less than 2 GW is built if distributed storage is expensive (with only negligible amounts of high-cost storage added when competing with high-availability DSR). We also observe that the deployment of storage increases in 2050 compared to 2040 when storage has low cost, as a result of increased demand electrification and the ensuing distribution network reinforcement cost which distributed storages helps to mitigate.

- *Benefits of flexible generation*. Even when available at low cost, flexible generation brings relatively small benefits in this Pathway; this is because this Pathway has higher inherent flexibility in the assumed generation mix than other Pathways. The majority of benefits come from operating cost savings, which are however offset by extra investment in generation and storage capacity.

  However, substantial amounts are installed when generation flexibility is available at low cost (over 90 GW). Less than 10 GW of flexible generation is installed when generation flexibility is available at high cost. We also observe that the deployed volume of flexible generation in cases when it is available at low cost increases slightly between 2040 and 2050. The installed flexible generation is shown in Figure 3.23, for different cost and availability scenarios of balancing technologies.

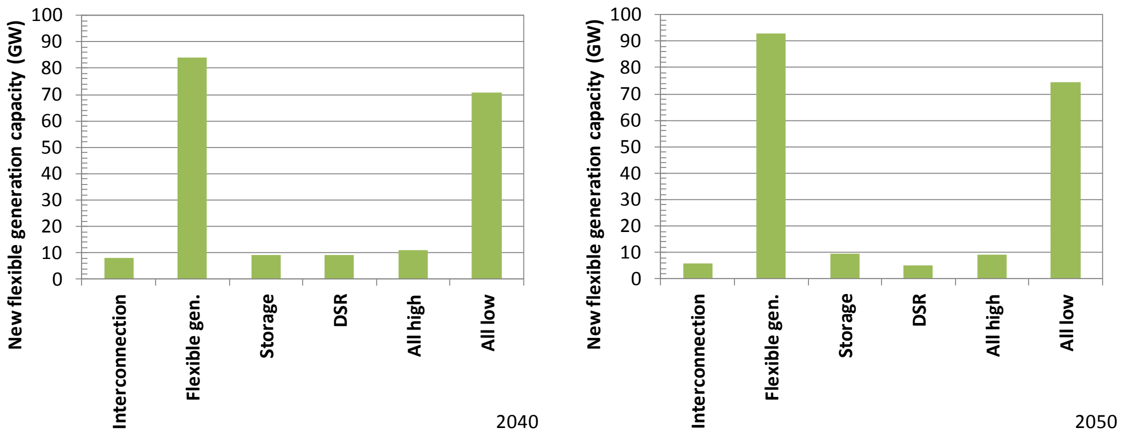

Figure 3.23. Deployment of flexible generation capacity in Pathway C (2040 and 2050)

- *Benefits of Interconnection.* Figure 3.24 presents the average optimal volumes of interconnection for Pathway C, laid out in the same way as for previous Pathways.

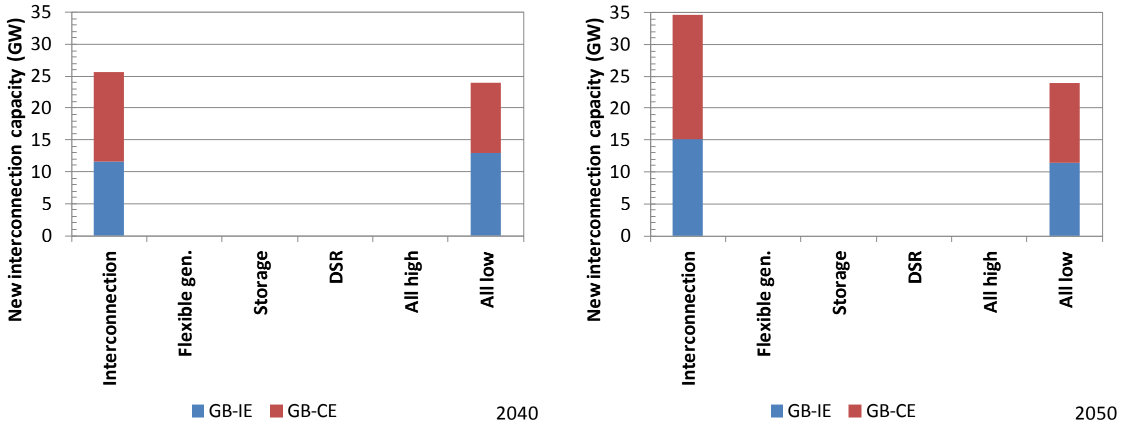

Figure 3.24. Deployment of interconnection capacity in Pathway C (2040 and 2050)

The volumes of interconnection are not highly sensitive to the cost and availability of other balancing technologies. About 12-15 GW is deployed between GB and Ireland, and 15-20 GW between GB and CE in 2050. 2040 interconnection levels are slightly lower than in 2050. It is important to note that interconnection is driven by the benefits that CCS generation can bring to balancing renewable generation in CE and Ireland, rather than specific GB needs. In the sensitivity with a high penetration of DSR outside GB and restrictions on the capacity of GB-IE, only 1 GW of new capacity is added between GB and CE, which also demonstrates that the interconnection in this case reduces the balancing cost outside GB.

- *Benefits of Demand-Side Response*. We find that the value of DSR rather insensitive to the contribution of wind to reserve management (given that the installed wind capacity in Pathway C is rather low). The composition of DSR benefits is quite balanced, with distribution CAPEX, generation CAPEX and operating cost savings contributing about one third each. High uptake of DSR again brings substantial benefits to the system.

Table 3.4 provides a summary of benefits and volumes of balancing technologies in Pathway C, as well as the results of all additional sensitivity analyses conducted.

Table 3.4. Summary of benefits and volumes of alternative balancing technologies for Pathway C in 2040 and 2050

PATHWAY C – Interconnection*	2040		2050	
Baseline	£1.2bn	(11.6+14.0) GW	£1.2bn	(15.1+19.5) GW
Additional sensitivity studies (Baseline)				
Interconnection providing security	n/a	n/a	£2.2bn	(14.7+23.8) GW
High uptake of European DSR	£1.3bn	(11.0+2.5) GW	£0.8bn	(10.3+0.0) GW
European DSR and restricted link to IE	n/a	n/a	£0.4bn	(0.0+1.1) GW

* Capacity (GW) = (GB-IE + GB-CE)

PATHWAY C – Flexible generation	2040		2050	
Baseline	£0.9bn	81.9 GW	£0.3bn	90.0 GW
Additional sensitivity studies (Baseline)				
High uptake of European DSR	£1.2bn	20.5 GW	£0.6bn	24.6 GW

PATHWAY C – Storage	2040		2050	
Baseline	£0.7bn	8.2 GW	£1.0bn	11.2 GW
Additional sensitivity studies (Baseline)				
High uptake of European DSR	£0.5bn	9.9 GW	£0.6bn	14.4 GW

PATHWAY C – DSR	2040		2050	
Baseline	£2.6bn	n/a	£3.3bn	n/a
Additional sensitivity studies (Baseline)				
High uptake of European DSR	£2.3bn	n/a	£2.9bn	n/a

PATHWAY C – All options	2040		2050	
High cost	£0.6bn	n/a	£0.5bn	n/a
Low cost	£3.4bn	n/a	£3.8bn	n/a
Additional sensitivity studies (Low cost)				
Interconnection providing security*	n/a	n/a	£6.1bn	n/a
High uptake of European DSR**	£3.3bn	n/a	£4.0bn	n/a
European DSR and restricted link to IE	n/a	n/a	£3.0bn	n/a

* Optimal interconnection capacity in 2050 increases from 23.9 to 42.3 GW.
** Optimal interconnection capacity in 2050 reduces from 23.9 to 11.0 GW.
*** Optimal interconnection capacity in 2050 reduces from 23.9 to 0.0 GW.

3.5. Pathway D

Figure 3.25 and Figure 3.26 present the potential savings across balancing technologies and with portfolios of balancing technologies for Pathway D in 2040 and 2050, using the same layout as for Pathways B and C.

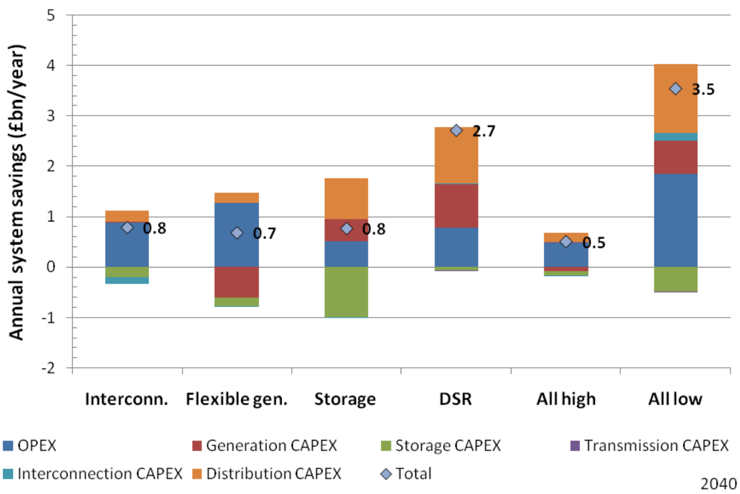

Figure 3.25. System benefits in Pathway D (year 2040)

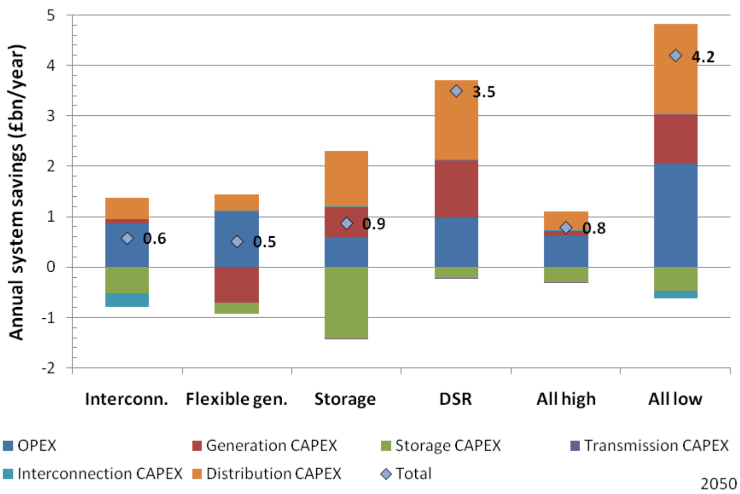

Figure 3.26. System benefits in Pathway D (year 2050)

System benefits in year 2040 for Pathway D follow a similar trend to those in 2050. The overall level of savings is somewhat lower than in 2050, suggesting a slightly reduced scale of balancing challenge in 2040 due to lower demand and lower renewable capacity in 2040. Total system savings are very sensitive to the cost and availability of balancing technologies; if all options are at high cost, only small amounts of balancing technologies are deployed, resulting in near-zero benefits, while in the case where all options have low costs the total savings can reach more than £4bn per annum.

The allocation of OPEX savings in the system is similar to Pathway C, i.e. we find these are shared between GB and the rest of Europe. We observe that storage is not as efficient as DSR in reducing OPEX, due to its efficiency losses in the process of storing energy.

Most generation CAPEX is saved when DSR or storage is available at low cost, and a similar remark is valid for distribution CAPEX as well. This is due to the reduced ability of the GB system to absorb Irish wind during peak hours, which is when DSR is most active in reducing demand to avoid distribution reinforcement cost.

In general, balancing technologies in Pathway D achieve lower overall levels of savings compared to Pathways A and B, due to lower electrification levels and less renewable capacity installed in GB.

Minimum benefits, when all options have high costs, are achieved in the case when wind generation does not contribute to the provision of balancing services, with total net savings at only about £0.8bn in 2050. The maximum benefits (£4.2bn) are observed in the case when all options have low costs. The overall level of benefits in Pathway D is significantly lower than in Pathways A and B, especially in cases where balancing technologies provide minimum benefits. This is largely due to less potential to reduce renewable curtailment in GB, and lower requirements for flexibility to accommodate the electrification of heat and transport sectors.

Figure 3.27 shows the optimal volumes of balancing technologies added to the system in Pathway D across the range of scenarios and sensitivity studies carried out for 2040 and 2050 (with the same layout used as in previous Pathways).

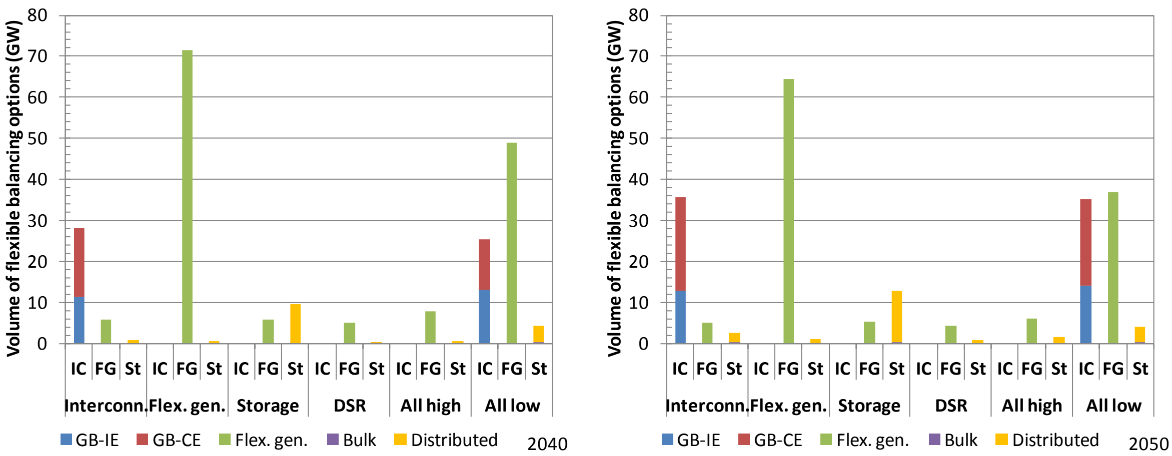

Figure 3.27. Optimal volumes of alternative balancing technologies in Pathway D in 2040 (left) and 2050 (right)

The optimal deployed volumes of flexible generation reduce between 2040 and 2050, across all cost/availability scenarios. The interconnection capacity increases by about 5-7 GW between 2040 and 2050, while storage capacity broadly remains similar.

- *Benefit of Storage*. In both minimum and maximum value cases only distributed storage is chosen for construction, suggesting it is more cost-efficient than bulk storage at the assumed cost levels. As shown in Figure 3.28, the average optimal volume of bulk storage amounts to less than 1 GW across all scenarios and sensitivities, while distributed storage gets installed at around 13 GW in 2050 when it is the only low-cost option.

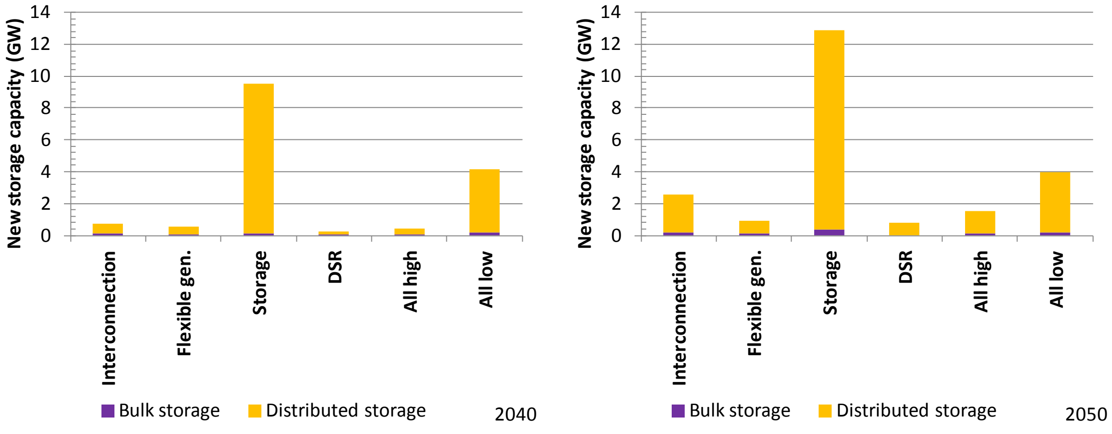

Figure 3.28. Deployment of storage capacity in Pathway D (2040 and 2050)

Deployment of distributed storage mostly depends on its cost and DSR uptake; very small amounts of distributed storage are chosen when it is expensive and DSR uptake is high; 1-2 GW is built in cases where other options are available at low cost. The optimal volumes increase between 2040 and 2050.

The benefits of storage reduce when exposed to competition from European DSR, although the deployed storage volume largely remains the same. The composition of benefits of storage is dominated by distribution and generation CAPEX savings, with a slightly higher contribution from operating cost savings in the maximum benefit case.

- *Benefits of flexible generation.* Figure 3.29 shows average optimal volumes of flexible generation deployed across the same scenarios and sensitivities as in previous Pathways.

