Imperial College London

NERA ECONOMIC CONSULTING

Value of Flexibility in a Decarbonised Grid and System Externalities of Low-Carbon Generation Technologies

For the Committee on Climate Change

October 2015

Imperial College Project Team:

Goran Strbac
Marko Aunedi
Danny Pudjianto
Fei Teng
Predrag Djapic

NERA Project Team:

Richard Druce
Alon Carmel
Konrad Borkowski

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

Acknowledgments

The authors would like to express their gratitude to the Engineering and Physical Sciences Research Council for the support obtained through the Whole Systems Energy Modelling Consortium and Energy Storage for Low Carbon Grids programmes. This support enabled the fundamental research that led to the development of system externalities modelling framework used in this study.

Contents

Foreword

Understanding the *system integration costs* of low-carbon generation technologies is critical for the future largely decarbonised UK electricity system. System integration costs of generation technologies, also referred to as *system externalities,* include various categories of costs that are incurred in the system when these technologies are added to the generation mix, such as increased balancing cost, necessary reinforcement of transmission and distribution grids, increased backup capacity cost, the extent to which technology's generation profile matches the demand profile or the cost of maintaining system carbon emissions. The quantification of system integration costs in addition to the cost of building and operating low-carbon generation capacity (i.e. their levelised cost of electricity, LCOE), therefore represents a critical input into planning for a cost-effective transition towards a low-carbon electricity system.

This analysis clearly demonstrates that the system integration costs of specific low carbon generation technologies will significantly depend on the generation mix for which these costs are analysed. For example, the system integration cost of additional renewables will be higher in systems with significant penetration of renewables when compared to systems with low volumes of renewable generation, as the result of (among other factors) increase in system balancing requirements.

One of the key findings of this work is that the system integration cost of low-carbon generation technologies will significantly depend on the level of system *flexibility*. Flexible options considered include application of more efficient and more flexible generation technologies, energy storage, demand side response, interconnection and also reduced needs for various balancing services through improved system management and forecasting techniques. The impact of the level of flexibility on the system integration cost of renewable generation is very significant. Enhancing system flexibility reduces system integration cost of renewables *by an order of magnitude*. For instance, as demonstrated in this study, the whole-system cost disadvantage of wind generation against nuclear reduces from circa £14/MWh in a low flexibility system to £1.3/MWh in a fully flexible system achieving 100 g/kWh emission intensity. At the same time, the whole-system cost of solar PV reduces from being £2.3/MWh higher than nuclear to being £10.7/MWh lower than nuclear as the result of improved flexibility.

Therefore *very significant cost savings* can be made by increasing flexibility in the core power sector decarbonisation scenarios considered (based on CCC scenarios and reaching an average grid intensity of between 50 to 100 g/kWh in 2030). For the 100 g/kWh scenario modelled, the total gross benefits of flexibility is between £3bn and £3.8bn per year, while for 50 g/kWh system the value of flexibility increases to £7.1bn to £8.1bn per year. These savings are realised as more variable renewables and inflexible nuclear can be accommodated in a more flexible system, relative to an inflexible system which would require significant deployment of CCS to reach an emissions target. Even in the system with grid intensity of 200g/kWh, the value of flexibility is significant generating savings at around £2.9bn per year.

In addition to testing the impact of flexibility in the core CCC 50 g/kWh and 100 g/kWh scenarios, we analysed a set of cases to study how different levels of *flexibility would affect the cost-optimal low-carbon generation mix*. The cost-optimised scenarios reveal a markedly different generation mix, depending on the level of flexibility that may be available (e.g. CCS and nuclear are preferred in a less flexible system while variable renewables are chosen in a more flexible system). This suggests that the flexibility will critically affect the integration cost of different low-carbon technologies. The optimal generation mixes for the cases of low, medium and very high flexibility are shown in Figure F.1 for both 50 g/kWh and 100 g/kWh targets.

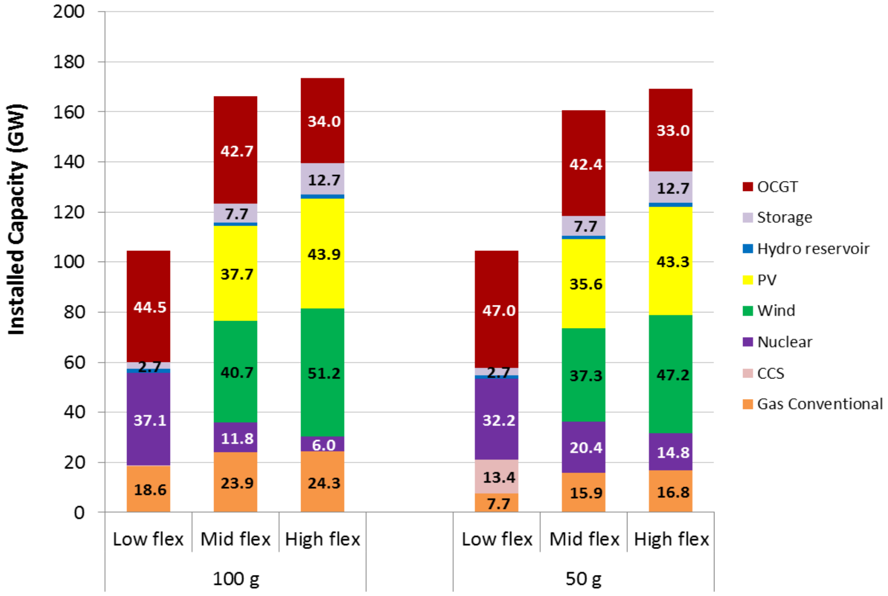


Figure F.1. Impact of system flexibility on optimal generation mix for 50 and 100 g/kWh targets in 2030

We observe that with a low level of flexibility in the system the technologies chosen to deliver a decarbonised electricity system are primarily nuclear and to a lesser extent CCS. No wind or PV generation is selected as part of the optimal generation portfolio, suggesting that despite having lower levelised costs their whole-system cost is comparatively higher than that of nuclear. Note that in the low flexibility scenario, reducing emissions from 100 g/kWh to 50 g/kWh is achieved by adding CCS plant, while in the medium flexible scenario this is achieved by adding nuclear generation.

In the other extreme case, where a high level of flexibility is available, we observe a massive shift in the generation mix towards renewable technologies, with about 90-95 GW of wind and PV capacity, reflecting the reduced integration cost of RES technologies enabled by enhanced flexibility. Nuclear capacity is still present, although with a far lower volume, while the model does not select CCS at the assumed technology costs, given that the additional system flexibility makes wind and PV more cost-effective from the system perspective considering their reduced integration costs. Note that in the medium flexibility scenario, reducing emissions from 100 g/kWh to 50 g/kWh is achieved by increasing the amount of nuclear plant capacity, while in the high flexibility scenario this would be achieved by increasing the capacity of renewable generation. Gross benefits of flexibility are reflected in the reduced cost of reaching a given emission target: between £4.2bn to 5.1bn per annum for 100 g/kWh scenario and between £5.2bn and 5.8bn per year for 50 g/kWh scenario. As in the core CCC scenarios, savings are realised due to the need for less CCS capacity to ensure decarbonisation in a less flexible system.

The analysis carried out clearly demonstrates that increasing system flexibility can significantly reduce system integration costs of low-carbon technologies. In this context, development of efficient market mechanism that would appropriately reward flexibility will be critically important for facilitating cost-effective decarbonisation of the GB electricity system.

Executive Summary

The UK electricity system is facing exceptional challenges in the coming decades. Meeting the medium and longer-term carbon emission reduction targets will require intensive expansion of the use of low carbon electricity generation technologies, such as renewables, nuclear and Carbon Capture and Storage (CCS).

In this context, the UK Committee on Climate Change has previously recommended that Government legislate a target to reduce the carbon intensity of power generation to 50-100 g/kWh by 2030, with some flexibility to adjust this in the light of new information, for example if the costs of emerging technologies reduce less quickly than expected, or if the roll-out of energy efficiency measures, deployment of nuclear or onshore wind are more constrained. A critical question when considering different approaches to reaching the carbon reduction targets is whether the UK electricity system can cost-effectively integrate higher penetrations of low-carbon technologies implied by decarbonisation.

The key policy tool that the Government is relying on to deliver investments in this new generation capacity is the Electricity Market Reform package and more specifically the Contracts for Difference (CfDs) framework, developed to support investment in low carbon generation, providing investors with the benefit of long-term revenue certainty.

One of the important questions in this context is whether "technology-neutral" auctions, i.e. selecting technologies based on the lowest strike price offered, can deliver a low-carbon power sector at lowest overall cost. Ideally, technologies would be selected based on their impact on total system costs. The difference arises because strike prices and levelised costs of generation do not capture all the impacts on the total cost of the energy system. Levelised costs cover plant investment and operating costs but not the costs of delivering energy to the final customer when required. For example, it is well recognised that variable renewable generation technologies will impose additional costs on the wider system, through the need for additional back-up capacity and balancing services (though all generation technologies would imply some system costs).

In this context, this work aims at explicitly identifying and quantifying the *system integration costs* of low-carbon generation technologies in the context of the future, largely decarbonised UK electricity system. System integration costs of generation technologies, also referred to as *system externalities*, include various categories of costs that are incurred in the system when these technologies are added to the generation mix, such as increased balancing cost, necessary reinforcement of transmission and distribution grids, increased backup capacity cost, the extent to which technology's generation profile matches the demand profile or the cost of maintaining system carbon emissions. The identification of system integration costs in addition to the cost of building and operating low-carbon generation capacity (i.e. their levelised cost of electricity, LCOE), therefore represents a critical input into planning for a cost-effective transition towards a low-carbon electricity system[1].

---

1 Recent report by ERP "Managing Flexibility Whilst Decarbonising the GB Electricity System" (2015) also stresses that low carbon generation technology costs should not be characterised only by LCOEs due to system externalities.

It is however important to emphasise that in the case that electricity market was fully cost-reflective, all generation technologies would be exposed to additional costs (externalities) they impose on the system and the CfD mechanism would hence endogenously include all components of system integration costs. For instance, a fully cost-reflective transmission network charging mechanism would ensure that generation, storage or flexible demand operators are adequately charged (or rewarded) for additional network costs (or benefits) that they impose on the system; similarly, in a fully cost-reflective market environment renewable generators would be exposed to the additional cost associated with increased balancing requirements driven by their output intermittency.[2]

The key objectives of this study are therefore the following:

- Assess the CO_2 performance of alternative core CCC scenarios under different levels of flexibility and establish the level of system flexibility required to meet corresponding grid decarbonisation targets;

- Understand the impact of flexibility on the choice of generation mixes that meet different grid decarbonisation targets under minimum cost;

- Quantify the sensitivity of achieving a 2030 grid CO_2 intensity target given unpredictable circumstances (e.g. changes in demand, renewables output and commodity prices);

- Assess the level of system externalities (or grid integration costs) that should be attached to individual low-carbon technologies under different scenarios; and

- Inform recommendations on whether policy should take account of system externalities, and if so, how this could best be achieved.

Main findings

Key overall observations from the study are:

- It is feasible to manage a future GB power system that is deeply decarbonised with high levels of intermittent renewables (i.e. up to around 50 GW of wind or solar).

- Achieving deep decarbonisation at efficient cost will require a significant increase in system-wide flexibility from the current levels, alongside the expansion of low-carbon capacity.

- Increasing flexibility is a low-regret option, reducing the overall cost even in a system that is less decarbonised (e.g. reaching 200 g/kWh in 2030), while maintaining security of supply requirements. For example, our analysis shows that gross benefits

[2] This report is focused on quantifying the fundamental system externalities of low-carbon technologies from the perspective of economic (cost-optimal) performance of the electricity system. The accompanying report, led by NERA Economic Consulting (hereafter referred to as "NERA report") analyses the implications of these quantitative findings on energy policy and market design.

of flexibility (primarily associated with the deployment of energy storage and DSR) for reaching the 50 g/kWh intensity are between £7.1-8.1bn per annum, while the corresponding benefits for the 100 g/kWh target amount to £3-3.8bn annually (savings in the system with 200 g/kWh would also be significant at around £2.9bn per annum). These flexibility options exist today or are likely to be available by 2030, but may not be sufficiently incentivised by the current market arrangements.

- Grid integration costs of low-carbon technologies are a function of different factors such as seasonal variability in available output, location, level of intermittency i.e. unpredictability etc.

- In the core CCC scenarios analysed, the integration costs of wind and solar are relatively marginal in a power sector reaching 100 g/kWh (ranging from £6-9/MWh), but these costs become more material when moving to a system achieving 50 g/kWh with high penetration of wind or solar (e.g. ~50 GW), with costs up to £16/MWh for wind and £28/MWh for solar (see Table E.1). This suggests that there may be limits or thresholds regarding the capacities of different low carbon technologies the grid can integrate cost-effectively, although these limits will be a function of system flexibility. The integration cost of wind and PV in a less decarbonised scenario at around 200 g/kWh, would further reduce compared to the 100 g/kWh scenario, to the level of around £6-8/MWh.

Table E.1. Summary of relative integration cost of wind, PV and CCS relative to nuclear (in £/MWh) across different scenarios in 2030

Scenario	Wind	Solar PV	CCS
100 g/kWh	6.2-7.6	6.1-9.2	(6.4)-(0.5)
50 g/kWh (wind-dominated)	12.5-15.6	12.1-17.1	(7.9)-4.6
50 g/kWh (solar-dominated)	9.5-14.3	26.2-27.6	(7.5)-(2.8)

Notes: ranges reflect various methods adopted; brackets indicate negative value.

- We observe that the integration cost of CCS can be both positive and negative (ranging between about -£8/MWh to £5/MWh) when compared to nuclear, depending on the calculation method employed. This is due to the greater controllability of CCS plant as well as the fact that connecting additional CCS capacity does not increase the requirements for ancillary services in the system.

- Flexibility can therefore significantly reduce the integration cost of intermittent renewables, to the point where their whole-system cost makes them a more attractive expansion option than CCS and/or nuclear.

- Provided that sufficient flexibility and reserve/response is available, the system can cope at times of stress (e.g. lots of wind, very low wind over several days, unexpected nuclear outages, low fuel prices, high demand) and achieve the carbon target.

Scenario development

We evaluate the system externalities of low-carbon technologies across two core scenarios and a number of variations or sensitivity studies around these scenarios. The core scenarios include a UK electricity system reaching an average grid carbon emission intensity of:

- *50 g/kWh in 2030*
- *100 g/kWh in 2030*

The generation mix and associated operational and investment costs in these scenarios are directly driven by the need to meet the emissions intensity target, which is explicitly enforced in the model.

The core scenarios were developed to include a balanced mix of low-carbon technologies (nuclear, onshore and offshore wind, solar PV and CCS). This portfolio of technologies reflects existing scenarios published by the CCC in its 2013 *Fourth Carbon Budget Review*[3], with some revisions to reflect updated information and evidence (e.g. potential delays to deploying new nuclear and required levels of investment in CCS and offshore wind to bring about innovation and cost reduction).

Table E.2 summarises the generation capacity assumptions in the core scenarios.

Table E.2. Low-carbon generation capacity assumptions (in GW) in core 2030 50 and 100 g/kWh scenarios

Technology	100 g/kWh	50 g/kWh (wind dominated)	50 g/kWh (solar PV dominated)
Nuclear	9.6	10.6	10.6
CCS	7.1	7.7	7.7
Onshore/offshore wind	36.0	53.0	45.4
Solar PV	20.0	20.0	50.0

While these technologies are "nominally" appropriate to achieve the specified emissions intensity targets when their expected annual energy outputs were considered, they do not consider real-time system operation requirements e.g. account for system requirements to balance short term fluctuations in demand and renewables output and maintain overall system security. Therefore, when these generation mixes were initially tested the outturn emissions intensity was found to be very significantly higher than the target level; e.g. above 190 g/kWh in an extremely inflexible system, for a mix targeting an average emissions intensity of 50 g/kWh.

[3] https://www.theccc.org.uk/publication/fourth-carbon-budget-review/

This high emission intensity is driven by two key factors which reduce the ability of the system to accommodate a combination of inflexible and intermittent low carbon generation renewables:

(a) ***A significant increase in system balancing requirements in a decarbonised grid***.

- <u>*Reserve requirements*</u>. Forecasting errors associated with outputs of renewable generation require appropriate amounts of reserves to be scheduled to ensure that generation and demand can be balanced at all times. This has an impact on emissions as conventional plant running to provide reserve will also produce energy, which may result in curtailment of renewables or reduction in nuclear output, particularly during low demand periods. The flexibility characteristics of the conventional plant providing reserve will therefore have a major impact on the emissions performance of the system (e.g. a less flexible system may prevent the efficient integration of low-carbon generation). Moreover, when a technology's generation profile is poorly matched to the demand profile, plant utilisation across the system is likely to be lower on average, requiring more capacity to deliver a given level of useful generation (e.g. due to wind curtailment or reducing nuclear output in summer months). Also, when a particular technology does not reliably generate at times of peak demand, additional ('back-up') capacity is required to ensure demand can be met at the peak with sufficient level of security.

- <u>*Frequency regulation requirements*</u>. Due to plant characteristics, wind and solar generators do not currently contribute to system inertia. Conventional generation plant on the hand regulates the frequency of the UK grid by providing system inertia[4] as well as fast frequency regulation which provides rapid increase in generator output (within seconds) required to compensate for a loss of largest plant operating at any particular point in time. In order to meet this requirement, a number of large power station generators run part-loaded when providing frequency response and maintain the system frequency within the required range. Therefore as more intermittent renewables is added to the system, more conventional plant running part-loaded will be required to provide frequency response. This is problematic in the context of meeting a decarbonisation target, as demand that could otherwise be met by renewables will instead be met by part-loaded conventional plant that is required to operate, thereby curtailing renewable output[5].

(b) ***A lack of flexibility in the present system***.
Present conventional gas and coal generators are relatively inflexible, particularly in terms of limited amount of frequency control that can be provided and relatively high minimum stable generation, which are the key factors that limit the amount of renewable generation that can be accommodated. Furthermore, at present renewable generation does not contribute to the provision of ancillary services (e.g. system

---

4 System inertia is provided by the rotating masses of turbines in conventional generation plant.

5 In this context, National Grid is considering updating frequency regulation standards, particularly the rate of change of frequency (RoCoF), which will be beneficial in enhancing the ability of the system to accommodate increased levels of renewable generation.

reserve and response). There is also a limited amount of demand-side response services that can support system balancing in the timeframe from seconds to hours. In the future however, system flexibility may significantly improve. In this context, an update of market arrangements to reward different forms of flexibility will be important [6]. For example, conventional generation technologies of significantly enhanced flexibility are already available at reasonable cost, but power companies do not presently find it attractive to make corresponding investments.

Similarly, energy storage technologies and demand-side response could significantly enhance system flexibility. Finally, strengthening the interconnection with the EU electricity system can also bring system integration benefits.

Therefore, a combination of low demand, high renewables output, and high output of must-run units such as nuclear plants, or conventional generators that have to be synchronised in order to provide frequency regulation will have an adverse impact the carbon intensity of the electricity system (as the curtailed renewables output needs to be compensated by increased energy from mid-merit fossil fuel-based power plant).

To enable the power system to more effectively accommodate low-carbon electricity and therefore achieve a decarbonisation target, the impact of deploying various flexible options was tested by successively adding more flexibility to achieve an emissions target at minimum overall cost. Flexible options considered and deployed included:

- **More efficient and more flexible generation technologies**: conventional plant that can operate stably at lower levels of output (and therefore less likely to push renewables out of system) and provide faster frequency response (requiring less overall thermal plant to balance the system).

- **Reduced primary frequency regulation requirements and improved system management and forecasting techniques** leading to reduced requirements for reserve and secondary response services (associated with short time scales). We assume that by 2030, intermittent renewable generators (e.g. wind farms) would be capable of contributing to reserve services when curtailed[7].

- Deployment of **energy storage** technologies that can deliver ancillary services (e.g. reserve and response) thereby reducing the need for part-loaded plant, additional back-up generation and network infrastructure reinforcement.

- **Demand-side response** capable of providing primary and secondary frequency response, short term operating reserve, services for network congestion management

---

6 National Grid has recently introduced additional frequency regulation products that should encourage provision of enhanced response services and hence increase the ability of the system to accommodate low carbon generation.

7 This is in line with recent developments in this research area, see e.g.:
Council on Large Electric Systems (CIGRE) Working Group "Wind generators and frequency-active power control of power systems", http://c4.cigre.org/WG-Area/JWG-A1-C4.52-Wind-generators-and-frequency-active-power-control-of-power-systems
National Renewable Energy Laboratory (NREL) Transmission and Grid Integration Group (TGIG), http://www.nrel.gov/electricity/transmission/active_power.html

services and security of supply. Our modelling assumes that DSR application would not result in compromises in service quality received by end consumers.

- Increased **interconnection** (e.g. with mainland Europe).

All assumptions regarding flexibility were made taking into account the realistic technical potential for deploying these options in the 2030-2050 horizon, particularly reflecting the latest evidence and industry consensus. For example, 50% of the total demand-side response potential is assumed to be unlocked by 2030. More detail on the flexibility assumptions is provided in Section 1.3.

The core 100 g/kWh and 50 g/kWh scenarios build in the low-carbon capacity and demand from the CCC scenarios as well as the assumed improvements in flexibility. Assumptions for fossil fuel prices[8], carbon prices[9], and technology costs are based on latest DECC estimates (more detail is provided in Section 3.2). The model then builds sufficient conventional plant (e.g. CCGT and OCGT) to meet reserve and response requirements and maintain security of supply. These scenarios are then adopted as counterfactuals for subsequent system externality studies, which estimate the grid integration costs associated with adding additional low-carbon capacity to the core systems. We developed two variants of a core power sector scenario achieving an average grid intensity of 50 g/kWh in 2030 – one with higher build rates of onshore/offshore wind and one with higher deployment of solar PV.

Figure E.1 illustrates the importance of flexibility in reducing grid emission intensity: it is evident that the gradual increase in system flexibility significantly reduces carbon emissions intensity. As the “initial system” condition presented in Figure E.1 is considered to be extreme, in the analysis carried out in this study we assumed that more flexible generation will be used (as these technologies are already available at reasonable cost) and that the requirement for system frequency regulation will reduce (as National Grid is already taking actions to modify the frequency standards). Hence the base line “low flexibility” system is characterised by the emissions of 94 g/kWh. In this context, the estimates of savings made by enhancing system flexibility presented in this study are conservative.

---

8 DECC, *Fossil Fuel Price Projections*, September 2014.

9 DECC, “Updated short-term traded carbon values for policy appraisal”, September 2013.

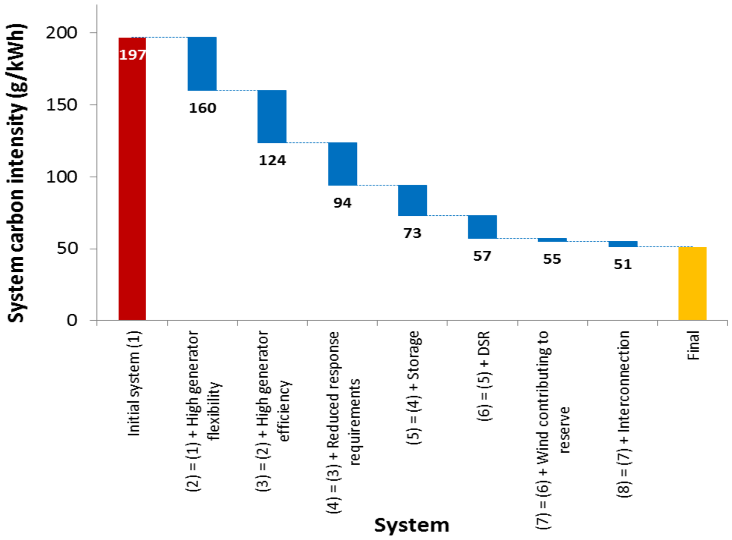


Figure E.1. Impact of increasing system flexibility on carbon emissions in a wind-dominated core scenario reaching 50 g/kWh in 2030

Figure E.2 illustrates the annualised cost savings for the UK system associated with moving from low to medium and high flexibility in the three core scenarios, while meeting the respective 50 or 100 g/kWh emission intensity targets.

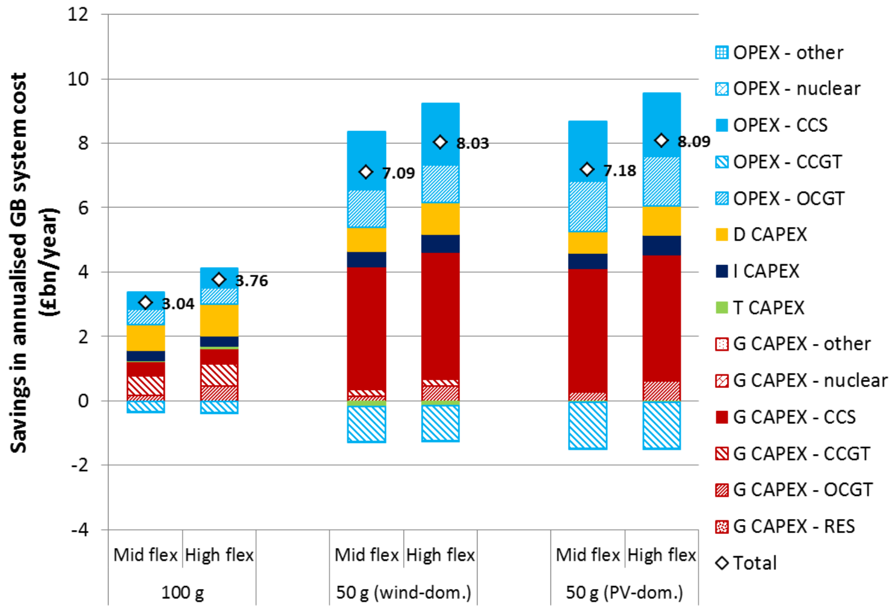


Figure E.2. Impact of increasing system flexibility on system cost savings in three core scenarios in 2030

For the 100 g/kWh scenario the value of flexibility is between £3bn and £3.8/bn per year for 100 g/kWh system, while for the 50 g/kWh system the value of flexibility increases to £7.1bn to £8.1bn. Key categories of system cost savings include reduced investment and operation cost of CCS, as the available renewable resources can be utilised more efficiently helping to reach the carbon target, reduced operating cost of OCGT plant (which face high running costs due to lower efficiency and increasing fuel and carbon prices), and to a smaller extent reduced requirement for distribution network reinforcement.

Note that the cost savings in Figure E.2 include the costs of deploying more flexible generating plant and interconnection, but the cost of deploying DSR and storage schemes is not included in annual cost savings. The rationale behind this approach is that the smart meter rollout, providing the technical functionality behind DSR, has already been mandated, while the additional cost of introducing DSR schemes (and in particular the cost of engaging customers) is uncertain with very little reliable cost estimates available. Nevertheless, it is likely that the benefits would significantly outweigh the cost of deployment and therefore the approach adopted in the study was to vary the percentage of uptake of DSR (50% uptake was assumed in mid-flex and 100% in high-flex studies).[10]

Regarding energy storage, 5 GW of additional storage is assumed to be deployed in mid-flex cases, which could be justified on the basis of accessing adequate revenues from delivering service within the present market, not only for the purpose of decarbonisation. Earlier studies have also shown that the benefits of deploying storage in a low-carbon system exceed the likely cost of investing in new energy storage up to the level of about 15 GW, recognising the uncertainty of the evolution of storage costs in the 2030 horizon[11].

On the other hand, system cost savings driven by flexibility include the avoided cost of building additional interconnection capacity between Great Britain and continental Europe in a given scenario. Table E.3 shows the new interconnection capacity for the three core scenarios and different flexibility levels, proposed by the model as a cost-optimal solution in addition to the minimum of 7.4 GW of interconnection capacity assumed to be available by 2030 (see Section 1.3 for more details).

Table E.3. Additional interconnection capacity (in GW) across core scenarios for different levels of flexibility (above the minimum of 7.4 GW of interconnection assumed to be available by 2030)

Scenario	Low flex	Mid flex	High flex
100 g/kWh	4.3	-	-
50 g/kWh (wind-dominated)	11.7	2.1	-
50 g/kWh (solar-dominated)	12.5	2.7	-

Given that interconnection offers flexibility to the system, significantly more interconnection is added in low flexible systems (e.g. 4.3 GW in the 100 g/kWh scenario, and 11.7-12.5 GW in the two 50 g/kWh scenarios) than in medium or high flexible systems. Also, the increased requirements for flexibility associated with higher penetrations of wind and PV in 50 g/kWh scenarios drive a higher deployment of interconnection than in the 100 g/kWh scenario,

10 A similar approach was adopted in: Imperial College and NERA Consulting, 2012, Understanding the Balancing Challenge, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48553/5767-understanding-the-balancing-challenge.pdf.

11 Imperial College London, "Strategic Assessment of the Role and Value of Energy Storage Systems in the UK Low Carbon Energy Future", July 2012. http://www.carbontrust.com/resources/reports/technology/energy-storage-systems-strategic-assessment-role-and-value

which is characterised by lower renewable capacity. Note that although energy exports and imports via interconnection are optimised on hourly basis, the *energy neutrality* constraint is imposed so that the total annual energy production and consumption in the UK is fully balanced. In other words, the total annual energy exports from the UK to the continental Europe exactly balance the total annual energy imports from the continental Europe to the UK.

Additional flexibility not only helps to decarbonise the system more cost-effectively, but also allow the system to cope more efficiently at times of stress, for instance by using storage and DSR resources to manage periods of high wind output and low demand or vice versa. Also, the model will ensure that sufficient backup capacity is in place to supply the demand even in the event of prolonged periods of low renewable output.

Flexibility implications in cost optimised scenarios

Cost-optimal generation mix

In addition to testing the impact of flexibility in the core CCC 50 g/kWh and 100 g/kWh scenarios, we analysed a set of cases to study how different levels of flexibility would affect the cost-optimal low-carbon generation mix (i.e. based on comparative LCOE). The cost-optimised scenarios reveal a markedly different generation mix, depending on the level of flexibility that may be available (e.g. CCS and nuclear are preferred in a less flexible system while intermittent renewables are chosen in a more flexible system). This also suggests that the flexibility will critically affect the integration cost of different low-carbon technologies. The optimal generation mixes for the cases of low, medium and high flexibility are shown in Figure E.3 for both 50 and 100 g/kWh targets.

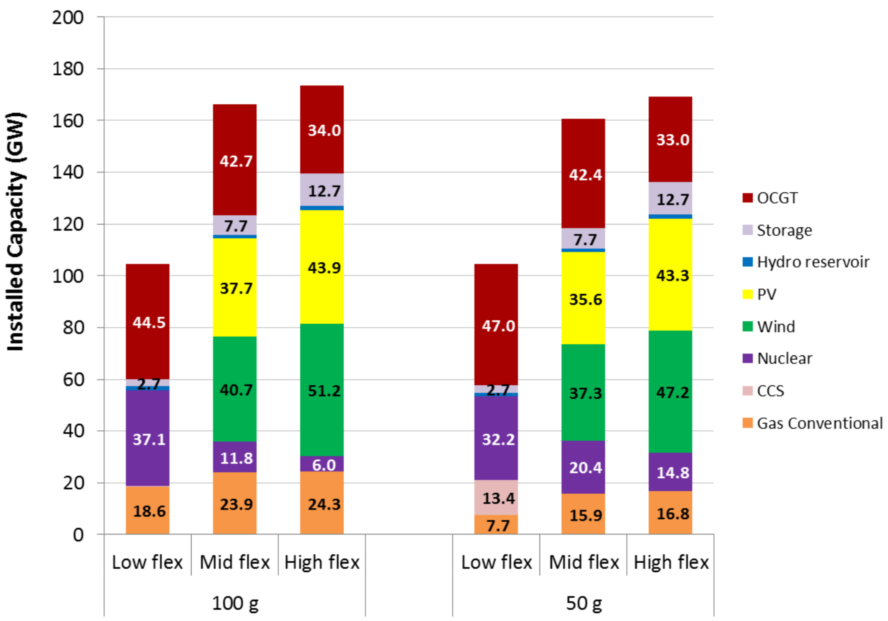


Figure E.3. Impact of system flexibility on optimal generation mix for 50 and 100 g/kWh targets in 2030

- With low level of flexibility in the system the technologies chosen to deliver a decarbonised electricity system are primarily nuclear and to a lesser extent CCS. No wind or PV generation is selected as part of the optimal generation portfolio, suggesting that despite having lower levelised costs its whole-system cost is comparatively higher than that of nuclear. Note that in low flexibility scenario, reducing emissions from 100 g/kWh to 50 g/kWh is achieved by adding CCS plant.

- In the other extreme case, where a high level of flexibility is available, we observe a massive shift in the generation mix towards renewable technologies, with about 90-95 GW of wind and PV capacity, reflecting the reduced integration cost of RES technologies enabled by enhanced flexibility. Nuclear capacity is still present, although with a far lower volume, while the model does not choose to build CCS at the assumed cost given that the additional system flexibility makes wind and PV more cost-effective from the system perspective considering their reduced integration costs. Note that in the medium flexibility scenario, moving from a 100 g/kWh to 50 g/kWh power system is achieved by increasing the amount of nuclear plant capacity, while in high flexibility scenario this would be achieved by increasing capacity of renewable generation.

Benefits of flexibility are reflected in reduced cost of reaching a given emission target. Figure E.4 illustrates cost savings for various flexibility levels deployed in the optimised 100 g/kWh and 50 g/kWh scenarios when compared to the same systems with low flexibility.

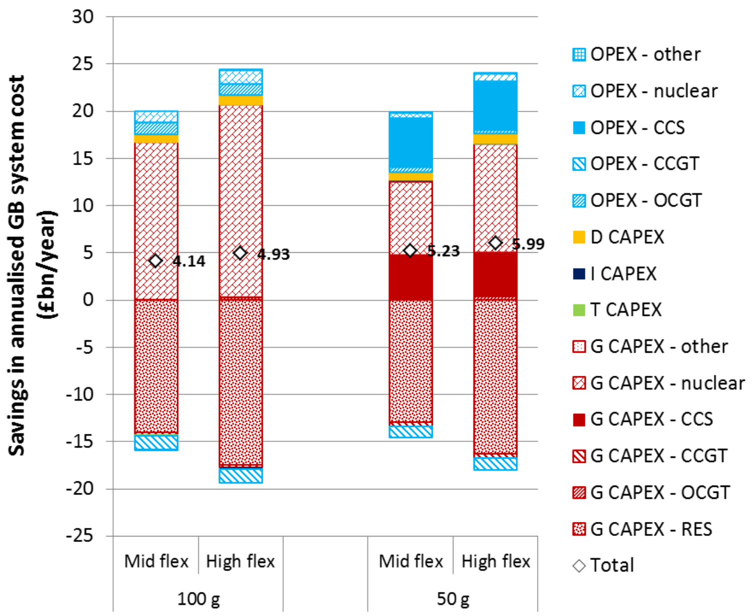


Figure E.4. Impact of system flexibility on cost savings while meeting 100 g/kWh and 50 g/kWh targets in 2030 (optimised generation mix)

As the flexibility increases, progressively higher volumes of wind and PV are able to replace nuclear generation, given that their cost disadvantage due to higher integration cost diminishes with enhanced flexibility. This replacement results in a net benefit of between £4.14bn to 4.93bn per annum for 100 g scenario and between £5.23bn and 5.99bn per year for 50 g/kWh scenario, representing the net effect of removing nuclear (with higher LCOE) and adding lower cost wind and PV generation.

The results, both in the core CCC scenarios (Figure E.2) and the additional cost optimised case studies (Figure E.4), *strongly suggest that system flexibility should be considered as a critical factor for designing decarbonised electricity systems and facilitating cost effective evolution to lower carbon electricity system while ensuring security and quality of supply*. In this context, it will be critical that different forms of flexibility are adequately rewarded for the benefits they provide to the system.

As opposed to imposing an explicit carbon emission constraint on the electricity system, it is also possible to reduce system emissions by sufficiently increasing the assumed carbon price. In the system with 50% (medium) flexibility, the carbon price needs to reach £104/t for the system emissions to drop to 50 g/kWh level, while in case of low-flexible (Figure E.3) carbon price required to reach carbon intensity is £245/t, i.e. significantly higher than in the 50% flexible case. This massive difference in efficient carbon price that would deliver target emissions further reinforces the importance of flexibility as a vehicle for delivering electricity supply decarbonisation at a lower cost.