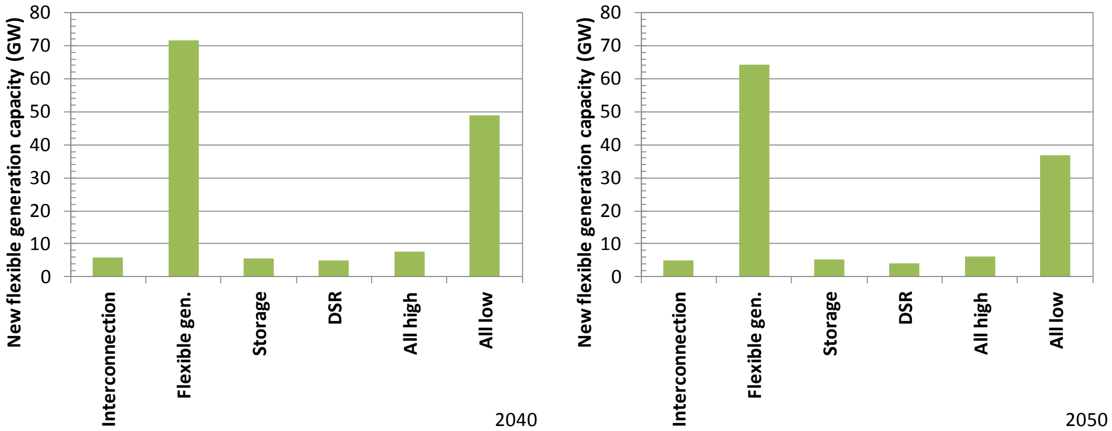

Figure 3.29. Deployment of flexible generation capacity in Pathway D (2040 and 2050)

In 2050 we observe that on average about 65 GW of flexible generation is installed if it is the only low-cost option, and about half of that amount is installed if other options are available at low costs as well. Less than 5 GW is installed when generation flexibility is available at high cost. The volumes in 2040 are slightly higher across all scenarios than in 2050, because there is less competition from storage and DSR in that year.

Flexible generation generates relatively low system benefits in this Pathway. The majority of benefits come from operating cost savings, which are to a large extent offset by extra investment in generation and storage capacity.

- *Benefits of interconnection*. As demonstrated in Figure 3.30, the optimal capacity of interconnection, if available at low cost, is not particularly sensitive to the costs/availability of other technologies. Around 35 GW is built in 2050, with the capacity of the interconnection to Ireland of around 13-14 GW. The optimal capacity in 2040 is 5-8 GW lower than in 2050, due to the lower scale of the balancing challenge.

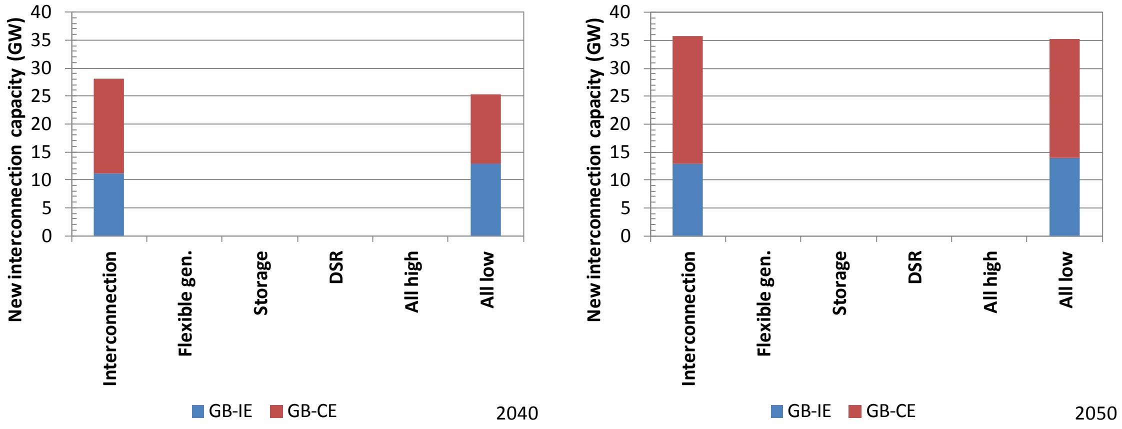

Figure 3.30. Deployment of interconnection capacity in Pathway D (2040 and 2050)

The overall level of benefits for interconnection is rather low (£0.6bn), although there is substantial new interconnection capacity installed – 13 GW is added between GB and Ireland, and 23 GW between Britain and Continental Europe. System savings are dominated by the operating cost component.

- *Benefits of Demand-Side Response*. The small differences between minimum and maximum cases for DSR indicate that DSR is rather insensitive to other parameters such as wind contribution to reserve, or even the existence of competing DSR resource outside GB. The composition of DSR benefits is a balanced mix of distribution CAPEX, generation CAPEX and operating cost savings.

Table 3.5 provides a summary of benefits and volumes of balancing technologies in Pathway D, compared with the results of additional sensitivity studies.

Table 3.5. Summary of benefits and volumes of alternative balancing technologies for Pathway D in 2040 and 2050

PATHWAY D – Interconnection*	2040		2050	
Baseline	£0.8bn	(11.2+16.9) GW	£0.6bn	(12.9+22.6) GW
Additional sensitivity studies (Baseline)				
Interconnection providing security	n/a	n/a	£2.1bn	(13.3+17.1) GW
High uptake of European DSR	£1.1bn	(10.9+2.2) GW	£0.8bn	(9.4+0.0) GW

* Capacity (GW) = (GB-IE + GB-CE)

PATHWAY D – Flexible generation	2040		2050	
Baseline	£0.7bn	67.9 GW	£0.5bn	62.5 GW
Additional sensitivity studies (Baseline)				
High uptake of European DSR	£0.5bn	17.3 GW	£1.0bn	12.8 GW

PATHWAY D – Storage	2040		2050	
Baseline	£0.8bn	10.0 GW	£0.9bn	14.4 GW
Additional sensitivity studies (Baseline)				
High uptake of European DSR	£0.9bn	10.7 GW	£0.6bn	14.9 GW

PATHWAY D – DSR	2040		2050	
Baseline	£2.7bn	n/a	£3.5bn	n/a
Additional sensitivity studies (Baseline)				
High uptake of European DSR	£2.7bn	n/a	£3.4bn	n/a

PATHWAY D – All options	2040		2050	
High cost	£0.6bn	n/a	£0.8bn	n/a
Low cost	£3.5bn	n/a	£4.2bn	n/a
Additional sensitivity studies (Low cost)				
Interconnection providing security*	n/a	n/a	£5.7bn	n/a
High uptake of European DSR**	£3.4bn	n/a	£4.9bn	n/a

* Optimal interconnection capacity in 2050 changes slightly from 35.4 to 36.0 GW.
** Optimal interconnection capacity in 2050 reduces from 35.4 to 10.9 GW.

3.6. Cross-Pathway Analysis of Balancing Technologies

This section provides a comparison of the performance of different balancing technologies across different Pathways (in terms of providing system benefits through reduced cost of operation and investment into the GB electricity system).

Figure 3.31 illustrates how the minimum and maximum savings from having a portfolio of balancing technologies available evolve over time for different Pathways. The chart is constructed so that Pathway A has separately evaluated benefits throughout the analysed time period (2020-2050), while the remaining three Pathways are plotted as continuing from the values found for 2020-2030 balanced EMR scenarios.

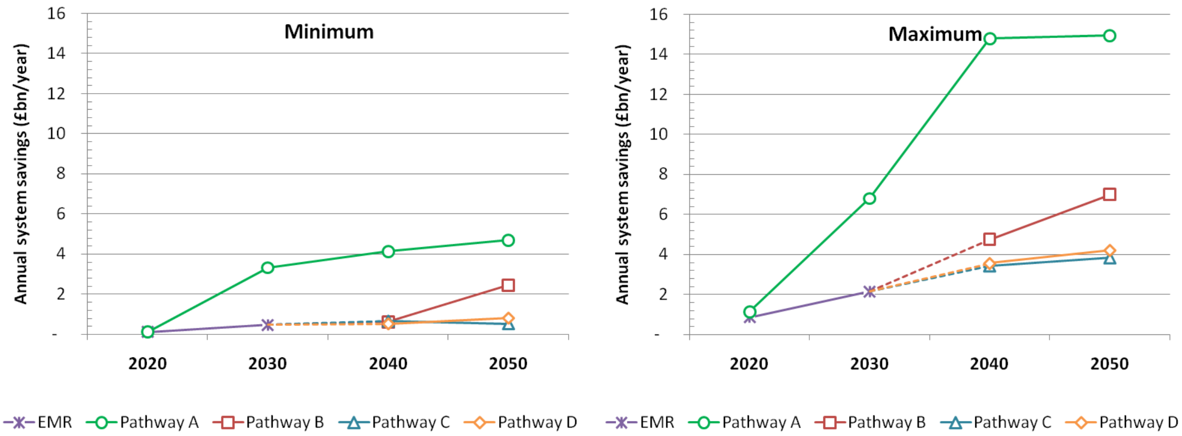

Figure 3.31. Minimum and maximum system savings with combinations of balancing technologies across Pathways and time

The value of balancing technologies, as well as the scale of the balancing challenge is clearly the greatest in Pathway A, followed by Pathways B, D and C. The maximum system benefits that could be achieved in 2050 if all balancing technologies are available at low cost ranges from around £15bn/year in Pathway A and £7bn/year in Pathway B, to around £4bn/year in Pathways C and D. Even when balancing technologies are available at high cost, the benefits in Pathway A are substantial, while in other Pathways the scope for high-cost flexible balancing options is reduced. We further note that the timing of a notable increase in the balancing challenge is dependent on the Pathway: the 2030 benefits in Pathway A are of similar magnitude as 2040 benefits in the other three Pathways.

We also find that a major part of system benefits of deploying balancing technologies is achieved in GB for Pathways A and B, while in Pathways C and D we note that the OPEX benefits are shared between GB and the rest of Europe, i.e. that balancing technologies in GB support system operation in continental Europe and Ireland, and reduce operating costs in these two systems.

3.6.1. Interconnection

Decisions regarding the deployment of interconnectors are highly sensitive to conditions prevailing in GB and the neighbouring markets. Our sensitivity studies indicate that the volume of interconnection may vary considerably: for example, assuming high uptake of DSR, or other flexibility in Europe, reduces interconnection levels between GB and CE; on the other hand allowing interconnections to provide security of supply to GB, increases the amount of efficient interconnection capacity significantly. Applying our central assumptions, we observe that in all Pathways the quantity of interconnection that the model suggests is efficient does not vary materially across scenarios or the cost of competing alternative balancing technologies. In general, a substantial volume of interconnections (in the order of tens of GW) is built across all scenarios when it is available at efficient cost (as described earlier, in the high cost case no new interconnections have been allowed beyond the expected 2020 capacity). The volume of new interconnection capacity built between GB and the neighbouring systems (above the levels expected in 2020) varies across 2050 Pathways as follows: Pathway A 26-27 GW, Pathway B 32-34 GW, Pathway C 24-35 GW, and Pathway D 35 GW. Under all scenarios where CE does not increase its own flexibility (e.g. through large-scale deployment of DSR), at least 10 GW is built to Continental Europe and 11 GW to Ireland.

The largest savings in 2050 from the combination of balancing technologies which is characterised by low-cost interconnection and other technologies at high cost, are achieved in Pathway A (£11.2bn per annum), followed by Pathways B (£2.8bn), C (£1.2bn) and D (£0.6bn per year).

A common occurrence in all Pathways is that interconnections to Ireland and to Continental Europe are significantly reinforced if the increase in interconnection capacity is allowed. Given that energy neutrality has been assumed for the GB system, this means that large quantities of surplus wind energy (based on the assumption of a significant expansion of Irish wind capacity) are imported from Ireland into GB, and then a similar annual amount of electricity is exported further into Continental Europe. This is driven by the fact that it is more cost-efficient to connect Ireland to Europe via GB, although the system-level benefits of GB becoming a hub for Irish wind energy are rather modest.

Impact of self-security criterion. Our sensitivity analysis conducted across all four 2050 Pathways suggest that when the self-security constraint is relaxed (i.e. interconnection is allowed to contribute to the security of supply to both GB and European systems), significantly more interconnection capacity is built. This results in a reduction in generation capacity requirements, given that generation capacity can be shared between regions through interconnection. We illustrate this effect in Figure 3.32, which presents the secure generation capacity across the four Pathways in 2050 for the scenario where all balancing technologies are available at low cost, and compares the self-secure cases with those allowing the sharing of security via interconnection lines. The chart on the right of Figure 3.32 depicts the newly constructed interconnection capacity for the self-secure and shared-security cases.

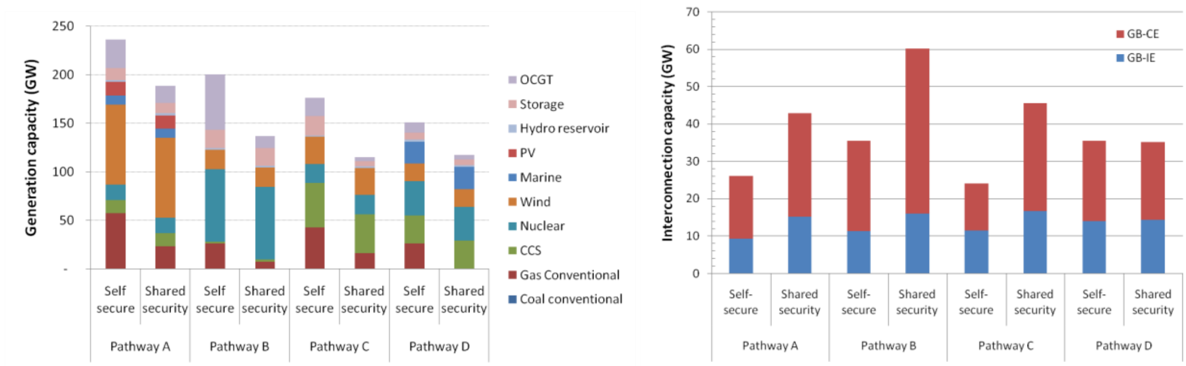

Figure 3.32. GB generation capacity in self-secure and shared-security cases (left) and new interconnection capacity for the same cases (for the scenario when all balancing technologies have low costs in 2050)

We observe that if interconnection is allowed to contribute to system security, generation capacity requirements in GB (as well as in Ireland and continental Europe) drop significantly (e.g. in Pathway A the generation capacity is reduced by about 50 GW, in Pathways B and C by over 60 GW, and in Pathway D around 30 GW). Also, system benefits of balancing technologies increase as a result, with shared security generating between £0.7bn (Pathway D) and £2.3bn (Pathway A) of additional system savings per annum across the four Pathways in 2050.

Capacity factors of interconnection. With respect to the utilisation of interconnection capacity, we observe rather high capacity factors for both GB-IE and GB-CE interconnectors, at the level of around 80-90% in all high-cost cases for interconnection (i.e. when no capacity is added beyond the 2020 levels). When new interconnection capacity is added (the low-cost cases for interconnection), the utilisation drops to 50-55% for the GB-CE interconnection, and to 55-75% for the GB-IE interconnection. Although these utilisation factors are lower, it has to be noted that these are achieved with a significantly expanded interconnection capacity (several times higher capacity levels than in 2020). We also observe that the dominant (although not exclusive) direction of electricity flow is to import energy from Ireland and export to CE. This tendency is more pronounced in scenarios with lower wind capacity in GB, as there is less diversity in the combined Irish and British wind output i.e. less occurrences of exporting excess wind energy from GB to Ireland. If we constrain the capacity of the Irish interconnection to the 2020 level, but allow the expansion of the CE interconnection, we observe a balanced import/export pattern through the CE interconnection, which ensures that the energy neutrality criterion is satisfied.

Asymmetrical benefits of interconnection. As noted previously, benefits generated by alternative balancing technologies deployed in GB or at its borders refer to the entire European system simulated in this study. The proportion of system-wide benefits that are gained within GB varies considerably across different Pathways and scenarios. Figure 3.33 illustrates this using the example of benefits created by deploying interconnection when it is available at low cost, while no other balancing technologies are available.

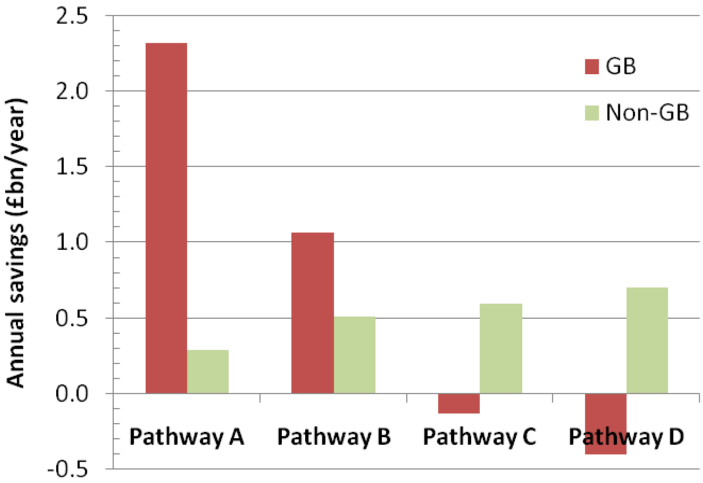

Figure 3.33. Comparison of benefits of interconnection generated within and outside GB in 2050 (for the case where interconnection is the only low-cost balancing technology)

We observe that in Pathways A and B the benefits located in GB dominate the overall system savings while the non-GB benefits less than half of GB benefits. In Pathways C and D on the other hand we notice a different trend, where GB in fact incurs additional costs compared to the counterfactual case, in order to support a more efficient operation of the overall European system (in both Pathways the savings achieved outside GB outweigh the additional cost in GB). This constitutes an optimal solution from the European-wide perspective; in reality, investing into balancing technologies in GB in order to support a more efficient operation of the systems of continental Europe and Ireland (or vice versa) would be contingent upon the existence of appropriate Europe-wide market and regulatory mechanisms to adequately remunerate the providers of flexibility for the benefits they provide to the system. This is discussed in more detail in Section 4.

3.6.2. Flexible generation

The volume of flexible generation deployed to support system operation and design appears most sensitive to the cost of generator flexibility and availability of interconnections. If flexible generation is available at low cost, we generally observe that a considerably high flexible generation capacity is selected by the model.

In Pathway A, 60-95 GW of flexible generation is built if available at low costs (more flexible generation is deployed when interconnection is limited and other competing options have high costs); if flexible generation is expensive, 10-15 GW is still built regardless of the characteristics of other balancing technologies. For Pathway B, between 25 and 70 GW is chosen for construction when the cost of flexibility is low (the volume is very sensitive to availability of interconnection and DSR); less than 5 GW of flexible generation is built when it is expensive. In Pathway C, between 75 and 92 GW of low-cost flexible generation capacity is deployed (the higher figure corresponds to the case when competing options are expensive), and less than 10 GW when generation flexibility is expensive. In Pathway D, new flexible generation capacity is 37-64 GW in the low-cost case, and around 5 GW for high cost of flexibility.

The largest amount of flexible generation is built in Pathways A and C, which are characterised either by very high penetration of intermittent renewables that require significant flexibility (A), or by the largest thermal generation capacity including CCS (C). The least amount of flexible generation is constructed in Pathway D, which is characterised by a more balanced generation mix, although the capacity is still high if flexible generation is available at low cost.

3.6.3. Bulk Storage

It should be emphasised that bulk storage has been offered as an option to the model *simultaneously* with distributed storage, with "synchronised" cost (either both bulk and distributed have low cost, or both have high cost). Given these assumptions, the model results indicate that bulk storage connected to the transmission network seems to be competitive only in Pathway A when DSR uptake is high (since this worsens the case for distributed storage); in such circumstances 2-3 GW of bulk storage is added to the system. In all other cases in Pathway A the bulk storage volume is less than 1 GW. In other scenarios (B, C and D) only marginal amounts of bulk storage are chosen, in the order of 0.1 GW.

Given that distributed storage offsets distribution network reinforcement while simultaneously facilitating more efficient system operation, distributed storage is more attractive than bulk storage in the majority of scenarios and Pathways analysed. However, if only bulk storage is available, significantly larger amounts would be installed, particularly in Pathway A, between 12 GW (at high cost) and 18 GW (at low cost), while the optimal deployment of bulk storage in other Pathways would be significantly lower due to less opportunities to reduce renewable curtailment. The location of bulk storage is found to be predominantly in Scotland, where it is able to capture the available wind resource while reducing the need for transmission grid reinforcement.[63]

3.6.4. Distributed storage

The efficient amount of distributed storage is found to be highly sensitive to its cost and the level of DSR in the system; on the other hand it is not sensitive to the level of interconnection and flexible generation.

Efficient volumes of distributed storage chosen across scenarios are as follows: in Pathway A 5-6 GW is built when DSR uptake is high (regardless of storage cost); if DSR uptake is low, 21 GW of distributed storage is installed in the low-cost case, and 9-10 GW in the high-cost case. In Pathway B, around 5 GW of distributed storage is constructed when DSR availability is high and storage is expensive; 28 GW if distributed storage is available at low cost and DSR uptake levels are low; 8-14 GW is built in other cases. In Pathway C if storage cost is low, 11 GW is built for low levels of DSR, and 4 GW for high DSR levels; only 1 GW or less is built if distributed storage is available at high cost. Finally, in Pathway D, 13 GW of distributed storage is built when inexpensive storage is combined with low DSR uptake levels; very small amounts for expensive storage and high DSR levels or low-cost flexible generation; and between 2 and 4 GW in other cases.

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[63] The Carbon Trust report "Strategic Assessment of the Role and Value of Energy Storage Systems in the UK Low Carbon Energy Future" presents the results of a comprehensive analysis of the future UK system with storage. Available at: http://www.carbontrust.com/resources/reports/technology/energy-storage-systems-strategic-assessment-role-and-value

The absolute level of distributed storage installed in the system depends significantly on the scenario – it is very significant in Pathways A and B (especially in combinations that are favourable for distributed storage, when DSR availability is low), and some 2-2.5 times lower in Pathways C and D. This is primarily driven by the high electrification of demand in the first two scenarios, which makes a strong case for distributed storage as it could offset distribution network reinforcement costs, along with improving operation efficiency and reducing backup generation.

As distributed storage tends to capture distribution investment savings that are not available to bulk storage, its optimal location also changes, so that more capacity is placed in regions with higher demand where the necessary reinforcement due to heat and transport electrification is the highest, i.e. semi-urban networks.

It is important to mention that when discussing the benefits of distributed storage for distribution networks, there may be some significant interactions with condition-driven asset replacement in distribution networks. If distribution network components, particularly at low voltage levels, are to be replaced in the next couple of decades, their replacement with higher-rated assets may be potentially very attractive given that the cost of installing new distribution infrastructure is characterised by a significant fixed cost component (installation costs) rather than costs related to equipment ratings (such as capacity of cables). If the timing of distribution network asset replacement is to coincide with the electrification of transport and heat sector, and a strategic approach to asset replacement is adopted, this would significantly reduce the opportunities to deploy balancing technologies such as distributed storage or DSR within the distribution network in order to avoid reinforcement cost.

3.6.5. Demand-side response

The model optimises DSR flexibility without compromising the service levels delivered by different demand technologies. DSR cost is not explicitly modelled but instead “high” and “low” costs of DSR have been represented through low and high availability of DSR (10% and 80% respectively of potentially flexible demand). High availability of DSR generates considerable system savings when competing technologies are available at high cost: £8.1-14.3bn per annum in Pathway A (depending on the contribution of wind to reserve and response provision), £6.1bn in Pathway B, £3.3bn in Pathway C, and £3.5bn in Pathway D.

DSR consistently reduces system integration costs across all Pathways, with added benefits of high DSR uptake being lower in cases with lower storage cost due to direct competition with distributed storage. We note again that there was no cost assumed for the deployment of DSR, for the reasons explained earlier in the report.

As mentioned in the section on distributed storage, the benefit DSR would achieve, in terms of avoided distribution network reinforcement cost, could be significantly undermined if the distribution network asset replacement strategy involves installing components of higher rating, and coincides with the electrification of transport and heat sector. A similar detrimental impact on the value of DSR would be observed in case smart voltage control or other advanced network technologies are deployed on a large scale.

3.6.6. Impact on distribution network investment

As shown in Section 2.3, the future evolution of electricity demand may require a substantial investment into distribution network reinforcement by 2050,[64] and our analysis demonstrates that some of the balancing technologies considered in this study (namely distributed storage and DSR) have the potential to greatly mitigate the need for reinforcing the network.

To illustrate the need for distribution network investment across different Pathways and over time, and indicate the value that balancing technologies can generate through avoided reinforcement cost, Figure 3.34 presents the cumulative value of the capitalised project cost of reinforcing GB distribution networks. The chart on the left represents the counterfactual scenarios, i.e. when there is no deployment of balancing technologies, while the one on the right represents the situation when all balancing technologies are available at low costs. The cumulative investment figures have been obtained by capitalising the annual reinforcement cost using the real pre-tax WACC of 5.3%.

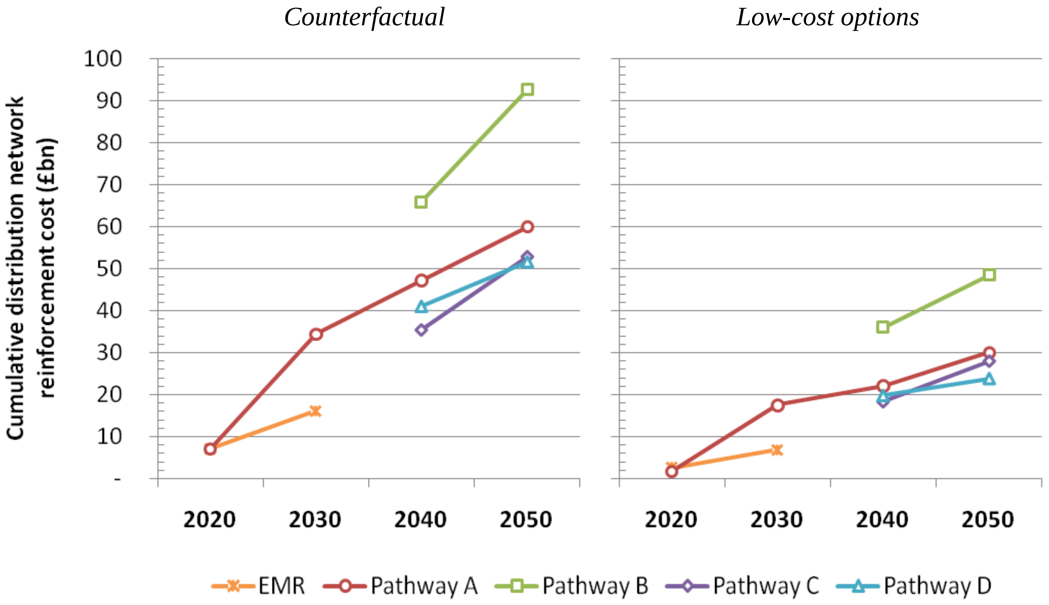

Figure 3.34. Distribution network reinforcement cost across Pathways and time for the counterfactual scenarios (left) and scenarios when all options have low costs (right)

We note that the reinforcement requirements are the greatest in Pathway B (around £93bn in 2050), which is driven by very high demand electrification levels coupled with less ambitious energy efficiency improvements and limited changes in consumer behaviour. In Pathway A the necessary investment is about £60bn, while in Pathways C and D this further reduces to £53bn and £52bn, respectively. We also observe a rapid increase in the reinforcement cost over time across all Pathways, so that the 2020 network reinforcement investment increases between 7 and 13 times by 2050.

Deployment of balancing technologies in the GB system, when they are available at low cost, significantly reduces the necessary investment levels in all years and for all Pathways; we

[64] Reinforcement cost for a given year is calculated by comparing that year with the reference year (2011 in this case), and finding the necessary investment into network reinforcement to accommodate the demand assumed to exist on the network in that particular year.

observe that balancing technologies broadly halve the required investment compared to the counterfactual scenario. This indicates that very high savings can be made when reinforcing the distribution network if options such as distributed storage or responsive demand are available to the network operators.

3.6.7. Impact on thermal plant operation

Deployment of balancing technologies affects the operation patterns of conventional generation plants in several ways:

- Balancing technologies generally flatten the net demand profile, reduce the necessary generation capacity and increase the load factors of generation plant;
- Additional flexibility generally reduces the curtailment of renewable electricity; this results in the corresponding reduction in output from conventional generators[65].

The summary of how load factors for GB conventional plant vary across the 2050 Pathways is provided in Table 3.6. In addition to fossil fuel technologies, the values for wind generation are also reported. The differences from the assumed potential wind load factors (40%) in the table result from curtailing wind output. For each generation technology and Pathway the load factors are provided for three scenarios: (i) counterfactual, (ii) when all options have high cost or low availability (resulting in minimum benefit from a portfolio of options), and (iii) when all options have low cost or high availability (maximum benefit case).

Table 3.6. Annual load factors for generation technologies and gas consumption across the 2050 Pathways

	2050 Pathway			
	A	**B**	**C**	**D**
Load factors [%] (CF / High / Low)*				
Nuclear	80 / 80 / 80	80 / 80 / 80	80 / 80 / 80	80 / 80 / 80
Coal CCS	65 / 60 / 74	33 / 25 / 36	90 / 90 / 89	50 / 52 / 58
Gas CCS	51 / 29 / 46	19 / 11 / 28	53 / 54 / 62	19 / 13 / 9
CCGT	10 / 13 / 11	10 / 9 / 10	7 / 8 / 6	4 / 5 / 6
OCGT	0.1 / 0.1 / 0.0	0.1 / 0.2 / 0.1	0.1 / 0.1 / 0.0	0.1 / 0.1 / 0.0
Wind	32 / 38 / 39	14 / 38 / 38	40 / 40 / 40	38 / 40 / 40
Annual gas consumption [TWh] (CF / High / Low)				
Unabated gas	123 / 124 / 110	95 / 44 / 33	63 / 69 / 87	26 / 28 / 16
CCS gas	323 / 26 / 40	7 / 4 / 8	288 / 279 / 304	47 / 17 / 27
Total	**447 / 149 / 149**	**102 / 48 / 41**	**351 / 348 / 391**	**73 / 45 / 44**

* CF = counterfactual scenario; High = scenario where all balancing technologies are available at high cost; Low = scenario where all balancing technologies are available at low cost.

65 In Pathway A, the increased ability to absorb renewable generation leads to a reduction in both CAPEX and OPEX associated with the CCS plant needed in the counterfactual scenario to maintain the CO_2 emissions targets.

The impact of alternative balancing technologies on the consumption of natural gas in the four 2050 Pathways is presented in the last row of Table 3.6, for the same three scenarios as generation capacity factors. The use of gas is quantified through annual gas consumption for electricity generation (used in CCGT, gas CCS and OCGT plants). In order to comply with the assumed carbon emission constraints (see Section 2.2.2.3) in cases with high requirements for additional generation capacity, the model eventually builds CCS if the carbon emissions from CCGT and OCGT plants would otherwise exceed the target.

The trends in gas consumption across 2050 Pathways are also depicted in Figure 3.35. We observe the most significant impact of balancing technologies on gas consumption in Pathway A, largely as a result of very high renewable curtailment (around 100 TWh) in the counterfactual scenario, which is subsequently mitigated by deploying alternative balancing technologies, resulting in a lower output of gas-fired plants. A similar effect occurs in Pathways B and D, although on a much smaller scale. On the other hand, in Pathway C (which relies more on gas due to high CCS capacity), there is no great challenge with respect to renewable curtailment, and balancing technologies slightly increase the use of gas for electricity generation, mainly to supply the additional demand due to efficiency losses in storage that is deployed as part of the flexible option portfolio.

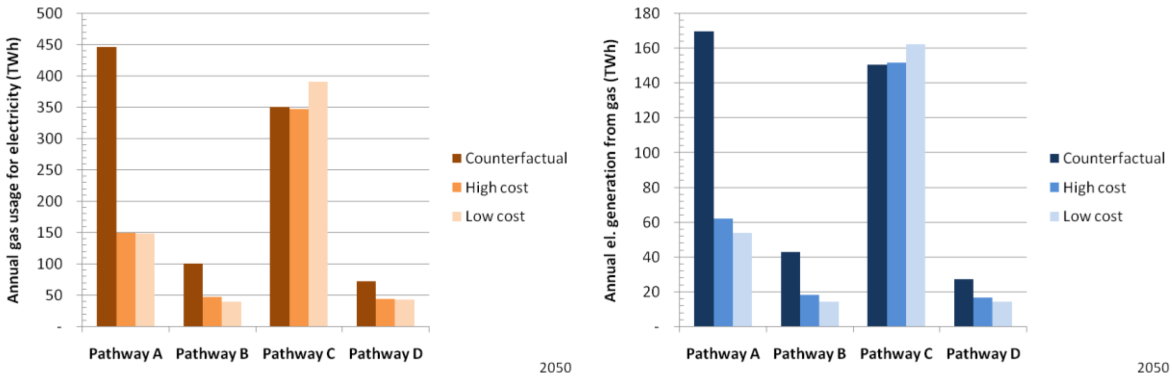

Figure 3.35. Annual gas consumption (left) and electricity generation from gas (right) in 2050 Pathways

3.6.8. Impact on carbon emissions

Annual carbon emissions from the GB electricity sector across the Pathways (and characteristic years analysed) are shown in Figure 3.36 (expressed as CO_2 emissions per unit of electricity supplied to GB consumers, i.e. as the carbon intensity of GB electricity generation).[66] The level of emissions is primarily driven by the assumptions behind different Pathways, in particular the generation background, but in some cases it is also affected by the emission constraints imposed on the system (as specified in Section 2.2.2.3). The level of emissions drops over time in line with the long-term emission reduction targets, as zero and low-carbon generation progressively replaces conventional thermal capacity.

The impact of deploying alternative balancing technologies varies across Pathways and over time, although we generally observe that the options reduce emissions in the long-term horizon. In 2020, when the assumed price of carbon is only about a third of the CO_2 price in

66 We have not considered biomass plants equipped with CCS as an option in our model, which could result in further reductions in carbon emissions.

2030-2050, coal generation is marginally less expensive than gas, even after including the cost of emissions in the generation cost. Also, the assumed capacity of coal plants (without CCS) in 2020 is still significant (about 15 GW). The cost-optimal effect of alternative balancing technologies in 2020 is therefore to increase the capacity factor (i.e. electricity output) of coal generation, and reduce the output of gas generation, which results in higher emissions. This phenomenon is directly driven by the assumptions on fuel and carbon prices; once the carbon price increases sufficiently to make gas generation less expensive than coal, a more efficient operation of the system tends to result in reduced carbon emissions.

With the increase in the assumed carbon price post-2020, gas and coal change places in the merit order, and the majority of coal plants retire from operation. We therefore observe reductions in UK carbon emissions when balancing technologies are deployed, with the most visible effect occurring in Pathway A in 2040 and Pathway B in 2050 (due to saved renewable curtailment). Pathway D emissions seem insensitive to the deployment of balancing technologies, while in Pathway C we observe a slight increase in emissions in 2040 (but still within carbon targets), as a result of the flexibility in GB being utilised to support balancing the system in mainland Europe.