Partially cost-optimal generation mix with minimum technology deployment levels

A slightly modified set of cost-optimised studies has further been carried out where generation capacities of low-carbon technologies were not optimised from zero, but there was rather the following minimum level of deployment assumed in the 2030 system: 35 GW of wind, 10 GW of PV and 7 GW of CCS capacity. As illustrated in Figure E.5, high levels of flexibility drive a similarly high deployment of renewable capacity as in fully optimised scenarios.

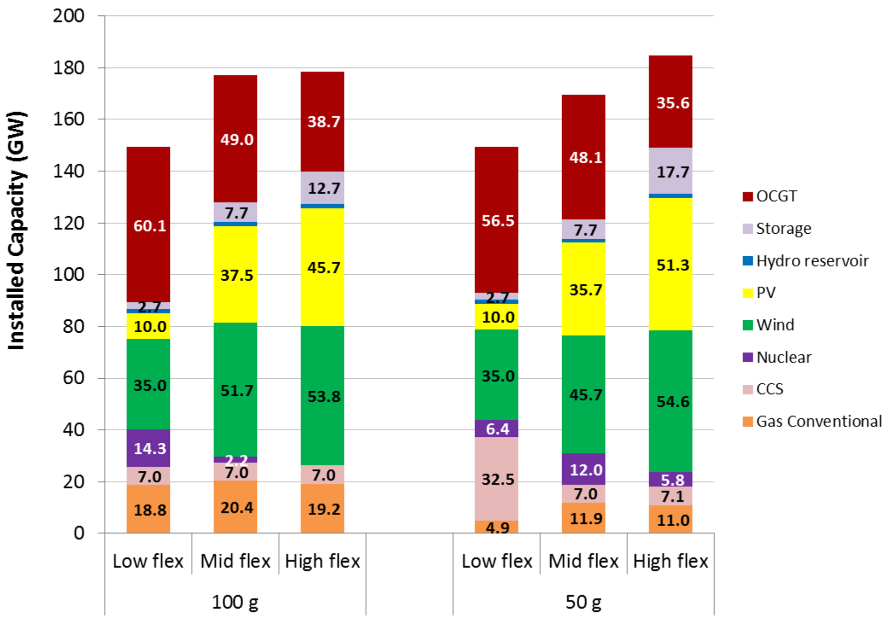


Figure E.5. Impact of system flexibility on partially optimised generation mix for 50 and 100 g/kWh targets and different system flexibilities in 2030

Generation portfolios in low-flexible systems however differ more profoundly as the significant volume of wind, PV and CCS capacity is forced to be present on the system where in the fully optimised case very little or none of this capacity would be chosen as part of the optimal mix. Changes in the mix are also driven by interactions between low-carbon technologies, so that for instance in the low-flexible 50 g/kWh system there is significantly higher CCS deployment to respond to the additional flexibility requirements driven by the minimum volume of wind and PV generation. Partially optimised 50 and 100 g/kWh systems have been used to calculate grid integration cost (see Figure E.9) and compare the results with those from the core scenarios later in the text.

Meeting a 2030 decarbonisation target under uncertainty

We developed "core" scenarios on the supply-demand background prevailing in the British power sector in 2030, on the assumption that it is planned to deliver outturn emissions intensity of either 50 g/kWh or 100 g/kWh. However the outturn level of CO_2 emissions intensity will be sensitive to variation in underlying supply-demand fundamentals, such as demand, available renewable energy (wind speeds, solar intensity), prices in neighbouring markets, etc.

Within each of the core scenarios, we therefore vary a range of factors (e.g. changes in demand, renewables output, fuel and carbon prices or prolonged outages of nuclear plant) that influence outturn emissions to examine the likely range of uncertainty around emissions in both core scenarios. The outturn carbon emissions across different sensitivities are presented in Table E.4 for the 100 g/kWh and wind-dominated 50 g/kWh core scenarios. When introducing variations in key drivers, the generation mix in the two scenarios was maintained as in the default case (i.e. the system was not allowed to adapt to changed circumstances by altering the generation mix).

Table E.4. Changes in outturn emission intensity (in g/kWh) in core 2030 50 g/kWh and 100 g/kWh scenarios across sensitivities to system perturbations

Parameter	Deviation from base case	Change in outturn emission intensity (g/kWh)	
		100 g/kWh	50 g/kWh
Demand	10% lower	-27.6	-18.2
	10% higher	24.1	27.0
Renewable output	10% higher	-11.7	-9.1
	10% lower	13.0	15.9
Fuel prices	High	-0.1	-0.1
	Low	0.2	1.0
Available nuclear output	6-month outage	7.5	7.2

Our modelling suggests that unpredictable circumstances do have an impact on grid emission intensity, although the magnitude of this impact highly depends on the type of variation introduced in the system, as well as on the analysed scenario. As expected, lower demand, higher renewable output or higher fuel prices all result in reduced emissions, however while lower demand would reduce baseline emissions by 27.6 g/kWh in 100 g/kWh or 18.2 g/kWh in 50 g/kWh scenario, an increase in fuel and carbon prices would only trigger an emission drop of 0.1 g/kWh. The highest impact magnitude is triggered by the assumed demand variations[12], followed by renewable output variations, and prolonged nuclear outages, while by far the lowest impact is associated with changes in fuel and carbon prices given that the capacities as well as relative merit order of generation technologies remains broadly the same. It can also be observed that, in relative terms, the 50 g/kWh core scenario is more sensitive to system perturbations than the 100 g/kWh system. Given the significant level of flexibility in the system that is helping to reduce carbon emissions cost-effectively, the risk of experiencing higher carbon intensity due to perturbations in supply or demand is kept at an acceptable level.

System externalities or integration costs of low-carbon technologies

System integration costs of low carbon generation technologies, also referred to as system externalities, include various categories of additional costs that are incurred in the system in addition to investment and operation cost of the technologies that are added to the generation mix, including but not limited to:

- *Increased balancing cost*. This can be the result of e.g. increased need for operating reserve driven by intermittency of renewable generation technologies, or the result of the generation pattern associated with a given technology – for instance, solar PV output peaks in summer, when the demand in the GB system tends to be low, while the PV output in high-demand winter periods is lower.

- *Cost of necessary reinforcement of transmission and distribution networks*. As an example, PV generation may cause significant reverse power flows and trigger the need for reinforcement of distribution networks; adding wind generation in the north of GB will require reinforcement of the transmission grid.

- *Backup capacity cost*. Intermittent technologies such as wind and PV have a limited ability to displace "firm" generation capacity needed to ensure adequacy of supply, although they will displace their output. As a consequence, some back-up capacity will need to be retained in the system to firm up intermittent renewable generation.

- *Cost of maintaining system carbon emissions*. This component becomes extremely important in the context of meeting a given carbon emission target. As an illustrative example, consider a low-carbon generation mix where a certain target is achieved by installing CCS in addition to nuclear and renewable generation. Adding 1 MWh of available nuclear energy into the system is then likely to displace a similar amount of CCS output as well as the corresponding amount of capacity while keeping the same system emissions. On the other hand, if the system has high installed wind capacity, the addition of 1 MWh of wind output is likely to result in only a part of that energy being absorbed by the system, as some may be curtailed, which would in turn allow a smaller amount of CCS output and capacity to be displaced when compared to

[12] It has to be noted that a 10% variation in annual demand represents a large change that is unlikely to occur unpredicted within a short timeframe (without the opportunity of the system to adapt), as the typical annual variations in demand levels over the recent years have been around the 1% mark.

nuclear generation. In other words, the cost of maintaining carbon emissions in the second case would be higher.

After modelling and establishing the level of flexibility required to reach the core 50 g/kWh and 100 g/kWh 2030 scenarios, we then estimated the system externalities associated with individual low-carbon technologies (or the marginal system costs of adding additional low-carbon capacity). In contrast to traditional analytical approaches developed to quantify ***absolute*** values of different components of integration cost, such as for example additional balancing or network cost, in this study the concept of ***relative*** system externality cost is also applied. The capacity of one of the low-carbon generation technologies is increased while the capacity of some other low-carbon technology is reduced, while meeting the system-wide carbon target. This enables the whole-system costs of these two technologies to be compared for a given scenario. In this report we adopt nuclear generation as the counterfactual low-carbon technology, against which the relative integration cost of other low-carbon generation technologies (wind, solar and CCS) are quantified. The choice of nuclear as the benchmark technology is arbitrary to an extent, however it does not affect the comparison between integration costs of other low-carbon technologies (such as e.g. between the integration cost of wind and PV).

It is important to bear in mind that both absolute and relative system externality costs will change when generation mix changes and will depend on the level of system *flexibility* that may be available. For example, if there are already high levels of renewables in a system, the marginal costs of integrating additional renewables will be higher. Similarly the marginal costs of integrating renewables in a less flexible system will be higher than in a more flexible system. In this process the individual components of the integration costs/benefits, which result from the system optimally adapting to changes in specific low-carbon technology capacity, are quantified.

Depending on the actual approach applied to re-adapt to the addition of a specific low-carbon generation technology, **three methods** are used to quantify the relative system integration of low carbon technologies:

- *Method 1 (Predefined replacement)*: A moderate amount of wind, PV or CCS capacity is added to the core systems, while at the same time the energy-equivalent [13] nuclear capacity is retired from the system. In all externality studies the model enforces the same level of carbon emissions, which is ensured by allowing CCS to be added above the base case level if necessary.[14]

[13] Energy equivalence here means that the addition of low-carbon capacity took into consideration the achievable capacity factors of different technologies, so that for instance, in order to replace 1 GW of nuclear capacity operating at about 90% capacity factor, about 2.5 GW of wind would be needed to compensate for the displaced annual nuclear output, if the capacity factor of wind is 36%.

[14] In order to test the swapping between low-carbon technologies in both directions, Method 1 studies included both the replacement of nuclear with wind or PV (i.e. incremental replacement) as well as the change in the opposite direction i.e. replacement of wind or PV with an energy-equivalent nuclear capacity (decremental replacement). All results for Method 1 presented here, unless otherwise specified, represent averages between incremental and decremental technology substitutions.

- *Method 2 (Optimised replacement)*: This method is similar to Method 1 in that a moderate amount of nuclear capacity is removed from the system, but instead of adding a specified capacity of another low-carbon technology, the model is allowed to optimally increase the capacity of that technology, while at the same time maintaining the same overall GB system emissions.[15]

- *Method 3 (Difference in marginal system benefits)*: In this method we add a moderate amount of nuclear, wind, PV or CCS capacity to the system, while allowing the system to readjust its CCS capacity (or nuclear if CCS is added) as well as any conventional capacity in a cost-optimal fashion while maintaining the same system emissions as in the base case.

The results are presented for all three methods investigated in this study, and also include all components of integration cost (generation, transmission and distribution capital expenditure as well as operational costs associated with all generation technologies). These results refer to relative integration cost of low-carbon technologies when compared to nuclear generators (e.g. reducing some nuclear capacity and replacing with renewables or CCS on an energy-equivalent or optimised basis). To aid comparison, the assumed levelised cost of energy (LCOE) differentials (i.e. cost advantages) of different low-carbon technologies against nuclear are also indicated in the chart. If the relative integration cost for a given technology is higher than its corresponding LCOE cost advantage, this suggests that this technology provides lower net marginal benefit to the system when compared to nuclear.

The level of flexibility assumed in the main studies involved the following assumptions on flexibility, which also correspond to medium flexibility level in e.g. Figure E.3:

- 50% utilisation of DSR (see Appendix C, Section C.5 for more detailed breakdown of DSR assumptions)

- 5 GW of new energy storage in the system (location optimised by the model in each base case)

- Interconnection is cost-optimised in each base case (above the level of 7.4 GW assumed to exist in 2030 – see Section 1.3 for more details)

- Conventional generators are characterised by high efficiency and high flexibility (details are provided in Appendix A)

- Wind and PV generators are able to provide reserve services if their output is curtailed, in the amount of 50% of output curtailment

The results demonstrate that the integration costs of low-carbon technologies are a function of the properties of the system (e.g. given generation mix and assumed level of flexibility) to

---

[15] Similar to Method 1, this Method was also applied in both directions: *incremental* where nuclear capacity was removed and wind or PV optimised while maintaining the carbon target, or decremental where wind or PV is removed from the system and nuclear capacity optimally added. Presented results for Method 2 are obtained by averaging the integration cost between incremental and decremental studies.

which they are being added. For example, we observe that integration costs are generally higher in a 50 g/kWh than in a 100 g/kWh core scenario, as the latter has a lower baseline capacity of low-carbon generation technologies. Similarly, the integration cost of wind decreases while the integration cost of PV increases when moving from wind-dominated to solar-dominated 50 g/kWh system.

Interestingly, different methods for establishing system integration cost are shown to provide reasonably similar results, with the variations between methods (in the order of up to several £/MWh) being attributable to different approaches to re-adapting the system after adding capacity of a given low-carbon technology.

100 g/kWh core scenario

In the 100 g/kWh scenario (Figure E.6) the relative integration costs of wind and PV (when compared to nuclear) are relatively marginal, in the range of £6-9/MWh.

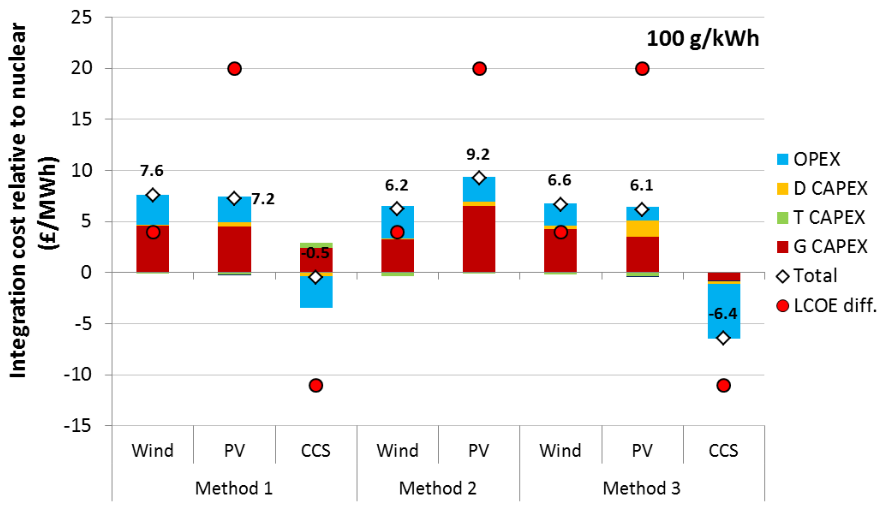


Figure E.6. Relative integration cost of low-carbon technologies compared to nuclear in 100 g/kWh core scenario (2030)

This is due to the lower initial volumes of wind and PV in this core scenario, combined with the significant presence of system flexibility measures, and therefore there is very little renewable curtailment necessary when adding additional wind and PV (and therefore no need to install additional CCS capacity to compensate for spilled low-carbon output while maintaining the same carbon emissions).

The additional capital costs (G CAPEX) for wind and PV are associated with an increased need for backup capacity, while the additional operational costs (G OPEX) follow from increased volumes of ancillary services resulting in lower operational efficiency of conventional generation.

For example, according to Method 1, removing 1 GW of nuclear and adding 2.1 GW of offshore wind capacity (needed to maintain the same level of low-carbon output) leads to an increase in system costs of £7.6/MWh (i.e. £7.6 for each MWh of wind generation absorbed), provided that carbon emissions are maintained at 100 g/kWh. This is driven by the increase in demand for balancing services (OPEX) and the need to add conventional plant to maintain security of supply (CAPEX)[16]. As the difference in LCOE cost between nuclear and wind is £4/MWh, replacing nuclear with wind will lead to net increase in system cost of £3.6/MWh (expressed in terms of wind energy accommodated). We note that the integration cost of PV, in addition to generation OPEX and CAPEX components also includes cost associated with the need to reinforce distribution network. On the other hand, as the LCOE of PV is assumed to be £20/MWh lower than nuclear, replacing nuclear with PV according to Method 1 will lead to net reductions in system cost of £12.8/MWh (expressed in terms of PV energy accommodated).

It is interesting to note that when nuclear is replaced by CCS, some OCGT plant is replaced by CCGT plant, which leads to increase in CAPEX, as the investment cost of CCGT is larger than that of OCGT, and reduced OPEX, as operating CCGT is less costly than OCGT (this is discussed further in Chapter 6).

The net increase in system cost when nuclear is replaced with wind (£3.6/MWh) suggests that the system would benefit from substituting wind with nuclear capacity i.e. that the installed capacity of wind is above, and of nuclear below the optimal deployment volume where the sum of LCOE and integration costs of all technologies should be equal. Similarly, the net decrease in total system cost when PV replaces nuclear capacity suggests that the system would benefit from adding more solar PV capacity. This reasoning is consistent with the results of the optimised 100 g/kWh scenario (see Figure E.3), where the cost-optimal capacity of PV is 44 GW (compared to 20 GW in the core scenario), nuclear is built with 12.6 GW (9.6 GW in core scenario), while wind remains at a similar capacity as in the core scenario.

It should be emphasised that the system integration cost will depend on the *location* of low-carbon technologies, which may be particularly relevant for wind. The default assumption in the core studies is that the additional wind will be offshore, connected to the onshore network in South. On the other hand, addition of wind in the north of GB would require considerable reinforcements of north-south transmission capacity in order to accommodate the increased wind output in the North, and this would be reflected in the appearance of significant additional transmission costs (T CAPEX) in the integration cost of wind.[17] That means that in reality, assuming cost-reflective and location-specific transmission charges, wind farms in the North would be exposed to a higher transmission-related integration cost, which would need to be reflected in the corresponding LCOE.

50 g/kWh core scenario, wind-dominated

In the core 50 g/kWh scenario with high amounts of wind (53 GW instead of 36 GW in the 100 g/kWh scenario), we observe in Figure E.7 that increasing wind or solar PV capacity while reducing nuclear capacity is characterised by a significantly higher system integration cost than in the 100 g/kWh core scenario (around £12-17/MWh), with the key components associated with:

---

16 Note that increase in operating costs is driven by increase in CCGTs output while the output of OCGTs is reduced, so that total emissions are maintained at 100 g/kWh.

17 See Section 6.5.5 for quantitative studies on the impact of wind location on its integration cost.

a) Increased generation capital costs (G CAPEX), mostly driven by additional CCS or wind or PV capacity required to maintain grid carbon intensity given that a part of additional wind output may need to be curtailed and/or that the additional ancillary service requirements may reduce the efficiency and increased emissions of thermal generation, but also to ensure sufficient backup capacity; and

b) Increased operational costs (G OPEX), again due to higher output from CCS plants to compensate for curtailment of zero-carbon wind generation.

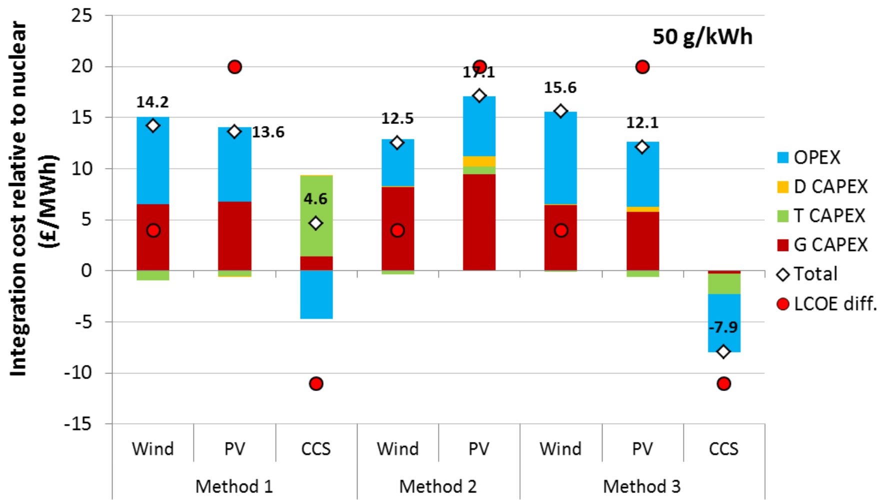


Figure E.7. Relative integration cost of low-carbon technologies compared to nuclear in wind-dominated 50 g/kWh core scenario (2030)

The G CAPEX component of integration cost of wind and PV in Methods 1 and 3 arises from the need to add CCS capacity when wind or PV replaces nuclear, in order to maintain same carbon emissions. Certain amount of conventional gas capacity (CCGT and OCGT) is also added to ensure system adequacy, further adding to the G CAPEX component. In Method 2, the G CAPEX consists of adequacy-driven cost of conventional gas units, as well as of additional wind or PV capacity beyond the energy-equivalent amount, in line with the definition of Method 2 where excessive carbon emissions are compensated by adding extra renewables rather than CCS capacity. The OPEX component of integration cost of wind and PV results from increased CCS output (Methods 1 and 3) or reduced efficiency of conventional gas generation output (Method 2) driven by increased requirements for balancing services.

The composition of the integration cost of CCS differs depending on the calculation method used. With the CCS-nuclear substitution adopted according to Method 1, there are OPEX benefits associated with reduced use of CCGT units to provide balancing services, resulting in improved overall efficiency, while there is a moderate increase in G CAPEX due to some replacement of OCGT with CCGT to improve the overall carbon performance. Note that a like-for-like replacement of 1 MWh of output of nuclear with CCS would on its own result in increased emissions due to less than 100% carbon capture rate of CCS. For the same reason in Method 1 the replacement of nuclear with CCS triggers a further reinforcement of North-South transmission corridors (i.e. results in considerable T CAPEX component) in order to reduce wind curtailment in the North and thus improve system carbon emissions (as no addition of low carbon capacity was allowed). In Method 3, however, the retirement of nuclear capacity following the addition of 1 GW of CCS is optimised, which results in only 0.9 GW of nuclear being removed from the system while maintaining the same emissions at the lowest cost. The remaining CCS output replaces CCGT generation, with further positive impact on carbon emissions, resulting in lower T CAPEX requirements to reinforce transmission grid in order to transport wind output from the North.

As in the 100 g/kWh scenario, the integration cost levels for wind and PV are found to be of similar magnitude. Given that it was assumed that both the additional wind and PV capacity would be available in the south of GB, there is no requirement for transmission reinforcement.[18]

Further details on the breakdown of integration costs into components are provided in Chapter 6 of the main report.

50 g/kWh core scenario, solar PV-dominated

In the core 50 g/kWh scenario with much higher PV capacity (50 GW instead of 20 GW) we observe that the integration cost of PV is significantly higher (ranging from £26-£28/MWh), as shown in Figure E.8.

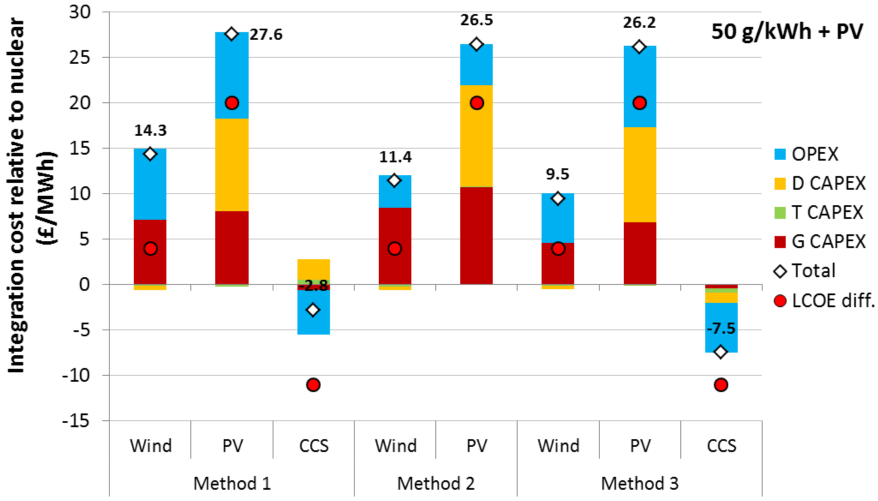


Figure E.8. Relative integration cost of low-carbon technologies compared to nuclear in solar-dominated 50 g/kWh core scenario (2030)

In this scenario there is again measurable curtailment of RES output, requiring additional CCS capacity and driving the additional G CAPEX and G OPEX components of wind and PV integration cost. Unlike the previous scenarios, the integration cost of PV now features a substantial distribution investment (D CAPEX) component, driven by reinforcements triggered by increased reverse power flows in the UK distribution grid.[19] A similar discussion

---

[18] Adding wind in the North of GB would potentially require the reinforcement of north-south transmission corridors, adding to the integration cost of wind.

[19] Installing 50 GW (or even 59 GW in integration studies with capacity increments) of PV capacity would create significant reverse power flows where solar PV injects energy into the distribution grid that currently only sees energy flowing from transmission grid towards consumers. 50 GW of PV would produce a peak output of around 40 GW during high summer, certainly exceeding the minimum demand levels during the summer season, in particular as large-

as for wind and transmission could be applied to PV with D CAPEX, as in some cases PV may already include the required D CAPEX cost (or a part of it).

Table E.5 provides a summary of the results of integration cost studies for the three core scenarios.

Table E.5. Summary of relative integration cost of wind, PV and CCS relative to nuclear (in £/MWh) across different scenarios

Scenario	Wind	Solar PV	CCS
100 g/kWh	6.2-7.6	6.1-9.2	(6.4)-(0.5)
50 g/kWh (wind-dominated)	12.5-15.6	12.1-17.1	(7.9)-4.6
50 g/kWh (solar-dominated)	9.5-14.3	26.2-27.6	(7.5)-(2.8)

Notes: ranges reflect various methods adopted; brackets indicate negative values.

A number of sensitivity studies have been conducted to study the impact of a range of variables on the integration cost of low-carbon technologies.

Partially optimised generation mix

In order to study the impact on integration cost of having a generation mix that is closer to a cost-optimal one, the integration studies have been carried out for the partially optimised generation 100 g/kWh and 50 g/kWh mixes presented in Figure E.5. Figure E.9 presents the relative integration cost of wind, PV and CCS against nuclear for incremental Method 1 studies with the partially optimised scenarios.

The integration costs of wind and PV are now much more aligned with the assumed LCOE cost advantages than in the three core 2030 scenarios. Nevertheless, there are differences (especially for PV) in the order of a few £/MWh, which result from: a) non-marginal capacity additions (9 GW in the case of PV), and b) the fact that the CCS capacity is not optimised in the base case, so that re-optimising it after wind, PV or nuclear capacity substitutions yields slightly higher benefits than what would be the case in a fully optimised system. The fact that the CCS capacity is above the cost-optimal is also reflected in the fact that its integration costs are above its LCOE cost differential.

scale PV installations are more likely to materialise in e.g. rural or semi-rural rather than in urban networks characterised by higher load density.

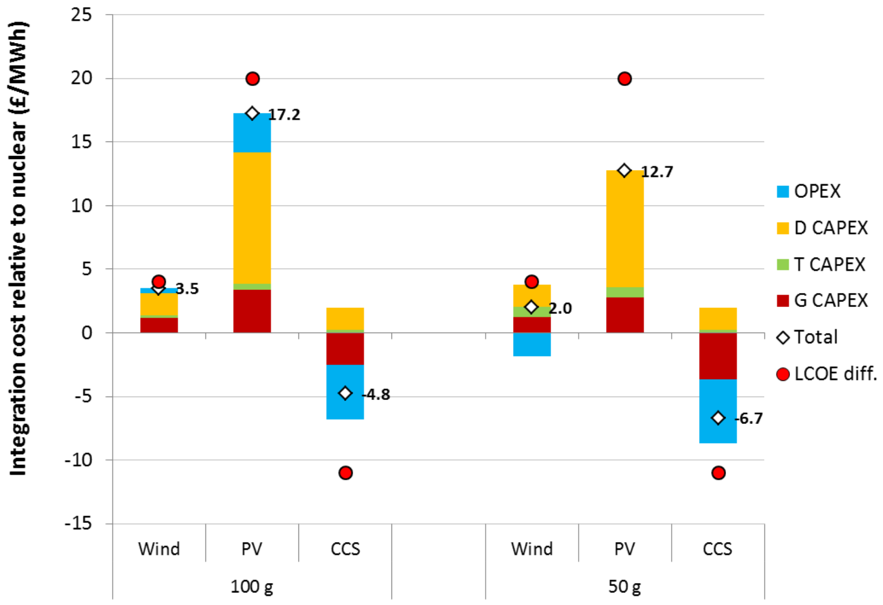


Figure E.9. System integration cost of low-carbon technologies in partially optimised systems for 50 and 100 g/kWh in 2030 (medium flexibility, Method 1, incremental only)

10 g/kWh scenario in 2050

A scenario in which the UK power sector achieves emissions intensity of 10 g/kWh by 2050 is analysed to quantify the system integration costs. This scenario is characterised by high nuclear capacity (21 GW), wind (90 GW) and PV capacity (100 GW). We let the model add CCS and conventional capacity if needed to ensure security of supply and meet the emissions intensity target at minimum cost. We assume in this scenario that 10 GW of additional energy storage is available in the system (as opposed to 5 GW in the 100 g/kWh and 50 g/kWh core scenarios), while the assumption on DSR utilisation was the same as in other core systems (50%). The integration cost of wind and PV are found to be broadly twice as high as in the wind-dominated 50 g/kWh core scenario, as illustrated in Figure E.10 for Method 1.

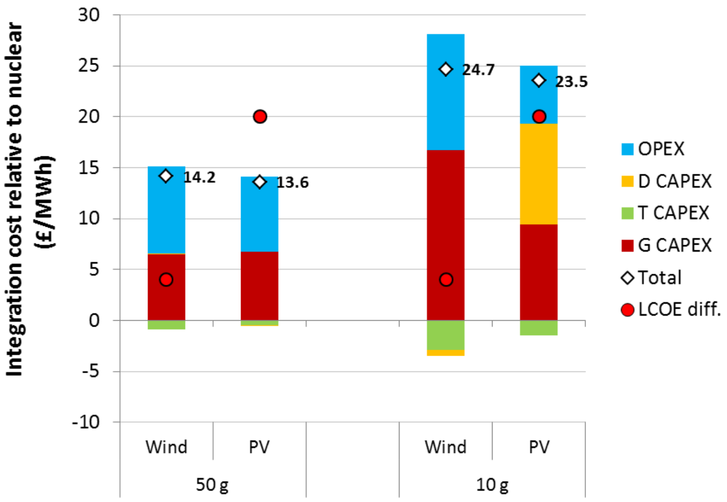


Figure E.10. Relative integration cost of low-carbon technologies compared to nuclear in 10 g/kWh scenario (2050)

This scenario suggests even more intermittent generation can be accommodated in the long-term with relatively moderate level of renewable output curtailment (5-6%); however this would require significant increases in system flexibility such as significant deployment of new storage capacity, a very advanced utilisation of DSR potential and also a significant expansion of interconnection capacity with continental Europe.

We further examined grid integration costs in a number of additional scenarios.

- *Further improvements in system flexibility*: further increase in DSR utilisation (to 100%) and storage deployment (to 10 GW) would reduce the integration cost of wind and PV in the 100 g/kWh scenario (Method 1) by £4.9/MWh and £1.7/MWh, respectively, while in the wind-dominated 50 g/kWh scenario the corresponding reductions would be £7.9/MWh and £5.3/MWh.

- *No nuclear development*: if no new nuclear is added in the 100 g/kWh system between today and 2030, the impact on the integration cost of wind and PV would be minimal i.e. within £1-2/MWh from the values in the 100 g/kWh core scenario.

- *Contribution of wind to system inertia, frequency regulation and improved forecasting*: The integration cost of wind in the wind-dominated 50 g/kWh scenario drops by £6.5/MWh if the accuracy of wind forecasting improves, while if wind is able to provide synthetic inertia and frequency regulation to the system, its integration cost would be £8.4/MWh lower in the same scenario.

- *Impact of largest generator size*: A sensitivity study was carried out where the largest generating unit (normally a nuclear station) was assumed to be 500 MW instead of 1,800 MW. The integration cost of wind is reduced by £6.8/MWh in this case, as smaller generator sizes reduce both primary and secondary response requirements that can act as a barrier to efficient integration of renewable generation.

- *Value of seasonal storage*: studies with 9.2 GW and 27.5 GW of seasonal storage were carried out (with the energy capacity of 9.26 TWh in both cases) to investigate the impact on integration cost in the solar-dominated 50 g/kWh scenario. In the medium flexible case, the 9.2 GW of seasonal storage reduced the integration cost of wind by £3.2/MWh and of PV by £2/MWh, while the seasonal storage with installed capacity of 27.5 GW reduced the integration costs by £8.4/MWh and £5.6/MWh, respectively.[20] Further system studies carried out demonstrate that the value of seasonal over daily energy storage is marginal.

More details on sensitivity analyses are provided in Section 6.5.

[20] Integration cost of wind and PV according to Method 1 (incremental) decrease from £13.7/MWh for wind and £26.7/MWh for PV to £10.5/MWh and £24.7/MWh for 9.2 GW of seasonal storage, or to £5.3/MWh and £21.1/MWh for 27.5 GW of seasonal storage.

Implications for market design

Whether the established levels of system integration cost of low-carbon technologies will be borne by investors in those technologies will depend on the prevailing market design. If the market was fully cost-reflective, all generation technologies would be exposed to additional costs (externalities) they impose on the system. For instance, a wind farm owner that is exposed to increased imbalance charges, and/or higher transmission charges would need to incorporate these costs in their bid into the CfD mechanism to include not only its LCOE, but also the additional cost components imposed on the system. Given that the market design in GB is still evolving and is not yet necessarily fully cost-reflective in all aspects of system cost, it is important to understand the additional system cost driven by low-carbon technologies.

Furthermore, the analysis carried out clearly demonstrates that increasing system flexibility, through enhancing dynamic performance of generating plant (both conventional and low-carbon), and the application of energy storage, demand side response and interconnection, can significantly reduce system integration costs of low-carbon technologies. In this context, development of efficient market mechanism that would appropriately reward flexibility would be important for facilitating a cost-effective decarbonisation of the GB electricity system. Devising a suitable support or incentive schemes for flexible providers will become increasingly important if the decarbonisation is to be achieved at least cost for the society.

A more detailed discussion on the implications of system externalities for the energy policy, regulatory framework and market design is included in the accompanying report led by NERA.[21]

[21] NERA Economic Consulting, "System Integration Costs for Alternative Low Carbon Generation Technologies – Policy Implications", accompanying report for the CCC, October 2015.

1. Introduction

1.1. Background and context

The UK electricity system is facing exceptional challenges in the coming decades. Meeting the carbon emission reduction targets will require intensive expansion of the use of low-carbon electricity generation technologies, such as renewables, nuclear and Carbon Capture and Storage (CCS). The UK Climate Change Act established an emission reduction target to reduce national GHG emissions by at least 80% from 1990 levels by 2050, while a system of five-yearly carbon budgets has been established to support the progress towards the 2050 target. The first four carbon budgets, leading to 2027, have been set in law. Meeting the fourth carbon budget (2023-27) will require that emissions be reduced by 50% on 1990 levels in 2025. The decarbonisation of electricity supply is also driven by the EU Renewables Directive[22], which stipulates that the UK's national share of energy from renewable sources in gross final consumption in 2020 should reach 15%.

In order for the UK to meet its legally binding carbon targets through 2050, it will be critical that the electricity sector makes large reductions to its carbon emissions by 2030, given its potential for decarbonisation when compared to other energy subsectors. This will require an intensive expansion of the use of renewables in the electricity sector as well as other low-carbon technologies such as nuclear and Carbon Capture and Storage (CCS). The key policy tool that the Government is relying on to deliver investments in this new generation capacity is the Electricity Market Reform (EMR) package and more specifically Contracts for Difference (CfDs), through which subsidy payments will be offered to low carbon generation investors. The mechanism should encourage investment in a range of low-carbon technologies so that they generate an increasing proportion of GB electricity. The first CfD Allocation Round covers the period until 2021.