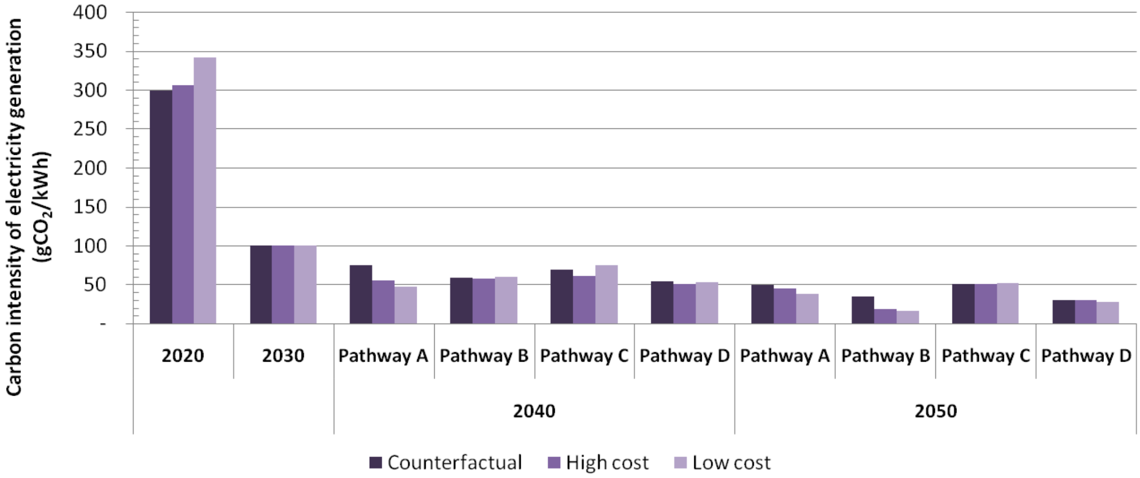

Figure 3.36. Annual carbon emissions from the GB electricity sector

3.6.9. Impact of restricted interconnection to Ireland

As mentioned earlier, we have investigated the impact of constraining the Britain-Ireland interconnection capacity to 2020 levels on the deployment of other balancing technologies and the corresponding cost savings. As an illustration of typical changes observed, Figure 3.37 shows the changes in interconnection capacities and system savings from deploying low-cost balancing technologies in Pathway A in 2050 when the GB-IE interconnection is maintained at the 2020 level (i.e. at 1 GW). Because there is no new interconnection capacity added at the GB-IE interface, the capacity of the direct link between Ireland and mainland Europe (IE-CE) increases to enable the export of surpluses of Irish wind to Europe. The impact on the capacity of GB-CE interconnector is however marginal, which is an occurrence observed in other Pathways, with typical changes in the order of 2-3 GW.

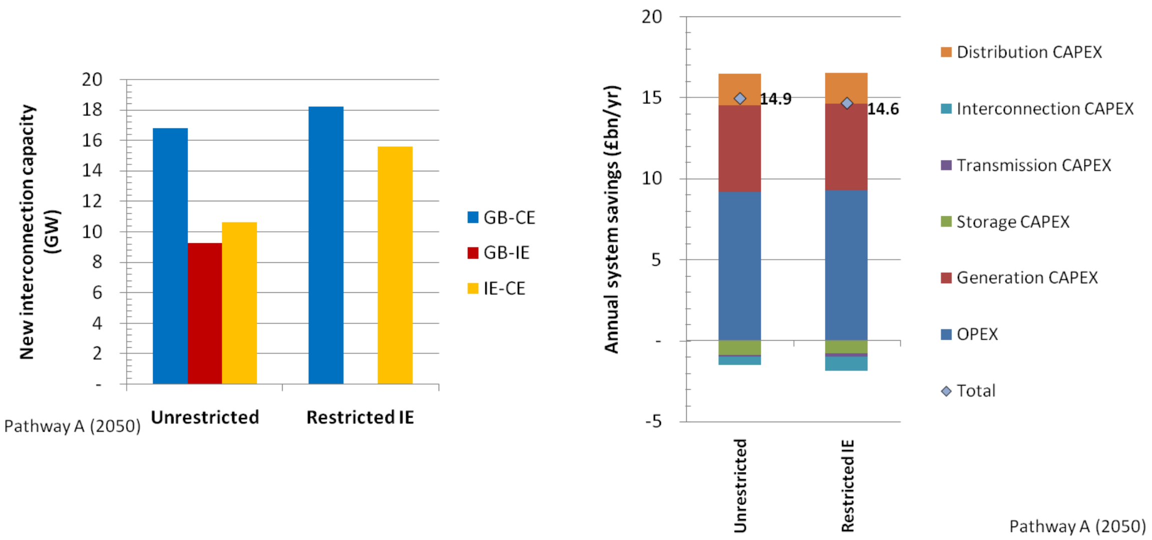

Figure 3.37. New interconnection capacity and system savings with restricted GB-IE interconnection (Pathway A, 2050, all options at low cost)

Despite considerable changes in the capacities of interconnections, changes in costs are marginal. Although the system benefits decrease due to the additional constraint introduced (limit interconnection capacity with Ireland), the reduction in benefits in most cases is below £0.5bn per year. This suggests that although it is cost-optimal for GB to become a hub for exporting Irish wind to mainland Europe, there is limited penalty involved if GB-IE interconnection does not fully develop.

3.6.10. Benefits of individual balancing technologies

In the analysis of the value of balancing technologies in this study we have so far considered portfolios of balancing technologies. In this section we examine the impact of having individual balancing technologies available without any contribution from other balancing technologies, in order to assess the contribution each individual option can provide when operating in the system individually.

Figure 3.38 represents the benefits of individual balancing technologies plotted for the entire range of Pathways and years studied in this report. Bar labels have the following meanings:

- IC: only interconnection available at low cost
- FGH: only flexible generation available at high cost
- FGL: only flexible generation available at low cost
- SBH: only bulk storage available at high cost
- SBL: only bulk storage available at low cost
- SDH: only distributed storage available at high cost
- SDL: only distributed storage available at low cost
- DL: only DSR available at high penetration
- All low: all options available at low cost or high availability

Performance of individual balancing technologies is hence compared to how they all perform when acting simultaneously in the system, assuming low cost or high availability for all options. Cases simulated in this section correspond to the "Base" cases discussed earlier in this section, i.e. assume no contribution of wind to reserve management and the 2020 level of wind forecasting accuracy.

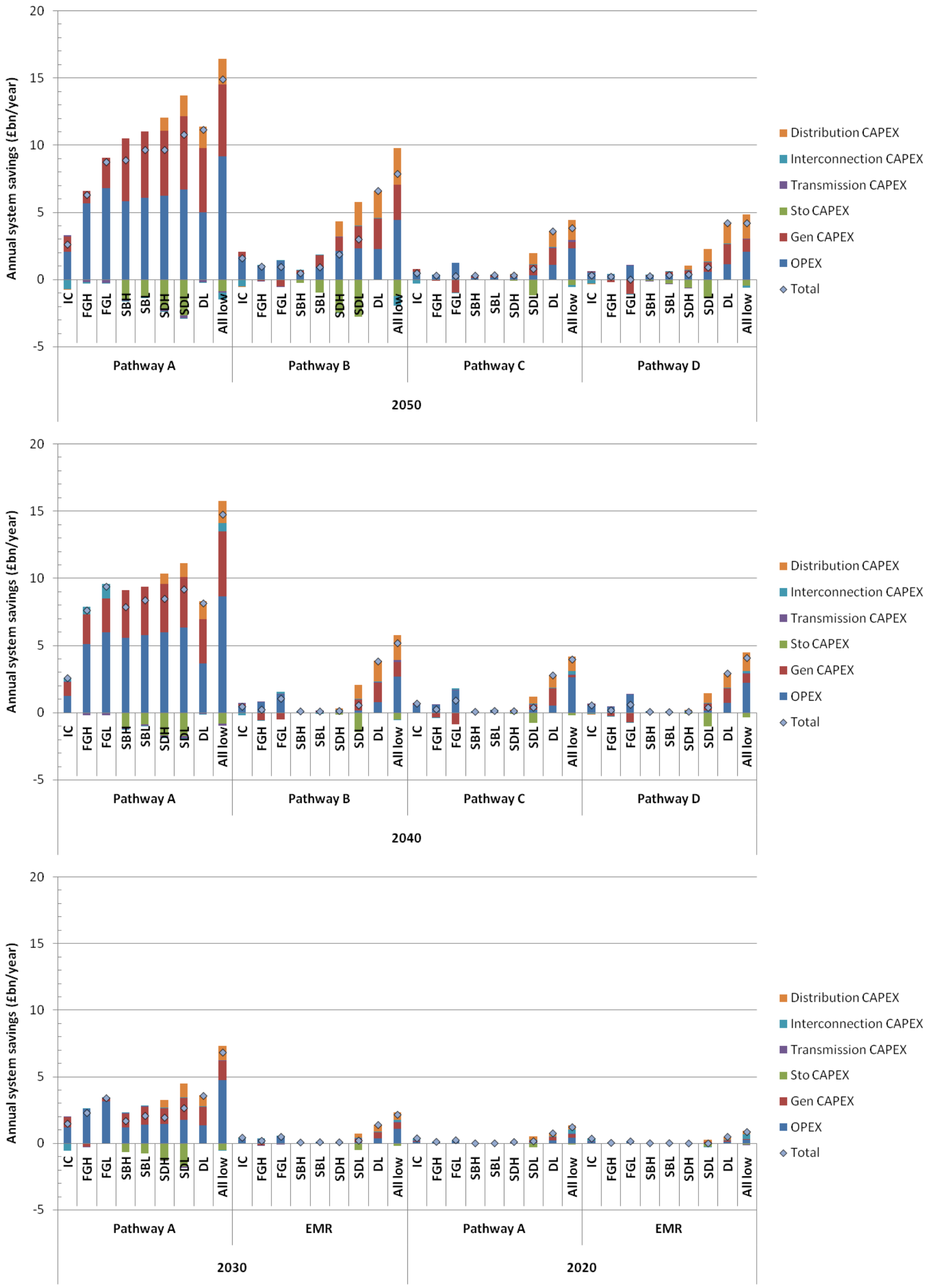

Figure 3.38. System benefits of individual balancing technologies across Pathways and time

As in the cases with combined options, we note that the benefits provided by individual options tend to be the highest in Pathway A, and increase towards the 2050 horizon. We further note that in Pathway A most individual options (with the exception of interconnection) are able to capture a large proportion of maximum system benefits when all options are combined, suggesting that each one of these options can be a valuable solution for addressing the balancing challenge in Pathway A, even when available at high cost. The situation changes in other Pathways, where the performance of individual options is more dependent on their cost. DSR is able to capture the most benefits on its own, given that it is assumed to be available at zero cost.

Figure 3.39 illustrates the optimal volumes of balancing technologies, when they are available individually without competition from other options. The layout of the figure is similar to Figure 3.38, except that the DL and “All low” cases have been omitted (DSR due to difficulties in quantifying the volume of DSR in GW terms, and “All low” has already been presented in sections discussing the results for individual Pathways).

We observe that the volumes of balancing technologies generally increase over time, and only modest additions occur until 2030 (with the exception of Pathway A). Selected volumes of flexible generation are very high when it is available at low cost, but it also very sensitive to its cost. The volume of interconnection is relatively stable across Pathways in a given year. With respect to storage, we observe that distributed storage is deployed in slightly higher volumes than bulk; bulk storage only appears in visible volumes in Pathway A (all years) and Pathway B in 2050, albeit in larger quantities than when competing with distributed storage in combined studies.

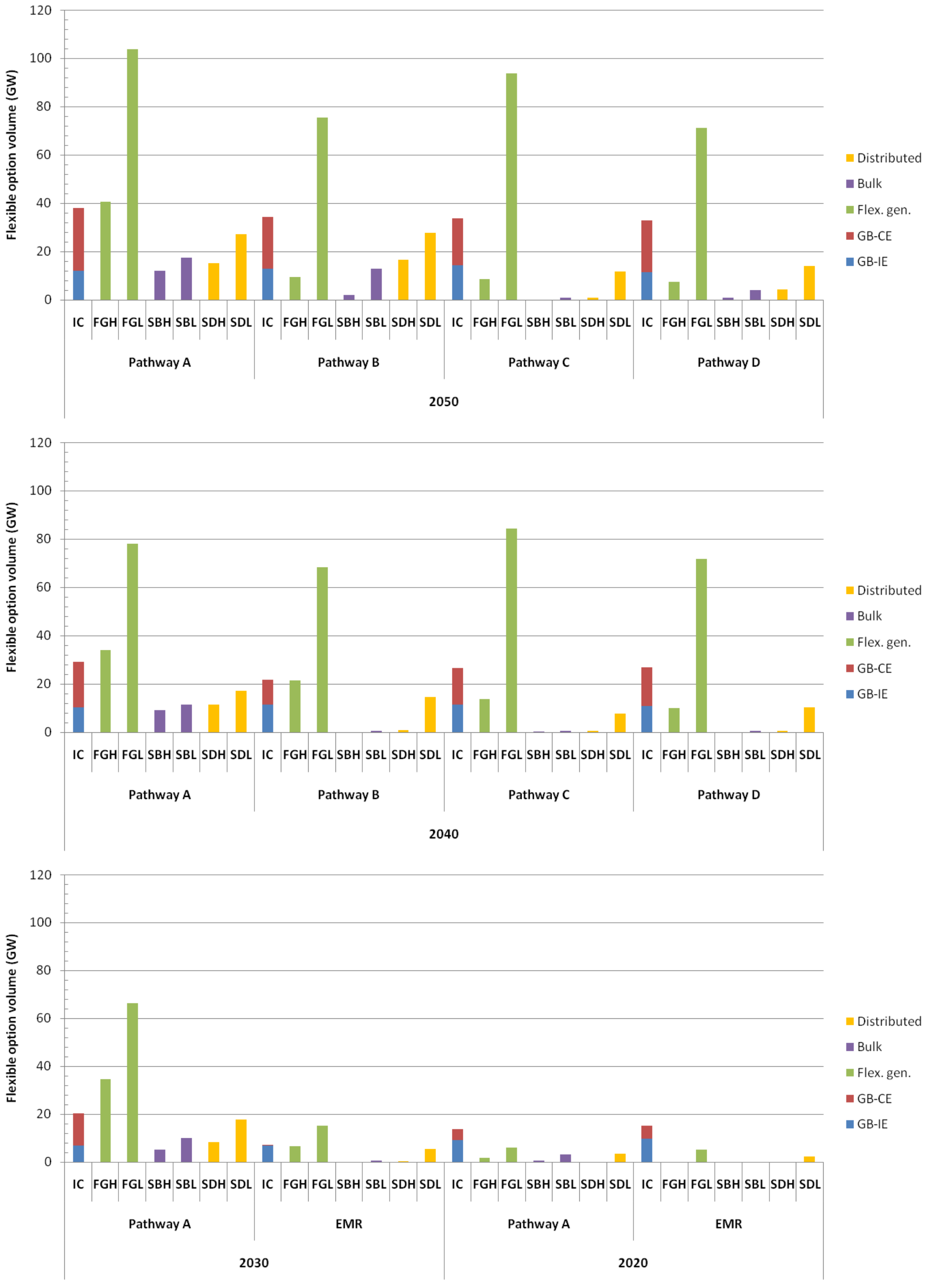

Figure 3.39. Volumes of individual balancing technologies across Pathways and time

3.6.11. Summary of cross pathway analysis

In summary, we observe that the value of balancing technologies, as well as the scale of the balancing challenge is greatest in Pathway A, followed by Pathways B, D and C.

Even when balancing technologies are available at high cost, the benefits in Pathway A are still substantial, while in other Pathways the scope for high cost flexible balancing options is reduced. We further note that the timing of a notable increase in the balancing challenge is dependent on the Pathway: the 2030 benefits in Pathway A are higher than 2040 benefits in any of the other three Pathways. The maximum system benefits that could be achieved in 2050 if all balancing technologies are available at low cost ranges from £15bn/year in Pathway A and £7bn/year in Pathway B, to around £4bn/year in Pathways C and D.

The volumes of individual balancing technologies generally increase over time. Selected volumes of flexible generation are very high when it is available at low cost, but it is also very sensitive to its cost. The volume of interconnection is relatively stable across all Pathways; sensitivity analysis conducted across all four 2050 Pathways suggest that when the self-security constraint is relaxed (i.e. interconnection is allowed to contribute to the security of supply to both GB and European systems), significantly more interconnection capacity is built. With respect to storage, we observe that distributed storage is deployed in higher volumes than bulk. Bulk storage only appears in visible volumes in Pathway A (all years) and Pathway B in 2050, although in larger quantities than when competing with distributed storage in combined studies.

We also find that a major part of system benefits of deploying balancing technologies is achieved in GB for Pathways A and B, while in Pathways C and D we note that the benefits are shared between GB and the rest of Europe, i.e. that balancing technologies in GB support system operation in continental Europe and Ireland, and reduce operating costs in these two systems.

4. The Balancing Challenge in Practice

4.1. Introduction

In each of the scenarios modelled for this report we make a range of assumptions regarding the power sector as a whole, and in particular the costs and performance of the alternative balancing technologies, reflecting the underlying uncertainty about how each technology will evolve over time. The model then selects the level and location of investment in each technology to minimise total system costs.

Hence, the model selects an "efficient" pattern of investment through a deterministic cost minimisation algorithm. In practice, however, the take-up of technologies depends on choices by electricity consumers and energy sector investors, which may not match the choices made by the model's cost minimisation algorithm. This chapter considers where the results from a cost optimisation model that makes 'perfect' decisions might differ from a real-world outcome, to support the interpretation of the modelling results. It also provides our thoughts on where these potential differences might have implications in the future. However, these do not reflect a comprehensive assessment of policy options. Formulating robust policy recommendations would require in-depth analysis of a range of policy options, taking into account the original aims of the policy, the challenges of implementation, as well as the impact on the system.