1.2. Grid integration costs of low-carbon generation technologies

The CfD regime ensures sufficient revenues, alongside any wholesale market or ancillary service revenues earned, to cover the costs that generation investors face to develop and operate their capacity. The CfD mechanism however only ensures that generators can cover the private costs faced by developers, and not consider the costs imposed by each individual plant on the electricity system as a whole, such as additional network investment costs, ancillary service costs, etc. While this approach may be appropriate for setting subsidy levels, in taking decisions regarding the efficient mix and location of technologies on the system, it is important that Government considers both private and wider system integration costs of different technologies when developing support policies and setting long-term targets for emissions intensity.

There is a question over whether "technology-neutral" auctions selecting technologies based on the lowest strike price offered can deliver a low-carbon power sector at the lowest overall cost. Ideally, technologies should be selected based on their impact on total system costs, and

[22] Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC.

up to the volume where the marginal benefit they provide to the whole system is equal to their cost. The difference between these two quantities can arise because strike prices and levelised costs of generation do not capture all the impacts on the total cost of the energy system. LCOE covers the costs of generating at full availability but not the costs of delivering energy to the final customer when required or of ensuring that electricity is always available when demanded. Generally, intermittent renewable generation technologies will tend to impose higher costs on the wider system, for example through the need for more back-up capacity and balancing services (though all generation options imply some system costs).

In this context, this report aims to identify the *system integration cost* of low-carbon generation technologies in the context of the future, largely decarbonised UK electricity system. System integration costs of generation technologies, also referred to as *system externalities*, include various categories of costs that are incurred in the system when these technologies are added to the generation mix, such as increased balancing cost, necessary reinforcement of transmission and distribution grids, increased backup capacity cost, or the cost of maintaining system carbon emissions. The identification of system integration costs in addition to the cost of building and operating low-carbon generation capacity from the investor perspective (i.e. their levelised cost of electricity, LCOE), therefore represents a critical input into planning for a cost-effective transition towards a decarbonised electricity system.

In this study, the system externality of a given technology can be evaluated as the impact of increasing its capacity on the total cost of the electricity system that is not accounted for by its LCOE, while respecting the requirement to meet electricity demand as well maintain the same level of average grid carbon intensity. System externalities are likely to become more costly at high levels of decarbonisation.

Components of system integration cost of low-carbon technologies may include:

- *Increased system operating cost*, driven by:
    - Technology's generation profile being poorly matched to the demand profile, reducing average plant utilisation across the system (for instance, solar PV output peaks in summer, when the demand in the GB system tends to be low, while the PV output in high-demand winter periods is significantly smaller).
    - Increased cost of system balancing associated with: a) increased requirements for system reserve due to higher uncertainty of intermittent generation output, resulting in lower operating efficiency of generators, and b) increased requirements for fast frequency regulation (response) due to reduced system inertia.
- *Increased cost of backup generation capacity*: Intermittent technologies such as wind and PV have a limited ability to displace "firm" generation capacity needed to ensure adequacy of supply, although they will displace their output. As a consequence, some back-up capacity will need to be retained in the system to firm up intermittent renewable generation.

- *Costs of increased requirements for interconnection, transmission and distribution infrastructure* (e.g. because of more remote/dispersed locations of new low-carbon capacity)

- *Cost of maintaining system carbon emissions*. When certain technologies are added to the system, the overall emission performance of the system may deteriorate, requiring that additional low-carbon capacity is installed and operated to maintain the same level of carbon emissions. This component becomes extremely important in the context of meeting a given carbon emission target.[23]

In line with the above list, all integration studies presented in this report disaggregate system externalities into three main parts: operating cost (OPEX), generation investment cost (G CAPEX), and network investment cost (interconnection, transmission and distribution CAPEX). The last component (cost of maintaining emissions) is embedded in the OPEX and G CAPEX components provided by the whole-system assessment model that explicitly considers a predefined emission target.

Some components of system integration costs are faced by generation plant owners in the market (e.g. the impact of location on transmission charges), but many of them are not.

1.3. Flexible options for cost-efficient integration of low-carbon technologies

A 2012 study carried out for the Department of Energy and Climate Change[24] concluded that if there were no alternative balancing technologies available to the GB electricity system, the scale of the balancing challenge would increase very significantly beyond 2030, with substantial investment needed in additional generation, transmission and distribution assets to achieving the carbon emission targets while ensuring security of supply, particularly in the pathways that are characterised by extensive electrification of heat and transport and/or deployment of inflexible or intermittent generation.

At the same time a lack of flexibility also limits the system's ability to absorb high output from intermittent renewable technologies. The 2012 study demonstrated that up to 30% of renewable electricity may be curtailed in 2050 if no flexible options are deployed. Curtailment is typically triggered by a combination of low demand, high renewable output, and high output of must-run units such as nuclear plants, or conventional generators that have to be synchronised in order to provide frequency regulation. All of this will have an adverse

[23] As an illustrative example, imagine a low-carbon generation mix where a certain target is achieved by installing CCS capacity in addition to nuclear and renewable generation. Adding 1 MWh of available nuclear energy into the system is then likely to displace a similar amount of CCS output as well as the corresponding amount of capacity while keeping the same system emissions. On the other hand, if the system has high installed wind capacity, the addition of 1 MWh of wind output is likely to result in only a part of that energy being absorbed by the system (with the rest having to be curtailed), which would in turn allow a smaller amount of CCS output and capacity to be displaced when compared to nuclear generation. In other words, the cost of maintaining carbon emissions in the second case would be higher.

[24] Imperial College and NERA Consulting, 2012, Understanding the Balancing Challenge, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48553/5767-understanding-the-balancing-challenge.pdf.

impact on the carbon intensity of the electricity system as the curtailed renewable output needs to be compensated by increased energy from mid-merit fossil fuel-based power plant.

As illustrated in Figure 1.1, there are broadly four categories of flexible options that we considered for the system studies: (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.

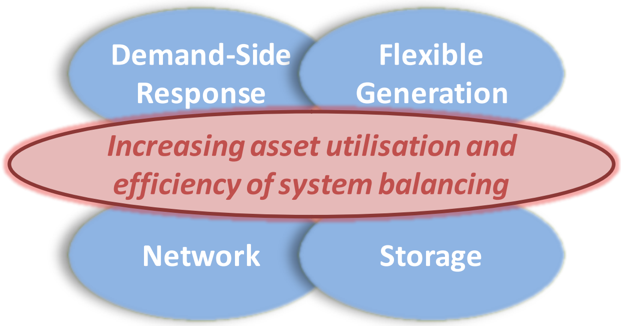


Figure 1.1. Flexible options in future electricity systems

Demand-side response (DSR)

There are a number of potentially flexible loads that could deliver *demand-side response*, such as flexible industrial and commercial (I&C) loads, flexible heat pump or HVAC systems, electric vehicles following smart charging strategies, smart domestic appliances etc.[25] DSR can support the integration of low-carbon generation by providing both energy arbitrage (load shifting or peak load reduction) and ancillary services. It is important to note that in our modelling the utilisation of DSR does not involve any compromise on the services delivered to end customers (e.g. internal temperatures achieved by heat pumps or the ability of consumers to use their electric vehicles). Also, some DSR technologies are able to dampen frequency fluctuations (i.e. provide synthetic inertia) or provide the frequency response service, which will reduce the need for synchronised generation capacity and in turn increase the ability of the system to absorb more renewable output.

Deployment of DSR schemes in today's system is still at the trial level, however with the planned rollout of smart meters in the UK, it is expected that the technical barriers to deploying DSR schemes would be largely removed.[26] The additional cost associated with the introduction of DSR schemes, in particular the cost of engaging customers, is at present highly uncertain with no reliable cost estimates available. Therefore, the cost of deploying and operating DSR schemes is not included in total system cost. Nevertheless, it is likely that the benefits of DSR would significantly outweigh the cost of deployment and therefore the

---

[25] M. Aunedi, P. A. Kountouriotis, J. E. Ortega Calderon, D. Angeli, G. Strbac, "Economic and Environmental Benefits of Dynamic Demand in Providing Frequency Regulation", IEEE Transactions on Smart Grid, vol. 4, pp. 2036-2048, December 2013.

[26] This would still leave the issue of customers' willingness to participate in DSR schemes to be resolved.

approach adopted in the study was to vary the percentage of uptake of DSR (50% uptake was assumed in mid-flex and 100% in high-flex studies).[27]

In the future system the cost of supplying customers with electricity will increasingly depend not only on the volume of energy consumed, but also on the way energy is used. It is therefore critically important to have cost-reflective pricing mechanisms that that dynamically reflect the changes in the value of electricity depending on the circumstances in the system. Achieving this will require the integration of retail and wholesale markets. The importance of DSR has been recognised by the Government and Ofgem, which is currently considering ways to address barriers to effective DSR implementation[28, 29].

The following assumptions of *full DSR flexibility* are made:

- Electric vehicles: up to 80% of EV demand could be shifted away from a given hour to other times of day;
- Heat pumps: heat storage enables that the 35% of HP demand can be shifted from a given hour to other times of day;
- Smart appliances: demand attributed to white appliances (washing machines, dishwashers, tumble dryers) participating in smart operation can be fully shifted away from peak;
- Industrial and commercial demand: 10% of the demand of I&C customers participating in DSR schemes can be redistributed.

It is important to stress that the magnitude of demand (and therefore the absolute volume of demand that can be shifted) in each of the above categories changes in time (it is time-specific).[30]

In this study we take as *the central assumption* that in 2030 50% of the total DSR potential in 2030 is actually utilised. This includes the potential from electric vehicles and heat pumps in addition to other domestic, industrial and commercial demand categories and implies that up to 9.1 GW of demand in a peak hour could be shifted to different times in a day. It could be argued that this assumption is both optimistic or pessimistic but, as shown later in the report, is compatible with a cost-effective decarbonisation of electricity supply and expansion of

---

[27] A similar approach was adopted in: Imperial College and NERA Consulting, 2012, Understanding the Balancing Challenge, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48553/5767-understanding-the-balancing-challenge.pdf.

[28] Ofgem, “Creating the right environment for demand-side response: next steps”, December 2013, https://www.ofgem.gov.uk/publications-and-updates/creating-right-environment-demand-side-response-next-steps

[29] Ofgem, “Making the electricity system more flexible and delivering the benefits for consumers” September 2015, https://www.ofgem.gov.uk/sites/default/files/docs/2015/09/flexibility_position_paper_final_0.pdf

[30] An overview of the rationale and evidence behind these assumptions is provided in:
M. Aunedi, F. Teng, G. Strbac, “Carbon impact of smart distribution networks”, Report D6 for the “Low Carbon London” LCNF project, December 2014.

renewable generation. More details on the modelling of DSR are provided in Appendix C, Section C.5.

Flexible generation

The operating flexibility of a *generator* is dictated by its operational limitations, such as its minimum stable generation (MSG), the ability to provide balancing services including frequency response and reserve, ramping rates, minimum up and down times, or the reduced efficiency when running part-loaded. Although more flexible versions of conventional generators are already available today at a moderately higher cost than its less flexible alternatives[31], the relatively low value of flexibility today does not generate a very high demand for this type of generation. This is likely to change in the future with further expansion of intermittent renewable capacity.

In the current system only conventional mid-merit/peaking power plants provide balancing services while base-load plants and renewable generators operate at maximum output in order to maximise their economic value. Increased requirements for balancing services driven by increased renewable capacity could lead to increased curtailment of renewable output due to the need to maintain a large volume of synchronised conventional capacity to deliver the necessary services; with more flexible generation technologies these services could be delivered with a smaller amount of online capacity, leading to cost and carbon savings.

Present GB Grid Code does not require renewable generators to provide any balancing services; however this may change in the future. In order to provide balancing services, renewable generators would also need to run part-loaded, which is not economic if the marginal value of their energy output is greater than the marginal value of providing the service. However, at high penetration levels the marginal value of energy may become lower than the marginal value of balancing services, rendering the curtailment of part of renewable output to provide balancing services justified.

In our system studies, we assume that all new build CCGT and OCGT plant required by 2030 has more flexible characteristics than the current fleet. For example in our 100 g/kWh scenario, 44 GW of new gas-fired generation is required to balance the system (in addition to 20 GW of existing plant that will still be online in 2030). Detailed assumptions on generators' dynamic characteristics in high and low flexible cases are provided in Appendix A.

Network solutions including interconnection

The benefits of cross-border *interconnection* include the enhanced efficiency of system operation due to easier access to more efficient resources, improved security of supply due to the ability of the interconnected markets to share secure generation capacity as well as ancillary services, and better ability to accommodate intermittent renewable generation by taking advantage of geographical diversity of renewable output. It has to be noted though that the decisions to deploy interconnection capacity are highly sensitive to conditions prevailing

---

[31] Based on recent communication with generating equipment manufacturers, it is estimated that more flexible version of CCGT plant would cost about 15% more than the standard less flexible version.

in GB and the neighbouring markets, in particular with respect to the allowed level of net import or export or the policy towards sharing security and services across border.

We assume that the expansion of interconnection is limited to those projects currently under development and that are likely to become operational by 2020, such that Britain has somewhat greater interconnection with Continental Europe and Ireland compared to today, and a new link to Norway. On that basis the interconnection capacity in 2030 has been set to include existing links with France, the Netherlands and Ireland totalling 4 GW, as well as the following projects (amounting to a total 7.4 GW of interconnection capacity in 2030):

- An additional 1 GW with France (ElecLink project);
- An additional 1 GW with Belgium (Nemo project); and
- An additional 1.4 GW with Norway (NSN project).

The basis for the above assumptions is the fact that the three projects have been approved for development by Ofgem. There is nevertheless potential for further expanding interconnection capacity, as confirmed by additional project applications to increase the connection capacity between GB and France, Denmark and Ireland.[32] We therefore assume that in the base case studies the model is allowed to increase interconnection capacity between GB and continental Europe at an annualised cost of £96/MW/km per year if cost-effective.[33]

Note that although energy exports and imports via interconnection are optimised on hourly basis, the *energy neutrality* constraint is imposed so that the total annual energy production and consumption within the UK is fully balanced. In other words, the total annual energy exports from the UK to the continental Europe exactly balance the total annual energy imports from the continental Europe to the UK. Furthermore, although our modelling framework can consider the contribution of interconnectors to security of supply, it was assumed that the adequate generation capacity would be located within the UK system.

Energy storage

Finally, earlier studies[34] suggest that *energy storage* technologies may have a potentially very important role to play in facilitating the cost-efficient transition to a low-carbon power system. Energy storage may deliver cost savings across the electricity system due to the ability to offset the need for generation, transmission and distribution investment while at the

---

32 These refer to the FAB Link, IFA2 and Viking Link interconnectors, which were granted a cap and floor regime in principle by Ofgem in July 2015, see https://www.ofgem.gov.uk/publications-and-updates/decision-initial-project-assessment-fab-link-ifa2-and-viking-link-interconnectors.

33 Following guidance from the CCC, the expansion of interconnection capacity between GB and Ireland was not considered in the study, which is in line with the recent assessment by Ofgem. See e.g. https://www.ofgem.gov.uk/publications-and-updates/cap-and-floor-regime-initial-project-assessment-fab-link-ifa2-viking-link-and-greenlink-interconnectors.

34 A comprehensive analysis of opportunities for energy storage applications in the future UK system is presented in our study conducted for the Carbon Trust: "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

same time contribute to operating cost savings through reducing wind curtailment and delivery of reserve and frequency regulation services.[35]

However, the optimal deployment of energy storage and hence its net benefits are rather sensitive to the assumptions on its cost. Given the finding of the 2012 Carbon Trust study that up to 15 GW of storage should be added to the system if its cost is towards the lower end of the scale, as well as the recent surge in trialling energy storage solutions in the UK, we assume in our central studies that 5 GW of additional storage capacity (without specifying the technology) will be available in the system by 2030 (currently there is 2.7 GW of storage capacity in the British power system, mainly from pumped storage). The 2012 study has also shown that the benefits of deploying storage in a low-carbon system exceed the likely cost of investing in new energy storage up to the level of about 15 GW, albeit subject to the uncertainty of the evolution of storage cost in the 2030 horizon. In light of that, a moderate assumption of 5 GW of additional storage deployment has been made in the studies, while the benefits of flexibility derived from energy storage (among other sources) are expressed as gross rather than net benefits factoring in the cost of storage. The assumed round-trip efficiency of storage was 75%, and the duration (ratio between energy and power of storage) was 5 hours.

Improved management of wind uncertainty and contribution to system balancing

With the evolution of the power system towards higher penetrations of renewable and low-carbon generation, it is likely that the future system management practices would adapt to the new circumstances. In particular, the requirements for primary and secondary frequency regulation services associated with short time scales (seconds to 30 minutes) may reduce.[36] We further assume that by 2030, intermittent renewable generators (e.g. wind farms) would be capable of providing reserve services when curtailed, at the level of 50% of curtailed output.

We also considered additional options for flexibility, such as the availability of seasonal storage, further improvements in wind forecasting techniques and wind providing fast frequency regulation and inertia. These options have not been modelled in the core sets of scenarios but were analysed in sensitivity studies described in Section 6.5, and were found to offer additional savings.

We show in Chapter 4 how the availability of various flexible options profoundly affects the cost-optimal generation mix that achieves a given carbon emissions intensity target. For instance, in a system without any additional system flexibility beyond current levels, the decarbonisation of the electricity system would be delivered by installing nuclear and CCS capacity, while neither wind nor PV would be of value for expansion due to their high integration cost. A diametrically opposite outcome would ensue in a system characterised by high flexibility, as options such as DSR or storage could significantly abate system

[35] R. Moreno, R. Moreira, G. Strbac, "A MILP model for optimising multi-service portfolios of distributed energy storage", Applied Energy, Volume 137, January 2015, Pages 554-566.

[36] National Grid is currently considering an update to the frequency regulation standards, particularly in terms of allowing higher rate of change of frequency (RoCoF), which will be beneficial in enhancing the ability of the system to accommodate increased levels of renewable generation.

integration costs of intermittent renewables. This suggests a critical role of flexibility in the electricity system as an enabler of cost-effective decarbonisation.

1.4. Key project objectives

In light of the above discussion, the main objectives of this report are:

- To quantify the impact of system flexibility on the cost of decarbonising the UK electricity system in the 2030 horizon; and
- To calculate the approximate level of system externalities that should be attached to individual low-carbon technologies in different scenarios.

2. Methodological approach to quantifying system integration costs

2.1. Introduction

System integration costs of generation technologies, also referred to as system externalities, include various categories of additional costs that are incurred in the system in addition to investment and operation cost of the technologies that are added to the generation mix. As discussed in Section 1.2, the integration costs can include increased balancing cost, increased cost of backup generation capacity, cost of reinforcing interconnection, transmission and distribution infrastructure and the cost of maintaining system carbon emissions.

The identification of system integration costs in addition to the cost of building and operating low-carbon generation capacity from the investor perspective (i.e. their levelised cost of electricity, LCOE) potentially represents a critical input into planning for a cost-effective transition towards a decarbonised electricity system.

In this chapter we provide an overview of previous methodologies developed to quantify system integration costs. Some of these approaches are based on quantifying individual component of system integration cost, while others make use of the marginal system value of low-carbon generation technologies. All of these methods quantify the *absolute integration cost* i.e. the cost associated with a single technology when added to a system. However, there is as yet no consensus on the preferred method to quantify system integration costs, as different definitions have their own issues with robustness or accuracy.

In this report we adopt several definitions that focus on the *relative integration cost* of pairs of generation technologies, reflecting the difference between the system externalities of pairs of low-carbon technologies. This approach is chosen to ensure a robust calculation approach with relatively few system variables to be adjusted, while at the same time indicating relative merits of different low-carbon technologies from the whole-system perspective.

In particular, in this report we adopt nuclear generation as the counterfactual low-carbon technology, against which the relative integration cost of other low-carbon generation technologies (wind, solar and CCS) are quantified. The choice of nuclear as the benchmark technology is arbitrary to an extent, but is considered reasonable given that it represents a baseload (non-intermittent) low-carbon generation technology. In any case, the choice of counterfactual technology does not affect the *differences* between integration costs quantified for other low-carbon technologies (such as e.g. between the integration costs of wind and PV generation).

It is also worth mentioning that in parallel to this project, efforts are also being undertaken by the Department of Energy and Climate Change to expand the capabilities of their Dynamic Dispatch Model (DDM)[37] to quantify whole-system costs of generation technologies.

---

[37] See e.g. https://www.gov.uk/government/publications/dynamic-dispatch-model-ddm.

2.2. Whole-electricity System Investment Model (WeSIM)

Given that different components of system integration costs span various segments of the electricity system (generation, transmission and distribution infrastructure as well as balancing), the quantitative framework adopted to evaluate the integration cost is based on the *whole-system modelling approach* i.e. the WeSIM model. This tool is capable of capturing the interactions between different time scales (investment vs. short-term operation) as well as across different asset types in the electricity system, while also considering the flexible technologies such as energy storage or demand-side response. By simultaneously balancing long-term investment decisions against short-term operation decisions, WeSIM is able to identify overall optimal strategies for the electricity system. A prominent feature of the model is the ability to capture and quantify the necessary investments in distribution networks in order to meet demand growth and/or distributed generation uptake, based on the concept of statistically representative distribution networks.

A more detailed description of the modelling framework can be found in Appendix C.

2.3. Approaches to calculating absolute integration cost

The key relationship behind any calculation of the system integration cost is given by the following equation:

$$WSC_{gen} = LCOE_{gen} + SIC_{gen}$$

The *whole-system cost* WSC is the sum of the LCOE of the technology under consideration and the corresponding System Integration Cost (SIC). All quantities are typically expressed in monetary units per unit of energy produced (e.g. in £/MWh). All technologies will potentially have system integration costs, which as elaborated earlier can include operation cost, adequacy cost and network reinforcement cost, although there is no consensus regarding the exact definitions of these components and their interactions, and the methods for evaluating and allocating these costs vary considerably.

In this chapter an overview of alternative methods for quantifying system integration cost is given first, followed by the definition of calculation methods for integration cost adopted in this report.

2.3.1. Methods used for evaluating individual components of system integration costs

While all generation technologies are associated with some form of system integration costs (e.g. due to the need to reinforce the transmission grid if located remotely), renewable generation is generally associated with all components of integration costs: adequacy costs due to limited ability displace capacity, balancing costs due to increased requirements for balancing due to variability and unpredictability, and grid cost due to remote locations. One possible approach to quantify different integration cost components is to calculate them separately. In this section we present alternative approaches to the evaluation of these cost components.

2.3.1.1. Additional generation capacity cost

The capacity cost of a generation technology typically arises from the fact that the technology displaces energy output from incumbent generation technology, but because of its generation patterns cannot displace the equivalent amount of firm generation capacity while maintaining the same level of reliability. As an example, in electricity system based on conventional thermal generation a capacity margin of around 20% is typically maintained to ensure that any difficulties to supply demand only occur very rarely. If this system now needs to integrate a certain amount of PV capacity, the renewable output will displace the output of conventional units, but because PV would not be expected to generate any output during system peak on winter evenings, the amount of conventional capacity on the system would essentially remain the same. In other words, the capacity credit of PV in this example would be 0%. The inability of PV to displace capacity implies that additional cost per MWh of solar output will be necessary to ensure sufficient back-up capacity is available in the system to deliver the same level of security of supply.

A generation technology such as PV, which has a close to zero capacity credit in GB, will always have a positive additional capacity cost. At the other end of the spectrum, a technology that can displace more capacity than the energy of incumbent generators would have a negative backup capacity cost. It is interesting to note that a base load plant, e.g. base load nuclear generation, would also impose additional adequacy costs as it operates at a higher load factor than the average incumbent plant, thus typically displacing more energy than capacity.[38]

2.3.1.2. Additional transmission and balancing cost

A generation-transmission system model such as WeSIM can be used to evaluate the impact of increased capacity of a certain generation technology on the capacity of main interconnected transmission and interconnection system and on balancing cost.

To evaluate the transmission cost, the capacity of the generating technology in question is increased and the analysis is carried out to quantify the additional transmission investment needed to accommodate that increased capacity in an efficient manner. The cost of increased network capacity can then be divided by the incremental energy output of the generation technology in question to determine its transmission component of integration cost.

In order to evaluate the balancing component of system integration cost, additional analysis is carried out where the contribution of a given generation technology (typically intermittent renewable generators) on the balancing requirements is set to zero. The second simulation should produce a lower cost than the first one, and the cost difference between the two divided by the annual energy output of the respective generating technology can be used to determine the additional balancing cost driven by that technology.

---

[38] J. Skea, D. Anderson, T. Green, R. Gross, P. Heptonstall, M. Leach, "Intermittent renewable generation and the cost of maintaining power system reliability", *IET Generation Transmission & Distribution*, Vol. 2, pp. 82-89, 2008.

2.3.1.3. Additional distribution network cost

In order to calculate the impact of distributed generation on distribution networks, a distribution network planning tool needs to be used to evaluate the impact of distributed generation technologies (in particular PV) on the necessary reinforcement of distribution network. For this purpose we have developed an approach where we generate a set of representative distribution network models that represent different types of GB low-voltage (LV) and high-voltage (HV) distribution networks.

The additional distribution network cost triggered by distributed generation (DG) installations such as e.g. solar PV installations can be divided with the annual DG output, and the resulting cost in £/MWh of DG output represents the distribution component of system integration cost for the DG technology. Depending on the penetration level of DG, as well as its typical output pattern, the impact of DG deployment on distribution network cost can be either positive or negative. For instance, DG may release some capacity of the network enabling additional load growth without the need for network upgrade while also reducing losses. On the other hand, DG may increase network cost by causing network overloads or due to voltage rise effect and increased reverse power flows towards the transmission grid.

2.3.2. Methods using marginal value of low carbon technologies

Hirth et al.[39] propose a definition of integration costs based on the marginal economic value of electricity, or market value. They decompose integration costs of wind and solar power into three components: temporal variability, uncertainty, and location constraints. The proposed definition of integration cost compares the marginal benefit of a generation technology with the load-weighted average marginal cost of electricity in the system, and the difference between the two quantities is defined as the integration cost of the technology. As noted by the authors, the choice of the benchmark technology with zero integration cost (in this case a technology that is in perfect synchronism with demand) is arbitrary, which potentially supports the case for quantifying relative integration costs between pairs of technologies, where the choice of benchmark technology becomes of secondary importance.

2.4. Definitions of relative integration cost adopted in this study

Unlike previous approaches to quantifying individual components of integration cost separately, such as e.g. by considering only additional balancing or network cost without looking at their interaction, this study quantifies the whole-system effects of adding a unit of low-carbon generation capacity in a given system scenario while maintaining a given carbon emission target. In doing so, we quantify the components of integration cost that result from the system optimally adapting to the addition of low-carbon technology across all segments of the electricity system i.e. by modifying the required network and generation infrastructure as well as system operation.

[39] L. Hirth, F. Ueckerdt and O. Edenhofer (2015): "Integration Costs Revisited – An economic framework of wind and solar variability", Renewable Energy 74, 925–939.

Depending on how the system is allowed to adapt to the addition of low-carbon generation, we distinguish between three different methods to quantify the relative integration cost, as elaborated in the following sections. All three methods have been agreed and developed in collaboration with the CCC.

As explained earlier, in this report we adopt nuclear generation as the counterfactual low-carbon technology, against which the relative integration cost of other low-carbon generation technologies (wind, solar and CCS) are quantified. This choice of counterfactual technology, although arbitrary, does not affect the differences between integration costs quantified for other low-carbon technologies, allowing to e.g. compare whether wind generation has a higher integration cost than PV in a given scenario.

In mathematical notation, the relationship between the relative integration cost of technology 1 compared to technology 2, their whole system costs and LCOE values can be expressed as follows:

$$RIC_{1-2} = WSC_1 - WSC_2 - (LCOE_1 - LCOE_2)$$

2.4.1. Method 1 – Predefined replacement

In this method we have carried out externality studies where a moderate amount of wind, PV or CCS capacity is added to the system (in separate studies), while at the same time the energy-equivalent[40] nuclear capacity is retired from the system. The following specific capacity substitutions were imposed on the system:[41]

1. Replacement of 1 GW of nuclear capacity in the south with 2.1 GW of offshore wind in the south of GB
2. Replacement of 1 GW of nuclear capacity in the south with 9 GW of solar PV in the south of GB
3. Replacement of 1 GW of nuclear capacity in the south with 1 GW of CCS in the south of GB

In all externality studies the model enforces the same level of carbon emissions intensity, which can be achieved by adding CCS capacity above the base case level if necessary. Changes in total system cost, excluding the investment and operation cost (i.e. LCOE) of the pairs of technologies involved in the substitution are divided by the annual output of the added low-carbon technology to establish its *relative integration cost* against nuclear power.

[40] Energy equivalence here means that the addition of low-carbon capacity took into consideration the achievable capacity factors of different technologies, so that for instance, in order to replace 1 GW of nuclear capacity operating at about 90% capacity factor, about 2.5 GW of wind would be needed to compensate for the displaced annual nuclear output, if the capacity factor of wind is 36%.

[41] Because of relatively high capacity increments in the case of wind and PV, we have also carry out analysis of cases where wind or PV capacity is being substituted by nuclear in the same amounts, in order to compensate for the effect of non-marginal capacity changes. Unless specified otherwise, the figures presented in the report represent the averages of the two directions of technology capacity change.

2.4.2. Method 2 – Optimised replacement

This method is similar to Method 1 in that a moderate amount of nuclear capacity is removed from the system, but instead of adding a specified capacity of another low-carbon technology, the model is allowed to optimally increase the capacity of that technology, while at the same time maintaining the same overall GB system emissions. The following studies are carried out using Method 2:[42]

1. Removing 1 GW of nuclear capacity in the south, and allowing the model to optimally add offshore wind in the south of GB

2. Removing 1 GW of nuclear capacity in the south, and allowing the model to optimally add solar PV in the south of GB

No change in CCS capacity is allowed in this method; the model is however allowed to adjust conventional (CCGT and OCGT) capacity if cost-efficient. Changes in total system cost are divided by the increase in generation output as in Method 1 to find out the relative integration cost, but this time the cost of e.g. wind or PV capacity added on top of the energy-equivalent volume is also taken into account when finding the total cost differential between the counterfactual case and a given externality study.

2.4.3. Method 3 – Difference in marginal system benefits

Finally, in this method we add a moderate amount of nuclear, wind, PV or CCS capacity to the system, while allowing the system to readjust its CCS capacity (or nuclear if CCS is added) as well as any conventional capacity in a cost-optimal fashion while maintaining the same system emissions as in the base case. We specify the following capacity additions in externality studies according to Method 3:

1. Additional 1 GW of nuclear in the south of GB

2. Additional 2.1 GW of offshore wind in the south of GB

3. Additional 9 GW of solar PV in the south of GB

4. Additional 1 GW of CCS in the south of GB

The reduction in total system cost (while ignoring the CAPEX and OPEX of the added low-carbon technology) is divided by the additional output of the added technology to establish the *marginal system benefit* per MWh for that technology. The difference between the marginal benefit of e.g. nuclear and wind then allows for an implicit quantification of the relative system externality of wind compared to nuclear, providing a comparable result with Methods 1 and 2.

---

[42] Similar to Method 1, in Method 2 we also carry out studies with the opposite changes in capacities of low-carbon technologies, i.e. where wind or PV is removed from the system, and nuclear capacity optimally increased while maintaining the system carbon intensity. Again, all results presented for Method 2 represent averages between these two approaches, unless otherwise specified.

While the report only presents the final results of Method 3 (based on differences in gross marginal system benefits), the results of individual marginal benefit studies that were used as basis for calculating the integration cost using Method 3 are included in Appendix B (Section B.2).

2.4.4. Comparison between methods

All three methods are conceptually similar, as they all involve a marginal addition (or removal for decremental studies) of one low-carbon technology, and the reduction of capacity of other technologies. The differences between the methods are in which technologies are used for the substitution, and to what extent is this substitution optimised. Table 2.1 compares the key elements of the three calculation methods for system integration cost.

Table 2.1. Comparison of approaches for different calculation methods for system integration costs

Method	Approach	Technology added	Technology removed	Adjusted capacity
Method 1	Predefined replacement	Wind (fixed)	Nuclear (fixed)	CCS, CCGT, OCGT
		PV (fixed)	Nuclear (fixed)	CCS, CCGT, OCGT
		CCS (fixed)	Nuclear (fixed)	CCGT, OCGT
Method 2	Optimised replacement	Wind (optimised)	Nuclear (fixed)	CCGT, OCGT
		PV (optimised)	Nuclear (fixed)	CCGT, OCGT
Method 3	Difference in marginal benefits	Nuclear (fixed)	CCS (optimised)	CCGT, OCGT
		Wind (fixed)	CCS (optimised)	CCGT, OCGT
		PV (fixed)	CCS (optimised)	CCGT, OCGT
		CCS (fixed)	Nuclear (optimised)	Nuclear, CCGT, OCGT

The key difference between Methods 1 and 2 is that while in Method 1 wind or PV replaces nuclear in fixed (energy-equivalent) proportions, and any excess in carbon emissions is compensated by adding more CCS if needed, in Method 2 the CCS capacity is fixed and any surplus in emissions is resolved by adding more wind or PV capacity. In Method 3 on the other hand, instead of retiring a fixed volume of nuclear generation, nuclear, wind and PV are added in fixed amounts while the model readjusts the mix by retiring CCS while maintaining carbon emissions. The only exception to this is when a fixed amount of CCS is added and the model is allowed to optimally remove nuclear generation.

2.5. Impact of flexibility on system integration costs

We show in Chapter 4 how the availability of various flexible options profoundly affects the cost-optimal generation mix that achieves a given carbon emission target. For instance, these studies show that the expansion of wind and PV capacity in order to decarbonise the electricity system require significant levels of flexibility, in the form of availability of DSR, storage and flexible generation technology. *In other words, flexibility can significantly reduce the integration cost of intermittent renewables, to the point where their whole-system cost (being the sum of their LCOE and the system integration cost) makes them a more attractive* *expansion option than CCS and/or nuclear***.** It is therefore of paramount importance to adequately consider the required flexibility in future development scenarios with high shares of renewable generation.

3. Scenario development

This chapter sets out the scenarios developed to estimate the system externalities associated with individual low-carbon technologies.

3.1. Objectives of scenario definition

Through this study, we are seeking to estimate the system externalities associated with the integration of a range of low carbon generation technologies. Because these system integration costs may be sensitive to different mixes of generation, we have developed scenarios on the supply mix in the British electricity system, which assume different penetrations of solar, wind, CCS, and nuclear generation. Additionally, the range of scenarios we define also examine variation in alternative balancing technologies, such as storage, demand side response, and so on, as these technologies may support the integration of low-carbon generation, and thus influence system externalities.

To the extent possible, we have based the scenarios we examine on existing scenarios published by the CCC in the 2013 Fourth Carbon Budget Review, albeit with some revisions to reflect updated information that has become available since they were first published (e.g. potential constraints to deploying new nuclear and levels of investment in CCS and offshore wind to bring about innovation and cost reduction[43]). These "core scenarios" are defined primarily by the emissions intensity of the power sector, so we consider:

1. A scenario in which the British power sector achieves an emissions intensity of 100 g/kWh by 2030;

2. A scenario in which the British power sector achieves an emissions intensity of 50 g/kWh by 2030; and

3. A scenario in which the British power sector achieves an emissions intensity of 10 g/kWh by 2050, which we examine solely for the purposes of estimating system externalities.

As noted above, and described below in more detail, we consider a number of sensitivities around these core scenarios to quantify the variations in system integration costs in response to changes in fundamentals.

The generation mix in core scenarios was driven by the target carbon intensities for the electricity system, and meeting the emission target was a critical ingredient integrated into the modelling when quantifying the performance of the system in terms of operation and investment cost.

All three scenarios contained a balanced mix of low-carbon technologies (nuclear, wind, PV and CCS) that are "nominally" appropriate to achieve the specified emission targets when their expected annual energy outputs were considered, not considering the real-time system

---

[43] For example see BVG Associates (2015) *Approaches to cost-reduction in offshore wind* and Poyry (2015) *Potential CCS Cost Reduction Mechanisms: Final Report Summary.*

operation requirements. However, when these generation mixes were tested in the initial WeSIM simulations the outturn emissions were found to be very significantly higher than the target level; e.g. the actual emissions were above 190 g/kWh for the system with the target emissions of 50 g/kWh.

This high emission intensity is driven by two key factors which reduce the ability of the system to accommodate the combination of inflexible low-carbon generation and intermittent renewables:

(a) A significant increase in system balancing requirements in a decarbonised grid.