For instance, the method of cost minimisation is equivalent to assuming that investment decisions are taken in a perfectly competitive market, in which 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 reality, market failures, such as the impact of externalities or natural monopoly, or inefficient market / network prices, mean the least cost level of deployment might not take place in practice. Changes to market signals created by regulatory interventions can also result in inefficiencies, and there may exist some other real-life costs and constraints of which the model has not taken account (e.g., the transaction costs of allocating asymmetric benefits of interconnection investment).

In this chapter, we therefore examine key themes of the results with a view to identifying barriers to achieving efficient levels of deployment of alternative balancing technologies.[67] Apart from certain topics that are outside the Department's remit and the scope of the project, we discuss the following "themes" of the modelling results in more detail below:

- As discussed in Section 4.2, flexible balancing technologies can potentially support the system by meeting demand in shortage conditions at a lower cost than through the construction of peaking plants and the reinforcement of transmission and distribution networks. They may also reduce the cost to the power system from managing conditions where a surplus of energy is generated by wind and other low carbon technologies;

[67] Our modelling suggests that alternative balancing technologies can make a substantial contribution to meeting the balancing challenge from 2030 (depending on the Pathway). Hence any recommendations to help remove barriers to investment in these technologies are only likely to materially improve the efficiency of deployment from then onwards. However, improving the efficiency of investment in alternative balancing technologies from 2030 may require the introduction of some measures we discuss below in the period before 2030 due to: (1) dynamic trade-offs in technology choices, and (2) the need to establish the credibility of market and regulatory mechanisms aimed at promoting efficient investment.

- Flexible balancing technologies can potentially support system balancing by supplying ancillary services more efficiently than conventional technologies. However, as the organisation and regulation of ancillary service markets is outside of the Department's remit, we do not analyse this topic in this chapter;
- If flexible balancing technologies are located efficiently, they can help reduce the need for transmission reinforcements, as discussed in Section 4.3;
- Efficiently located developments of flexible balancing technologies can also offset the need to reinforce distribution networks following the extensive electrification of the heat and transport sectors, as discussed in Section 4.4;
- The deployment of DSR can materially reduce system costs, but the modelling does not make any assumptions regarding the costs of deployment (although two different levels of DSR uptake are analysed), so the extent to which it will be efficient to rely on DSR for system balancing is uncertain, as discussed in Section 4.5;
- Interconnection can also contribute significantly to meeting the balancing challenge, but the extent to which the modelling suggests it is efficient to increase interconnection with neighbouring markets is highly sensitive to assumptions regarding fundamental supply-demand conditions in neighbouring markets, as discussed in Section 4.6; and
- The deployment of flexible balancing technologies can help reduce emissions of CO_2 from the power sector, as discussed in Section 4.7.

In addition to these themes emerging from the modelling results, we also discuss in Section 4.7 some limitations associated with the modelling work related to its representation of uncertainty.

4.2. Managing Shortage and Surplus Conditions Efficiently

4.2.1. Trade-offs between flexible balancing technologies and peaking plant investments

Our "counterfactual" scenarios show that significant investments in peaking generators and network reinforcement are required to balance the system between 2030 and 2050 if none of the flexible balancing technologies is available.[68] In scenarios where we allow the model to develop flexible balancing technologies, the model identifies the potential for significant generation and network CAPEX savings compared to the counterfactual, as the model meets peaks in demand at lower cost, and reduces peaks in demand that need to be met by conventional generation. Investments in flexible balancing technologies can therefore substitute investments in conventional peaking capacity.

Given the role that balancing technologies can play in meeting demand in periods of scarcity, developers' incentives to deploy them efficiently depend on the price signals conveyed to them in periods of shortage. To support efficient future investment decisions in flexible balancing technologies, as for peaking plants, operators should be exposed to a wholesale

[68] Over time, the generation backgrounds modelled in this study assume that the demand to be met by thermal generators becomes significantly "peakier" than it is today over the period to 2050. This occurs because the electrification of heat adds substantially to demand in peak (i.e. cold winter) conditions, whilst adding less to annual energy consumption. Also, wind generators can have low availability in cold winter peak conditions

electricity price that reflects the underlying value of energy at times of scarcity. In particular, this condition will be important for promoting an efficient trade-off between developing peaking generators and alternative balancing technologies. For example, private investors in peaking plants bear the costs of construction, and benefit by earning margins in times of scarcity that help to remunerate these investments. Likewise, investors in alternative balancing technologies also incur the costs of deployment, and benefit from the value of their output (or deferred/avoided consumption) in periods of scarcity.

If this condition is met, we see no fundamental reason why private investors should not make an optimal trade-off between the alternative balancing technologies and peaking plants, which, as shown above, will help meet the balancing challenge. However, as described below, the requirement that energy prices in periods of scarcity reflect the underlying marginal value of energy may not hold in practice, and so may lead to inefficiency in the deployment of both peaking plants and alternative balancing technologies.[69]

4.2.2. Representing the value of scarcity in the model

In periods of scarcity, when available supply of electricity is insufficient to meet demand, the cost of load shedding that the model incurs is determined by our assumed Value of Lost Load (VOLL, £10,000/MWh). In a competitive market, prices during these periods would rise to the system marginal cost (i.e. to VOLL), and any party supplying energy in such shortage conditions would receive revenue equal to VOLL for each unit of output. Because our modelling assumes a competitive market, it also assumes that the value of providing energy in scarcity conditions is reflected in energy prices. Any practical features of the energy market that cause peak prices to deviate from VOLL will therefore result in under investment in alternative balancing technologies, as compared to our model's projections of efficient investment.

In reality, the pricing of energy in scarcity conditions may not reflect this underlying value, and as a result, those parties supplying energy at times of shortage may not capture the marginal social benefit of their investment. This "missing money" problem, created by implicit or explicit caps on energy prices, undermines incentives for efficient investment in technologies that can alleviate supply shortages, including peaking plants and alternative balancing technologies. In reality, caps on energy prices may arise either because of the prevailing market arrangements, or due to the (real or perceived) threat that politicians or regulators will intervene in periods of scarcity to limit energy price spikes. These features of real-life energy markets may act as a barrier to the deployment of the alternative balancing technologies that our modelling suggests would be efficient.

4.2.3. Ensuring alternative balancing technologies participate effectively in any future capacity mechanism

Caps on energy prices result in a "missing money" problem, by reducing cash flows to generators supplying energy in shortage conditions. A capacity payment mechanism, as is being proposed through the Electricity Market Reform (EMR) process, makes a side-payment

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[69] Although many non-intermittent low-carbon technologies are expected to run at high load factors in the near term (e.g. nuclear, CCS, biomass), over time some subsidised low-carbon technologies may compete with alternative balancing technologies and peaking plant for system balancing, and thus may distort efficient capacity choices to some extent.

to market participants to replace this "missing money", and is therefore one approach to correcting the inefficiency associated with caps on energy prices.

Capacity mechanisms differ widely in their design.[70] While this paper does not seek to identify the design of a Capacity Payment Mechanism (CPM) that is most likely to encourage the efficient development of the British power market, incentivising efficient investment in flexible balancing technologies will require that any technology capable of exporting power to the grid (generation, storage, interconnection, flexible generation) should be eligible for support under any CPM (i.e., a level playing field between technologies).[71]

In particular, special consideration might be required to ensure smaller scale technologies such as distributed storage benefit, and that payments for capacity recognise that small scale technologies can make just as significant a contribution to system balancing as large scale technologies. Given the trade-offs between balancing technologies that our modelling highlights, providing different levels of support for small and large-scale technologies under a CPM may result in inefficiency.

One approach to facilitating the participation of small scale balancing technologies in the CPM would be to allow aggregators of small-scale facilities to offer capacity into the capacity mechanism. For example, aggregators of small demand side units already offer capacity into the GB balancing mechanism; similar arrangements may facilitate participation in any future capacity market.

4.2.4. Preventing distortions to prices in off-peak periods

As well as efficient pricing of energy in periods of scarcity, the efficient deployment of alternative balancing technologies requires that prices in periods of surplus also reflect system marginal cost. Periods of extremely low energy prices are not prone to intervention in the same way as peak prices, but may be exposed to other constraints that cause them to deviate from system marginal cost. In particular, prices that fall below underlying short-run marginal cost in surplus conditions might incentivise more deployment of the alternative balancing technologies than our modelling suggests is efficient, as it will increase the margins available from buying power (or decreasing production) in surplus periods, and selling power (or deferring consumption) in shortage periods.

4.2.5. Incentivising the efficient provision of "flexibility"

In a well-functioning energy market, generators, storage operators and interconnector capacity owners will have strong incentives to supply energy in periods of scarcity when prices are most likely to "spike", and consume or cease production of energy in times of surplus when prices fall. Our modelling captures the differing ability of flexible and non-flexible generators (as defined in Chapter 2) to capture price spikes and switch off when prices fall. For example, some price spikes may be short-lived and/or hard to predict, which

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70 Key design decisions include, amongst numerous others, setting the quantity of capacity that is bought under the mechanism, defining the types of capacity that qualify for support, and establishing rules that define when individual units are considered available and so eligible to receive capacity payments on an hour-to-hour basis. See, for example: Hamish Fraser (2007). Capacity Payment Mechanisms: How to Pick the One That's Right for You. *In*: Sarah Potts Voll and Michael J. King, (ed). *The Line in the Sand: The Shifting Boundary Between Markets and Regulation in Network Industries*, White Plains, NY: NERA Economic Consulting, pp307-334.

71 It might be necessary to account for (expected) availability in shortage conditions as we describe below.

would prevent relatively inflexible generators from benefiting from them. Hence, an efficiently functioning energy-only market would allow relatively flexible generators (and other suppliers of energy to the system) to capture higher revenues than those with less operational flexibility.

However, as noted above, prices may not fully reflect the marginal value of energy in periods of scarcity, so in practice an energy only market may not fully reward increased flexibility. Hence, any payments to generators and other suppliers of energy aimed at correcting this problem could recognise the extent to which different technologies are available to supply energy during shortage conditions, taking account of flexibility characteristics. In other words, a (real or perceived) price cap creates different amounts of "missing money" for different technologies, and a CPM ideally needs to recognise these differences.

4.2.6. Avoiding Transmission Reinforcement Costs

Our modelling shows that the contribution of alternative balancing technologies to reducing system balancing costs can be highly sensitive to the location where they are deployed. In particular, our modelling illustrates that these technologies can help meet the balancing challenge by reducing the need to invest in costly transmission reinforcements. For instance, in Pathway A where we assume extensive development of renewables, the model develops bulk storage in Scotland as it reduces the need for transmission reinforcement to allow the GB market as a whole to absorb output from Scottish wind farms (albeit the volume of investment in bulk storage is very limited in our scenarios, unless distributed storage is unavailable).[72] Placing the same amount of bulk storage in England and Wales would not achieve the same reductions in system balancing costs.

The cost minimisation algorithm used in our modelling produces outcomes consistent with a perfectly competitive electricity market in which all market participants receive revenue equal to the marginal value of their output, which can vary depending on their location on the network. This implies that providers of alternative balancing technologies receive locational signals through the locational pricing of energy, which is not currently the case in Great Britain.

4.3. Avoiding Distribution Reinforcement Costs

4.3.1. Conveying cost signals to distribution network users

Our modelling suggests that the need for cost reflective signals on distribution systems is also important for promoting efficient investment, as DSR and distributed storage have the potential to materially reduce (or defer) the need for distribution reinforcement, if deployed efficiently. The scale of reinforcement costs that users impose on distribution networks, or enable distribution networks to avoid, depends on many factors including their location on the grid, the size of their maximum load, the coincidence of their maximum load with the maximum load in the wider network area, etc. The extent to which a network user

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72 Under the other "Pathways" the model develops much less bulk storage capacity. However, locational signals are important for minimising transmission reinforcement costs across all scenarios. Another example is that under "Pathway C", where CCS deployment is most extensive, the model chooses to develop flexible generation primarily in south east England, as this results in less transmission reinforcement than locating the same plant further north.

participates in DSR and/or provides distributed storage will therefore change the cost that the distribution network operator incurs to accommodate its presence.

If it is not possible to reflect the value of avoided distribution reinforcements in network charging, it may be that storage developers will tend to develop more bulk storage and less distributed storage than our modelling suggests.[73] For example, the model does not account for the transaction costs associated with conveying cost reflective signals to distribution network users, so may overstate the extent to which it is efficient to develop distributed rather than bulk storage. While this would reduce the savings in distribution reinforcements that our model identifies, the costs of storage developments would be lower, as bulk storage is cheaper to construct.[74] Operating costs may also fall as bulk storage might be more efficient than distributed storage.[75]

4.3.2. The scale of avoided distribution reinforcement costs

Although our modelling illustrates that distributed storage and DSR have the potential to offset significant investments in distribution reinforcement (see Figure 3.34), this result is sensitive to our assumptions on the replacement profile of existing distribution assets. For example, increased electrification of heat and transport will increase peak load, which in many cases would necessitate distribution reinforcement. The need for reinforcement may be reduced through the deployment of distributed storage.

Over the period to 2050 it may become necessary to replace some distribution assets. Therefore rather than incurring the costs of deploying alternative balancing technologies in the distribution system, it may be cheaper to deploy distribution wires with higher capacity in the course of the normal replacement cycle. On the other hand, we understand that many existing distribution cables are many decades old and are expected to last for several decades to come, so it may be that little asset replacement will take place over our modelling horizon anyway. Hence, the actual scale of distribution reinforcements that can be avoided or deferred through the deployment of distributed storage (and DSR) is uncertain.

This fundamental uncertainty associated with the need for replacement expenditure by the DNOs means there is also a range of uncertainty around the scale of distribution network cost savings identified through our modelling. This factor also illustrates the complexity associated with reflecting the cost savings that distributed storage and DSR provides to DNOs in access charges, as the need to replace particular cables that have reached the end of their working lives significantly affects the cost savings obtained by the DNO through the deployment of storage or DSR in particular areas.

In any case, DNOs may have a limited incentive to install oversized cables in anticipation of future electrification of heat and transport, either because of current uncertainty regarding the scale of resulting demand growth, or because they do not have confidence that they will be allowed to recover the costs of oversizing assets through their price control. Uncertainty regarding the future need for network capacity means it might not be efficient to oversize

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73 This is illustrated in the scenarios where we assume that bulk storage is the only alternative balancing technology available to the model (see Section 3.2.4) and it builds substantially more than if other options are also available.

74 See our modelling assumptions in Chapter 2.

75 Essentially, the efficiency of storage is defined as the amount of energy it is capable of exporting to the grid per MWh of electricity it imports from the grid.

cables today if the cost of doing so is not justified by the expected future saving in reinforcement costs if demand does grow due to electrification.

4.3.3. Interactions with distribution network planning

Our modelling effectively assumes that the DNO has perfect information regarding the users of their networks, and can plan their networks optimally as a result. Hence, it may overstate somewhat the potential savings from distribution reinforcements. In practice, a DNO may not know that an individual consumer has chosen to participate in a DSR scheme. In this case, they are likely to continue planning their network to accommodate historic rates of growth in that consumer's peak load, so the potential reductions in the DNOs' costs through that consumer's participation in a DSR scheme would not be realised in practice.

Hence, the modelling also illustrates the importance of ensuring that DNOs have as much information as possible regarding the characteristics of the consumers connected to their grids. In practice, it is possible that the deployment of smart meters will help DNOs to access more detailed information on the characteristics of network users and the extent to which they participate in DSR or provide distributed storage on their premises.

4.4. Ensuring the Efficient Deployment and Use of DSR

4.4.1. Identifying the efficient level of DSR deployment

The main capital expenditure required to deploy DSR is smart metering infrastructure, the deployment of which the government has already decided to mandate over the coming decade. In practice however, there will be additional technological costs to make DSR happen which we have not considered here for the sake of simplicity, for example, equipment to connect appliances to smart meters, costs to the industry for upgrading their own systems, and other infrastructure costs to allow electric vehicles and heat pumps to interact with smart meters directly.

As described above in Chapter 2, there will also be additional costs faced by consumers in deploying DSR, such as the opportunity cost of the time it takes to participate in DSR schemes, the costs consumers incur to change their behaviour (e.g. the lost utility of avoiding consumption in peak periods), and the additional costs consumers face to purchase "smart" as opposed to conventional appliances. The most significant of these additional costs are likely to be the opportunity cost of consumers' time, the costs of deferring consumption, and the cost of acquiring information.

Our modelling has included a detailed "bottom-up" representation of the demand-side that assumes participants in DSR consume power optimally to help minimise system costs, while ensuring they do not suffer any reduction in the service quality offered in terms of heating, use of EVs or use of household appliances. For example, our modelling allows the demand from heat pumps to vary to balance the system, but only if internal temperature remains within limits. Likewise, the model can defer consumption by smart appliances such as dishwashers or washing machines, as long as their cycles are completed within a given period of time. This suggests that assisting in system balancing in the way our model suggests is feasible would not materially reduce consumers' utility.

However, other barriers or costs may still prevent consumers from participating in DSR and managing their demand optimally. For instance, a lack of knowledge that DSR can deliver savings, and of the magnitude of savings potentially available (i.e. whether they are sufficient to overcome the inconvenience of changing demand), may present a barrier to DSR deployment. In practice, private agencies such as producers and retailers of smart appliances and electricity suppliers may have strong incentives to advertise the potential of DSR, and so convey valuable information to consumers that will remove this barrier.

Additionally, the costs of participating in DSR schemes would influence whether an individual consumer has an incentive to participate and so support system balancing. If consumers engage in DSR schemes by buying smart appliances, the on-going cost of participation might be negligible. However, if they actively manage their own consumption in response to the price signals conveyed by time-of-use tariffs, the on-going costs of participation might be more significant. Ultimately, therefore, low levels of DSR penetration should not necessarily be seen as inefficient. The costs of DSR deployment are to some extent determined by the opportunity cost of consumers' time which may be high, and many consumers may choose not to participate due to an unwillingness to accept even small changes in convenience or comfort, etc. While these costs are hard to observe, they may mean it is simply not efficient for consumers to participate in DSR schemes to the extent we assume in our modelling.

Our modelling illustrates that distributed storage is, at least to some extent, substitutable with DSR. Hence, if DSR penetration turns out to be limited, e.g. due to high participation costs, then it may be possible to achieve similar savings in system costs through the deployment of distributed storage.

4.4.2. Organising the use of DSR

As noted above, consumers can engage in DSR schemes either by actively responding to time-of-use price signals, or by automating their consumption of electricity through the use of smart appliances.

To the extent that consumers engage in DSR through the use of smart appliances, and once smart metering infrastructure is in place, it will be possible for an agency to optimise the use of those smart appliances that are deployed on the GB system. Smart appliances will provide savings to consumers by allowing them to shift their energy consumption from periods of relative scarcity (e.g. high demand/low wind conditions) when prices are high to periods of relative surplus (e.g. lower demand/higher wind conditions) when prices are lower, while ensuring the performance of their appliances remains within certain operational parameters specified by users.[76]

One option is for suppliers to fill the role of the agent controlling the use of smart technologies rather than DNOs. In principle, suppliers will have commercial incentives to use appliances efficiently in order to minimise energy purchase and network access costs they

[76] These operating parameters might include the range of temperature variation they are willing to tolerate in smart fridges, the time by which they expect smart dishwashers or washing machines to have finished their cycles, or the time by which they expect electric cars to have completed charging.

incur to serve end-users, as competition incentivises suppliers to seek least cost solutions.[77] Suppliers could then pass the benefits of DSR through to consumers through time-of-use tariffs, or possibly by offering fixed discounts in exchange for the option of managing the consumer's demand, which reduces the total cost of serving them. Developing the functionality to perform this role will impose costs on supply companies, but because there exists a competitive supply market and the potential savings from the use of DSR are largely internalised between the supplier and consumer, we see no reason why such costs should prevent the efficient deployment and use of DSR. However, the decision over how it is best to organise the use of DSR will require further investigation by industry.

As for distributed storage, an efficient network charging regime will be important for supporting the efficient use and deployment, and realising the potential cost savings available from avoiding reinforcement in distribution networks. However, as described above in Section 4.4 the complexities associated with distribution network charging may limit the extent to which participants in DSR schemes can capture the benefit they provide.

Another possibility is that consumers will not contract with an agency (such as their supplier) to manage elements of their consumption, and instead will sign up for time-of-use tariffs and adjust their electricity consumption themselves in response to price signals. This may lead to lower savings in power system costs from the deployment of DSR than our modelling indicates are achievable, as we assume that the demand side will respond optimally at all times to minimising system costs. If instead consumers engage "manually" in DSR schemes, they may only assist in system balancing when prices (or price spreads between peak and off-peak periods) are sufficiently high to justify altering their behaviour. While this would not necessarily be inefficient, it would reduce the savings achievable through the deployment of DSR as compared to the estimates in our modelling results.

4.5. Efficient Investment in Interconnection

4.5.1. Uncertainty regarding the efficient level of interconnection

The model's decisions regarding the deployment of interconnectors are highly sensitive to conditions prevailing in neighbouring markets. For instance, we assume a significant expansion in wind capacity on the island of Ireland. As a result, our modelling illustrates that some cost savings might be available by expanding interconnection between GB and Ireland, and between GB and continental Europe, primarily to allow the export of Irish wind generation without constructing a direct link between Ireland and France. Hence, the extent to which it is efficient for GB to be interconnected to neighbouring markets depends partly on Irish renewables deployment. Our modelling also illustrates that the deployment of balancing technologies in the rest of the European system influences the model's decision regarding their deployment in GB. For instance, in model runs where DSR is not deployed extensively in other European markets, our model develops a significant amount of interconnection to allow the alternative balancing technologies deployed in GB to provide flexibility to the wider NW European power market.

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77 By reducing the consumption of their customers in periods of relative shortage, suppliers can reduce the costs they incur to purchase power on the wholesale market. This might require that the settlement system recognise consumption of each consumer in each trading interval, but such changes would be required anyway to implement time of use tariffs following the smart meter roll out.

If these conditions did occur in reality, it may well be efficient for GB to significantly expand interconnection with neighbouring markets, in effect to export system balancing services to the region. Developers of balancing technologies (storage, flexible generation, etc) in GB would then benefit from offering these services to neighbouring markets by buying and selling energy over interconnectors. However, given the similar generation mixes prevailing across several markets in the region (gas and wind generation, with some nuclear), it is likely that other markets will develop alternative balancing technologies if it is efficient for GB to do so. Thus, analysis in which significant interconnection capacity is developed based on assumed differences in the deployment of alternative balancing technologies between GB and neighbouring markets probably overstate the efficient quantity of interconnection. For example, in the run where we assume a high take-up of DSR in Europe in Pathway C, the modelled development of interconnection between GB and CE systems in 2050 falls from around 20 GW to around 3 GW as GB ceases to export flexibility services to other markets, as it does in a number of other runs.

As described in previous chapters, although our model represents the GB system with a much higher degree of granularity than other markets, it minimises total system costs across the whole of the EU and assumes strong cross border interconnection between member states. The sensitivity of modelled interconnector deployment to conditions in neighbouring markets shows that more robust estimates of the value of alternative balancing technologies within GB may be obtained by modelling continental Europe and the Nordic markets in more detail than was able, given the scope of this study.

4.5.2. Self-sufficiency within GB

As described above, we imposed constraints on the model to ensure that it had sufficient capacity domestically to meet peak load without reliance on interconnectors ("self-security") and that GB neither imports nor exports energy on average over the year ("energy-neutrality"). Following discussions with DECC, we made these assumptions primarily to ensure consistency between our model outputs and the four generation and demand Pathways we consider in this exercise. In particular, relaxing the energy neutrality assumption would have caused model results to diverge significantly from the assumptions made for the Carbon Plan Pathways.

In practice, it may not be efficient for GB to be self-secure because interconnectors can contribute towards system security. Energy-neutrality may also be inefficient if it is possible, for example, to import energy more cheaply than generating it within GB. The substantial Irish wind resource means it may be possible to import power generated from Irish wind farms to GB, instead of developing similar wind farms in less favourable sites in GB. Hence, both the self-security and the energy-neutrality assumptions will tend to undervalue interconnection. In particular, the model runs that assume interconnectors cannot contribute to GB system security may understate the potential of interconnection to help meet the balancing challenge.

4.5.3. Market arrangements in neighbouring jurisdictions

The benefits of interconnection in assisting with system balancing are essentially the same as for other forms of transmission, i.e. interconnectors transport energy from low price areas to high-price areas. However, the commercial regime facing interconnector owners can be considerably more complex than the regime facing transmission owners due to the interaction with regulatory frameworks in more than one nation state. Hence, political and institutional factors in neighbouring markets can affect the economic viability of developing interconnectors, even if underlying market conditions would support their deployment.

Market signals for interconnector investment will be strengthened with wholesale power market arrangements that set price equal to system marginal cost in each area of NW Europe, combined with some alignment of market organisation (e.g., gate closure and trading intervals) to allow for efficient arbitrage. Continued harmonisation of European energy market structures might also promote efficient investment in alternative balancing technologies in GB and elsewhere.

Differences in infrastructure charging arrangements across jurisdictions may also distort incentives to efficiently locate alternative balancing technologies. Increasing harmonisation of infrastructure access charging may therefore support efficient investment in alternative balancing technologies in the region as a whole. For example, if interconnector developers face onshore infrastructure access charges below the marginal cost of onshore reinforcement they impose on the GB system, they would be more inclined to construct Ireland-GB and GB-France interconnection than is efficient, and less Ireland-France interconnection than is efficient, and vice versa.[78]

Finally, it is well-known that the benefits of interconnection can in some cases be asymmetric (as discussed in Section 3.6.1); power prices in the high cost market fall following interconnection to a low price market, while prices in the low cost market rise. This problem does not affect commercial incentives to invest efficiently in interconnector capacity to arbitrage price spreads, but it can lead low cost markets to resist development of interconnection, and so inhibit efficient investment (i.e., investment that produces gains from trade), in order to protect their consumers from higher prices. This constraint is reflected in the scenarios in which we prevent the model from developing interconnection capacity beyond the levels we assume for 2020. These model runs show some initial estimates of the impact on European power system costs from any constraints on interconnector deployment between GB and neighbouring markets, although we have not estimated the impact on GB power sector costs (or GB power prices) as a result of this constraint.

4.6. Performance Against CO_2 Emissions Targets

For the purposes of this study, we impose a CO_2 constraint on the model, and we also assume an emissions price floor. Hence, if the CO_2 emissions constraint is binding, then the shadow value of emissions from the power sector can rise above the floor, but cannot fall any lower. Ultimately, the shadow value of CO_2 emissions from the power sector will be determined by government policy, and will depend on the scale of emissions reduction required in the economy as a whole, and the relative cost of reducing emissions in the power sector as compared to other sectors (heat, transport, agriculture, etc).

[78] Even within GB different regulatory and charging regimes apply to different sections of transmission infrastructure: onshore transmission, merchant interconnectors, and offshore transmission operators. It is possible that different regulatory treatments of similar infrastructure could distort investment incentives, and limit the potential for efficient coordination of interconnector and transmission infrastructure development. However, more work would be needed to assess whether this is a material risk in practice.

As illustrated above, the deployment of alternative balancing technologies has the potential to reduce emissions in some scenarios, in particular because they can reduce the curtailment of low carbon generation such as wind. Hence, the extent to which it is efficient to deploy alternative balancing technologies within the power sector depends on the CO_2 price faced by fossil fuel-fired generators. This suggests that, if the CO_2 price they face is below the social cost of CO_2 emissions, then the market may deliver lower deployment than is economically efficient, or vice versa.

4.7. Treatment of Uncertainty in our Modelling

For each run, the model takes as given a set of input assumptions and optimises deployment of alternative balancing technologies in a particular year. In reality, however, uncertainties regarding the cost and performance of the alternative balancing technologies, and the timing with which these uncertainties are resolved, means that a model optimising deployment using a static, deterministic framework may not project the true "efficient" levels of deployment of alternative balancing technologies within the GB market.

A first step to improving the robustness of the modelling results would be to perform dynamic modelling that optimises investment in the whole period to 2050. Such an approach may help identify inter-temporal trade-offs between substitutable investments, albeit the consistency between the model's decisions regarding the deployment of alternative balancing technologies in 2040 and 2050 suggests this effect would be limited.

More significantly, however, a framework that recognises explicitly the wide range of uncertainty surrounding the future costs and performance of the alternative balancing technologies, as well as supply-demand conditions in the power sector as a whole, would more robustly estimate the value of these technologies in the GB power market.

In our modelling framework, we represent the risk surrounding the value of alternative balancing technologies by annuitizing fixed costs at different costs of capital. As described above, our weighted average cost of capital (WACC) estimates are taken from a study that uses market evidence in an attempt to represent the hurdle rates applied by investors for decision-making.[79] However, this approach may somewhat oversimplify the impact of the uncertainty surrounding investments in alternative balancing technologies.

Firstly, there is very little market evidence on the hurdle rates that developers of new technologies will need to achieve before they will invest. It may be possible to obtain more robust estimates by performing bottom-up analysis of the risk profile of particular investments, but such an analysis is beyond the scope of this report.

Secondly, as has been discussed extensively in the literature on "real options", there are conditions in which investors may require a higher hurdle rate incorporating a premium over the WACC before they will invest. For this to be the case, investors must expect some of the investment risks to fall over time, for example because uncertainties regarding the cost/performance of new technologies are removed. This expectation of information revelation regarding the future value of investments means that it may be efficient to delay

79 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.

investments and wait for information about future uncertainties to emerge, thus creating a "value to waiting" or "option premium" that increases the hurdle rate required by investors today. Of course, once the uncertainties are removed, there would be no "option premium" and the hurdle rate will fall to reflect the WACC.[80]

In practice, even if option value were factored into the modelling, the risk of divergence between the model assumptions and the real world would remain, and hence optimal outcomes would differ from those produced by a model. For example, our modelling has illustrated that there are trade-offs between investments in balancing technologies due to substitution effects, and diverse portfolios of technologies tend to produce higher benefits than one technology option produces alone. Investors operating in competitive markets with accurate signalling of marginal costs are best placed to assess these risks and trade-offs. In these conditions, modelling can be used to investigate the decisions that investors are likely to take in certain scenarios, but in practice cannot comprehensively forecast investor behaviour.

4.8. Conclusions

Least-cost modelling of the GB power market does not provide information on the "optimal" level of investment in alternative balancing technologies that GB should be targeting, primarily because modelling by its nature requires a wide range of simplifications. However, the modelling does illustrate the potential contribution that alternative balancing technologies can make to meeting the balancing challenge, and highlights some trade-offs between investments in these technologies.

In this chapter we highlight certain barriers to the efficient deployment of alternative balancing technologies based on a review of incentives. We also highlight areas where the modelling may over or understate the potential for the deployment of alternative balancing technologies, which arise either because the model does not account for certain costs of deployment (e.g. the costs of participating in DSR schemes), or because the assumptions and/or methodology we applied limit their role in system balancing (e.g. the self-security and energy-sufficiency assumptions). We also set out a number of power market design features that may help incentivise private investors to deploy alternative balancing technologies efficiently (e.g. transparent real-time markets for ancillary services). Finally, we also highlight areas for potential further work to improve the robustness of model results and derive firm conclusions on policy options, including:

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80 As described here, although there may be a "value to waiting" when deciding whether to invest in the face of uncertainty regarding the costs and performance of new technologies, it is sometimes suggested that there may be some value from the early adoption of new technologies. However, any suggestion that an individual investor might invest earlier than would otherwise be efficient to capture or "lock in" the benefits of a particular balancing technology is undermined by the ability of other players to enter the market and compete away any super-normal profitability that it earns.
Early deployment might be beneficial for research and development (R&D) purposes. For an individual investor, an early trial of a new balancing technology might be beneficial if it expects to patent new innovations from which it can earn revenues later. However, early investment to conduct R&D might take place to a lesser extent that is economically efficient if "spill-over" effects prevent the parties funding R&D from patenting all the learning that results from it.

- Considering the value of various potential investments in alternative balancing technologies using a “real options” framework;
- Further analysis of the benefits of diversifying investment through a portfolio of balancing technologies given the very significant uncertainties involved, and a review of approaches to incentivise efficient levels of diversity;
- Conducting more modelling using a more detailed representation of neighbouring NW European power markets to more robustly identify efficient levels of interconnection investment, and reviewing approaches to overcoming the problem of asymmetric benefits and thus ensure efficient interconnector investment is achieved; and
- Conducting research into the investment profile of distribution networks (e.g., replacement cycles), and how the requirement for reinforcement is influenced by heat pumps, electric vehicles, DSR and embedded generation.

Appendix

Overview of the methodology for assessing the value of flexible balancing technologies

In this section we describe our approach and models used to quantify the value of flexible balancing technologies for the operation and design of future electricity systems. We highlight the key capabilities of our novel modelling framework, which enables a holistic economic assessment of electricity systems that include alternative balancing technologies. This framework makes optimal operation and investment decisions aimed at minimising the total system cost, by trading off short-term operating decisions against those related to long-term investment into new generation, transmission and distribution networks or storage capacity.

We first highlight the necessity to adopt a whole-systems approach when assessing the value of flexible balancing technologies in future low-carbon electricity systems, and describe Imperial's *Dynamic System Investment Model* (DSIM), which is specifically designed to perform this type of analysis. We also present our approach to estimating the distribution reinforcement cost at the national scale, using the concept of statistically representative networks. The description of our modelling approach is concluded with the overview of flexible demand technologies considered in studying the impact of demand-side response. This involves a number of different demand technologies, each of which is studied in detail using dedicated bottom-up models that enable us to quantify the flexibility potentially provided by these technologies, while maintaining the level and quality of service provided to end consumers.

Our approach to quantifying the value of flexible balancing technologies considers total system cost (including both investment and operation) for a given generation and demand scenario, and compares the case when the model is allowed to add new capacity of alternative balancing technologies (such as interconnection, flexible generation, storage or DSR) in a cost-optimal manner, with the case where no such addition is allowed in the system. The reduction in total system cost as a result of deploying flexible balancing technologies is interpreted as the value generated by these technologies, which also takes into account the investment needed to build the new capacity of flexible technologies.

Whole-systems modelling of electricity sector

When considering system benefits of enabling technologies such as storage, Demand-Side Response (DSR), interconnection and flexible generation, 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 A1); this is important as the alternative balancing technologies can both contribute to savings in generation and network investment as well as increasing the efficiency of system operation.

- **Different assets in the electricity 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 alternative balancing technologies may be placed at different locations in the system and at different scales. For example, bulk storage is normally connected to the national transmission network, while highly distributed technologies may be connected to local low-voltage distribution networks.