- *Reserve requirements.* Forecasting errors associated with outputs of renewable generation require appropriate amounts of reserves to be scheduled to ensure that generation and demand can be balanced at all times. This has an impact on emissions as conventional plant running to provide reserve will also produce energy, which may result in curtailment of renewables or reduction in nuclear output, particularly during low demand periods. The flexibility characteristics of the conventional plant providing reserve will therefore have a major impact on the emissions performance of the system. Moreover, when a technology's generation profile is poorly matched to the demand profile, plant utilisation across the system is likely to be lower on average, requiring more capacity to deliver a given level of useful generation (e.g. due to wind curtailment or reducing nuclear output in summer months). Also, when a particular technology does not reliably generate at times of peak demand, additional ('back-up') capacity is required to ensure demand can be met at the peak with sufficient level of security.

  In the studies presented in this report it is assumed that the uncertainty (i.e. forecasting error) of wind output fluctuations is higher than for the output of solar PV generators, which is in line with the findings in the relevant literature.[44] A consequence of this is that, relative to wind, PV is likely to cause a lower increase in the cost of system balancing associated with the provision of longer-term system reserve.

- *Response requirements.* One of the key contributors to the stability of a power system is the system inertia[45], which represents the stored energy in the rotating masses of the synchronous generators and motors. The lower the system inertia, the lower the system's capability to withstand the changes in system frequency. When the majority of energy supplied to the grid is provided by synchronous machines (such as thermal plants), there is a high level of system inertia available due to their inherent design. However, as the proportion of energy supplied by non-synchronous sources (such as

---

[44] While the short-term (less than 1 hour) variability of diverse wind and solar portfolio is similar in relative terms, the mid-term (over 1 hour) forecast of PV output is likely to be more accurate than wind. See e.g.:
A. Mills and R. Wiser, "Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power", LBNL-38884E, Berkeley, CA: Lawrence Berkeley National Laboratory, 2010.
J. Marcos et al., "Power output fluctuations in large-scale PV plants: One-year observations with one-second resolution and a derived analytic model", *Progress in Photovoltaics: Research and Applications*, vol. 19, pp. 218-227, 2011.

[45] System inertia is provided by the rotating masses of turbines in conventional generation plant.

solar PV, wind and interconnector) increases, the overall system inertia will decrease. One of the consequences of a reduction in system inertia is an increase in the rate of change of frequency during frequency incidents (sudden loss/increase of generation or demand).[46] This approach would significantly reduce the efficiency as well as the carbon intensity of power system operation.

Wind and solar generators currently do not contribute to system inertia, resulting in greatly reduced system inertia as the share of renewable generation increases at the expense of synchronised conventional capacity. The reduction in system inertia on the other hand increases the system response requirement, and that requires an increased number of synchronised conventional generators, which would limit the ability to accommodate renewable energy output. The amount of frequency response requirement for different conditions in the GB system is shown in Figure 3.1.[47] The requirement for frequency response increases sharply during low demand and high wind conditions.

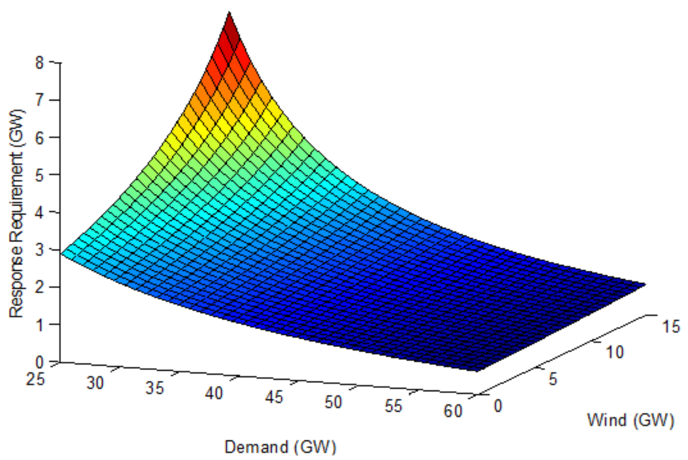


Figure 3.1. Primary frequency response requirement in GB system under different system conditions

The value of frequency regulation in the future GB system is expected to increase dramatically. This will in turn require that ancillary service markets evolve to recognise the value of different speeds of response, given that the present design is based on typical response times of conventional power stations.

(b) ***A lack of flexibility in the present system.***

Present conventional gas and coal generators are relatively inflexible, particularly in terms of limited amount of frequency control that can be provided and relatively high minimum stable generation. These two features represent the key limiting factors for the amount of renewable generation that can be accommodated, given that a

[46] In this context, National Grid is considering updating frequency regulation standards, particularly the rate of change of frequency (RoCoF), which will be beneficial in enhancing the ability of the system to accommodate increased levels of renewable generation.

[47] F. Teng, V. Trovato and G. Strbac, "Stochastic Scheduling with Inertia-dependent Fast Frequency Response Requirements," IEEE Transaction on Power Systems, issue 99, 2015.

significant volume of conventional generation will need to operate in order to deliver the required level of balancing services, while at the same time injecting energy into the grid that may not be required during high renewable output periods. There is also a limited amount of demand-side response services that can support system balancing in the timeframe from seconds to hours. In the future however, system flexibility may significantly improve. In this context, an update of market arrangements to reward different forms of flexibility will be important [48]. For example, conventional generation technologies of significantly enhanced flexibility are already available, but power companies do not presently find it attractive to make corresponding investments. Similarly, energy storage technologies and demand-side response could significantly enhance system flexibility. Finally, strengthening the interconnection with the EU electricity system can also bring system integration benefits.

Therefore, a combination of low demand, high renewables output, and high output of must-run units such as nuclear plants, or conventional generators that have to be synchronised in order to provide frequency regulation will have an adverse impact the carbon intensity of the electricity system (as the curtailed renewables output needs to be compensated by increased energy from mid-merit fossil fuel-based power plant).

To enable the power system to better accommodate low-carbon electricity and therefore achieve a decarbonisation target, we tested the impact of deploying various flexible options, successively adding more and more system flexibility to achieve an emissions target at minimal overall cost. Flexible options considered and deployed included:

- **More efficient and more flexible generation technologies**: conventional plant that can operate stably at lower levels of output (and therefore less likely to push renewables out of system) and provide faster frequency response (requiring less overall thermal plant to be built to balance the system).

- **Reduced primary frequency regulation requirements and improved system management techniques** leading to reduced requirements for reserve services (particularly for secondary response associated with short time scales). We assume that by 2030, intermittent renewable generators (e.g. wind farms) would be capable of providing ancillary services when curtailed.

- Deployment of **energy storage** (e.g. battery technologies) that can deliver ancillary services (e.g. reserve and response) thereby reducing the need for additional back-up generation and network infrastructure.

- **Demand-side response** capable of supporting short-term operation as well as providing primary and secondary frequency response and security of supply

- Increased **interconnection** with mainland Europe.

[48] National Grid has recently introduced additional frequency regulation products that should encourage provision of enhanced response services and hence increase the ability of the system to accommodate low carbon generation.

All assumptions regarding flexibility were made taking into account the realistic technical potential for deploying these options in the 2030-2050 horizon, particularly reflecting the latest evidence and industry consensus. For example, 50% of the total demand-side response potential is assumed to be unlocked by 2030. More detail on flexibility assumptions is provided in Appendix A and Section 3.2.

There are potentially additional sources of flexibility that could further improve the cost-effectiveness of integrating low-carbon technologies. These include the availability of seasonal storage, further improvements in wind forecasting techniques and wind providing fast frequency regulation and inertia. These options have not been deployed in the core scenarios but are analysed in supplemental studies described in Section 6.5.

The core scenarios build in the assumed improvements in flexibility and are then adopted as counterfactuals for subsequent system externality studies. We developed two variants of a core power sector scenario achieving an average grid intensity of 50 g/kWh in 2030 – one with higher build rates of onshore/offshore wind and one with higher deployment of solar PV. Figure 3.2 and Figure 3.3 illustrate the importance of flexibility in reducing grid emission intensity: it is evident that the gradual increase in system flexibility significantly reduces carbon emissions intensity, as well as system operation and investment cost.

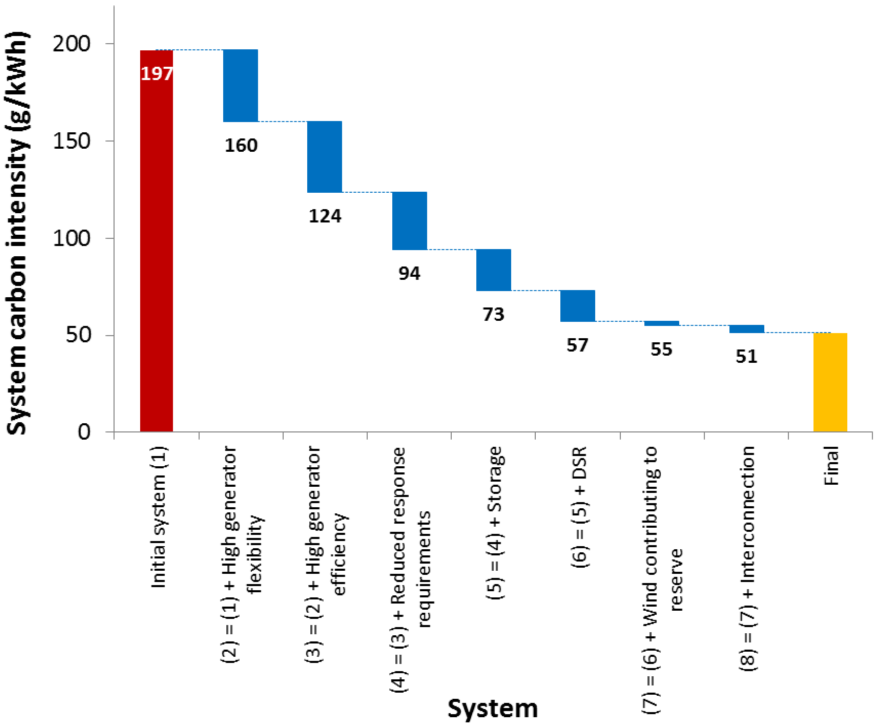


Figure 3.2. Impact of increasing system flexibility on carbon emissions in the wind-dominated core scenario reaching 50 g/kWh in 2030

The assumptions behind different steps applied in Figure 3.2 to reach system emissions close to 50 g/kWh included:

- Higher generator flexibility (lower MSG, higher response capability etc. – see Appendix A for more details)

- Higher generator efficiency (improved heat rate at minimum output – see Appendix A for more details)

- Reduced frequency response requirements to 50% of current level

- Deployment of additional 5 GW of energy storage

- Deployment of 50% of theoretical DSR potential

- Allowing wind generators to contribute to system reserve when their output is curtailed (reserve provision limited to 50% of curtailed output)

- Allowing the model to expand interconnection capacity to continental Europe

As the "initial system" condition presented in Figure 3.2 is considered to be extreme, in the analysis carried out in this study we assumed that more flexible generation will be used (as these technologies are already available at reasonable cost) and that the requirement for system frequency regulation will reduce (as National Grid is already taking actions to modify the frequency standards). Hence the base line "low flexibility" system is characterised by the emissions of 94 g/kWh. In this context, the estimates of savings made by enhancing system flexibility presented in this study are conservative.

Figure 3.3 illustrates the annualised cost savings for the UK system associated with moving from low to medium and high flexibility in the three core scenarios, while meeting the respective 50 or 100 g/kWh emission intensity targets.[49] In this figure, as well as in later figures referring to systems with low, medium and high flexibility, the medium flexibility (mid flex) corresponds to the "Final" system in Figure 3.2, low flexibility assumes a system without any additional storage or DSR and with no contribution of wind to reserve, while high flexibility case assumes 100% deployment level of DSR, 10 GW of additional storage and wind being able to contribute to both response and reserve when curtailed.

For the 100 g/kWh scenario the value of flexibility is between £3.04bn and £3.76/bn per year for 100 g/kWh system, while for the 50 g/kWh system the value of flexibility increases to £7.09bn to £8.09bn. As demonstrated later in Section 3.4.1, flexibility was found to deliver significant savings even in a less decarbonised 2030 system scenario such as the 200 g/kWh system, where flexibility-driven cost savings of up to £2.89bn were observed.[50]

---

[49] Note that the annualised system cost savings represent gross benefits as the cost of deploying and operating DSR and storage are not included. The rationale behind this approach is that the already mandated smart meter rollout will provide the technical functionality behind DSR, while the additional cost of introducing DSR schemes (e.g. cost of engaging customers) is uncertain with few reliable cost estimates available, although it is likely that the benefits would significantly outweigh the cost. Similarly, as found in the 2012 Carbon Trust study, energy storage could also provide significant net benefits when deployed in highly renewable electricity systems, so a moderate level of deployment has been assumed (5 GW in core scenarios) that is significantly lower than the levels proposed in the 2012 study..

[50] Given our modelling approach, the annual cost savings presented here refer to a snapshot of system costs in 2030. The evolution of potential cost savings over time will depend on the dynamic of deploying renewable and other low-carbon generation towards the 2030 horizon.

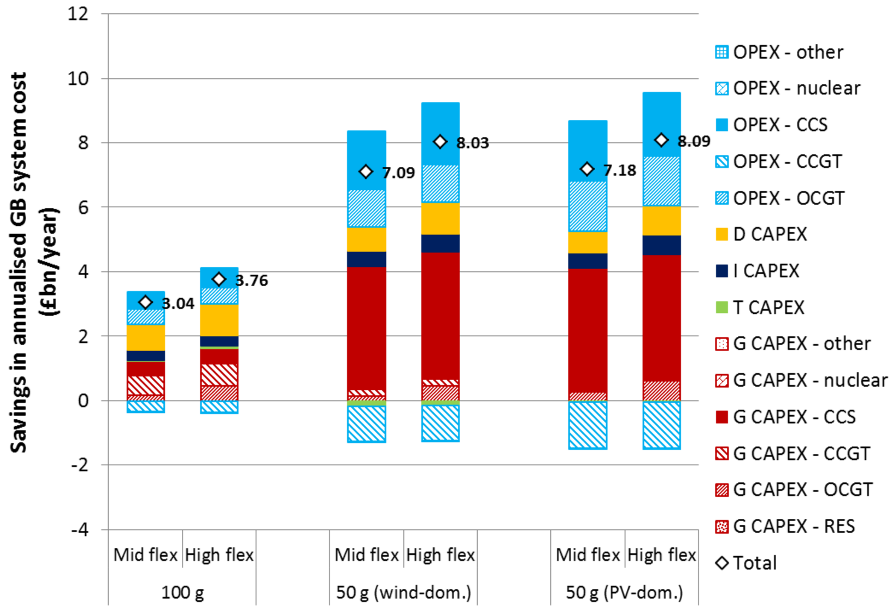


Figure 3.3. Impact of increasing system flexibility on system costs in three core scenarios in 2030

Key categories of system cost savings include reduced investment and operation cost of CCS, as the available renewable resources can be utilised more efficiently helping to reach the carbon target, reduced operating cost of expensive OCGT plant, and to a smaller extent reduced requirement for distribution network reinforcement and reduced investment in interconnection capacity. It can also be noted that while the total system cost reduces, there are some cost categories that increase in value (i.e. result in negative cost savings) but are more than compensated for by cost reduction in other categories as the result of generation capacity and output being shifted between technologies.

System cost savings driven by flexibility in Figure 3.3 include the avoided cost of building additional interconnection capacity between Great Britain and continental Europe in a given scenario. Table 3.1 shows the additional interconnection capacity for the three core scenarios and different flexibility levels, proposed by the model as a cost-optimal solution in addition to the minimum 7.4 GW of interconnection capacity assumed to be available by 2030 (see Section 1.3 for more details). Given that interconnection offers more flexibility to the system, significantly more interconnection is added in low flexible systems (e.g. 4.3 GW in the 100 g/kWh scenario, and 11.7-12.5 GW in the two 50 g/kWh scenarios) than in medium or high flexible systems. Also, the increased requirements for flexibility associated with higher penetrations of wind and PV in 50 g/kWh scenarios drive a higher deployment of interconnection than in the 100 g/kWh scenario, which is characterised by lower renewable capacity.

Table 3.1. Additional interconnection capacity (in GW) across core scenarios for varying levels of flexibility (above the minimum of 7.4 GW of interconnection assumed to be available by 2030)

Scenario	Low flex	Mid flex	High flex
100 g/kWh	4.3	-	-
50 g/kWh (wind-dominated)	11.7	2.1	-
50 g/kWh (solar-dominated)	12.5	2.7	-

Additional flexibility not only helps to decarbonise the system more cost-effectively, but also allow the system to cope more efficiently at times of stress, for instance by using storage and DSR resources to manage periods of high wind output and low demand or vice versa. Also, the model will ensure that sufficient backup capacity is in place to supply the demand even in the event of prolonged periods of low renewable output.

3.2. Assumptions

3.2.1. Electricity demand

The electricity demand forecast for this study is based on information obtained from the CCC's 2013 Fourth Carbon Budget Review analysis. The expected demand in 2030, expressed on a final consumption basis, is 379 TWh with demand from heat pumps and electric vehicles equal to 27.0 and 18.9 TWh, respectively. The demand forecast excludes autogeneration, defined as the generation of electricity for own use by companies whose main business is not electricity generation.

The hourly demand profiles for residential and commercial sectors, electric vehicles and heat pumps used in the study were based on the profiles used in the 2012 DECC study[51], which were scaled according to the forecasted annual demand. The profiles for electric vehicles and heat pumps were based on our bottom-up demand modelling applied in the same study.

The CCC scenarios did not include a forecast of peak demand, but peak demand is implied by our application of hourly demand profiles to the annual energy demands of each sector, including separate profiles for demand from heat pumps and electric vehicles. As our bottom-up demand modelling suggests, the peak load is expected to rise to 87.4 GW in 2030.[52]

3.2.2. Levelised costs of generation technologies

The levelised cost assumptions for key low-carbon technologies have been obtained from the CCC and the latest published DECC estimates[53], and are summarised in Table 3.2. In addition to numbers in the table, we also ran several sensitivity studies where the LCOEs of the four low-carbon technologies were all assumed to be equal to £100/MWh (see Section 4.1).

---

51 Imperial College and NERA Consulting, 2012, Understanding the Balancing Challenge, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48553/5767-understanding-the-balancing-challenge.pdf.

52 Current peak system demand is around 60 GW; the increase is driven by increased demand from electrified transport and heating sectors.

53 DECC, "Electricity Generation Costs", July 2013, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/223940/DECC_Electricity_Generation_Costs_for_publication_-_24_07_13.pdf.

Table 3.2. Levelised cost parameters of low-carbon technologies in 2030[54]

Technology	LCOE (£/MWh)
Nuclear	89
Gas CCS	100
Offshore wind	85
Solar PV	69

We separated the LCOEs of all generation technologies into fixed (capacity-related) and variable (output-related) components to be able to accurately quantify the impact of both investment and operating decisions.

The costs of other generation technologies have been assumed in line with DECC's 2013 Update of Non-Renewable Technologies[55].

3.2.3. Other assumptions

Commodity prices

Following guidance from CCC, we took fossil fuel price projections from DECC's "Reference Scenario" in the Updated Energy & Emissions Projections publication from September 2014. The scenario assumes a price of gas of 76.4 pence/therm, US$102.6/barrel for oil and US$103.3 /tonne for coal. We assumed a carbon price of £77 per tonne in 2030, consistent with DECC's forecast for 2030, with no distinction between the CO_2 prices prevailing in Britain and Continental Europe.

Interconnection capacity

We assume expansion of interconnection is limited to those projects currently under development, such that Britain has somewhat greater interconnection with Continental Europe compared to today, and a new link to Norway.

On that basis the interconnection capacity in 2030 has been set to include existing links with France, the Netherlands and Ireland totalling 4 GW, as well as the following projects:

- An additional 1 GW with France;
- An additional 1 GW with Belgium; and
- An additional 1.4 GW with Norway.

[54] The assumed load factors for determining the LCOE of the four technologies in DECC's report are: nuclear and CCS 90%, offshore wind 39%, PV 11%.

[55] Parsons Brinckerhoff, "Electricity Generation Cost Model – 2013 Update of Non-Renewable Technologies", April 2013.

Trade between markets

As indicated, we impose on the model an assumption that trade flows are constrained to ensure Britain is "energy neutral", i.e. that total TWh of energy demand over the year equals total production from British generators. Therefore, while the model can use interconnectors to support system balancing at any point of time, the model will ensure the energy neutrality constraint is respected.

Assumptions on alternative balancing technologies

A range of "alternative balancing technologies" may support the efficient integration of intermittent renewable generation, and other low carbon technologies onto the British power system, affecting both emissions intensity and the system integration costs:

Electrical storage capacity is currently limited to 2.7 GW of pumped storage capacity on the current grid, an expansion could significantly add to the flexibility of a low carbon power system. However, given the uncertain future development of the costs and technical capability of storage technologies, there is considerable uncertainty on their future penetration. We have therefore assumed some modest growth in storage capacity in core 100 g/kWh and 50 g/kWh scenarios, where storage capacity increases by 5 GW.

Demand side response provides an alternative means of system balancing that may substitute for storage, especially as the penetration of smart meters rises, but the efficacy of demand response depends on unknown factors such as the degree of consumer engagement with demand response schemes and their responsiveness to time of use tariffs. We have therefore assumed a robust growth in demand response in 100 g/kWh and 50 g/kWh scenarios to the level of 50% of technically feasible potential.

Increasing the flexibility of the generation fleet to reduce unit commitment costs and loosen dynamic constraints may also support balancing in low carbon power systems where flexibility is valuable. We assume that the future generation technologies will have improved flexibility characteristics as well as enhanced operational efficiency compared to standard models prevailing today.

A summary of the headline assumptions used in the study is shown in Table 3.3.

Table 3.3. Main assumptions for 2030

Item	Assumptions
Electricity Demand	379 TWh[56] inclusive of: EV: 18.9 TWh HP: 27.0 TWh
Commodity Prices (real 2014)[57]	Gas: 76.4 p/therm Coal: $103.3/t Carbon: £78.0/t
Interconnection capacity:	7.4 GW (minimum capacity) Trade constrained by energy-neutrality assumption
Alternative balancing technologies:	DSR – 50% Storage – 5 GW (additional) Flexible plant (all new unabated plant required to balance system assumed to have flexible characteristics)
Security Standard	Loss of Load Expectation (LOLE) = 3 hrs / year

Hourly wind and solar profiles used in the study have been based on the profiles used in recent studies, in particular the profiles obtained as part of the 2012 DECC study ("Understanding Balancing Challenge") and the PV Parity project[58].

More details about the assumptions used in this analysis, in particular generation technology efficiencies and dynamic parameters etc. are provided in Appendix A.

3.3. Core Decarbonisation Scenarios

This section outlines the assumptions behind the three "core" 2030 scenarios.

3.3.1. 100 g/kWh scenario in 2030

This power sector scenario is based on the "Higher Energy Efficiency" case in the CCC's 2013 *Fourth Carbon Budget Review* and the 2014 progress report to Parliament, albeit with some updated data provided to us by the CCC (e.g. potential delays to new nuclear and required investments in CCS and offshore wind to bring down costs and help meet the longer term targets[59]). This scenario is defined by assumptions on the penetration of solar, on and offshore wind, CCS and nuclear generation capacity by 2030, as well as the level of demand.

It assumes a balanced expansion of low-carbon capacity, with renewables continuing to expand at a similar rate in the 2020s as in the 2010s, a significant new nuclear programme and a CCS programme. Reflecting the recent trend of rapidly falling costs of PV panels and

---

56 Final consumption basis, excludes autogeneration.

57 Source: "Reference Scenario" from DECC Updated Energy & Emissions Projections, September 2014.

58 PV Parity: Definition of competitiveness for photovoltaics and development of measures to accompany PV to grid parity and beyond, Intelligent Energy Europe project, http://www.pvparity.eu/.

59 For example see BVG Associates (2015) *Approaches to cost-reduction in offshore wind* and Poyry (2015) *Potential CCS Cost Reduction Mechanisms: Final Report Summary.*

their accelerated deployment in the UK and elsewhere, the share of solar in the generation mix has been increased compared to the original CCC Fourth Carbon Budget Review scenario. It also considers around 20 GW of existing gas-fired capacity that will still operate in 2030. We assume that the flexibility of the existing gas-fired plant is less than the new gas-fired plant. With regards to the coal-fired power stations, we assume that all stations will be decommissioned and cease to operate by 2030.

Further to these basic generation assumptions, which are inputs to the model, we allow the model to deploy new CCGT and OCGT generation, as well as additional CCS, to ensure a reliability standard of 3 hrs Loss of Load Expectation (LOLE), consistent with the level of security targeted in the British Capacity Mechanism. Assuming interconnectors will be able to participate in the Capacity Mechanism from 2015, we assume that interconnection capacity can be used by the model to meet peak requirements, and the extent to which they provide peak security is defined endogenously by the model. In selecting generation investments, the model seeks to minimise costs, and we take assumptions on the cost of new build capacity from PB Power's recent report on generation technology costs for DECC.[60]

The generators are distributed proportionally across the GB system based on the similar distribution applied in the Imperial and NERA's studies for DECC.[61] From the same studies, we also took hourly profiles of production for wind farms and PV generation. We assume all generators except the solar PV are transmission connected. 25% of solar PV is connected to Low Voltage (LV) and the rest is High Voltage (HV) connected.

3.3.2. 50 g/kWh scenario in 2030, wind-dominated

This scenario is very similar to the 100 g/kWh scenario in that it assumes growth in a mix of low-carbon generation technologies, but delivers a higher level of decarbonisation mainly due to additional 17 GW of wind compared to the 100 g/kWh scenario. As shown in Figure 3.4, specifically, this more onerous emissions target is achieved through developing more low-carbon generation capacity than the 100 g/kWh case. However, for ease of comparison between scenarios all other assumptions remain unchanged. The generation mix of both scenarios (50 and 100 g/kWh) and the annual electricity production in both scenarios are compared in Figure 3.4.

---

60 Parsons Brinckerhoff, "Electricity Generation Cost Model – 2013 Update of Non-Renewable Technologies", April 2013.

61 Imperial College and NERA Consulting, 2012, "Understanding the Balancing Challenge", analysis commissioned by DECC to support this publication. Please see https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48553/5767-understanding-the-balancing-challenge.pdf

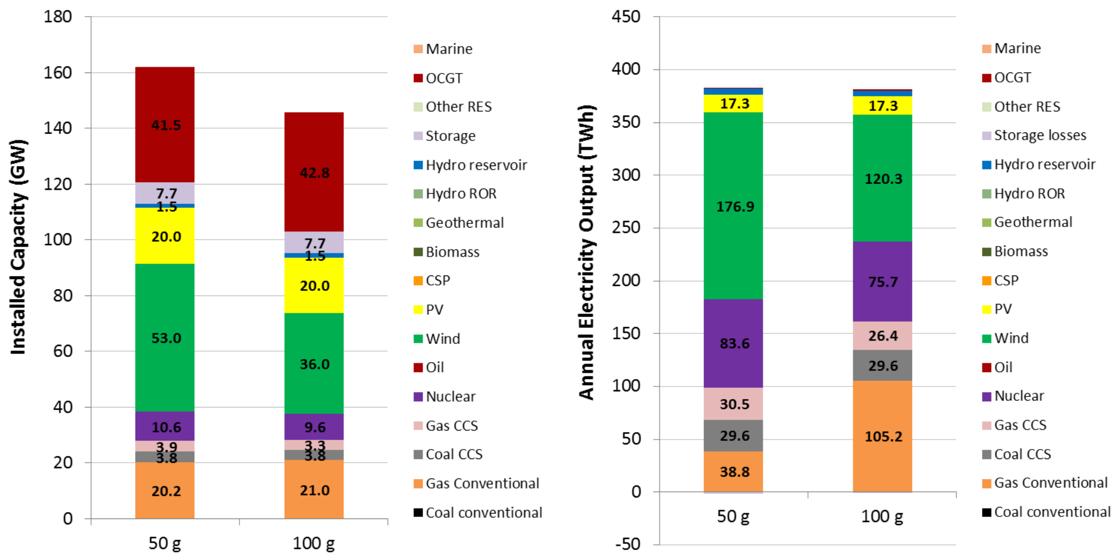


Figure 3.4. Comparison between the generation mix and annual electricity output for 50 g/kWh (wind-dominated) and 100 g/kWh scenarios in 2030

In this scenario, the additional 17 GW of wind power, 1 GW of nuclear and around 0.6 GW of CCS are added to the system in comparison to the previous (100 g/kWh) scenario in order to achieve the 50 g/kWh emissions target. This increases the total installed generating capacity to about 162 GW from 145.7 GW in the previous scenario. The difference is largely contributed by the additional capacity of wind power which has modest capacity value and therefore it cannot displace the capacity of conventional generators.

In the 50 g/kWh scenario, there is limited room for the electricity production from the conventional gas-fired (non-CCS) plants, the annual energy from CCGT allowed in this scenario is around 38.8 TWh, much less than the production in the 100 g/kWh scenario (105.2 TWh). The 50 g/kWh scenario uses much more wind energy in combination with other low carbon technologies such as nuclear and CCS to reduce the emissions. This is demonstrated in the right diagram of Figure 3.4.

3.3.3. 50 g/kWh scenario in 2030, solar PV dominated

In this scenario the capacity of PV generation was increased from 20 to 50 GW. At the same time, the capacity of wind was reduced by about 7.6 GW (for a total of 45.4 GW) in order to maintain the same total available output from wind and PV. Despite seemingly high PV capacity, the annual PV output is only about a quarter of wind output due to an inherently lower PV capacity factor. Figure 3.5 shows the comparison between generation capacities and outputs in wind- and solar-dominated variants of the 50 g/kWh scenario.

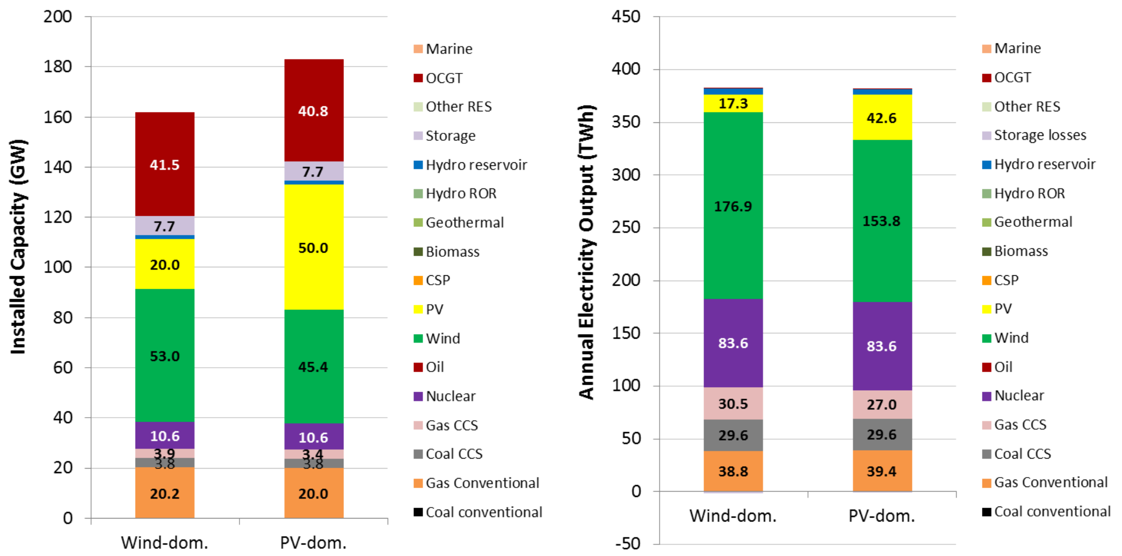


Figure 3.5. Comparison between the generation mix and annual electricity output for wind-dominated and PV-dominated 50 g/kWh scenarios

Table 3.4 summarises the generation capacity assumptions across all three core 2030 scenarios.

Table 3.4 Generation capacity mix for three core 2030 scenarios

Technology	Capacity (GW)		
	100 g/kWh	50 g/kWh (wind-dom.)	50 g/kWh (PV-dom.)
Nuclear	9.6	9.6	9.6
Gas CCGT	20.8	20.0	20.2
OCGT	43.0	41.6	40.5
Coal	0.0	0.0	0.0
CCS	7.1	7.6	7.2
Onshore and offshore wind	36.0	53.0	46.4
Solar	20.0	20.0	50.0
Hydro	1.5	1.5	1.5
Pumped storage	2.7	2.7	2.7
Other dedicated storage	5.0	5.0	5.0
Interconnection	7.4	7.4	7.4
Total	**153.1**	**169.4**	**190.5**

3.4. Additional system scenarios

In this section we present the key features of two further decarbonisation scenarios used to evaluate the integration cost of low-carbon technology: 1) 2030 scenario with 200 g/kWh carbon intensity, and 2) 2050 scenario with 10 g/kWh carbon intensity.

3.4.1. 200 g/kWh scenario in 2030

This scenario is developed in order to assess the system integration cost and the corresponding impact of flexibility in a system that is designed to meet a less ambitious decarbonisation target. The capacities of low-carbon technologies assumed as a starting point in this scenario were as follows:

- Nuclear: 4.4 GW
- CCS: 0.6 GW
- Onshore and offshore wind: 22.5 GW
- Solar PV: 10.2 GW
- Hydro, biomass and marine: 5.5 GW

It was further assumed that 2 GW of coal plant would still exist in the system, while the gas capacity (CCGT and OCGT) was optimised by the model. The outturn emissions based on the above generation mix, before imposing any carbon emission constraints, was around 250 g/kWh. An additional study was therefore carried out with carbon emissions explicitly limited to 200 g/kWh, which resulted in the addition of 3.8 GW of extra CCS by the model.

The demand assumptions for this scenario were the same as in the previously described 2030 core scenarios. The flexibility assumption in the central case was also the same as in the core scenarios (medium flexibility level).

Two additional baseline 200 g/kWh cases have been simulated, one with a low flexibility level (using the same assumptions as in Figure 3.3, i.e. without any additional storage or DSR and), and one with an intermediate flexibility level which represents a midpoint between low and medium flexibility (i.e. with 2.5 GW of storage and 25% DSR utilisation added to the low-flexible system), denoted by "Low-mid flex". The cost savings in low-mid flex and mid-flex cases compared to the low flexible case are shown in Figure 3.6 (as in the previous scenarios, the figures represent gross cost savings without including the cost of deploying DSR and storage).

The resulting cost savings suggest that the gross value of enhanced flexibility in this scenario is between £2.2bn and £2.9bn per annum, demonstrating that increasing flexibility is a low-regret option, reducing the overall cost even in a system that is less decarbonised. The key cost savings categories delivered by higher flexibility include the cost of building and operating CCS to meet carbon intensity target, distribution network reinforcement, cost of building OCGT and CCGT capacity to ensure security, and the cost of operating peaking OCGT units characterised by a high operating cost.

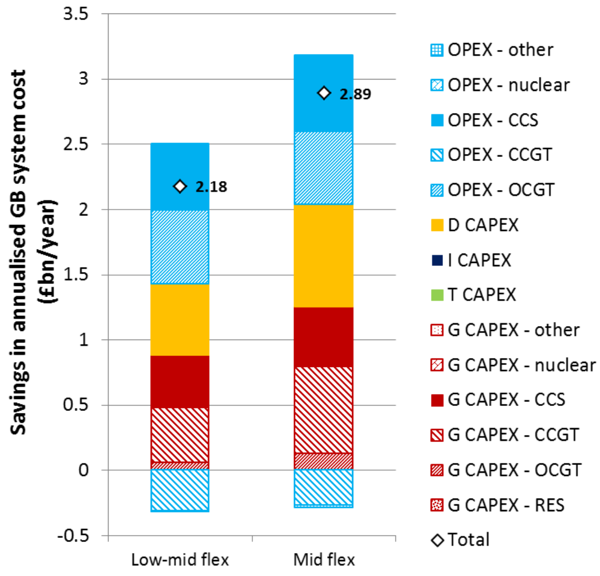


Figure 3.6. Impact of increasing system flexibility on total system costs in 200 g/kWh scenario in 2030

3.4.2. 10 g/kWh scenario in 2050

This scenario is characterised by very high nuclear (21 GW), wind (90 GW) and PV capacity (100 GW).[62] We let the model add CCS and conventional capacity if needed to ensure security of supply and meet the emission target at the minimum cost. The same system flexibility is assumed in the central (medium flexible) case as in the 2030 core scenarios, with the exception of storage, where we assumed that 10 GW of additional storage is available in the system.

Annual electricity demand for this scenario was assumed to be higher to reflect possible evolution of electricity consumption including the rapid electrification of heating and transport sectors. Total annual demand for this scenario was 573 TWh, of which 72 TWh was the demand for electrified road transport, while 101 TWh was the annual heat pump demand. Such high levels of electrification can lead to significant increases in total annual demand, but even more so in peak demand level that drives the capacity adequacy requirement in the system. Peak demand in this scenario was 134 GW in the central run, which required that some 125 GW of firm OCGT capacity is added to the system to ensure adequate security of supply standards given that the capacity value of wind and PV is very low.

This scenario assumes a higher level of flexibility due to higher storage deployment (5 GW more than the baseline assumption for 2030 scenarios), while DSR utilisation in relative terms remains the same, 50% (although in absolute terms the volume of DSR would increase massively due to very high level of heat and transport electrification). Higher deployment of

62 2050 demand assumptions were obtained from the CCC (2012) *The 2050 target – achieving an 80% reduction including emissions from international aviation and shipping*

storage in the 2050 horizon would be compatible with the rapid deployment of renewables and heat and transport electrification envisaged in the scenario.

3.5. Conclusions

This chapter presented the key features of scenarios to be used in this study of integration cost of low-carbon technologies. Scenarios differ in terms of the target carbon intensity, but also in terms of the composition of the low-carbon mix expected to deliver the targeted emission intensity. The same level of system flexibility is assumed in all scenarios (i.e. medium flexibility) except in the 10g scenario, where 10 GW instead of 5 GW of additional storage is assumed to be available in the system.

Reaching a given emission target from today's state will require certain cost. Figure 3.7 illustrates the baseline cost differences between wind-dominated 50 g/kWh scenario on one hand and PV-dominated 50 g/kWh scenario and 100 g/kWh scenario on the other. G CAPEX and OPEX cost components are disaggregated across different generation technologies.

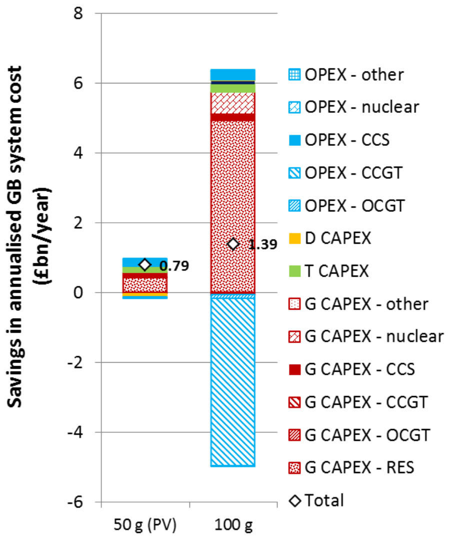


Figure 3.7. Comparison between baseline costs of PV-dominated 50 g/kWh scenarios and 100 g/kWh scenario vs. wind-dominated 50 g/kWh scenario

The cost differentials apply to the system with medium flexibility level (which corresponds to the central assumption in all core scenarios). Moving from 100 g/kWh to 50 g/kWh with medium flexibility will cost about £1.4bn per year if the 50 g/kWh target is achieved through a wind-dominated system or about £0.6bn per annum if PV is more prominent in the low-carbon mix. The additional studies discussed in more detail in Chapter 4 also suggest that relaxing the decarbonisation target further to 200 g/kWh would make the system £2.9bn per year less expensive than the wind-dominated 50 g/kWh scenario, or around £1.5bn per year cheaper than the 100 g/kWh scenario.

These cost differentials appear moderate; however, they may increase significantly if the emission targets are imposed on inflexible systems: e.g. moving from low-flexible 100 g/kWh scenario to low-flexible PV-dominated 50 g/kWh scenario would entail an additional cost of £4.55bn per year, while the shift towards wind-dominated 50 g/kWh scenario would require an extra cost of £5.32bn per year.

Moderate cost differentials at medium system flexibility also suggest that the system is able to integrate wind and PV generation with manageable additional cost. This is also reflected in the curtailed volume of wind and PV output, which is negligible in the 100 g/kWh scenario (0.04%) and still relatively small in the wind-dominated 50 g/kWh scenario (0.87%). Nevertheless, in low-flexible 100 g/kWh and 50 g/kWh systems, curtailment levels would increase to 0.25% and 9%, respectively, suggesting that integrating intermittent renewables is far more challenging in systems with limited flexibility.

4. Impact of flexibility on 2030 generation mix in additional system scenarios

A dedicated set of case studies has been carried out using the WeSIM model to determine the optimal generation mix in 2030 to meet the carbon targets of 50 and 100 g/kWh, for varying levels of flexibility, rather than following the prescribed core CCC generation scenarios. This chapter investigates how sensitive the composition of the cost-efficient low-carbon technology mix is both to actual generation costs and to the level of flexibility that may be available. The results suggest that the flexibility will critically affect the integration cost of different low-carbon technologies.

In this chapter the generation mix is optimised in WeSIM by allowing new investment in all generating technologies in order to meet a given emissions target (50 or 100 g/kWh). WeSIM minimises the overall investment and operating cost needed to achieve the target. It is important to note that when optimising the generation mix WeSIM simultaneously considers the increased balancing requirement if it decides to increase the capacity of renewable generation.

Five levels of flexibility are analysed in cost-optimal studies:

- Low flex: no DSR and no additional storage
- 25% flex: 25% of DSR potential utilised plus 2.5 GW of new storage
- 50% flex: 50% of DSR potential utilised plus 5 GW of new storage (same assumption as in the main core scenario studies)
- 100% flex: 100% of DSR potential utilised plus 10 GW of new storage
- Full flex: 100% of DSR potential utilised plus 15 GW of new storage

The assumptions on interconnection, generation plant flexibility and response requirement level across the flexibility studies have not been changed compared to the medium-flexibility core scenario assumptions (see Section 3.1).

Except for Section 4.3, all studies in this chapter have been carried out by assuming that generation capacity in 2030 can be added from (or retained at) zero to determine a cost-optimal outcome. This may not be fully realistic given that some generation capacity present in the system today is likely to remain operational until 2030; nevertheless, the insights obtained from these studies are valuable for establishing the impact of flexibility on the choice of the least-cost pathway to power system decarbonisation.

4.1. Cost-optimal scenarios with equal levelised costs

In the first set of studies the focus is on relative merits of low-carbon technologies in terms of supporting cost-effective system design and operation. For that reason the levelised costs

(LCOE) of nuclear, gas CCS, wind and PV generators was set at an identical value of £100/MWh, and the generation mix was cost-optimised to achieve 100 or 50 g/kWh intensity.[63]

The optimal generation mix with 100 g/kWh intensity with equal LCOEs of low-carbon technologies is shown in Figure 4.1. Despite the same LCOEs for nuclear, CCS, wind and PV, there are stark differences between the optimal generation mixes for different levels of system flexibility.

In a low-flexible system, the only low-carbon generation technology selected in the portfolio to achieve decarbonisation by 2030 is CCS, in the amount of about 40 GW. A lack of flexibility makes it more costly to integrate baseload nuclear or intermittent renewable generation than the relatively more flexible CCS plant. The remaining capacity in the low-flexible system consists of CCGT and OCGT, with the role to provide security of supply and occasionally provide balancing services to the system within the boundaries determined by the imposed carbon constraint.

Adding flexibility to the system profoundly changes the composition of the least-cost generation mix, by replacing CCS capacity with a mix of wind and nuclear capacity. The share of nuclear is relatively high at moderate levels of flexibility, but reduces as progressively more flexibility is introduced in the system. Added flexibility reduces the integration cost of wind, which makes it an attractive option for expansion given its seasonal output variations that peaks in winter and is better correlated with annual demand variations than baseload nuclear. Similarly, the PV output peaks in summer and therefore has a less favourable annual profile, making it a much less attractive low-carbon option and resulting in virtually zero capacity being added regardless of the flexibility. Also, we note that the combined output of nuclear and wind at flexibility levels of 25% and above (around 275 TWh) is lower than the output of CCS in the low-flexible case (313 TWh, or about 82% of the total UK demand). This is possible because of the non-zero emission rate of CCS generators (i.e. less than 100% carbon capture rate) combined with explicit carbon emission constraint, which allows a lower volume of zero-carbon nuclear and wind output to displace CCS generation. The optimal capacity of wind saturates at around 45 GW at very high flexibility levels.

---

63 When equalising the LCOEs of low-carbon technologies, their investment costs have been updated so as to result in an LCOE of £100/MWh; the operating cost (if any) was not adjusted.

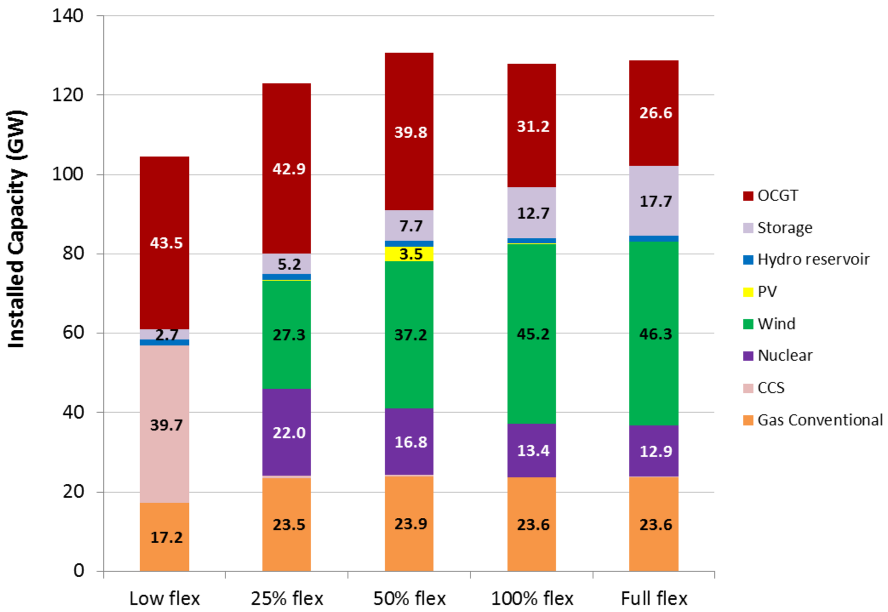


Figure 4.1. Cost-optimal generation mixes with equal LCOEs of low-carbon technologies, achieving 100 g/kWh carbon intensity in 2030 with different levels of system flexibility

Figure 4.2 presents the cost-optimal portfolios when the target carbon intensity is 50 g/kWh. Similar trends can be observed as for the 100 g/kWh target, but with more CCS and nuclear capacity being installed to meet the emission target. The CCS capacity in the low-flexible case is almost 50 GW generating around 95% of total system demand, while nuclear generation enters the system at 25% flexibility with about 30 GW. Increasing flexibility gradually reduces the optimal volume of nuclear generation, but never below the 20 GW level. Wind is chosen in smaller quantities than in the 100 g/kWh studies, given that its balancing requires progressively higher utilisation of thermal generators, which can have an adverse impact on system emissions and cost and is therefore scaled down. Still, at very high flexibility levels the optimal volume of wind reaches about 44 GW, which is very similar to the results in the comparative 100 g/kWh studies.

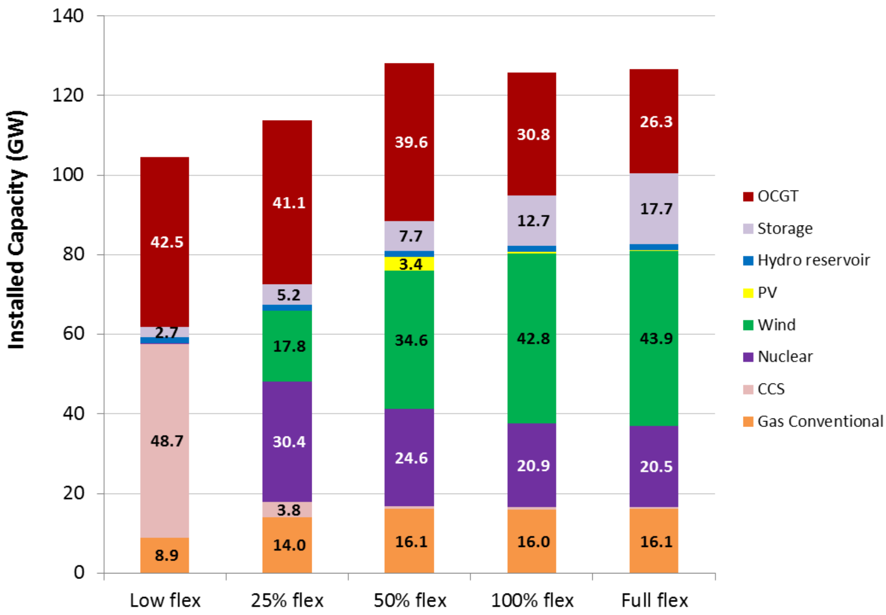


Figure 4.2. Cost-optimal generation mixes with equal LCOEs of low-carbon technologies, achieving 50 g/kWh carbon intensity in 2030 with different levels of system flexibility

In summary, even when differences in levelised costs between low-carbon technologies are ignored, the optimal choice of low-carbon portfolio will be strongly driven by the flexibility level present in the system. Low-flexible systems with ambitious carbon emission targets tend to favour CCS as the predominant low-carbon technology, while more flexible systems feature a mix of nuclear and wind capacity (with more flexibility typically associated with more wind), without any CCS capacity being chosen. PV capacity, when competing with other low-carbon technologies on an equal LCOE basis, is less attractive due to its seasonal output that peaks at times of low system demand.

4.2. Cost-optimal 50 g/kWh and 100 g/kWh scenarios

In the next set of studies the optimal low-carbon generation mix is determined by the model using the actual LCOE values for low-carbon technologies assumed in the report (see Section 3.2.2). As the generation mix in these studies is cost-optimised, the marginal benefit of each generation technology (including low-carbon) is necessarily equal to its LCOE. This means that in the optimal portfolio, the relative integration costs of wind and PV against nuclear should be equal to their cost advantages over nuclear generation. In the non-optimised generation portfolios such as those assumed in the core scenarios, the integration costs will generally differ from LCOE differentials i.e. will be either higher or lower depending on the scenario and the assumed level of flexibility.

We run a number of studies to obtain cost-optimised generation mixes that produce 50 g/kWh or 100 g/kWh carbon intensity for different levels of system flexibility (as described in Section 3.1).

4.2.1. 50 g/kWh optimised scenario

The generation mixes proposed by WeSIM to meet the 50 g/kWh carbon intensity for the 2030 scenario with different levels of system flexibility are shown in Figure 4.3.

The results show that the cost-optimal generation mix in the low-flexible case features no renewable capacity. As the flexibility gradually increases, the combined installed capacity of wind and PV increases from 41 GW in the 25% flex case to 102 GW at full flexibility. The installed capacity of CCS shows an opposite trend: 13.4 GW of CCS is selected in the low-flexible case, but as soon as some flexibility materialises in the system, CCS is no longer selected as part of the optimal mix. Referring to the key theme of this report, this can be interpreted as the consequence of the reduced integration cost of wind and PV at higher levels of system flexibility, making the intermittent renewables comparatively more attractive from the whole-system cost perspective.

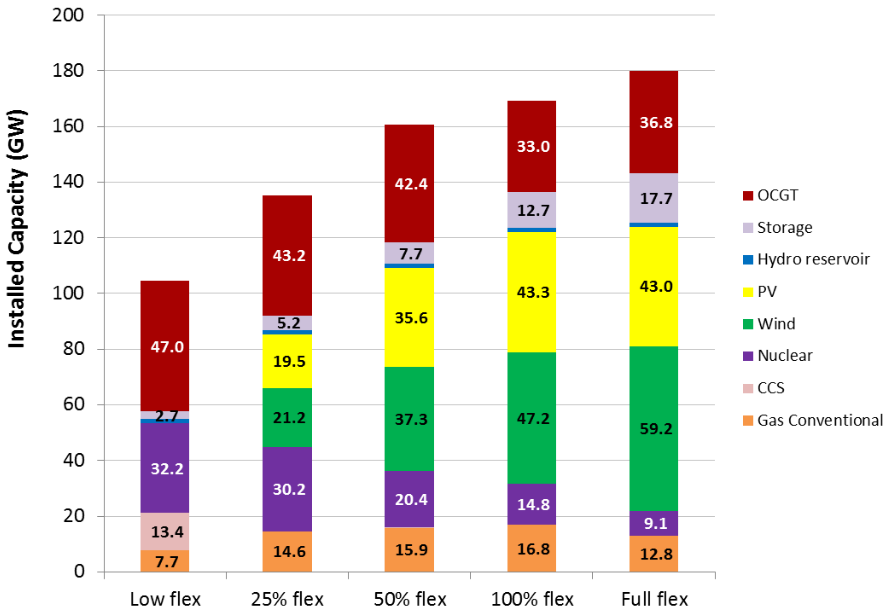


Figure 4.3. Generation mixes proposed by WeSIM to achieve 50 g/kWh carbon intensity in the 2030 scenario with different levels of system flexibility

We also note that the optimal installed capacity of nuclear gradually decreases with increasing system flexibility. Again, flexibility drives the integration cost of wind and PV downward, increasing their attractiveness in comparison to nuclear. Nevertheless, unlike CCS, some nuclear capacity is still part of the cost-optimal low-carbon portfolio even at higher flexibility levels; e.g. at full flexibility, even with 109 GW of wind and PV on the system it is still economical to install 10 GW of nuclear. It is also important to highlight that nuclear capacity also requires certain degree of system flexibility given that it normally operates as baseload plant and is less flexible with very limited balancing capability.

It should be noted that these results are very sensitive to the cost assumptions used in the studies. At different cost assumptions (especially if the order of technologies according to their LCOEs changed), the results may vary considerably.

Figure 4.4 shows the annual electricity production of each generation technology for cases with different levels of flexibility. The chart also shows the load factor of each generation. For example, conventional gas (CCGT) in the No flex case has a load factor of 37%, CCS 78%, and nuclear 90%, while in e.g. 50% flexible case wind operates at a load factor of 43%, and PV at 10%.

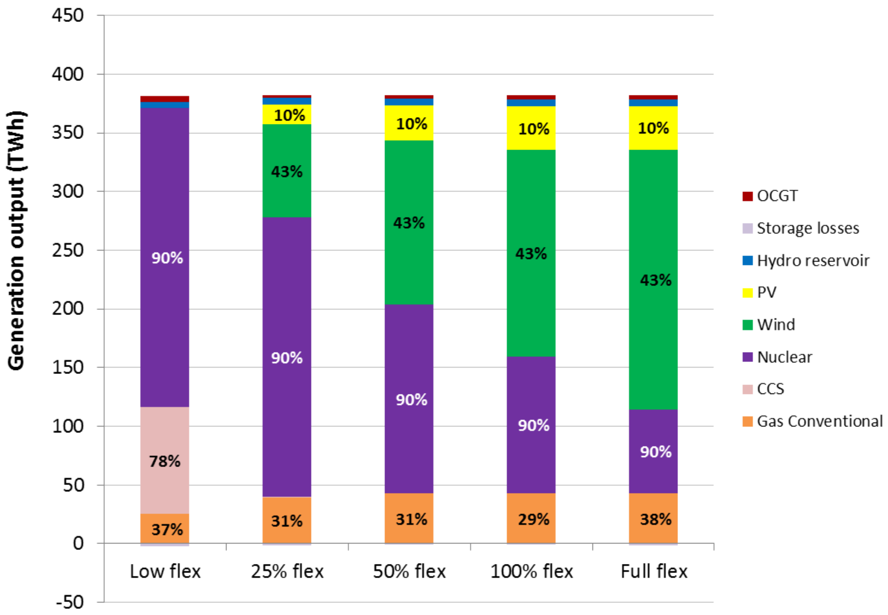


Figure 4.4. Annual electricity production of each generation technology in the optimised 50 g/kWh scenario in 2030 with different levels of system flexibility

With additional flexibility, most low-carbon technologies operate close to their maximum achievable utilisation factor. This is consistent with optimal investment decisions made in the model, where baseload plants and renewables are only installed up to the volume where they are used at maximum capacity factors i.e. with minimal curtailment.

4.2.2. 100 g/kWh optimised scenario

We also carried out the same set of studies to obtain the generation mixes for the system with 100 g/kWh carbon intensity target for different levels of system flexibility. The results are shown in Figure 4.5.

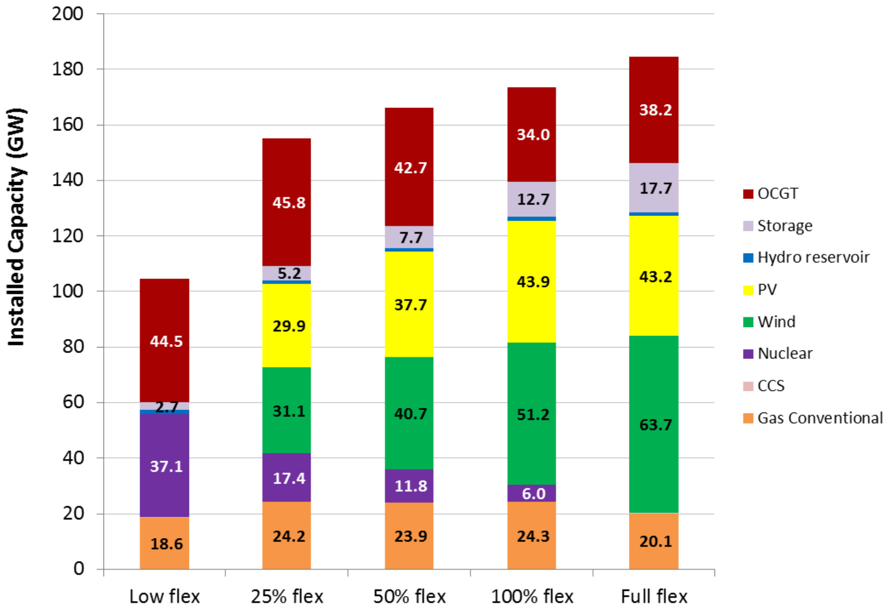


Figure 4.5. Generation mixes proposed by WeSIM to achieve 100 g/kWh carbon intensity in the 2030 scenario with different levels of system flexibility

The results show similar trends with the 50 g/kWh studies. The combined capacity of wind and PV increases from zero in the non-flexible case to 61 GW in 25% flexible case, increasing gradually towards 107 GW in the system with maximum flexibility. On the other hand, the capacity of nuclear plant decreases at higher flexibility levels. The results again suggest that renewables gradually become more attractive than nuclear as their integration cost is mitigated through enhanced flexibility in the system.

Since the emissions target is less onerous than in the 50 g/kWh studies, the results suggest that CCS is not required even in the low-flex case, where the emission target is achieved by installing high nuclear capacity.

Enhanced flexibility also reduces the amount of peaking capacity or the overall firm capacity in the system since the peak load can be reduced by shifting the load from peak to off-peak conditions through DSR actions or by using storage to deliver firm capacity.

Annual generation output results (Figure 4.6) again suggest maximum utilisation of nuclear and renewable capacity. Less nuclear output is required to meet the target than in the 50 g/kWh studies, which also allows CCGT plants to operate at higher capacity factors.

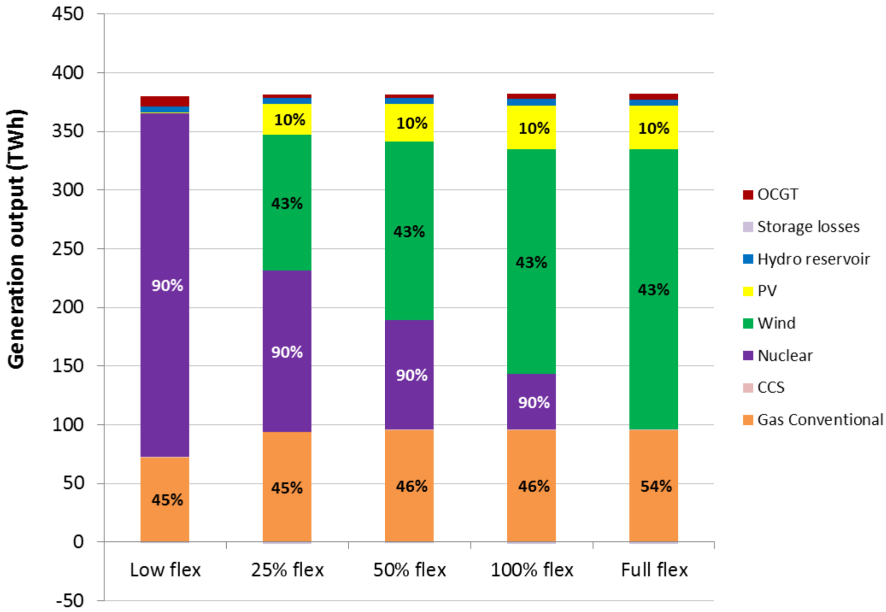


Figure 4.6. Annual electricity production of each generation technology for optimised 100 g/kWh scenario in 2030 with different levels of system flexibility

Gross benefits of flexibility are reflected in reduced cost of reaching a given emission target (note that, as emphasised earlier, the savings from enhanced flexibility do not factor in the cost of deploying additional DSR and storage resources). Figure 4.7 illustrates cost savings for various flexibility levels deployed in the optimised 100 g/kWh and 50 g/kWh scenarios when compared to the same systems with low flexibility. As the flexibility increases, progressively higher volumes of wind and PV are able to replace nuclear generation, given that their cost disadvantage due to higher integration cost diminishes with enhanced flexibility. This replacement results in a net benefit of between £4.14bn to 4.93bn per annum for the 100 g/kWh scenario and between £5.23bn and 5.99bn per year in the 50 g/kWh scenario, in which case the savings represent the net effect of removing nuclear (with higher LCOE) and adding lower-cost wind and PV generation.

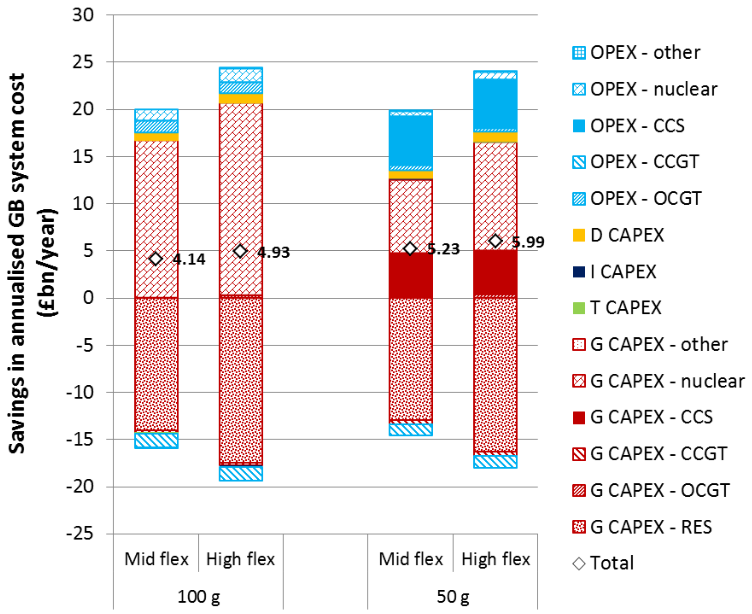


Figure 4.7. Impact of system flexibility on cost savings while meeting 100 g/kWh and 50 g/kWh targets (optimised generation mix)

These results strongly suggest that system flexibility should be considered as a critical factor for designing decarbonised electricity systems and facilitating cost-effective evolution to lower carbon electricity system.

4.3. Partially cost-optimal generation mix with minimum technology deployment levels

A slightly modified set of cost-optimised studies has further been carried out where generation capacities of low-carbon technologies were not optimised from zero, but there was rather the following minimum level of deployment assumed in the 2030 system:

- 35 GW of onshore and offshore wind,
- 10 GW of solar PV,
- 7 GW of CCS.

The purpose of this set of system scenarios is to investigate the impact of a generation mix that is closer to the theoretical cost optimum than the three adopted core scenarios on integration costs of low-carbon technologies. This chapter only discusses the resulting optimal generation mix and the impact of flexibility on partially optimised systems, while the results of system integration cost studies are presented in Section 6.5.7.

As illustrated in Figure 4.8, high levels of flexibility facilitate a similarly high deployment of renewable capacity as in fully optimised scenarios. Generation portfolios in low-flexible systems however differ more profoundly as the significant volume of wind, PV and CCS capacity is forced to be present on the system where in the fully optimised case very little or none of this capacity would be chosen as part of the optimal mix. Changes in the mix are also driven by interactions between low-carbon technologies, so that for instance in the low-flexible 50 g/kWh system there is significantly higher CCS deployment than in the fully optimised case, in order to respond to the additional flexibility requirements driven by the minimum volume of wind and PV generation.

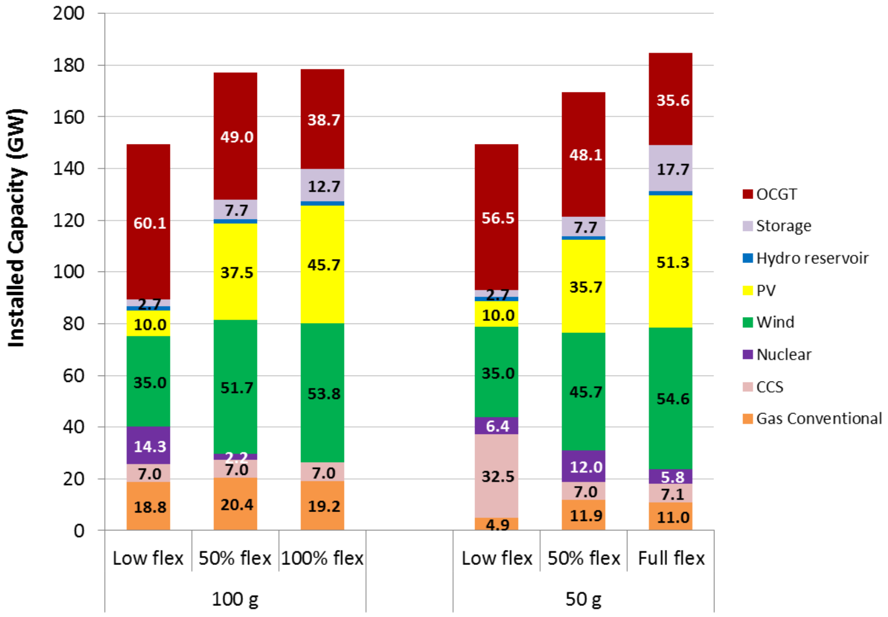


Figure 4.8. Impact of system flexibility on partially optimised generation mix for 50 and 100 g/kWh targets and different system flexibilities

Much less nuclear capacity is deployed in partially optimised scenarios (e.g. only 2 GW in 50% flex case compared to 13 GW in fully optimised studies), as the results of reduced scope for deployment against the fixed minimum volumes of wind, PV and CCS. Renewable generation capacity at higher flexibility levels is deployed in similar volumes as in the fully optimised cases.

Annual system cost savings resulting from enhanced flexibility in the partially optimised cases are again substantial: £3.2bn in 50% flexible and £4.3bn for fully flexible 100 g/kWh cases; £8.4bn in 50% flexible and £9.6bn for fully flexible 50 g/kWh case.

4.4. Impact of carbon price on optimal generation mix in the absence of emission constraints

As opposed to imposing an explicit carbon emission constraint on the electricity system, it is also possible to reduce system emissions by sufficiently increasing the assumed carbon price. We therefore ran a series of studies where we relaxed the CO_2 constraint while varying the carbon price in a relatively broad range to evaluate the impact on outturn system emissions as well as on the resulting cost-optimal generation portfolio.

The strong impact of flexibility seen earlier in the chapter has also been observed in this supplementary set of studies with relaxed system-level CO_2 constraint, particularly with respect to the level of CO_2 price required to achieve 50 g/kWh emissions in the 2030 system. As shown in Table 4.1, in a system with 50% (medium) flexibility, the carbon price needs to reach £104/t for the system emissions to drop to about 50 g/kWh. At this carbon price the resulting cost-optimal generation mix (Figure 4.9) is very similar to the 50% flexible case with the explicit 50 g/kWh carbon emission constraint depicted in Figure 4.3, where the low-carbon generation mix is dominated by nuclear, wind and PV.

Table 4.1. Carbon prices required to achieve 50 g/kWh intensity for different system flexibility levels

System flexibility	Carbon price resulting in 50 g/kWh
Medium (50% flex)	£104/t
Low (No flex)	£245/t

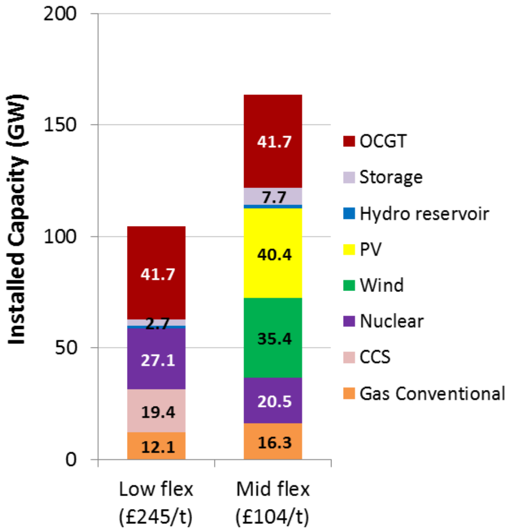


Figure 4.9. Optimised system generation portfolios reaching the 50 g/kWh target through CO_2 price variation for low and medium system flexibility

A similar set of studies has been carried out for the low-flexible 50 g/kWh system (corresponding to "Low flex" in Figure 4.3). The level of carbon price required to reach the 50 g/kWh carbon intensity is now £245/t, significantly higher than in the 50% flexible case. The resulting composition of the cost-optimal low carbon generation mix is also markedly different, consisting of a mix of nuclear and CCS capacity, while wind and PV capacity are not chosen as part of the generation mix (see Figure 4.9). This massive difference in efficient carbon price that would deliver target emissions further reinforces the importance of flexibility as a vehicle for delivering electricity supply decarbonisation at a lower cost.

4.5. Key findings

Key overall observations from optimised system studies presented in this chapter are:

- It is feasible to manage a future GB power system that is deeply decarbonised with high levels of intermittent renewables (i.e. up to around 50 GW of wind or solar).

- Achieving deep decarbonisation at efficient cost will require a significant increase in system-wide flexibility from the current levels, alongside the expansion of low-carbon capacity.

- As the flexibility increases, progressively higher volumes of wind and PV are able to replace nuclear generation, given that their cost disadvantage due to higher integration cost diminishes with enhanced flexibility. Gross system benefits of enhancing flexibility amount to £4.24bn to 5.09bn per annum for the optimised 100 g/kWh scenario and between £5.15bn and 5.75bn per year in the optimised 50 g/kWh scenario. Increasing flexibility is a low-regret option, reducing the overall cost even in a system that is less decarbonised (see e.g. Section 6.5.8 for the discussion on 200 g/kWh scenario in 2030).

- The flexibility options considered in the analysis, in particular energy storage and DSR, exist today or are likely to be available by 2030, but may not be sufficiently incentivised by the current market arrangements.

The optimised system studies demonstrate that flexibility can significantly reduce the integration cost of intermittent renewables, to the point where their whole-system cost makes them a more attractive expansion option than CCS and/or nuclear.

At low levels of system flexibility, i.e. with no DSR or new storage deployment, the cost-optimal solution requires the installation of nuclear and CCS plant to deliver low-carbon electricity, while high integration cost prevent wind or PV to be a part of the cost-optimal solution despite their lower levelised cost than nuclear or CCS. However, starting already at relatively moderate levels of flexibility, the optimal solution begins to include increasing amounts of wind and PV, resulting from the reduced integration cost delivered by enhanced flexibility, while at the same time reducing or completely removing the capacity of firstly CCS and then nuclear plant, although some nuclear capacity is retained even with high flexibility. At very high flexibility levels the model installs just over 100 GW of intermittent renewable capacity for both 100 g/kWh and 50 g/kWh targets.