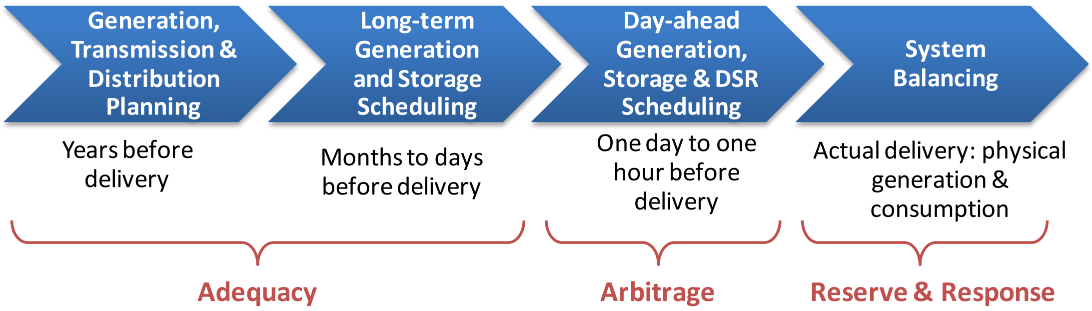

Figure A1. Balancing electricity supply and demand across different time horizons

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*, 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 has been extensively tested in previous projects studying the interconnected electricity systems of the UK and the rest of Europe.[81] An 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 alternative mitigation measures, such as DSR and storage, for real-time balancing and transmission and distribution network and/or generation reinforcement management. For example, the model captures potential conflicts and

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

synergies between different applications of distributed storage in supporting intermittency management at the national level and reducing necessary reinforcements in the local distribution network.

DSIM problem formulation

DSIM carries out an integrated optimisation of electricity system investment and operation and considers two different time horizons: (i) short-term operation with a typical resolution of one hour or half an hour (while also taking into account frequency regulation requirements), which is coupled with (ii) long-term investment i.e. planning decisions with the time horizon of typically one year (the time horizons can be adjusted if needed). All annual investment decisions and 8,760 hourly operation decisions are determined simultaneously in order to achieve an overall optimality of the solution. An overview of the DSIM model structure is given in Figure A2.

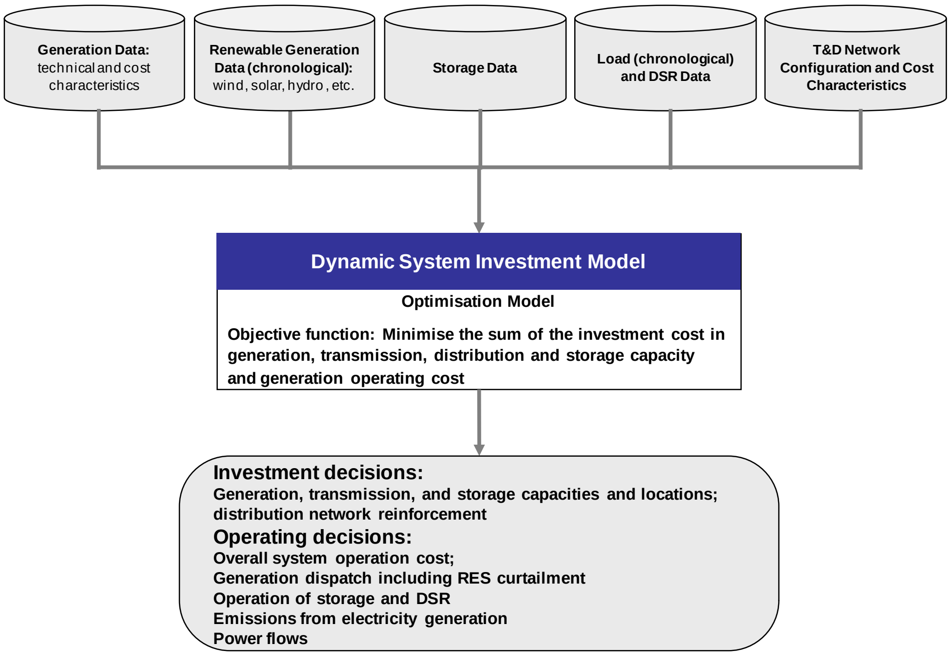

Figure A2. Structure of the Dynamic System Investment Model (DSIM)

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 the 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 (driven by efficiency), and (iii) start-up cost. Generation operating cost is determined by two input parameters: fuel prices and carbon prices (for technologies which are carbon emitters).

There are a number of equality and inequality constraints that need to be respected 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) reserves, typically split between spinning and standing reserve, with delivery occurring within the timeframe of tens of minutes to several hours after the request (this is also linked with need to re-establish frequency regulation services following outage of a generating plant). The need for these services is also 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[82] forecasting error of wind, being at present at about 15% of installed wind capacity, may reduce to 10% post-2020 and then further to less than 6%, 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 an input into the model. DSIM then schedules the optimal provision of reserve and response services, taking into account the capabilities and costs of potential providers of these services (response slopes, efficiency losses of part loaded plant etc) and finding the optimal trade-off between the cost of generating electricity to supply a given demand profile, and the cost of procuring sufficient levels of reserve and response (this also includes alternative balancing technologies such as storage and DSR as appropriate).

  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

[82] 4 hours is generally the maximum time needed to synchronize a large CCGT plant

- o Stand-by fast generating units (OCGT)
- o Electricity storage
- o 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.[83,84] These models find the cost-optimal levels of reserve and response by performing a probabilistic simulation of the actual utilisation of these services. Stochastic scheduling is particularly important when allocating storage resources between energy arbitrage and reserve as this may vary dynamically depending on the system conditions.

- *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 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, as indicated in Figure A3.

- Given that the functional relationship between the available response and the reduced generation output has a slope with an absolute value considerably lower than 1, the maximum amount of frequency regulation that a generator can provide (R_{max}) is generally lower than the headroom created from part-loaded operation ($P_{max} - MSG$).

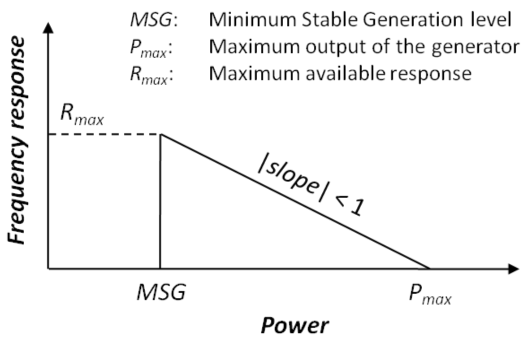

Figure A3. Provision of frequency regulation from conventional generation

83 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.

84 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.

- *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.

- For *wind, solar, marine, and hydro run-of-river* generators, the maximum electricity production is limited by the available energy profile, which is specified as part of the input data. The model will maximise the utilisation of these units (given zero or low marginal cost). In certain conditions when there is oversupply of electricity in the system or reserve/response requirements limit the amount of renewable generation that can be accommodated, it might become necessary to curtail their electricity output in order to balance the system, and the model accounts for this.

- For *hydro generators with reservoirs and pumped-storage units*, the electricity production is limited not only by their maximum power output, but also by the energy available in the reservoir at a particular time (while optimising the operation of storage). The amount of energy in the reservoir at any given time is limited by the size of the reservoir. It is also possible to apply minimum energy constraints in DSIM to ensure that a minimum amount of energy is maintained in the reservoir, for example to ensure the stability of the plant. For storage technologies, DSIM takes into account efficiency losses.

- *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 lighting and industrial demand, (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 the "Demand modelling" section.

- *Power flow constraints* limit the energy flowing through the lines between the areas in the system, respecting the installed capacity of network as the upper bound (DSIM can handle different flow constraints in each flow direction). The model can also invest in 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 sides 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 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 the section "Distribution network investment modelling").

- *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.[85] If there is storage in the system, DSIM may make use 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.[86] 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 are:

- GB is *self-sufficient* in terms of capacity, i.e. there is no contribution from other regions to the capacity margin in the GB and vice versa. However, sensitivity studies are carried out to understand the impact of relaxing the self-sufficient constraint on the cost of making the system secure and the value of alternative balancing technologies in supporting the system.

- GB is *energy-neutral*. This means that the net annual energy import / export is zero. This allows GB to import power from and export to Europe / Ireland as long as the annual net balance is zero. In other words, the GB is still able to export power when there is excess in energy available, for example when high wind conditions coincide with low demand, and import energy from Europe when economically efficient e.g. during low-wind conditions in GB.

System topology

The configuration of the interconnected GB electricity system used in this study is presented in Figure A4. Given that the GB transmission network is characterised by North-South power

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[85] Historical level of security supply are achieved by setting VOLL at around 10,000£/MWh.

[86] 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.

flows, it was considered appropriate to represent the GB system using the four key regions and their boundaries, while considering London as a separate zone.

The two neighbouring systems, Ireland and Continental Europe (CE), are considered (CE is an equivalent representation of the entire interconnected European system). Several generation and demand backgrounds in CE and Ireland are considered (for example, DSIM optimises the operation of the entire European system, including seasonal optimisation hydro in Scandinavia, pump storage schemes across CE and DSR across CE).

Lengths of the network in Figure A4 do not reflect the actual physical distances between different areas, but rather the equivalent distances which are chosen to reflect the additional investment associated with local connection and reinforcements. Network capacities indicated in the figure refer to capacities expected to be in place by 2020.

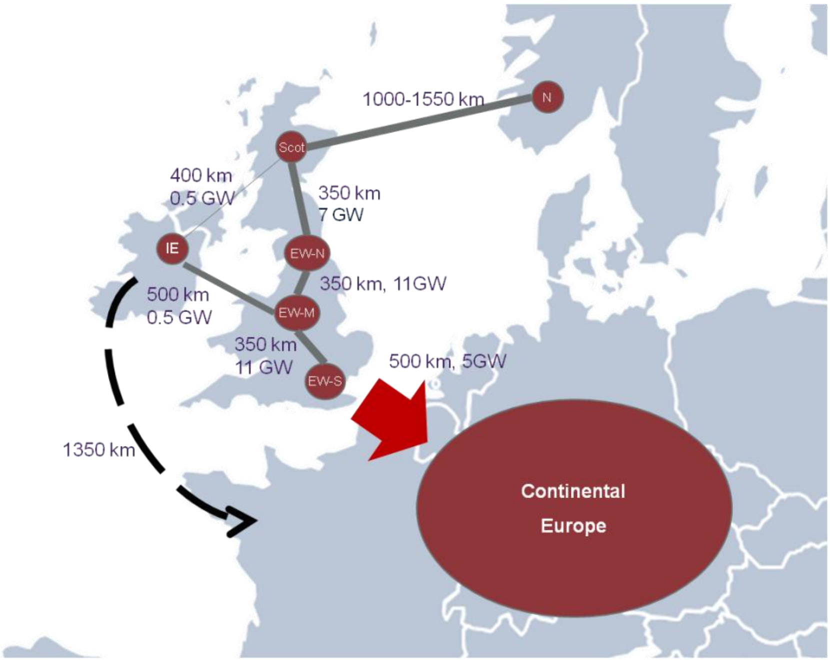

Figure A4. System topology used for studying the value of flexible balancing technologies

Distribution network investment 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: Scotland, North England and Wales, Midlands, London, and South England and Wales. The 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 overall approach to evaluation of regional distribution network reinforcement cost is illustrated in Figure A5. Regional loading of an entire region is split into ten *representative networks* according to the characteristics of different network types. Reinforcement cost of each representative network is estimated as a function of peak demand, and this information is provided as input into DSIM to perform an overall system cost assessment.

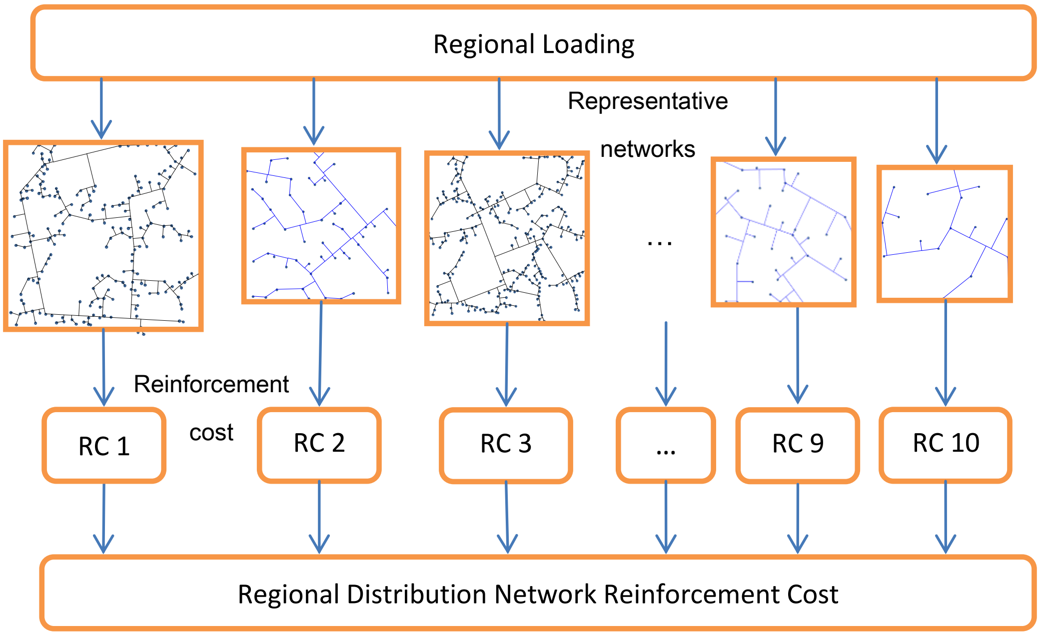

Figure A5. Representative networks approach to estimate GB-wide distribution reinforcement cost (RC)

The procedure of generating representative networks consists of the following steps: (i) creation of consumer layouts, (ii) generation of supply networks, and (iii) supply network design. Examples of different consumer patterns / layouts that can be created by specifying the desired layout parameters[87] are shown in Figure A6 for different urban, rural and intermediate layouts. Parameters of representative networks are calibrated against the actual GB distribution systems.[88] [89]

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[87] 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.

[88] 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.

[89] ENA and Imperial College, "Benefits of Advanced Smart Metering for Demand Response based Control of Distribution Networks", April 2010.

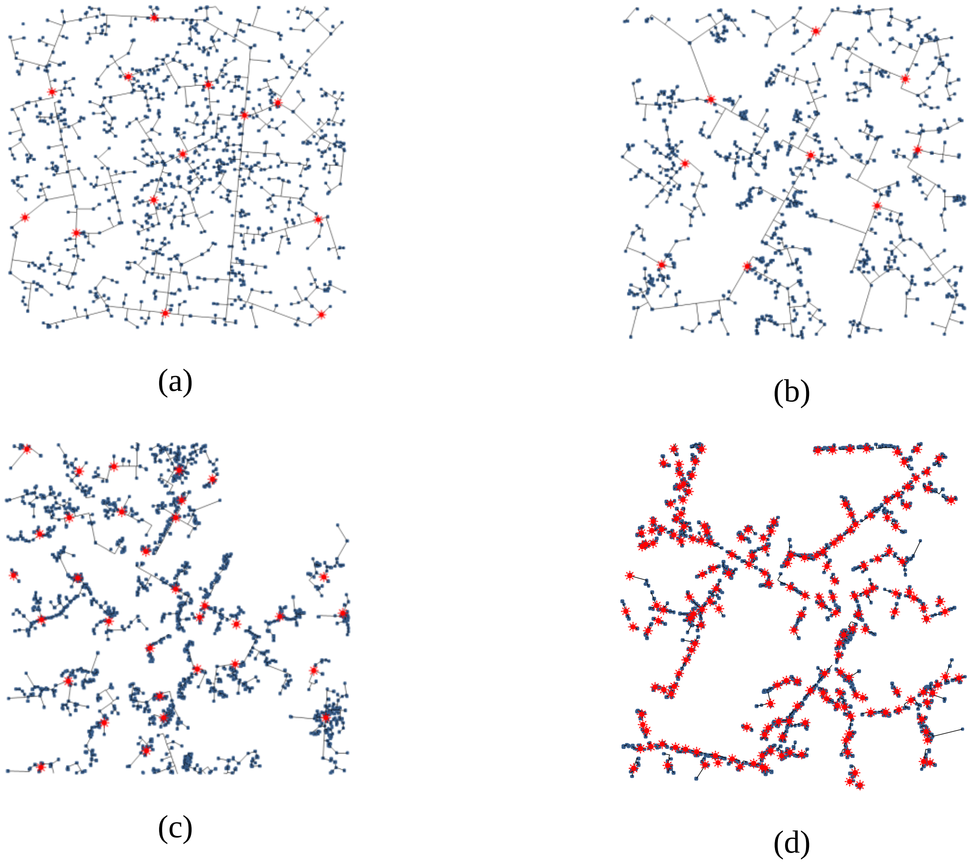

Figure A6. Examples of generated consumer layouts: a) urban area; b) semi-urban area; c) semi-rural area; and d) rural area. (Blue dots represent consumers, while red stars represent distribution substations.)

Many statistically similar consumer layouts can be generated with this approach and the corresponding distribution networks will have statistically similar characteristics. Any conclusions reached are then applicable to areas with similar characteristics.

Based on the geographical representation of GB in this study through the five regions, and the allocation of different DNO areas to these regions, we first determine 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, as shown in Table A1.

Table A1. Regional distribution network parameters

Parameter		Scotland	N England & N Wales	Midlands	London	S England & S Wales	GB
Consumers		2,996,192	7,656,576	5,047,743	2,311,841	11,403,761	29,416,113
LV	Overhead (km)	8,552	12,160	10,896	0	33,321	64,929
	Underground (km)	36,192	89,863	59,570	22,556	119,428	327,609
DT	PMT	67,823	68,388	57,706	0	149,940	343,857
	GMT	26,175	50,448	35,058	17,145	101,639	230,465

Allocation of consumers in each representative network per region is presented in Table A2. We use ten representative networks in this study, each containing a specific consumer mix that reflects the actual numbers of consumers of different types across regions.