If levelised costs of low-carbon technologies were equal, the optimal solution favours wind over PV given the differences in their seasonal output variations (wind output peaks in winter i.e. at the same time as demand, while PV output is the highest in summer when the demand is low). In those cases having any flexibility in the system enables a mix of wind and nuclear to become the selected low-carbon technologies. With differentiated LCOEs i.e. PV being less expensive than wind, a mix of wind and PV is chosen whenever there is some flexibility in the system. This suggests that wind represents a rather robust choice for decarbonisation with the only exception of cases with very low flexibility.

The studies on the partially optimised system have shown that if a certain volume of low-carbon generation capacity is locked in the system, this could have an impact on the composition of the cost-optimal low-carbon portfolio, so that for instance, fixing a certain amount of CCS and wind capacity would considerable reduce the scope for nuclear deployment. Finally, it has been shown in this chapter that a given system carbon intensity target can be achieved by suitably adjusting the CO_2 price instead of specifying an explicit emission constraint. However, the level of carbon price that will deliver e.g. 50 g/kWh greatly depends on system flexibility: £104/t is sufficient in medium flexible system, while £245/t would be required in a low flexible system.

The results strongly suggest that system flexibility should be considered as a critical factor for designing decarbonised electricity systems and facilitating cost-effective evolution to lower carbon electricity system. In this context, it will be critical that different forms of flexibility are adequately rewarded for the benefits they provide to the system.

5. Meeting a 2030 decarbonisation target under uncertainty

We developed "core" scenarios on the supply-demand background prevailing in the British power sector in 2030, on the assumption that it is planned to deliver outturn emissions intensity of either 50 g/kWh or 100 g/kWh. However the outturn level of CO_2 emissions intensity will be sensitive to variation in underlying supply-demand fundamentals, such as total annual demand, available renewable energy (wind speeds, solar intensity), prices in neighbouring markets, etc.

Within each of the core scenarios, we therefore vary a range of factors (e.g. changes in demand, renewables output, fuel and carbon prices or prolonged outages of nuclear plant) that influence outturn emissions to examine the likely range of uncertainty around emissions in both core scenarios. In particular, we investigate the impact of the following drivers:

- Variations in annual demand levels: 10% above or below the central assumption
- Variations in available renewable (wind and PV) generation output: 10% above or below the central assumption
- Variations in fuel and carbon prices: high or low price levels according to DECC's fuel price projections
- Prolonged outage i.e. reduced availability of a large nuclear unit

The outturn carbon emissions across different sensitivities are presented in Figure 5.1 for the 100 g/kWh and wind-dominated 50 g/kWh core scenarios. When introducing variations in key drivers, the generation mix in the two scenarios was maintained as in the default case i.e. the system was not allowed to adapt to changed circumstances by altering the generation mix.

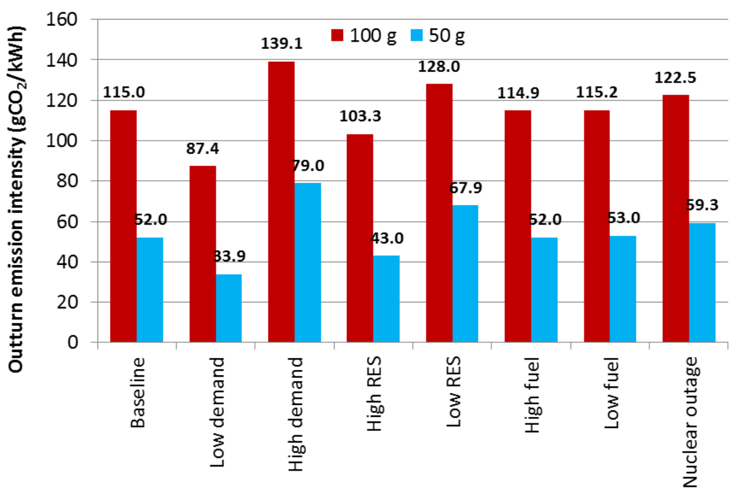


Figure 5.1. Outturn emission intensity (in g/kWh) in core 2030 50 g/kWh (wind-dominated) and 100 g/kWh scenarios across sensitivities

The results of sensitivity studies suggests that unpredictable circumstances do have an impact on grid intensity, although the magnitude of this impact highly depends on the type of variation introduced in the system, as well as on the analysed scenario. As expected, lower demand, higher renewable output or higher fuel prices all result in reduced emissions, however while lower demand would reduce baseline emissions by 24% in 100 g/kWh or 35% in 50 g/kWh scenario, an increase in fuel and carbon prices would only trigger an emission drop of 0.1-0.2%. The highest impact magnitude is triggered by the assumed demand variations[64], followed by renewable output variations, and prolonged nuclear outages, while by far the lowest impact is associated with changes in fuel and carbon prices given that the capacities as well as relative merit order of generation technologies remain broadly the same. It can also be observed that, in relative terms, the 50 g/kWh core scenario is more sensitive to system perturbations than the 100 g/kWh system.

Given the significant level of flexibility in the system that is helping to reduce carbon emissions cost-effectively, the risk of experiencing higher carbon intensity due to perturbations in supply or demand, such as sudden changes in demand, available low-carbon output or fuel prices, is kept at an acceptable level.

[64] It has to be noted that a 10% variation in annual demand represents a large change that is unlikely to occur unpredicted within a short timeframe (without the opportunity of the system to adapt), as the typical annual variations in demand levels over the recent years have been around the 1% mark.

6. System externalities associated with low-carbon technologies

6.1. Introduction

This section presents the results of the case studies to determine system externalities of low-carbon generation technologies when a small amount of them is added to the system. The studies clearly demonstrate that the integration cost of low-carbon technologies is a function of the system they are being added to, for instance the volume of low-carbon capacity already present in the system, level of flexibility etc. The results of system integration cost studies are shown for all three methods investigated in this study, and are disaggregated across different components of integration cost (generation, transmission and distribution CAPEX as well as OPEX). G CAPEX and OPEX components are further broken down by technologies to identify where different components of integration cost originate.

The results presented in this chapter refer to relative integration cost of low-carbon technologies when compared to nuclear generators. To aid comparison, the assumed LCOE differentials (i.e. cost advantages) of different low-carbon technologies against nuclear are also indicated in the charts. If the relative integration cost for a given technology is higher than its corresponding LCOE cost advantage against nuclear, this suggests that a unit of this technology provides a lower net marginal benefit to the system than a unit of nuclear capacity.

Quantitative results from system integration studies are presented for all three methods defined in Section 2.4. Where both incremental and decremental studies were carried out (such as for Methods 1 and 2), the results shown represent averages between the two studies, unless otherwise specified [65]. Appendix B (Section B.2) includes the results of individual study results for all methods and all capacity change directions, changes in generation capacity and changes in generation outputs. The marginal benefit studies used for calculating the system integration cost according to Method 3 are also included in the same location.

6.2. 100 g/kWh scenario in 2030

In the 100 g/kWh scenario (Figure 6.1) the relative integration costs of wind and PV (when compared to nuclear) are found to be moderate, in the range of £6-9/MWh. Key components of integration costs of wind and PV include:

a) Increased generation CAPEX, mostly driven by the need to ensure sufficient backup capacity

b) Increased OPEX, driven by increased volumes of ancillary services associated with lower operational efficiency.

[65] In Method 1, for the incremental case, 1 GW of nuclear capacity in the south is replaced with 2.1 GW of offshore wind, while for the detrimental case 2.1 GW of offshore wind is replaced by 1 GW of nuclear. For each of these cases, system integration cost of wind is calculated and in this section of the report, average value of these two is presented. Similarly, for Method 2, system integration costs based on incremental and decremental studies are quantified, but in this section of the report, average value of these two costs is presented. Detailed results of individual studies, incremental and decremental, are presented in Appendix B.

Given the lower volume of wind, PV and nuclear power in this scenario, there is very little renewable curtailment necessary, and therefore no need to install additional CCS capacity to compensate for curtailed low-carbon output when small amounts of wind or PV replace nuclear in the system. Given that it was assumed that the additional wind, PV and CCS capacity would be available in the south of GB, there is no requirement for transmission reinforcement to integrate PV generation. Also, given the relatively low annual output of PV compared to other low-carbon technologies, it does not require significant distribution network reinforcement.

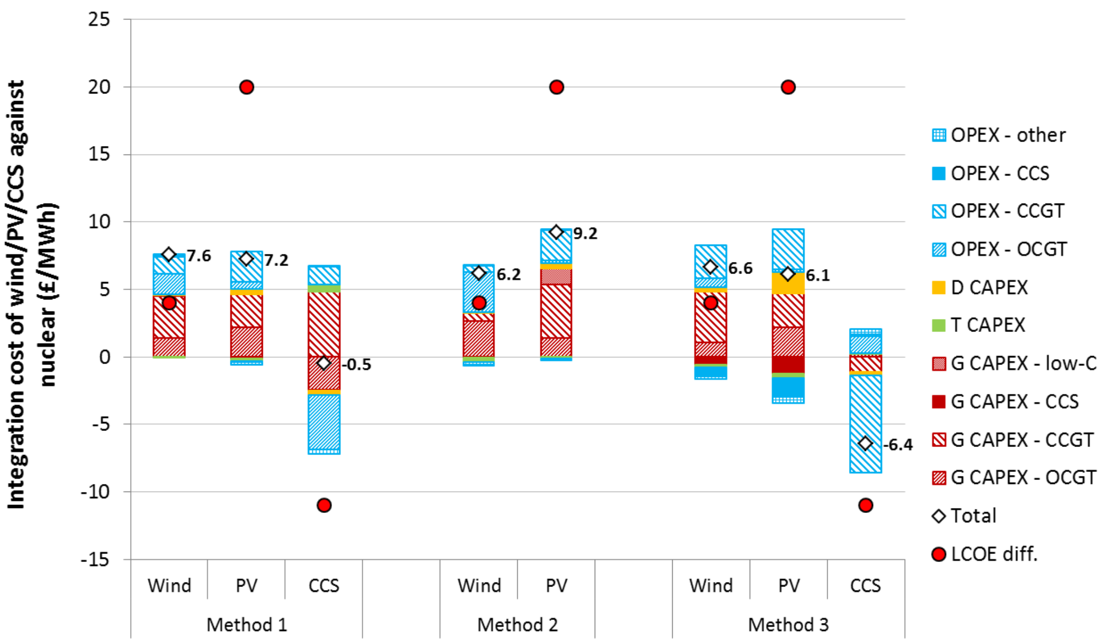


Figure 6.1. Relative integration cost of low-carbon technologies compared to nuclear in 100 g/kWh core scenario

For example, according to Method 1, removing 1 GW of nuclear and adding 2.1 GW of wind capacity, needed to maintain the same level of low-carbon output, leads to an increase in system costs of £7.6/MWh (i.e. £7.6 for each MWh of wind generation absorbed), provided that carbon emissions are maintained at 100 g/kWh. This is driven by the increase in demand for balancing services (OPEX) and the need to add conventional plant to maintain security of supply (CAPEX)[66]. Across the three methods, the integration cost of wind in this scenario is found to be between £6.2 and £7.6/MWh.

We note that the integration cost of PV, in addition to generation OPEX and CAPEX components also includes cost associated with the need to reinforce the distribution network. This cost is relatively modest at this level of PV penetration (20 GW), and does not exceed £1.6/MWh across all calculation methods. The total integration cost of PV across the three methods varies between £6.1 and £9.2/MWh,

[66] Note that the increase in operating costs is driven by increase in CCGTs output while the output of OCGTs is reduced, so that total emissions are maintained at 100 g/kWh. See Appendix B, Section B.2 for detailed results of integration studies including changes in generator outputs and installed capacity.

When nuclear capacity is replaced by CCS in Method 1, some OCGT plant is replaced by CCGT plant, which leads to an increase in CAPEX (as the investment cost per unit of CCGT is larger than that of OCGT) as well as reduced OPEX, given that operating CCGT is less costly than OCGT.

The net increase in system cost when nuclear is replaced with wind (£3.6/MWh) suggests that at current cost assumptions the system would benefit from substituting wind with nuclear capacity i.e. that the installed capacity of wind is above, and of nuclear below the optimal deployment volume where the sum of LCOE and integration costs of all technologies should be equal. Similarly, the net decrease in total system cost when PV replaces nuclear capacity suggests that the system would benefit from adding more solar PV capacity. This reasoning is consistent with the results of the optimised 100 g/kWh scenario (see Figure 4.5), where the cost-optimal capacity of PV is 44 GW (compared to 20 GW in the core scenario), nuclear is built with 12.6 GW (9.6 GW in core scenario), while wind remains at a similar capacity as in the core scenario.

It should be emphasised that while the LCOEs of additional low-carbon capacity, in particular wind, were assumed to include the cost of connecting new generation capacity to the UK's transmission grid, they did not include any costs associated with the necessary reinforcement of the national transmission system depending on the location of new capacity. As illustrated in sensitivity studies presented in Section 6.5.5, the location where new wind capacity is installed can have a significant impact on the integration cost and in particular on the transmission investment component; the addition of wind in the north of GB (as opposed to the south which was the default assumption in the main results presented here) would require considerable reinforcements of north-south transmission links in order to absorb the increased wind output in the North. That means that in reality, assuming cost-reflective and location-specific transmission charges, wind farms in the North would be exposed to a higher transmission-related integration cost, which would need to be reflected in the corresponding LCOE (e.g. up to £12-14/MWh).

6.3. 50 g/kWh scenario in 2030, wind-dominated

In the 50 g/kWh scenario (Figure 6.2) it can be observed that the relative integration costs of wind and PV approximately double compared to the 100 g/kWh scenario, increasing to the level of £12-17/MWh. The generation CAPEX component is mostly driven by additional CCS (Method 1) or additional wind/PV capacity (Method 2) required to maintain emission intensity given that a part of additional wind/PV output is curtailed.[67] Similarly, the increase in OPEX is predominantly driven by higher output of CCS plants to compensate for curtailment of zero-carbon wind or PV generation.

[67] For instance, the reduction of nuclear capacity by 1 GW in Method 2 triggers the investment in wind/PV which is higher than energy-equivalent capacity: 2.4/10.4 GW instead of 2.1/9 GW to maintain the same carbon emissions.

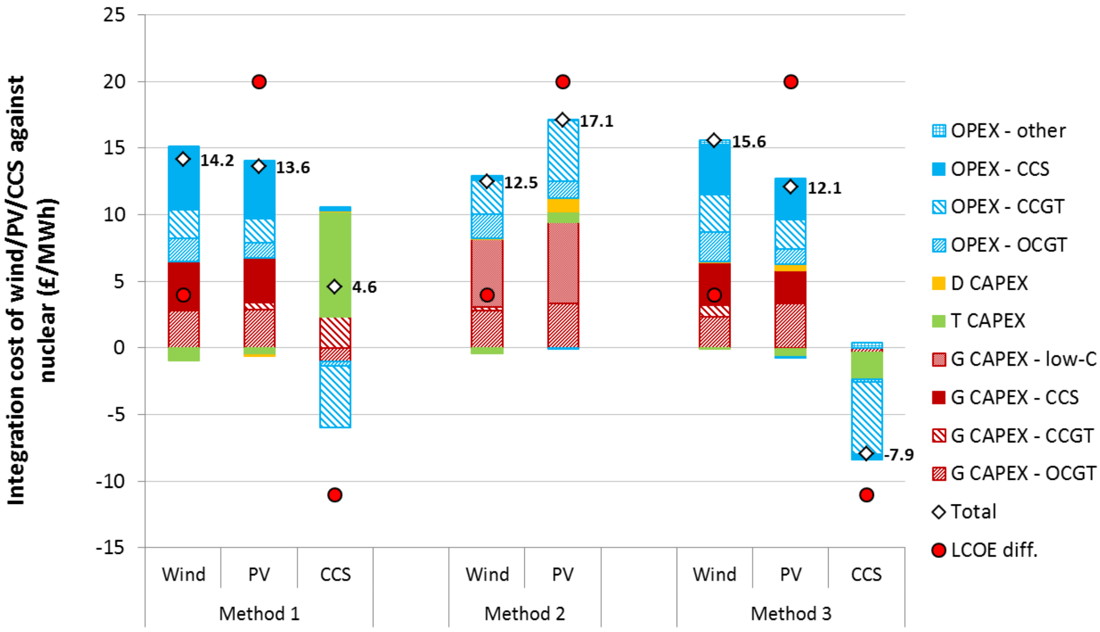


Figure 6.2. Relative integration cost of low-carbon technologies compared to nuclear in 50 g/kWh wind-dominated core scenario

Due to the fact that the core 50 g/kWh scenario features higher amounts of wind than the 100 g/kWh scenario (53 GW instead of 36 GW), increasing the offshore and onshore wind or solar PV capacity while reducing nuclear capacity is characterised by a higher system integration cost than in the 100 g/kWh core scenario.

The G CAPEX component of integration cost of wind and PV in Methods 1 and 3 arises from the need to add CCS capacity when wind or PV replaces nuclear, in order to maintain the same carbon emissions. Certain amount of conventional gas capacity (CCGT and OCGT) is also added to ensure system adequacy, further adding to the G CAPEX component. In Method 2, the G CAPEX consists of adequacy-driven cost of conventional gas units, as well as of additional wind or PV capacity beyond the energy-equivalent amount, in line with the definition of Method 2 where excessive carbon emissions are compensated by adding extra renewable rather than CCS capacity. The OPEX component of the integration cost of wind and PV results primarily from increased CCS output (Methods 1 and 3) or reduced efficiency of conventional gas generation output (Method 2) driven by increased requirements for balancing services.

As in the 100 g/kWh scenario, the integration cost levels for wind and PV are found to be of similar magnitude. Given that it was assumed that both the additional wind and PV capacity would be available in the south of GB, there is no requirement for transmission reinforcement.[68] At the same time, there is a relatively small D CAPEX component of the integration cost of PV in some methods (up to £0.5/MWh).[69]

The composition of the integration cost of CCS differs depending on the calculation method used. With the CCS-nuclear substitution adopted according to Method 1, there are OPEX benefits associated with reduced use of CCGT units to provide balancing services, resulting in improved overall efficiency, while there is a moderate increase in G CAPEX due to some replacement of OCGT with CCGT to improve the overall carbon performance. Note that a like-for-like replacement of 1 MWh of output of nuclear with CCS would on its own result in increased emissions due to less than 100% carbon capture rate of CCS. For the same reason in Method 1 the replacement of nuclear with CCS triggers a further reinforcement of North-South transmission corridors in order to reduce wind curtailment in the North and thus improve system carbon emissions (as no addition of low carbon capacity was allowed). In Method 3, however, the retirement of nuclear capacity following the addition of 1 GW of CCS is optimised, which results in only 0.9 GW of nuclear being removed from the system while maintaining the same emissions at the lowest cost. The remaining CCS output replaces CCGT generation, with further positive impact on carbon emissions, resulting in lower requirements to reinforce transmission grid in order to transport wind output from the North.

6.4. 50 g/kWh scenario in 2030, solar PV-dominated

Finally, in the 50 g/kWh scenario with the PV capacity increased from 20 GW to 50 GW (Figure 6.3) we observe that the integration cost of PV becomes significantly higher (i.e. £26-£28/MWh), than in the previous two scenarios (e.g. £6-9MWh in the 100 g/kWh scenario). In this scenario there is again measurable curtailment of additional wind and PV output resulting from capacity additions when performing integration studies, requiring additional CCS capacity and driving the additional G CAPEX and OPEX components of wind and PV integration cost.

Unlike in the previous scenarios, the integration cost of PV now features a substantial distribution investment (D CAPEX) component, driven by reinforcements triggered by increased reverse power flows in distribution grid. A similar discussion as for wind and transmission could be applied to PV with D CAPEX, as in some cases PV may already include the required D CAPEX cost.

Similar to the wind-dominated 50 g/kWh scenario, the G CAPEX component of integration cost of wind and PV in Methods 1 and 3 is associated with adding CCS capacity when wind or PV replaces nuclear, in order to maintain the same carbon emissions. Conventional gas capacity (CCGT and OCGT) is added to ensure system adequacy because of low capacity credit of wind and PV.

---

68 Adding wind in the North of GB would potentially require the reinforcement of north-south transmission corridors, adding to the integration cost of wind. See Section 6.5.5 for more details on the impact of wind location.

69 Methods where more than energy-equivalent PV capacity is added, such as Method 2 with incremental PV capacity change, result in slightly more visible D CAPEX component of the integration cost of PV. This is in line with the increased reverse power flows driven by additional PV installations, which may trigger network reinforcement in some distribution networks.

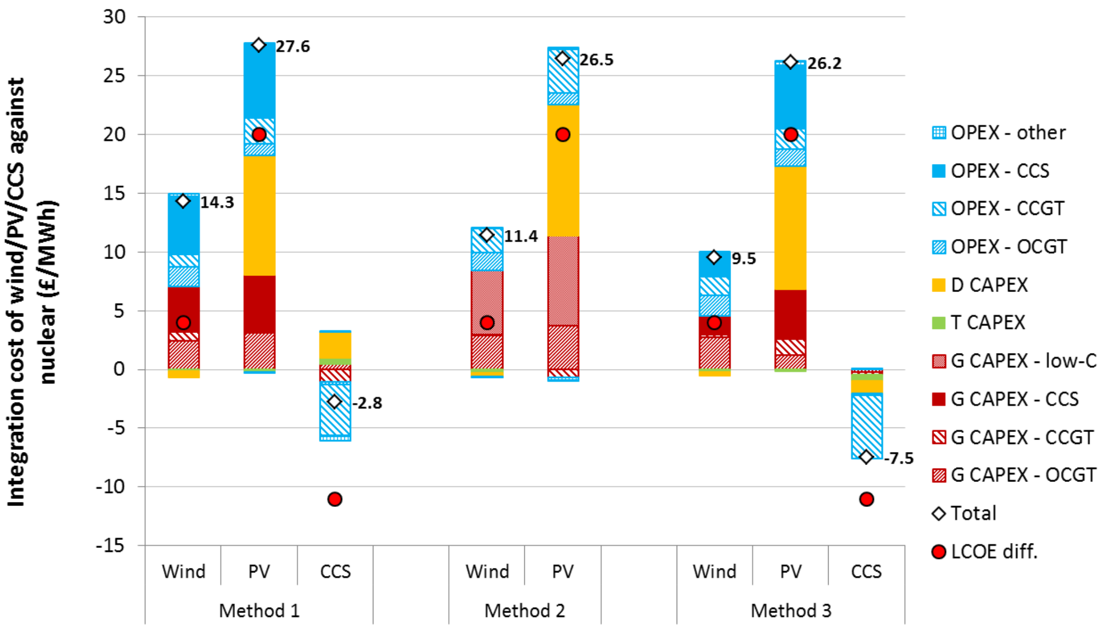


Figure 6.3. Relative integration cost of low-carbon technologies compared to nuclear in 50 g/kWh core scenario with increased PV capacity

In Method 2, the CCS component of G CAPEX is replaced with the cost of additional wind or PV capacity beyond the energy-equivalent amount. The increased OPEX when wind and PV replace nuclear mainly results from higher CCS output (Methods 1 and 3) or reduced efficiency of conventional gas generation output (Method 2) driven by increased requirements for balancing services.

The composition of the integration cost of CCS is again slightly different depending on the calculation method used, in particular with respect to the D CAPEX component. Because of small but still present emissions from CCS plant, replacing the same volume of nuclear generation would increase system emissions, so to compensate for that the model invests more in distribution network reinforcement in order to reduce PV curtailment and thus help to achieve the target emission intensity by maximising the utilisation of solar PV. In Method 3 on the other hand, the optimised retirement of nuclear results in only 0.92 GW of its capacity being removed while maintaining the same emissions. The residual CCS output then replaces CCGT generation, further reducing carbon emissions, which allows the system to invest slightly less in reinforcing the distribution grid in order to absorb PV output.

6.5. Sensitivities on core scenarios

In addition to the core 50 g/kWh and 100 g/kWh scenarios with medium level of flexibility deployed, we ran a number of further sensitivity studies to estimate the impact of modified system assumptions on system integration costs.

6.5.1. Improved wind forecasting and contribution to system inertia and frequency regulation

Given the criticality of renewable output intermittency as a driver for reserve and response requirements, in Figure 6.4 we quantify the impact of *improved wind forecast accuracy* as well as of *wind contributing to system inertia* and active provision of *frequency regulation* on wind integration cost. The assumptions for the modified assumptions on wind capabilities are as follows:

- *Improved wind forecast accuracy*: prediction error of wind output in the horizon of several hours reduces by 50%, leading to reduced reserve requirements driven by wind uncertainty.

- *Contribution to system inertia*: wind generators provide synthetic inertia at the level similar to conventional generation.[70]

- *Active provision of primary frequency regulation*: wind generators are able to provide direct frequency response at the level of up to 2% of their absorbed output.[71]

The results in Figure 6.4 are compared to the 50 g/kWh core scenario runs with low, medium (default) and high flexibility.[72]

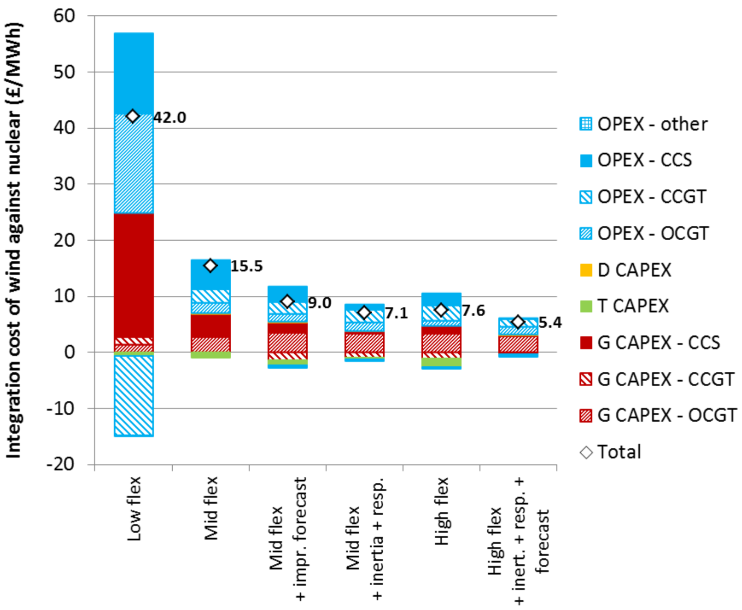


Figure 6.4. Relative integration cost of wind (Method 1, incremental) compared to nuclear in wind-dominated 50 g/kWh scenario for various levels of system flexibility and contributions of wind to system balancing

---

[70] This assumption is arguably on the conservative side as relevant research literature shows that wind turbines could extract even more kinetic energy to provide inertia than synchronous generators. See e.g. F. M. Hughes, O. Anaya-Lara, N. Jenkins, and G. Strbac, "Control of DFIG-Based Wind Generation for Power Network Support", *IEEE Transactions on Power Systems*, vol. 20, pp. 1958-1966, Nov. 2005.

[71] This is consistent with current Grid Code requirements towards conventional generators that may in the future also apply to wind generation.

[72] Note that the results presented in Figure 6.4 are obtained only from incremental Method 1 studies, therefore the integration cost in the medium flexibility case (£15.5/MWh) is slightly different from the value in Figure 6.2 (£14.2/MWh) that has been obtained by averaging the results of incremental and decremental Method 1 studies.

System flexibility has a substantial effect on the integration cost of wind: reducing it from default (medium) to low level (no new storage or DSR) almost triples the integration cost from £15.5 to £42/MWh, while increasing the flexibility to a high level effectively halves the integration cost, reducing it from £15.5 to £7.6/MWh.

The integration cost of wind in the medium flexible case drops by £6.5/MWh if the accuracy of wind forecasting improves, to the level of £9/MWh. If wind generators are capable of providing synthetic inertia and primary frequency regulation to the system, the integration cost is found to drop to £7.1/MWh in the medium flexible case. If the effects of improved wind forecasting and the provision of inertia and response are combined in the high-flexibility case, the observed effect is the reduction of integration cost from £7.6/MWh to £5.4/MWh.

6.5.2. Impact of seasonal storage

We further investigate the impact of *seasonal storage* on the baseline cost and wind and PV integration cost in the solar-dominated 50 g/kWh scenario. Power rating of the seasonal storage is chosen as either 25% or 75% of peak national PV output, while the energy rating is chosen to match either 25% or 75% of summer PV output (resulting in four combinations of power and energy ratings, as summarised in Table 6.1). In order to test the value of longer-term as opposed to short-term storage, the benefits of seasonal storage are also compared with the benefits from installing energy storage with the same power but with only 10-hour duration (Figure 6.5).

Table 6.1. Parameters of seasonal storage

Seasonal storage scenario	Installed capacity (GW)	Duration (hours)	Energy (TWh)
P25%, E25%	9.2	1,010	9.3
P25%, E75%	9.2	3,030	27.8
P75%, E25%	27.5	337	9.3
P75%, E75%	27.5	1,010	27.8

As expected, the value of storage is several times higher in the low-flexible scenario, resulting from high savings from displaced CCS capacity and output that would otherwise be needed to meet the target carbon intensity. The results further suggest that the value of increasing the energy capacity of storage from 25% to 75% of summer PV output yields no improvement in total system cost, as the energy size of storage far exceeds the maximum difference in state of charge (SoC) between summer and winter (see Figure 6.6).

Finally, the results suggest very limited additional benefits of replacing short-term (10-hour) storage with seasonal storage of same power. In both low and medium flexible scenarios the added benefit of longer-term storage varies between about £160m and £200m per annum.

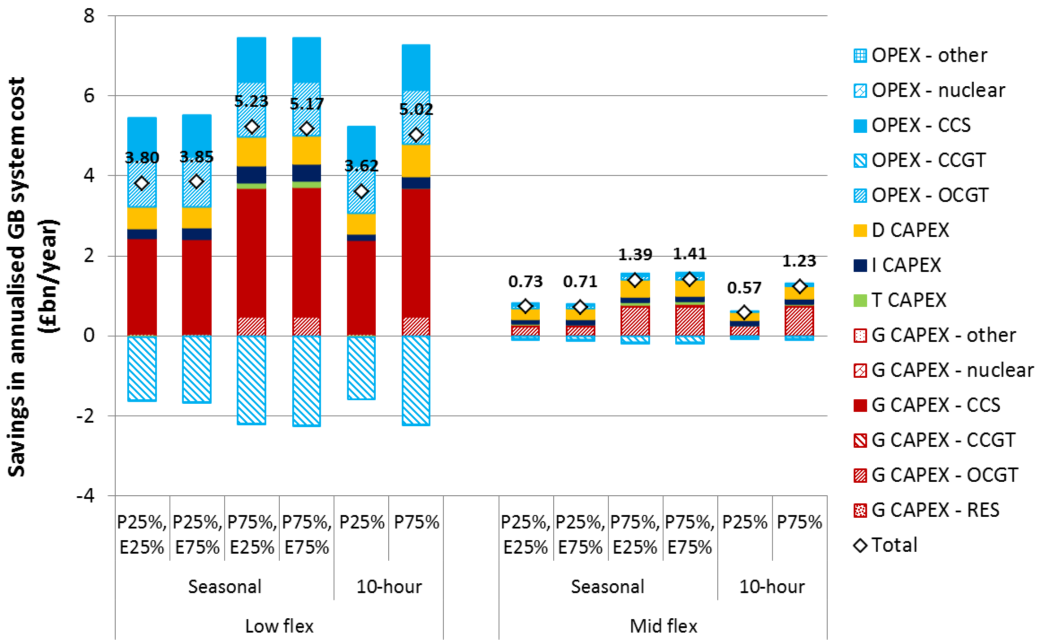


Figure 6.5. Annual system savings with seasonal storage in solar-dominated 50 g/kWh scenario

Figure 6.6 (left) reveals that the annual fluctuations in storage SoC are relatively smooth (note that charging and discharging of storage is assumed to occur at 75% cycle efficiency), and tend to be more volatile with higher power rating of seasonal storage. Increase from 25% to 75% of energy capacity introduces no change in the annual operating pattern, making the added energy capacity effectively redundant. The right-hand side of Figure 6.6 further shows that the operation of seasonal storage tends to be more volatile in a lower-flexible system as short-term balancing becomes superimposed onto seasonal energy management. In both cases the seasonal variations of demand and PV generation dictate that storage is predominantly charged between the end of March and end of October, after which it starts gradually discharging over the winter period.

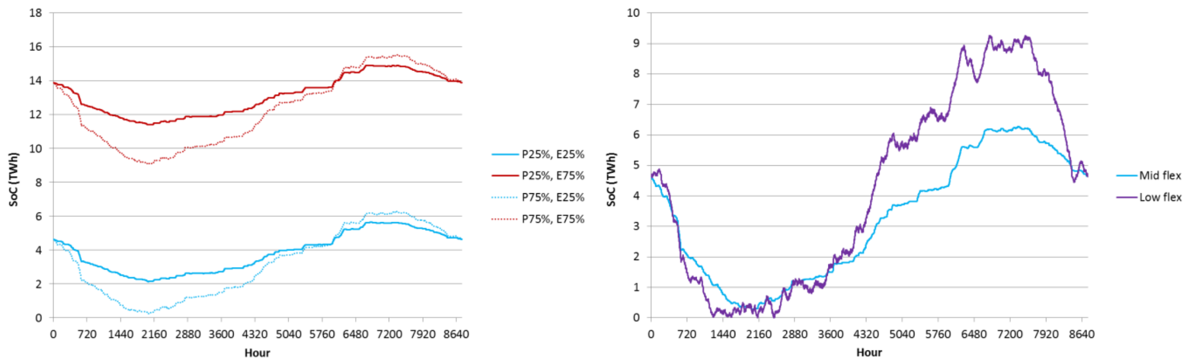


Figure 6.6. Annual variation in SoC of seasonal storage for different ratings in medium flexible solar-dominated 50 g/kWh scenario (left) and comparison between annual SoC variations in medium and low-flexible cases for P75%, E25% (right)

In light of the above, system integration studies for wind and PV have been carried out for lower (25%) and higher (75%) installed power of seasonal storage, but only with the lower energy rating (25%). The results are presented in Figure 6.7 for the medium-flexible PV-dominated 50 g/kWh scenario, comparing the results for incremental Method 1 studies before and after adding seasonal storage. The results suggest that seasonal storage reduces the integration cost of both wind and PV; the reduction with 9.2 GW of seasonal storage is £3.2/MWh for wind and £2/MWh for PV, while the respective cost reductions with 27.5 GW of seasonal storage amount to £8.2/MWh and £5.6/MWh.

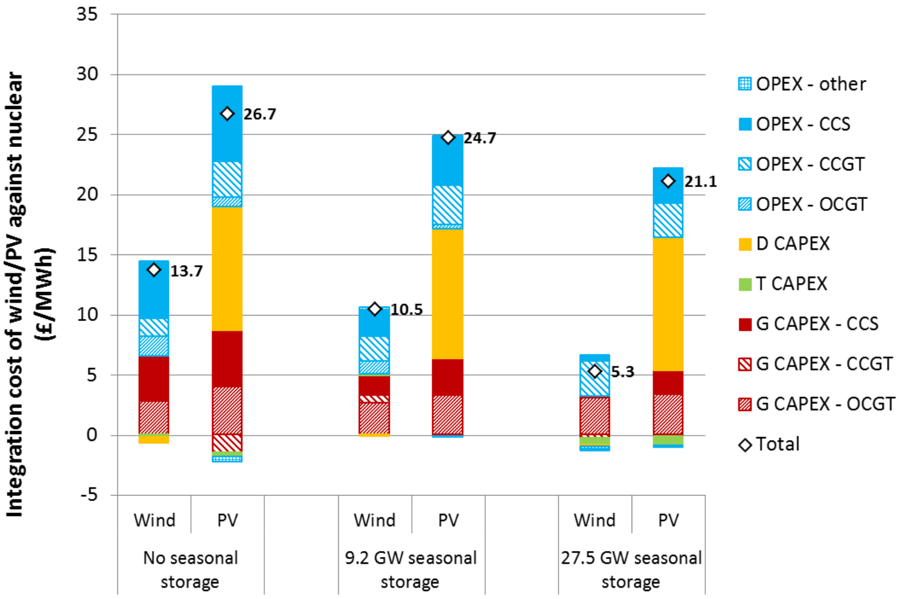


Figure 6.7. Relative integration cost of wind and PV (Method 1, incremental) compared to nuclear in solar-dominated 50 g/kWh scenario with seasonal storage in 2030

6.5.3. Impact of largest generator size

The cost of balancing the system is to a large extent driven by the intermittency of renewable generation that requires additional volumes of reserve and response to be procured in the system. However, these requirements are also driven by the *size of the largest foreseeable generator loss*. The largest units in the system are typically nuclear generators; in the current system the largest unit is 1.2 GW (Sizewell B nuclear station), but this is expected to further increase to 1.8 GW with the construction of next-generation nuclear reactors. To test the proportion of renewable integration cost that could be attributable to the nuclear-driven ancillary services requirements, we ran a sensitivity study for the wind-dominated 50 g/kWh scenario where the largest generating unit was assumed to have only 500 MW. The results are presented in Figure 6.8 for both low and medium flexibility levels (note that the results presented here only refer to Method 1 with incremental changes in wind capacity).

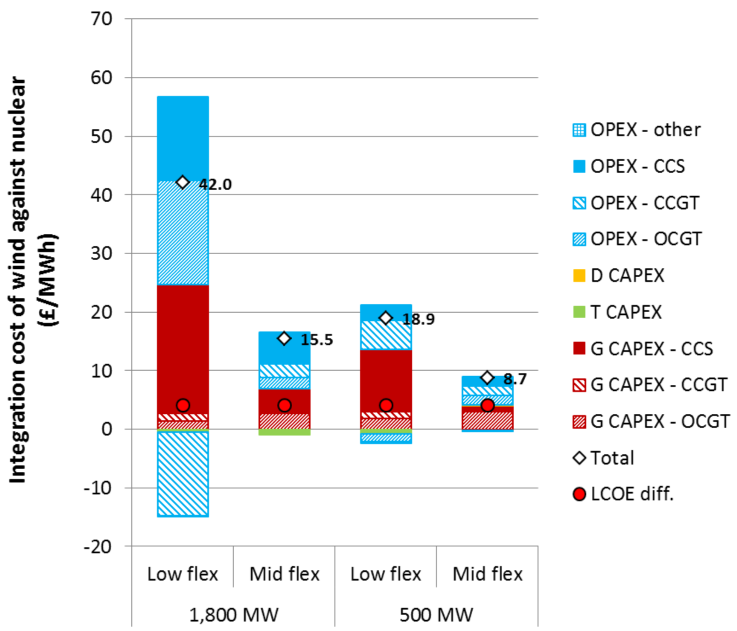


Figure 6.8. Impact of largest generator size on wind integration cost in wind-dominated 50 g/kWh scenario in 2030 (Method 1, incremental)

Reducing the size of the largest generator significantly reduces the integration cost of wind, as smaller generator sizes reduce both primary and secondary response requirements that can act as a barrier to efficient integration of renewable generation. In the low-flexible wind-dominated 50 g/kWh system the integration cost reduces from £42/MWh to £18.9/MWh, while in the medium flexible case the integration cost almost halves, dropping from £15.5/MWh to £8.7/MWh.

6.5.4. Impact of variations in system flexibility

The set of studies presented in this section focuses on the impact of flexibility on the integration cost of wind and PV in the three core scenarios. As before, the medium flexibility level (mid flex) corresponds to the central set of assumptions elaborated in Section 3.1. Low flexibility assumes a system without any additional storage or DSR and with no contribution of wind to reserve, while high flexibility case assumes 100% deployment level of DSR, 10 GW of additional storage and wind being able to contribute to both response and reserve when curtailed.

As depicted in Figure 6.9, the enhancement of system flexibility has a profound positive impact on system integration cost of wind and PV, and that impact is more pronounced in the two 50 g/kWh scenarios than in the 100 g/kWh scenario.[73] Taking wind generation as an example, the integration cost in the 100 g/kWh scenario drops from £17.9/MWh in the low-flex system to £10.2/MWh and £5.3/MWh in mid- and high flex cases, respectively. In the two 50 g/kWh scenarios on the other hand, flexibility improvements reduce the integration

[73] As in the previous sensitivity studies presented in this section, the studies presented in Figure 6.9 are based on the results of incremental Method 1 calculations. Therefore there are slight discrepancies between these figures and the averaged results of Method 1 presented in Sections 6.2 to 6.4.

cost of wind from £40.4-42/MWh in the low-flex system to £13.7-15.5/MWh in the medium flexible case and to £7.6-8.7/MWh in the high flexible case..

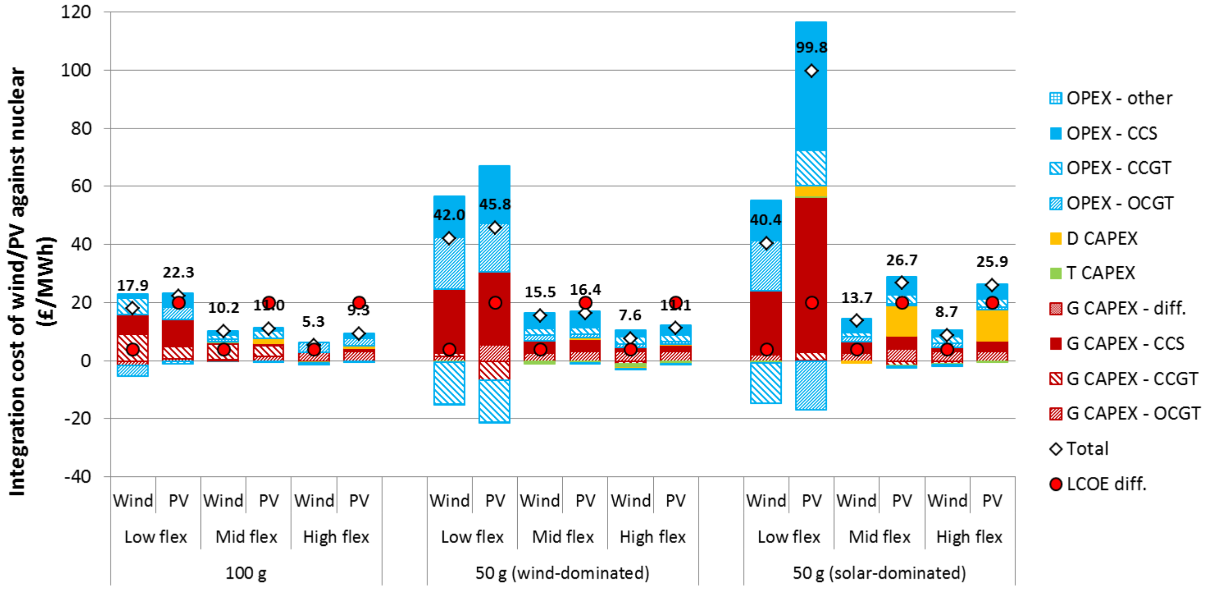


Figure 6.9. Impact of system flexibility on integration cost of wind and PV in three core scenarios in 2030 (based on Method 1, incremental)

6.5.5. Impact of wind location

In main core scenario studies all additional wind capacity in system integration studies is assumed to be connected in the South of the UK. An additional set of sensitivity studies was run to investigate the impact of location of new wind capacity, i.e. to quantify how the location of new wind generation may impact its integration cost. Figure 6.10 presents the results of the integration cost studies for wind in the North, compared to those for wind connected in the South in the wind-dominated 50 g/kWh scenario (only incremental Method 1 studies are presented).

An immediate observation is that the integration cost of wind increases several times if its location is moved to the North. In the medium flexible version of the wind-dominated 50 g/kWh scenario this increase is from £15.5/MWh to £47.8/MWh, while in the high-flexible variant this increase is from £7.6/MWh to £31.4/MWh. A major part of this increase is represented by the T CAPEX component at the level of £12-14/MWh, reflecting the additional transmission investment required to transport wind output from the North towards the South (where the majority of demand is located).

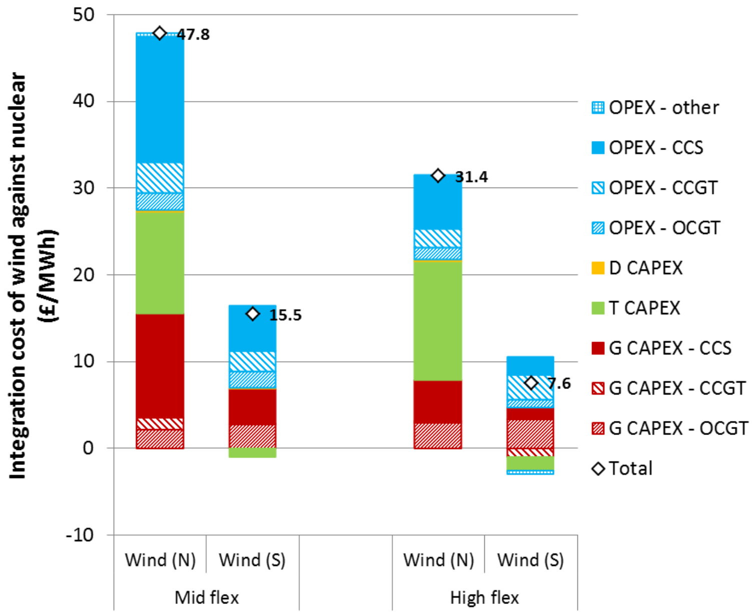


Figure 6.10. Impact of wind location on integration cost in wind-dominated 50 g/kWh scenario in 2030 (based on Method 1, incremental)

Nevertheless, T CAPEX represents only a part of the difference between externalities of wind in the North and South. Given the limited North-South transmission capacity, a part of the additional wind output in the North is curtailed as the model finds an optimal trade-off between investing more in transmission to absorb wind output and investing into CCS in the South to meet the carbon target. When wind generation is added in the North, about 13% i.e. 6% of the additionally available output is curtailed in medium and high-flexible cases, respectively. The model compensates for this curtailment by adding more CCS capacity in the South in order to meet the emission target. The cost of building and operating this added CCS capacity is reflected in the integration cost of wind in the North as additional G CAPEX and OPEX associated with CCS. In summary, the model adapts to the addition of wind capacity in the North by adding more transmission to absorb the majority but not all of wind output, as it is more cost-effective to curtail some wind generation and provide the remaining low-carbon output by adding CCS in the South.

6.5.6. 100 g/kWh scenario with no new nuclear capacity

In a further set of sensitivity studies, the integration cost of low-carbon technologies was calculated for a modified 100 g/kWh core scenario in which no nuclear development materialises in the future, so that the only nuclear capacity present in 2030 is the 1.2 GW of Sizewell B. In order to reach the carbon emission target in this scenario that has 8.4 GW less of nuclear capacity, the model was allowed to add gas CCS, which resulted in about 9 GW more of gas-fired CCS in the base case for this scenario. The results of system integration studies across all three calculation methods are presented in Figure 6.11.

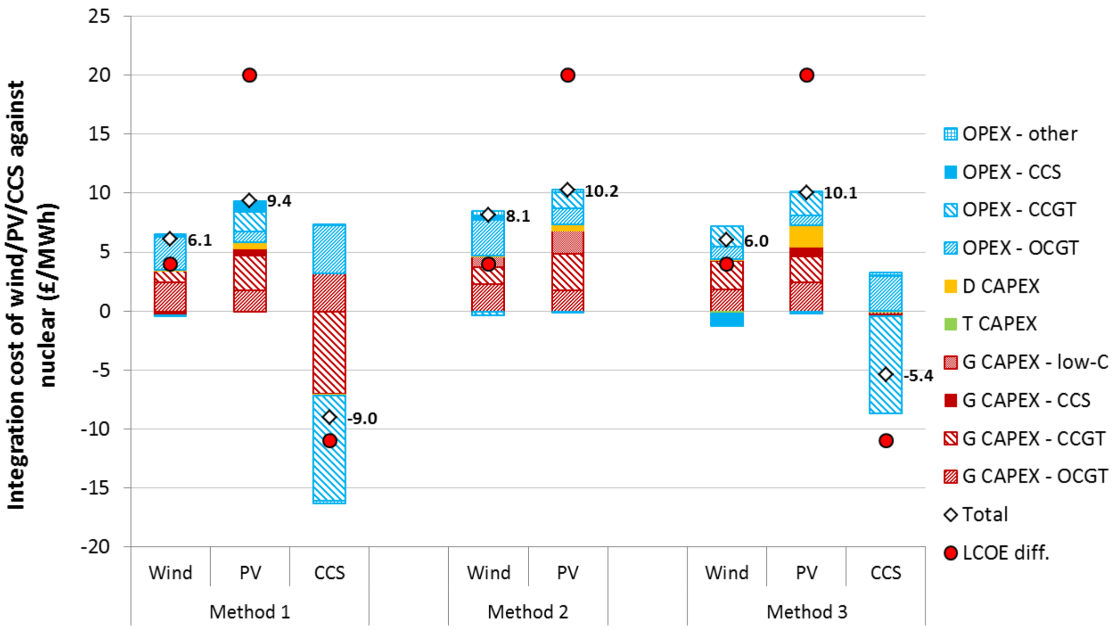


Figure 6.11. Relative integration cost of low-carbon technologies compared to nuclear in 100 g/kWh scenario with no new nuclear capacity in 2030

The values of system integration costs in this case are rather similar as in the core 100 g/kWh scenario, i.e. about £6.0-8.1/MWh for wind, £9.4-10.1/MWh for PV and £(9.0)-(5.4)/MWh for CCS. These studies show that the reduction of nuclear capacity in the 100 g/kWh scenario has a relatively minor impact on the integration cost of wind and PV. As shown in Section 6.5.3, it appears that the size of the largest nuclear generator is more critical than the total volume of nuclear capacity (as long as it is moderate) in terms of the impact on system integration cost.

6.5.7. Partially optimised 50 g/kWh and 100 g/kWh scenarios

This set of sensitivity studies is based on the partially optimised 50 g/kWh and 100 g/kWh scenarios described in Section 4.3. Figure 6.12 shows the integration costs for these two scenarios (medium flexible cases), based on incremental studies in Method 1 only. As expected, the integration cost values in these studies are much closer to the LCOE differentials than in the core scenarios, given that these scenarios have been optimised and are therefore much closer to a full optimum than the core scenarios.

Discrepancies between the integration cost values and the assumed LCOE differentials can be explained by the fact that some CCS capacity has been forced onto the system that might not have been selected in a fully optimised system. Also, the calculation methods applied include discrete (in GW scale) additions of capacity rather than infinitesimal amounts that are relevant within the actual optimisation model.

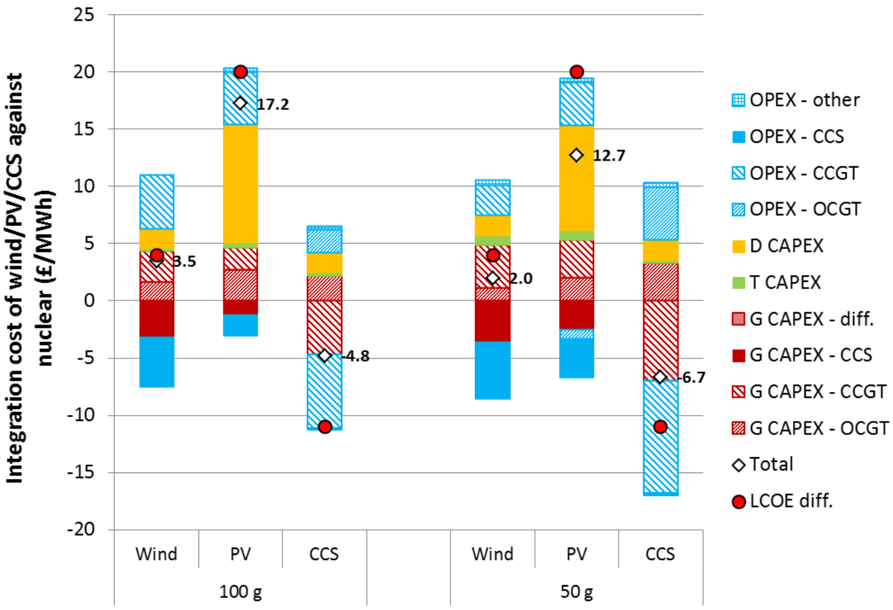


Figure 6.12. Relative integration cost of low-carbon technologies compared to nuclear in partially optimised 50 g/kWh and 100 g/kWh scenario in 2030 (Method 1, incremental)

6.5.8. 200 g/kWh scenario (2030)

In order to estimate the integration cost of wind and PV in a less decarbonised system, another set of sensitivity studies presented in Figure 6.13 quantified the integration cost for the 200 g/kWh scenario described in Section 3.4.1 (the results are again presented only for the incremental Method 1 calculations).

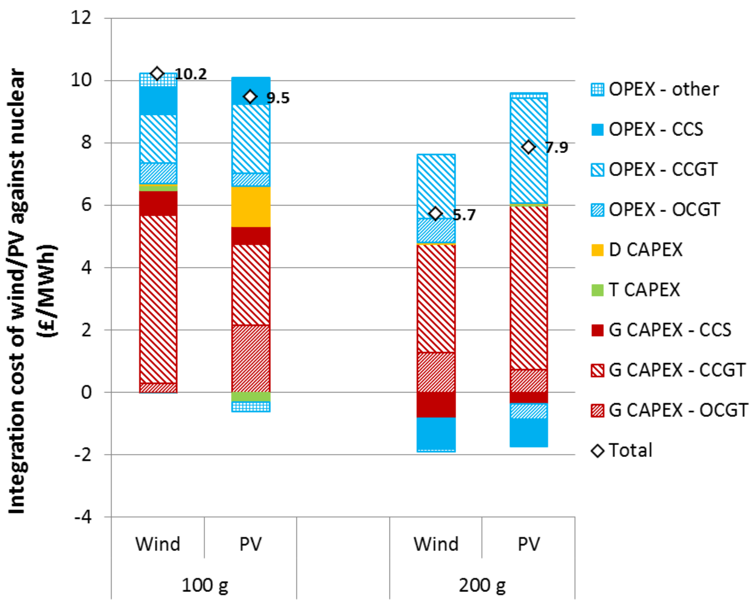


Figure 6.13. Relative integration cost of low-carbon technologies compared to nuclear in 100 g/kWh and 200 g/kWh scenarios in 2030 (Method 1, incremental)

As expected, the integration cost of wind and PV in the 200 g/kWh scenario decreases compared to the 100 g/kWh system: from £10.2/MWh to £5.7/MWh for wind and from £9.5/MWh to £7.9/MWh for PV. The reduction is relatively modest, given that the integration cost in the 100 g/kWh scenario was already at a rather low level. It is also interesting to note that because of the 50% lower PV capacity in the 200 g/kWh scenario, the D CAPEX component vanishes from the integration cost of PV.

6.5.9. 10 g/kWh scenario (2050)

Finally, we investigate a scenario in which the British power sector achieves an emission intensity of 10 g/kWh by 2050 (see Section 3.4.2). This scenario is characterised by very high nuclear (21 GW), wind (90 GW) and PV capacity (100 GW). We let the model add CCS and conventional capacity if needed to ensure security of supply and meet the emissions intensity target at minimum cost. We also assume in this scenario that 10 GW of additional storage is available in the system (as opposed to 5 GW as the central assumption in 2030 core scenarios).

The integration cost of wind and PV has been found to be significantly higher than in the wind-dominated 50 g/kWh core scenario, as illustrated in Figure 6.14. While the wind-dominated 50 g/kWh scenario had the relative integration cost of wind vs. nuclear of £12.5-15.6/MWh, in the 10 g/kWh scenario this cost increases to £16.3-24.7/MWh across the three calculation methods. The respective values for the PV integration costs increase from £12.1-17.1/MWh in the 50 g/kWh scenario (wind-dominated) to £21.1-23.5/MWh (with the exception of Method 3[74]). Similar to the PV-dominated 50 g/kWh scenario, the integration cost of PV features a significant D CAPEX component at the level of £10-11/MWh, resulting from additional PV triggering reinforcement of distribution network due to reverse power flows.

More detailed results for the 10 g/kWh scenario, such as changes in generation capacity and output across technologies, can be found in Appendix B, Section B.2.4.

This scenario suggests even more intermittent generation can be accommodated in the long-term with relatively moderate level of renewable output curtailment (5-6%); however, this would require significant increases in system flexibility such as significant deployment of new storage capacity, a very advanced utilisation of DSR potential and also a significant expansion of interconnection capacity with continental Europe.

[74] The results of Method 3 require a more careful interpretation here. Although the addition of 1 GW of nuclear retires more CCS capacity from the system than the addition of 9 GW of PV in Method 3 studies, the absorbed energy of PV in the second case is only about 80% of the available energy. Therefore, when CCS-related G CAPEX and OPEX savings are divided with the absorbed nuclear or PV output, the PV actually seems to remove more CCS generation per MWh of absorbed output than nuclear, resulting in negative CCS G CAPEX and OPEX components in the integration cost of PV in Method 3.

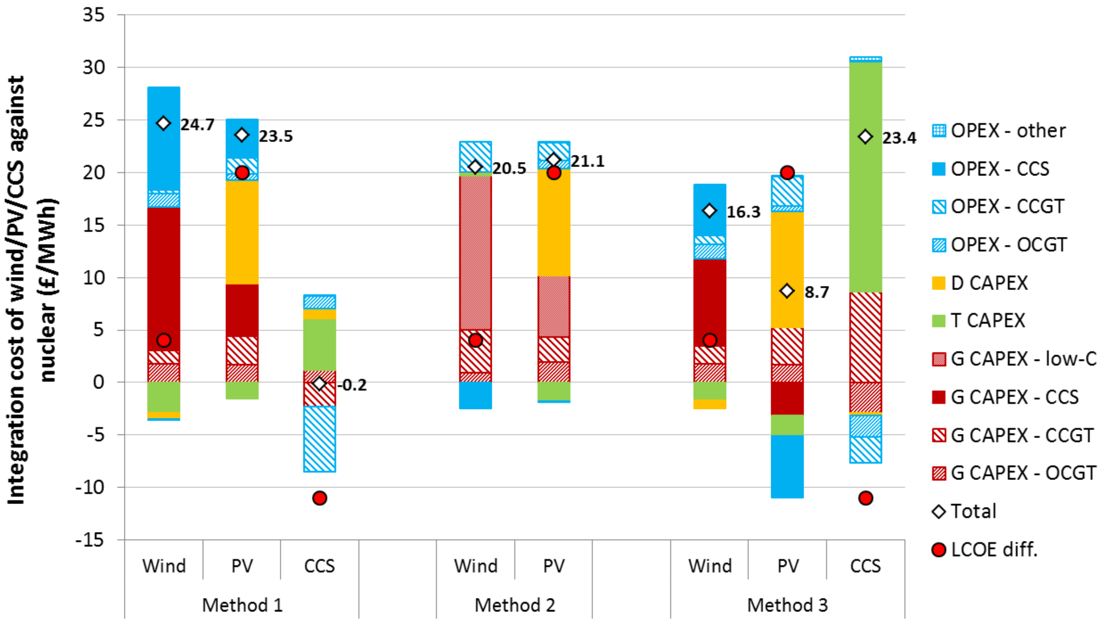


Figure 6.14. Relative integration cost of low-carbon technologies compared to nuclear in 10 g/kWh scenario in 2050

6.6. Comparison with dual value results from WeSIM

Similar to other linear programming (LP) problems, the solutions of the WeSIM model also include *dual values*[75] of all constraints in the model. In a suitably formulated model, these dual values can be used to extract the information on the marginal system benefit of any technology by looking at the duals of constraints defining the upper bound on the installed capacity of the technology. For instance, by observing the dual value of the constraint limiting the installed capacity of wind generation, it is possible to extract either marginal net system benefit (if the actual cost of wind is considered in the model) or marginal gross benefit (if the cost of wind is set to zero). Marginal gross benefit is conceptually very similar to the marginal system benefit quantified using fixed capacity additions in Method 3, and allows for the calculation of relative integration cost of wind against nuclear by finding the difference in their respective marginal system benefits.

Although theoretically elegant, the disadvantage of this approach of calculating integration cost is that it only provides a single figure for the marginal system benefit or system integration cost and therefore cannot be used to disaggregate the integration cost into individual CAPEX and OPEX components (as elaborated earlier in this chapter) in order to obtain a detailed insight into the key drivers behind the integration cost of different technologies.

[75] In constrained optimisation problems, the *dual value* of a constraint, also referred to as the *shadow price* or *Lagrangian multiplier*, is the change in the objective value of the optimal solution of an optimisation problem obtained by relaxing the constraint by one unit. In other words, it is the marginal utility of relaxing the constraint, or, equivalently, the marginal cost of strengthening the constraint.

Nevertheless, for the sake of validation of the results obtained using Methods 1 to 3 we compare these results with dual values extracted from the wind-dominated 50 g/kWh core scenario. The comparison of results is provided in Table 6.2.

Table 6.2. Comparison of system integration cost against nuclear (in £/MWh) between the results of Methods 1 to 3 and those obtained though dual values

Method	Wind	Solar PV
Method 1	14.2	13.6
Method 2	12.5	17.1
Method 3	15.6	12.1
Dual values	12.1	15.8

The results obtained through dual values correspond reasonably well with the results from Methods 1 to 3, confirming that the three methods provide good estimates of the system integration cost of low-carbon technologies.

6.7. Summary of key findings

Key findings from system externality studies are:

- The three methods applied to establishing system integration cost provide reasonably similar results. Slight variations between methods can be attributed to different approaches to re-adapting the system after adding capacity of a given low-carbon technology.

- Grid integration costs of low-carbon technologies are a function of different factors such as seasonal variability in available output, location, level of intermittency i.e. unpredictability etc.

- In the core CCC scenarios analysed, the integration costs of wind and solar are relatively marginal in a power sector reaching 100 g/kWh (ranging from £6-9/MWh), but these costs become more material when moving to a system achieving 50 g/kWh with high penetration of wind or solar (e.g. ~50 GW), with costs up to £16/MWh for wind and £28/MWh for solar (see Table 6.3). This suggests that there may be limits or thresholds regarding the capacities of different low carbon technologies the grid can integrate cost-effectively, although these limits will be a function of system flexibility. The integration cost of wind and PV in a less decarbonised scenario at around 200 g/kWh, would further reduce compared to the 100 g/kWh scenario, to the level of around £6-8/MWh.

Table 6.3. Summary of relative integration cost of wind, PV and CCS relative to nuclear (in £/MWh) across different scenarios in 2030

Scenario	Wind	Solar PV	CCS
100 g/kWh	6.2-7.6	6.1-9.2	(6.4)-(0.5)
50 g/kWh (wind-dominated)	12.5-15.6	12.1-17.1	(7.9)-4.6
50 g/kWh (solar-dominated)	9.5-14.3	26.2-27.6	(7.5)-(2.8)

Notes: ranges reflect various methods adopted; brackets indicate negative value.

- We observe that the integration cost of CCS can be both positive and negative (ranging between about -£8/MWh to £5/MWh) when compared to nuclear, depending on the calculation method employed. This is due to the greater controllability of CCS plant as well as the fact that connecting additional CCS capacity does not increase the requirements for ancillary services in the system.

- Flexibility can therefore significantly reduce the integration cost of intermittent renewables, to the point where their whole-system cost makes them a more attractive expansion option than CCS and/or nuclear.

- Additional studies for the 10 g/kWh scenario for 2050 demonstrate a major increase in the integration cost of wind and PV in the highly decarbonised system, but also suggest that very significant volumes of intermittent generation can be accommodated in the long term with relatively moderate level of renewable output curtailment (5-6%), provided that there is a large-scale deployment of flexible options in the system.

- Additional sensitivity studies further show that increasing flexibility in the system reduces the integration cost of intermittent renewables. Similarly, the integration cost of wind would reduce significantly if the wind forecasting accuracy improved, and/or if wind was able to contribute to system inertia and frequency response. The integration cost is slightly lower in a version of future development scenario that does not assume any construction of new nuclear capacity beyond the current level. Finally, visible reductions in integration costs of wind and PV are observed when the size of the largest generator loss drops to 500 MW as well as following the deployment of seasonal storage in the system.

7. Conclusions

This report has presented a framework to assess system integration cost of low-carbon generation technologies for different future development scenarios. The results show that different methods for establishing system integration cost adopted in the report provide reasonably similar results.

In wind-dominated 50 g/kWh and 100 g/kWh core scenarios wind and PV have been found to have a similar level of integration cost (around £12-17/MWh in the former and £6-9/MWh in the latter). On the other hand, in a system with higher PV capacity, the distribution network investment component may become dominant, driven by the need to reinforce the network to handle reverse power flows triggered by PV. In that scenario the integration cost of PV increases to £26-28/MWh. A summary of ranges of integration cost for wind, PV and CCS against nuclear across different methods is provided in Table 7.1.

Table 7.1. Summary of relative integration cost of wind, PV and CCS relative to nuclear (in £/MWh) across different scenarios

Scenario	Wind	Solar PV	CCS
100 g/kWh	6.2-7.6	6.1-9.2	(6.4)-(0.5)
50 g/kWh (wind-dominated)	12.5-15.6	12.1-17.1	(7.9)-4.6
50 g/kWh (solar-dominated)	9.5-14.3	26.2-27.6	(7.5)-(2.8)

Notes: ranges reflect various methods adopted; brackets indicate negative values.

Both wind and PV have positive integration costs against nuclear generation in all core scenarios. The magnitude of the integration cost of RES generation is a function of the system scenario considered, in particular the assumed generation mix and the level of flexibility. Table 7.2 provides a summary of how the integration costs of wind and PV and their LCOEs combine to produce a full system cost advantage (or disadvantage if negative) over nuclear, providing an indication as to whether adding a marginal amount of wind or PV output is more or less beneficial for the system as a whole than adding nuclear generation.

Table 7.2. Full system cost advantage of renewable technologies against nuclear in 100 g/kWh and 50 g/kWh scenario (wind-dominated) with varying degrees of system flexibility[76]

		Full system cost advantage over nuclear (£/MWh)					
		100 g/kWh			50 g/kWh		
Technology	LCOE cost advantage over nuclear (£/MWh)	Low Flex	Medium Flex	High Flex	Low Flex	Medium Flex	High Flex
Wind	4	-13.9	-6.2	-1.3	-38.0	-11.5	-3.6
PV	20	-2.3	9.0	10.7	-25.8	3.6	8.9

[76] The results in this table are based on Method 1, incremental calculations, and correspond to the results presented in Figure 6.9.

Results of case studies with optimised generation mixes have clearly shown that flexibility in the form of DSR, energy storage or flexible generation technologies, should be considered as a critical factor for designing cost-efficient decarbonised electricity systems in the future.

Key overall observations from the study are:

- It is possible to manage a future GB power system that is deeply decarbonised with high levels of intermittent renewables (i.e. up to around 50 GW of wind or solar).

- Achieving deep decarbonisation at reasonable cost relies on a significant increase in system-wide flexibility from current levels alongside the expansion of low-carbon capacity.

- Increasing flexibility is a low-regret option, reducing the overall cost even in a system that is less decarbonised (e.g. reaching 200 g/kWh in 2030), while maintaining security of supply requirements. For example, our analysis shows that gross benefits of flexibility (primarily associated with the deployment of energy storage and DSR) for reaching the 50 g/kWh intensity are between £7.1-8.1bn per annum, while the corresponding benefits for the 100 g/kWh target amount to £3-3.8bn annually (savings in the system with 200 g/kWh would also be significant at around £2.9bn per annum). These flexibility options exist today or are likely to be available by 2030, but may not be sufficiently incentivised by the current market arrangements.

- Grid integration costs of low-carbon technologies are a function of different factors such as seasonal variability in available output, location, level of intermittency i.e. unpredictability etc.

- Flexibility can significantly reduce the integration cost of intermittent renewables, to the point where their whole-system cost makes them a more attractive expansion option than CCS and/or nuclear.

- In the core CCC scenarios analysed, the integration costs of wind and solar are relatively marginal in a power sector reaching 100 g/kWh (ranging from £6-9/MWh), but these costs become more material when moving to a system achieving 50 g/kWh with high penetration of wind or solar (e.g. ~50 GW), with costs up to £16/MWh for wind and £28/MWh for solar (see Table E.1). This suggests that there may be limits or thresholds regarding the capacities of different low carbon technologies the grid can integrate cost-effectively, although these limits will be a function of system flexibility. The integration cost of wind and PV in a less decarbonised scenario at around 200 g/kWh, would further reduce compared to the 100 g/kWh scenario, to the level of around £6-8/MWh.

- We observe that the integration cost of CCS can be both positive and negative (ranging between about -£8/MWh to £5/MWh) when compared to nuclear, depending on the calculation method employed. This is due to the greater controllability of CCS plant as well as the fact that connecting additional CCS capacity does not increase the requirements for ancillary services in the system.

- The integration costs of wind and solar are relatively small in a power sector reaching 100 g/kWh by 2030, but these costs become material when moving to a system achieving 50 g/kWh in 2030 with high penetration of wind or solar (e.g. ~50 GW). This suggests that there may be limits or thresholds to how much of certain technologies the grid can integrate cost-effectively, although these limits will be a function of system flexibility.

- Provided that sufficient flexibility and reserve/response is available, the system can cope at times of stress (e.g. lots of wind, very low wind over several days, unexpected nuclear outages, low fuel prices, high demand) and achieve the carbon target.

Whether the established levels of system integration cost of low-carbon technologies will be borne by investors in those technologies will depend on the prevailing market design. If the market was fully cost-reflective, all generation technologies would be exposed to additional costs (externalities) they impose on the system. For instance, a wind farm owner that is exposed to increased imbalance charges, and/or higher transmission charges would need to incorporate these costs in their bid into the CfD mechanism to include not only its LCOE, but also the additional cost components imposed on the system. Given that the market design in GB is still evolving and is not yet necessarily fully cost-reflective in all aspects of system cost, it is important to understand the additional system cost driven by low-carbon technologies.

Furthermore, the analysis carried out clearly demonstrates that increasing system flexibility, through enhancing dynamic performance of generating plant (both conventional and low-carbon), and the application of energy storage, demand side response and interconnection, can significantly reduce system integration costs of low-carbon technologies. In this context, development of efficient market mechanism that would appropriately reward flexibility would be important for facilitating a cost-effective decarbonisation of the GB electricity system. Devising a suitable support or incentive schemes for flexible providers will become increasingly important if the decarbonisation is to be achieved at least cost for the society.

A more detailed discussion on the implications of system externalities for the energy policy, regulatory framework and market design is included in the accompanying NERA report. [77]

[77] NERA Economic Consulting, "System Integration Costs for Alternative Low Carbon Generation Technologies – Policy Implications", report for the CCC, October 2015.

Appendix A. Generator data assumptions

Table A.1 and Table A.2 provide detailed assumptions on the operating parameters of thermal generators used in the study: operating cost, carbon emission factors, efficiency, frequency regulation capability, ramping rates etc.

Table A.1. Carbon and operating cost parameters of thermal generators with low and high efficiency

Generation technology	Low efficiency						High efficiency					
	Average cost (£/MWh)		Efficiency (%)		Average CO2 emissions (g/kWh)		Average cost (£/MWh)		Efficiency (%)		Average CO2 emissions (g/kWh)	
	MSG	FULL	MSG	FULL	MSG	FULL	MSG	FULL	MSG	FULL	MSG	FULL
Coal	110.0	90.0	36.0%	44.0%	1,076	880	99.0	90.0	40.0%	44.0%	968	880
Coal CCS	54.4	39.5	25.4%	35.0%	116	80	46.6	39.5	29.7%	35.0%	97	80
CCGT	84.7	74.1	51.5%	58.8%	422	368	79.1	74.1	55.1%	58.8%	393	368
CCGT CCS	63.4	55.9	45.2%	51.3%	39	34	59.5	55.9	48.1%	51.3%	36	34

Table A.2. Dynamic parameters of generators with low and high response characteristics

		MSG	Response slope	Maximum response (% rating)	Ramp up (% rating/h)	Ramp down (% rating/h)	Min up time (h)	Min down time (h)
Low	Coal	35%	0.3	n/a	60%	60%	4	4
	Gas	50%	0.4	n/a	60%	60%	4	4
	Coal CCS	40%	0.2	n/a	50%	50%	4	4
	Gas CCS	50%	0.3	n/a	50%	50%	4	4
	Nuclear*	60%	-	n/a	10%	10%	-	-
	Gas OCGT	40%	0.3	n/a	100%	100%	1	1
High	Coal	35%	1.0	5%	60%	60%	4	4
	Gas	50%	0.85	17%	60%	60%	4	4
	Coal CCS	40%	1.0	5%	50%	50%	4	4
	Gas CCS	50%	0.5	10%	50%	50%	4	4
	Nuclear*	80%	-	0	10%	10%	-	-
	Gas OCGT	40%	1.0	40%	100%	100%	1	1

Appendix B. Detailed results of system externality studies

B.1. Constructing the 50 g/kWh baseline scenario

This section presents a series of case studies conducted on the 50 g/kWh core scenario (wind-dominated) in order to test the impact of enhanced flexibility parameters and construct a feasible baseline scenario with emissions close to the 50 g/kWh target.