Table A2. Number of connected consumers per each representative network per region

Representative network	Scotland	N England & N Wales	Midlands	London	S England & S Wales	GB
Rural 1	45	183,202	220,042	0	830,048	1,233,337
Rural 2	47,599	184,144	131,151	0	535,248	898,143
Rural 3	353,533	154,569	110,331	0	167	618,600
Semi-rural 1	1,608,899	1,302,743	1,025,507	722,388	3,053,402	7,712,940
Semi-rural 2	395	33,503	56,452	114,368	2,036,067	2,240,786
Semi-rural 3	1,544	2,216,451	1,334,728	2,019	884	3,555,626
Semi-urban 1	898,249	3,581,960	1,891,938	826,475	3,194,184	10,392,805
Semi-urban 2	3,285	0	277,587	143,988	56,093	480,954
Urban 1	6,359	0	1	67,043	1,696,171	1,769,574
Urban 2	76,286	1	2	434,196	1,496	511,979
Total	**2,996,194**	**7,656,574**	**5,047,738**	**2,310,478**	**11,403,759**	**29,414,744**

We then generate representative networks that are calibrated to match the actual distribution systems. The mismatches in control parameters between the actual and representative networks characterised using this process, are less than 0.1%, as illustrated in Table A3 (which closely matches the data presented in Table A1).

Table A3. Regional representative networks parameters

Parameter		Scotland	N England & N Wales	Midlands	London	S England & S Wales	GB
Consumers		2,996,194	7,656,574	5,047,738	2,310,478	11,403,759	29,416,238
LV	Overhead (km)	8,552	12,160	10,896	0	33,321	64,929
	Underground (km)	36,192	89,863	59,570	22,558	119,428	327,598
DT	PMT	67,823	68,388	57,706	0	149,940	343,857
	GMT	26,175	50,448	35,058	17,143	101,639	230,474

Designed representative networks satisfy the network design (security) standard ER P2/6.[90] 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 A4 shows an excerpt from the list of cost items.

[90] 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.

Table A4. 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 transformer	#	13.2
11/0.4 kV pole mounted transformer	#	2.9
HV overhead line	km	35.0
HV underground cable	km	82.9
EHV/11 kV ground mounted transformer	#	377.9

Demand modelling

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. We have gained understanding of specific features of these demand sectors, and have developed detailed bottom-up models which enabled us to produce hourly demand profiles based on large databases of transport behaviour and building stock data. This allows us to develop detailed hourly profiles 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.[91] In order to offer flexibility, 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. This in turn requires bottom-up modelling of each individual demand side technology (appliance) understanding how it performs its actual function, while exploiting the 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 and investment, given the relatively modest amount of energy needed daily, generally short driving times, and relatively high power ratings expected for EV batteries.[92] We have the capability to quantify how much of EV charging demand can be shifted at each point in time to support the electrify system while ensuring, at the same time, that all intended daily journeys can be completed.
  Our modelling of EVs is based on statistics for light-vehicle driving patterns calibrated with the GB driving data obtained from Department of Transport. We model two approaches to charging EVs: uncontrolled and optimised. The first

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

[92] “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.

approach is where EV charging is carried out on demand. Such a policy may increase peak demand significantly, although the additional 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.[93,94,95] 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, as illustrated by Figure A7, where workday and weekend vehicle usages are presented for a representative UK sample.[96]

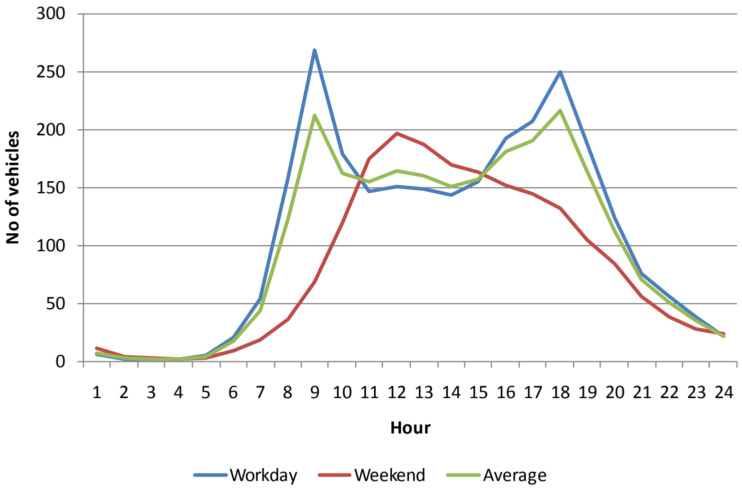

Figure A7. Representative driving patterns for the UK

- *Heat pumps.* Our model can identify the patterns of thermal load (cooling and heating) for a variety of building types and sizes covering both commercial and domestic sector, 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. We apply a detailed thermal building simulation model to develop detailed characteristics of space heating loads for various types of domestic and commercial premises. The modelling is then used to investigate building thermal response under different control strategies. This provides insights into the trade-offs between energy consumed and (slightly reduced) comfort level

93 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.

94 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.

95 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).

96 Green eMotion, EU FP7 project.

against power reduction when performing different Heating, Ventilation and Air Conditioning (HVAC) control strategies.[97] Performance models of HVAC appliances enable appropriate transformation of thermal load to 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 data from the Carbon Trust MicroCHP Accelerator project, which are further calibrated using National Grid Gas regression coefficients to capture the temperature dependency of daily space heating requirements. Figure A8 provides an example for this, where chronological half-hourly heating requirements are estimated for two development pathways i.e. levels of energy efficiency, and for a year with average temperature variations. The chart on the left corresponds to lower energy efficiency levels leading to higher consumption, while the one on the right assumes more ambitious energy efficiency levels. Besides the chronological half-hourly profile (green line), the charts also depict the heat load duration curve (red line).[98] In addition to average temperature conditions, the model is also capable of capturing temperature variations for the 12-year period 1998-2010 to account for years that are colder or milder than average.

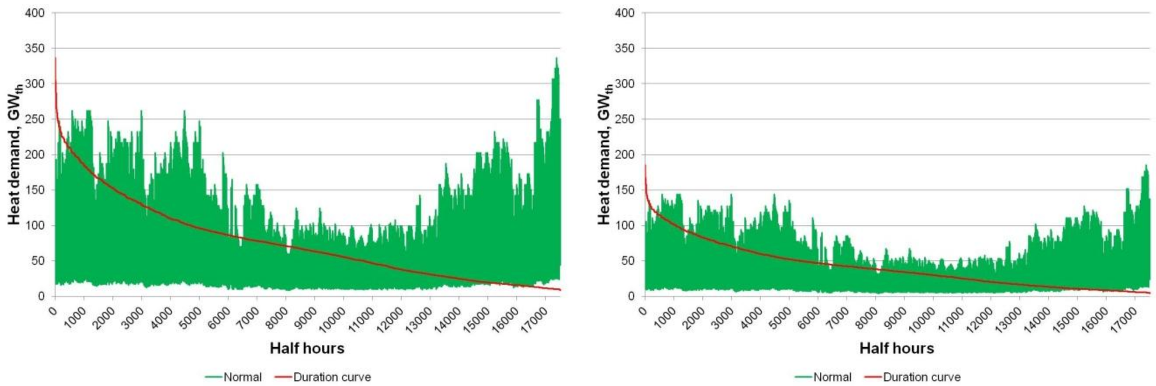

Figure A8. Half-hourly UK heating demand profiles for 2050 for higher (right) and lower (left) energy efficiency levels

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 is particularly relevant for air-source heat pumps (ASHP). In our studies we assume a normal year with average temperature variations, but also introduce a cold spell lasting several days (in line with a year classified as cold), which also coincides with significantly reduced wind output. We take this approach to stress-test the resilience of the system to cold and low wind conditions that may occur during the winter in the UK.

97 Imperial College London, "System-level assessment of flexible demand contribution to operation and planning of a low-carbon energy system", Task 2.2 report of the Demonstration of Distributed Flexible Demand (DD-FD), TSB-funded project No. 200083, December 2010.

98 Note that both chronological and duration curves never drop to zero, which is the result of water heating demand that is present in the system regardless of weather conditions.

- *Smart wet 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: washing machines, dishwashers, and tumble dryers. The data relevant for the use of appliances is sourced from previous European-level projects,[99] 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. Figure A9 provides an illustration of diversified appliance consumption profiles for the UK, expressed per appliance.

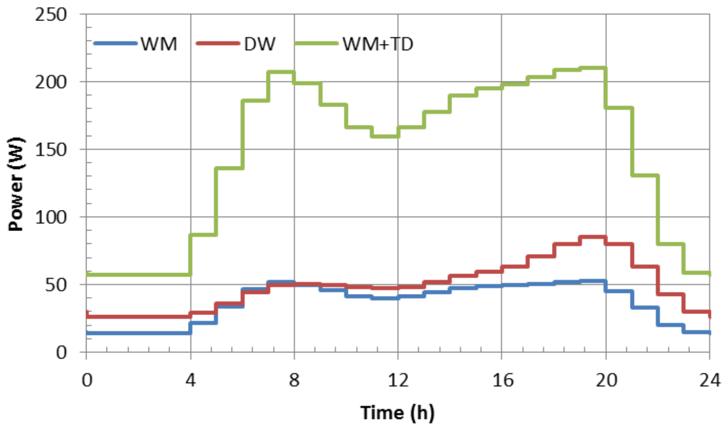

Figure A9. Diversified profiles for washing machines (WM), dishwashers (DW) and washing machines with tumble dryers (WM+TD)

- *Smart refrigeration (SR).* Refrigeration appliances can potentially contribute to providing frequency regulation services to the system, which are currently predominantly sourced from part-loaded synchronised generation.[100] If equipped with an adequate control mechanism, the appliances would be able to quickly respond to fluctuations in system frequency, such as e.g. following a loss of a major generator, by adjusting their duty cycles in such a way that their aggregate consumption helps the system to restore frequency in a way which is similar to large-scale generators. The difference between the behaviour of appliances and generator-based frequency regulation is that while providing the service, refrigerators deliver some of their stored energy to support the system, causing their average internal temperature to increase slightly. After some time, the temperature increase will cause the disconnected refrigerators to progressively reconnect to keep the temperature within prescribed limits. They will need energy to gradually restore their duty cycle length to the original pre-disturbance level, the effect normally referred to as *payback.*

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[99] 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.

[100] 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

Understanding the interdependency between the level and duration of service provided and energy paid back to appliances is the key to understanding their potential to support system management.

Figure A10 shows how the process of load reduction and load recovery can be optimised to match the range of the generation system.

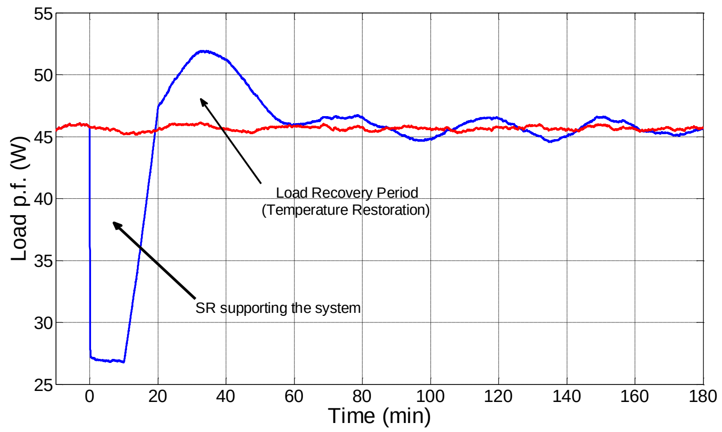

Figure A10. Frequency regulation using Smart Refrigeration

Quantifying the value of alternative balancing technologies

The projections of the supply-demand mix in GB electricity market out to 2050 based on DECC's Carbon Plan scenarios (HM Government, "The Carbon Plan: Delivering our low carbon future", December 2010) define the total energy production and demand on an annual level. In this work we assess the system integration cost associated with enforcing the operational feasibility of the system, i.e. balancing of demand and supply in real time, and also enforcing security of supply requirements driven by stressed conditions when cold spells coincide with low renewable output condition.

Starting from the Pathway assumptions on generation and demand, the model first enforces the feasibility of the real-time operation of each of the Pathways while maintaining the acceptable levels of security of supply, through investing in network and generation assets within a 'business as usual' context. We impose constraints on energy neutrality and self-security for the GB system, and progressively tighter carbon emission constraints towards 2050 in line with the Government's emissions targets. Given these constraints, we allow the model to reinforce transmission and distribution infrastructure within GB as well as the capacity of conventional generation technologies including gas-fired CCGTs, OCGTs, and CCGTs fitted with CCS. Our assumptions of generation availability are based on historical reliability performance of conventional generation, and the assumption of system stress condition characterised with several days of low wind output coinciding with cold weather conditions. From this starting point, we assume no contribution from alternative balancing technologies (such as DSR or storage) beyond the capacities assumed to exist in 2020.[101] We refer to these cases as *counterfactual* scenarios for each Pathway, and these represent the baseline scenario that we use as a reference to calculate the value of balancing technologies

[101] Interconnection, storage and demand side response are included in the original 2050 Pathways but have been removed in order to create the reference *counterfactual* Pathways.

(through quantifying the reduced operating and capital expenditure that these alternative balancing technologies create).

Figure A11 and Figure A12 illustrate the original and secure generation capacity (as suggested by our model) for the examples of Pathways A and B in 2050. Generation capacity in these figures is plotted in parallel with the daily demand profiles on a peak day in both pathways. This emphasises the importance of hourly demand variations as the key driver for generation capacity requirements, and this impact clearly cannot be captured by looking at annual energy balances only. The contribution of electrified heat demand to the increase in peak demand is particularly critical, given that the customers will not only require more electricity due to increased heating requirements during very cold periods, but there will also be an effect of degraded performance of heat pump systems (especially the air-source ones) for very low outdoor temperatures, resulting in the consumption of more electricity per one unit of heat energy delivered to customers.

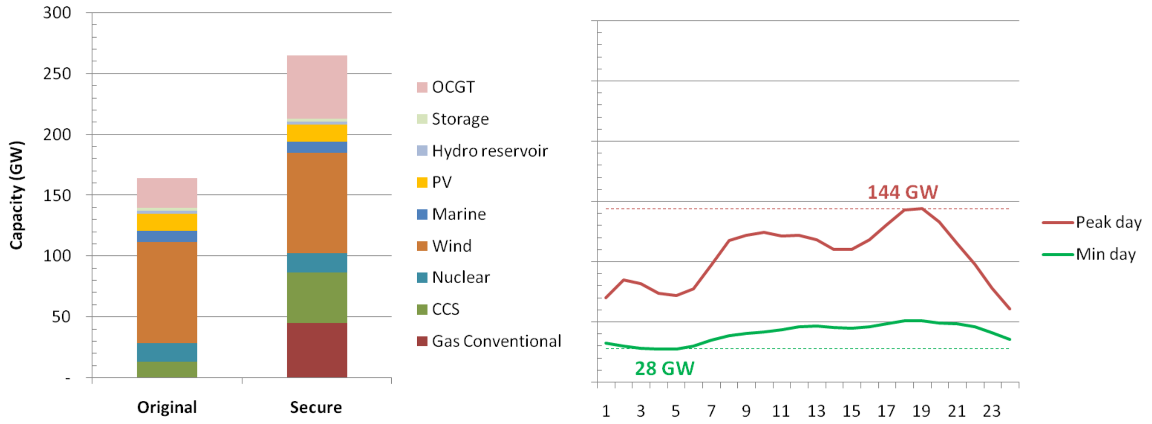

Figure A11. Original and secure generation capacity vs. peak demand in Pathway A

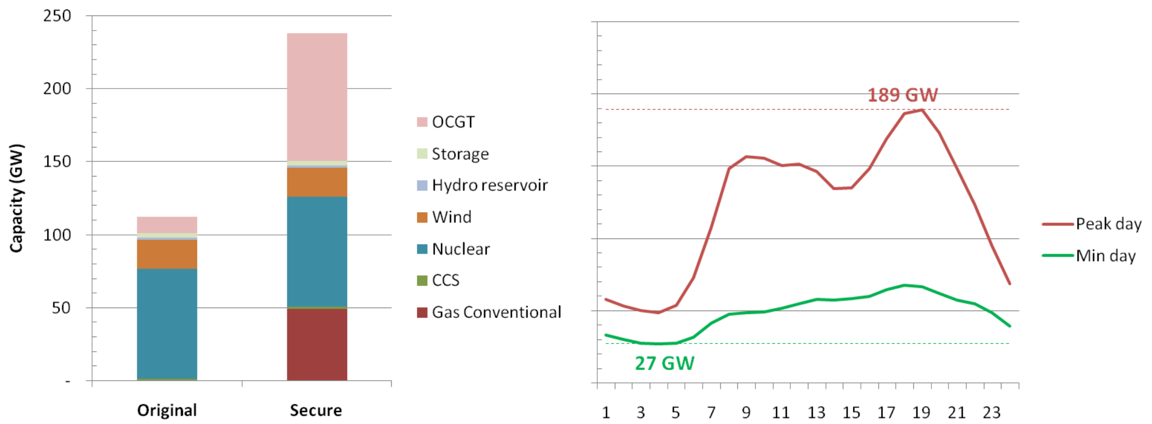

Figure A12. Original and secure generation capacity vs. peak demand in Pathway B

The cost of developing a secure power system using only conventional balancing technologies provides a benchmark, which enables us to evaluate the benefits of deploying alternative balancing technologies. In other words, the difference in the total system cost between the counterfactual scenario and the scenarios where we allow the model to deploy alternative balancing technologies defines the scale of the balancing challenge, and also the value of benefits provided to the system by a particular portfolio of alternative balancing technologies available at a certain cost.