B.1.1. Generation and demand-side opportunities for improving carbon emissions performance

The objective of the first set of studies is to understand the opportunities for generation and demand side technologies to improve carbon and economic performance of future GB electricity system. The studies analyse the impact of the following key parameters:

(1) Generator response capability

(2) Generator efficiency

(3) System response

(4) System reserve requirements

(5) Flexibility provided by demand-side technologies (DSR)

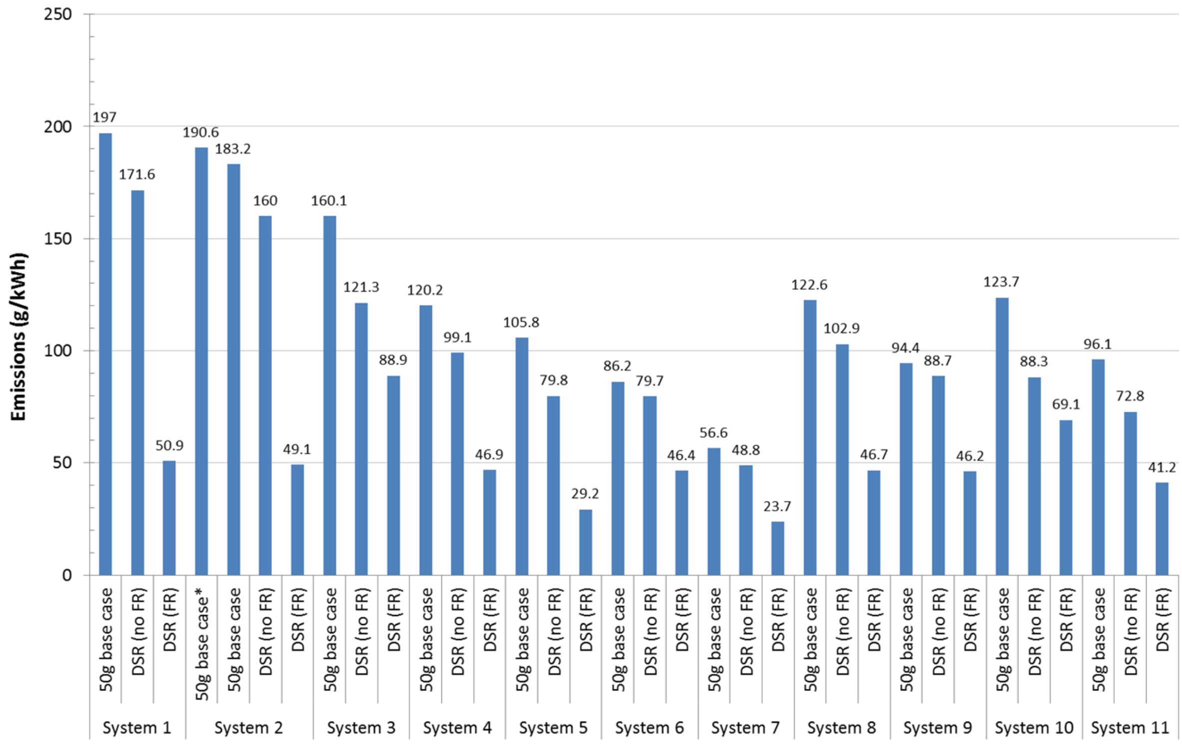
Table B.1 lists the variations in system parameters introduced in this set of studies, including variations in generator response capability and efficiency as well as the level of system requirements for frequency response and operating reserve.

Table B.1. List of test systems used to identify the impact of generation response, generation efficiency, system response and reserve on the system's carbon and economic performance

	Generation response characteristics	Generation efficiency	System response requirement	System reserve requirement
System 1	Low	Low	High (adv)	Medium
System 2	Low	High	High (adv)	Medium
System 3	High	Low	High (adv)	Medium
System 4	High	Low	Medium (adv)	High
System 5	High	Low	Medium	High
System 6	High	Low	Adv	Medium
System 7	High	Low	Low	Medium
System 8	High	Low	Medium (adv)	Medium
System 9	High*	Low	Medium(adv)	Medium
System 10	High	High	High (adv)	Medium
System 11	High	High	Medium (adv)	High

Note: *Minimum stable generation level and maximum response limit of CCGT are set to 40% and 20%, respectively.

Figure B.1 presents the outturn system carbon intensity for the system studies listed in Table B.1. It is evident how enhanced flexibility greatly improves the carbon performance of the system, in particular when supported by flexible DSR operation that also involves the provision of frequency regulation services.



Note: *without heat storage in the base case

Figure B.1. System emissions for different scenarios analysing the impact of generation and demand-side flexibility

B.1.2. Impact of wind power based balancing services and interconnection

A further group of studies investigated the potential impact of wind contributing to system balancing as well as the benefits of interconnection, as listed in Table B.2.

Table B.2. List of test systems used to identify the impact of balancing services from wind power generation and interconnection on the system's carbon and economic performance

	Generation response characteristics	Generation efficiency	System response requirement	System reserve requirement
System 14	High	High	Medium(adv)	Medium
System 15	High	High	adv	Medium
System 16	High	High	Medium(adv)*	Medium
System 17	High	High	Adv*	Medium
System 18	High	High	Medium(adv)**	Medium
System 19	High	High	Adv**	Medium
System 20	High	High	Medium(adv)***	Medium
System 21	High	High	Adv***	Medium

Notes:
* 50% of the curtailed wind can be converted into frequency response services
** wind curtailment is converted into reserve services
*** interconnectors are optimised

Figure B.2 demonstrates the positive impact of wind generation contributing to balancing, which helps to bring the system emissions close to the 50 g/kWh mark.

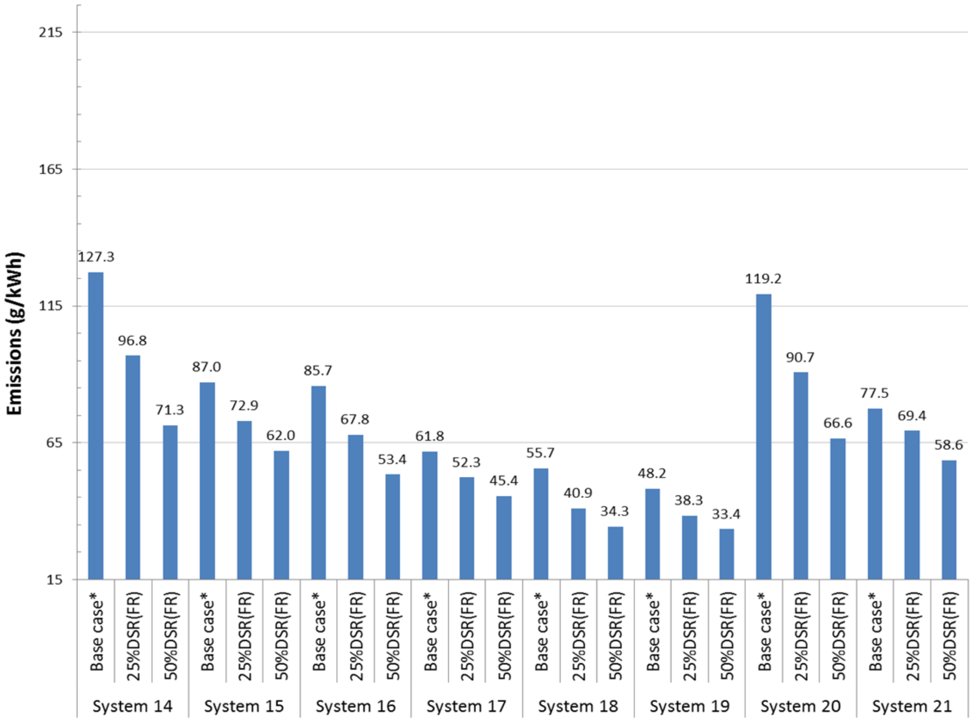


Figure B.2. System emissions for different scenarios analysing the impact of balancing services provided by wind and impact of interconnection

Figure B.3 illustrates how enhanced flexibility and system balancing supported by wind also results in greatly reduced levels of renewable output curtailment, helping both with the cost and emission performance of the system.

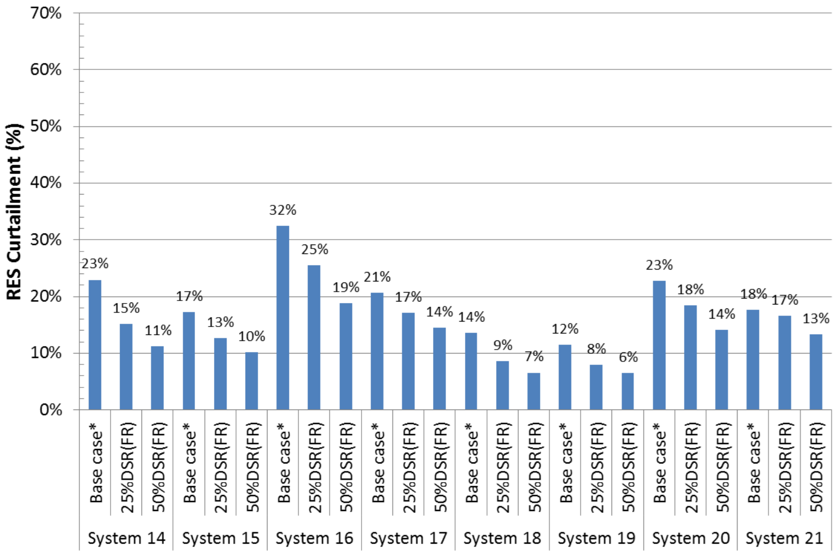


Figure B.3. RES curtailment for different scenarios analysing the impact of balancing services provided by wind and impact of interconnection

B.2. Detailed results of system integration cost studies

In this section we present the detailed results of system externality studies across all calculation methods and for both directions of low-carbon technology replacement (incremental and decremental). To aid understanding the key drivers behind system externalities, we also include additional explanatory diagrams for all studies that show changes in generation capacities as well as in generation output between the baseline scenario and each externality study.

For each scenario and sensitivity the results for Method 1 and 2 are presented separately from Method 3, for which the charts include marginal benefits of low-carbon technologies used to evaluate their integration cost.

All integration cost charts present a breakdown of generator cost components (OPEX and CAPEX) across different technologies.

B.2.1. 100 g/kWh core scenario

Components of system integration costs, changes in generation capacity and changes in generation output for Methods 1 and 2 applied to the 100 g/kWh core scenario are presented in Figure B.4, Figure B.5 and Figure B.6, respectively.

Components of system integration costs, changes in generation capacity and changes in generation output for Method 3 applied to the 100 g/kWh core scenario are presented in Figure B.7, Figure B.8 and Figure B.9, respectively.

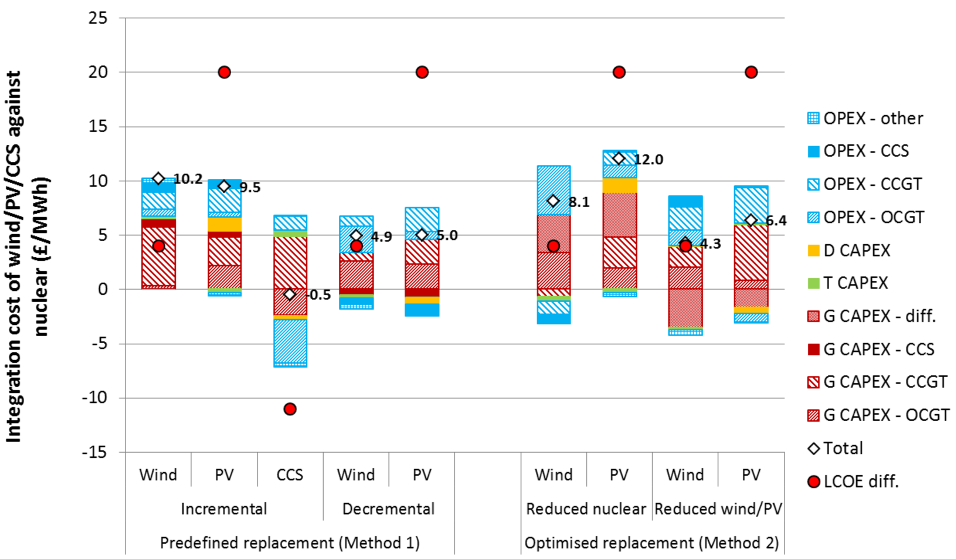


Figure B.4. Relative integration cost of wind, PV and CCS against nuclear in all Method 1 and 2 studies (100 g/kWh core scenario)

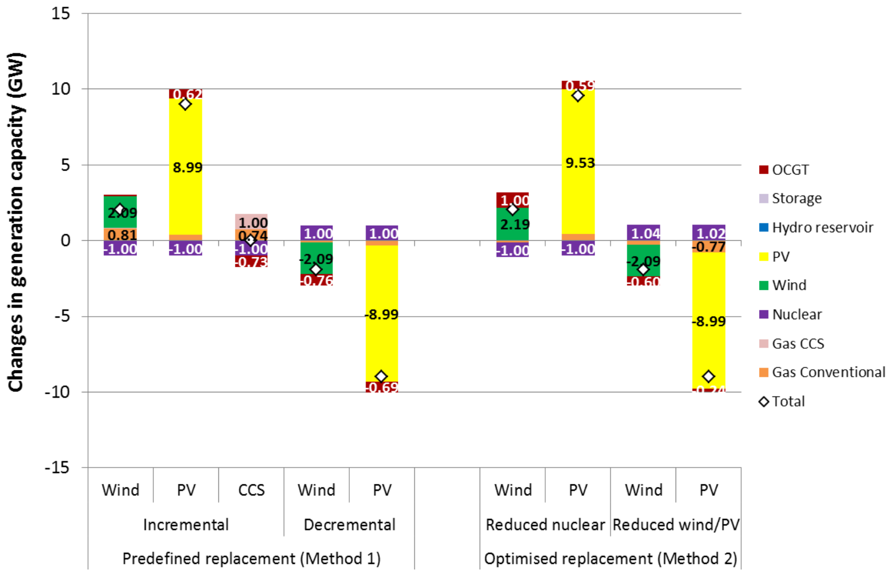


Figure B.5. Changes in UK generation capacities in all Method 1 and 2 studies (100 g/kWh core scenario)

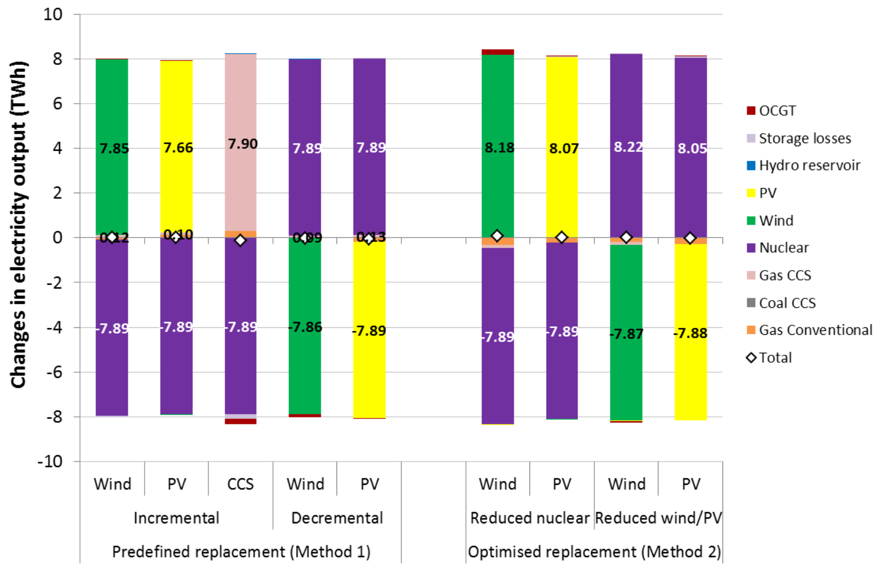


Figure B.6. Changes in UK generation outputs in all Method 1 and 2 studies (100 g/kWh core scenario)

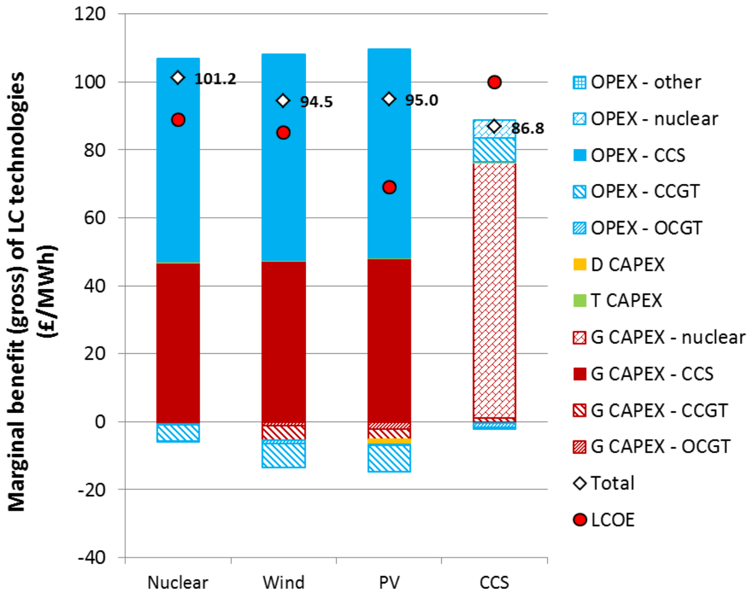


Figure B.7. Marginal system benefits of nuclear, wind, PV and CCS in Method 3 studies (100 g/kWh core scenario)

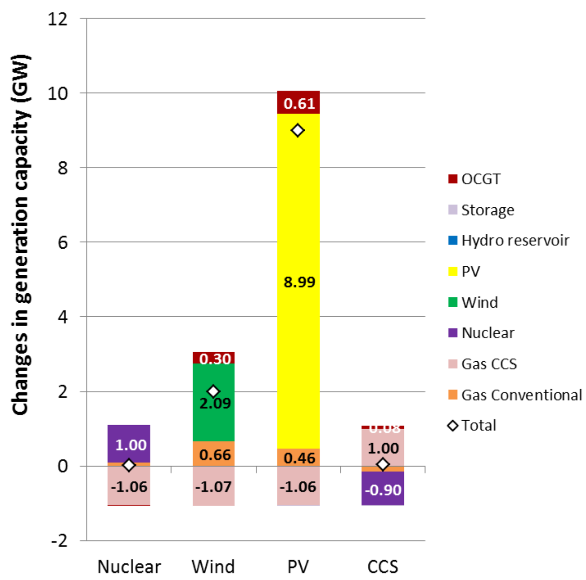


Figure B.8. Changes in UK generation capacities in Method 3 studies (100 g/kWh core scenario)

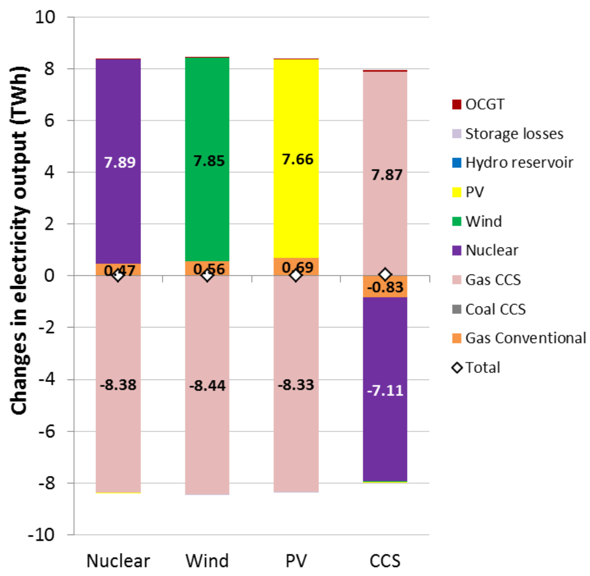


Figure B.9. Changes in UK generation outputs in Method 3 studies (100 g/kWh core scenario)

B.2.2. 50 g/kWh core scenario (wind-dominated)

Components of system integration costs, changes in generation capacity and changes in generation output for Methods 1 and 2 applied to the wind-dominated 50 g/kWh core scenario are presented in Figure B.10, Figure B.11 and Figure B.12, respectively.

Components of system integration costs, changes in generation capacity and changes in generation output for Method 3 applied to the wind-dominated 50 g/kWh core scenario are presented in Figure B.13, Figure B.14 and Figure B.15, respectively.

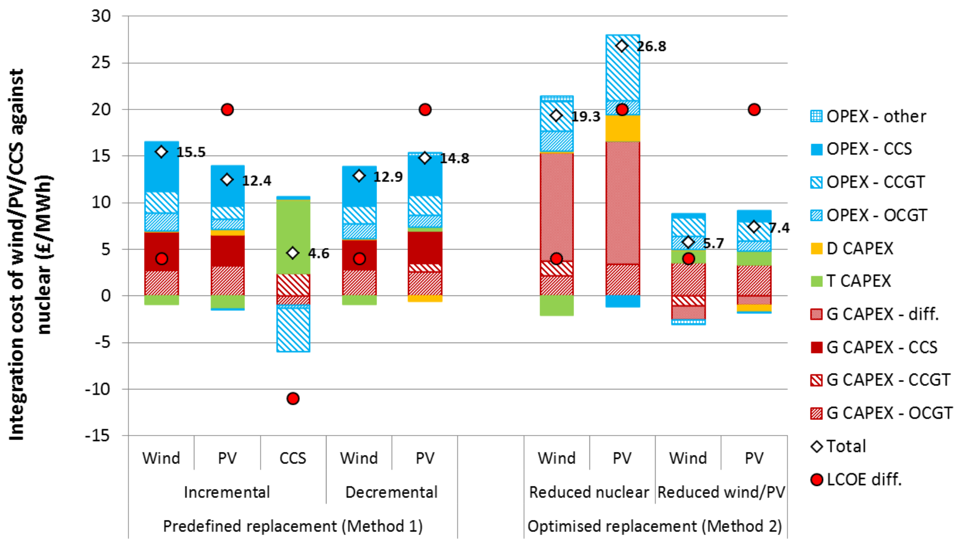


Figure B.10. Relative integration cost of wind, PV and CCS against nuclear in all Method 1 and 2 studies (50 g/kWh core scenario, wind-dominated)

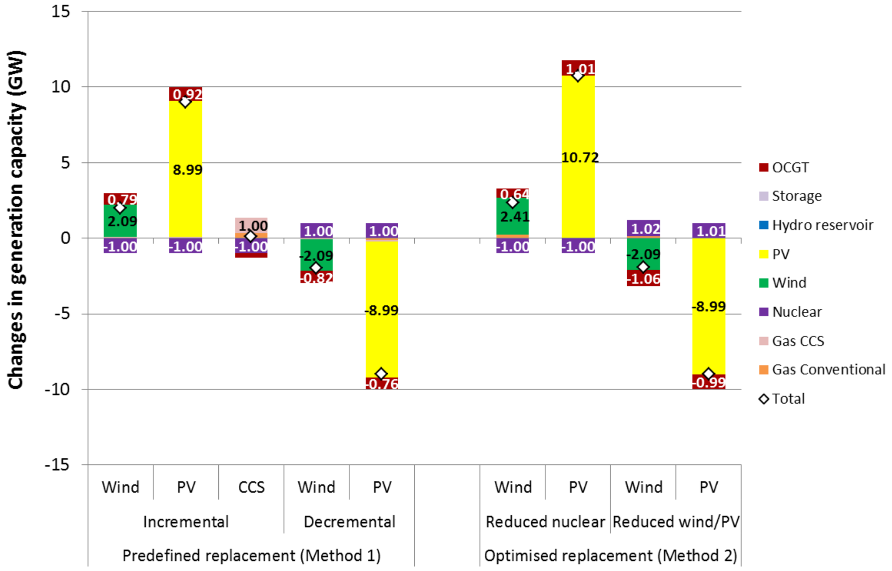


Figure B.11. Changes in UK generation capacities in all Method 1 and 2 studies (50 g/kWh core scenario, wind-dominated)

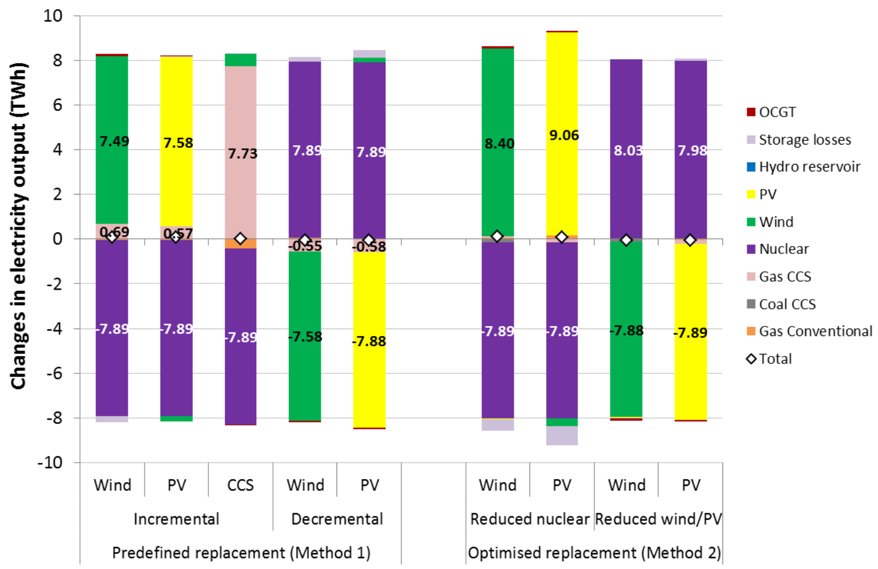


Figure B.12. Changes in UK generation outputs in all Method 1 and 2 studies (50 g/kWh core scenario, wind-dominated)

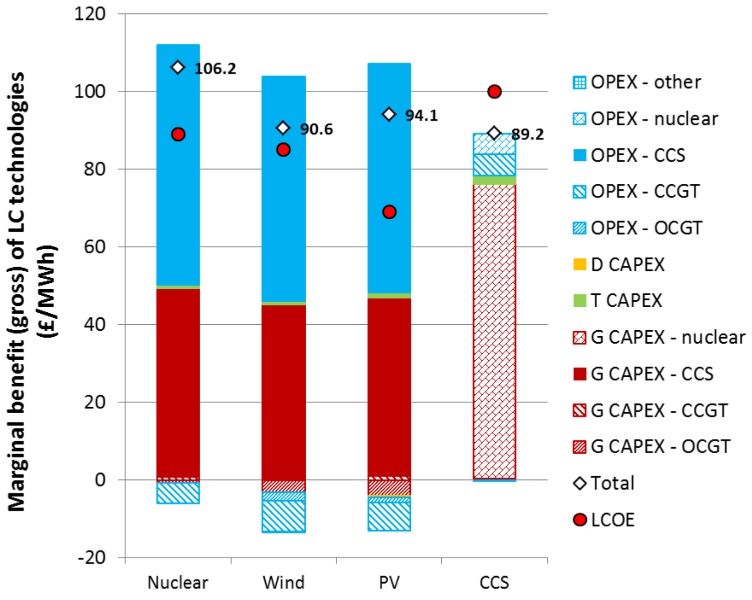


Figure B.13. Marginal system benefits of nuclear, wind, PV and CCS in Method 3 studies (50 g/kWh core scenario, wind-dominated)

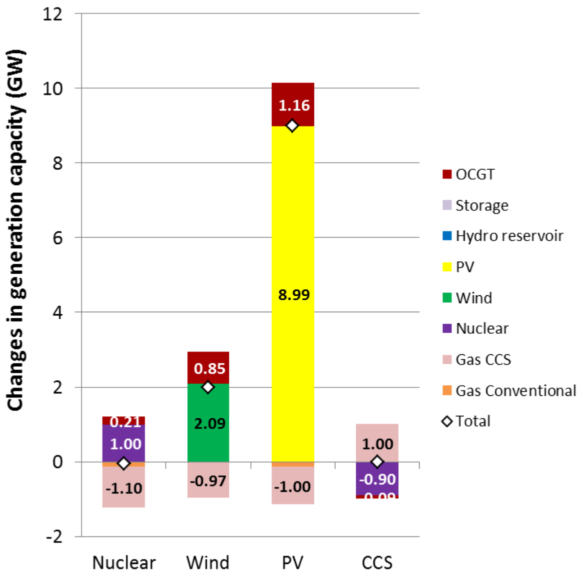


Figure B.14. Changes in UK generation capacities in Method 3 studies (50 g/kWh core scenario, wind-dominated)

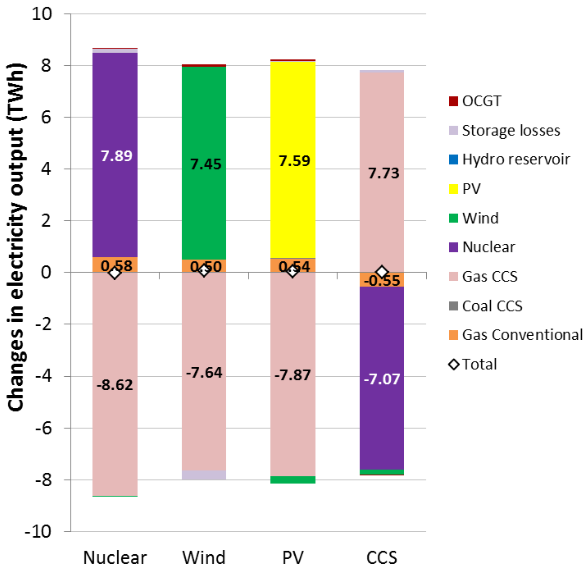


Figure B.15. Changes in UK generation outputs in Method 3 studies (50 g/kWh core scenario, wind-dominated)

B.2.3. 50 g/kWh core scenario (solar-dominated)

Components of system integration costs, changes in generation capacity and changes in generation output for Methods 1 and 2 applied to the solar-dominated 50 g/kWh core scenario are presented in Figure B.16, Figure B.17 and Figure B.18, respectively.

Components of system integration costs, changes in generation capacity and changes in generation output for Method 3 applied to the solar-dominated 50 g/kWh core scenario are presented in Figure B.19, Figure B.20 and Figure B.21, respectively.

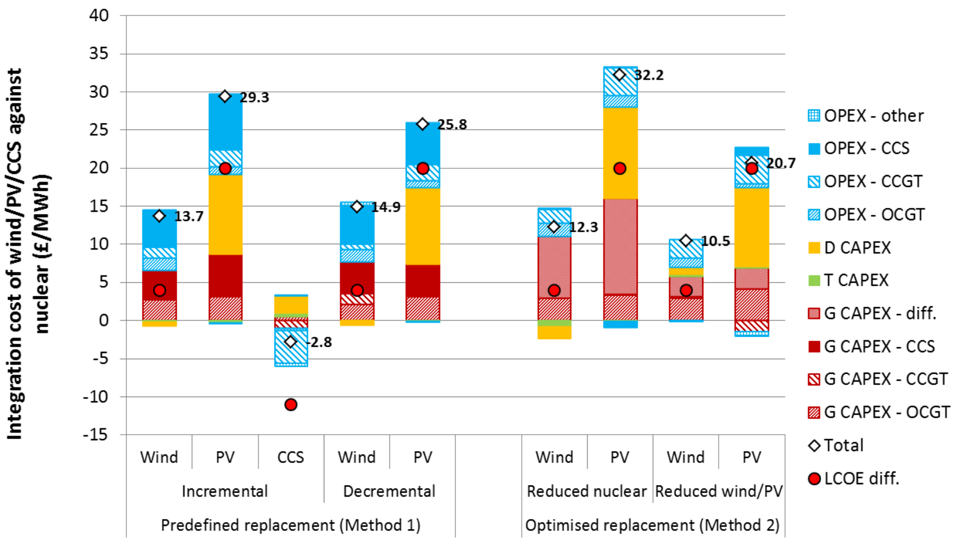


Figure B.16. Relative integration cost of wind, PV and CCS against nuclear in all Method 1 and 2 studies (50 g/kWh core scenario, solar-dominated)

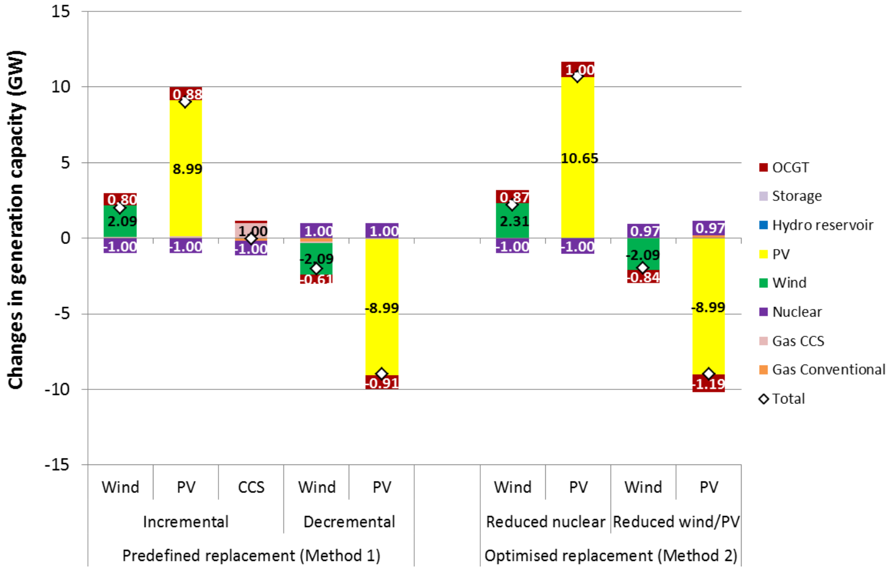


Figure B.17. Changes in UK generation capacities in all Method 1 and 2 studies (50 g/kWh core scenario, solar-dominated)

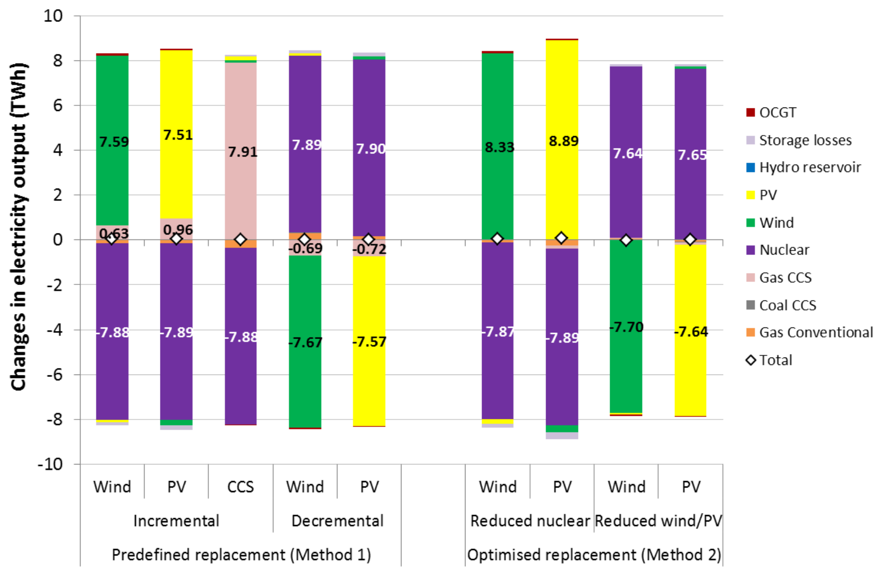


Figure B.18. Changes in UK generation outputs in all Method 1 and 2 studies (50 g/kWh core scenario, solar-dominated)

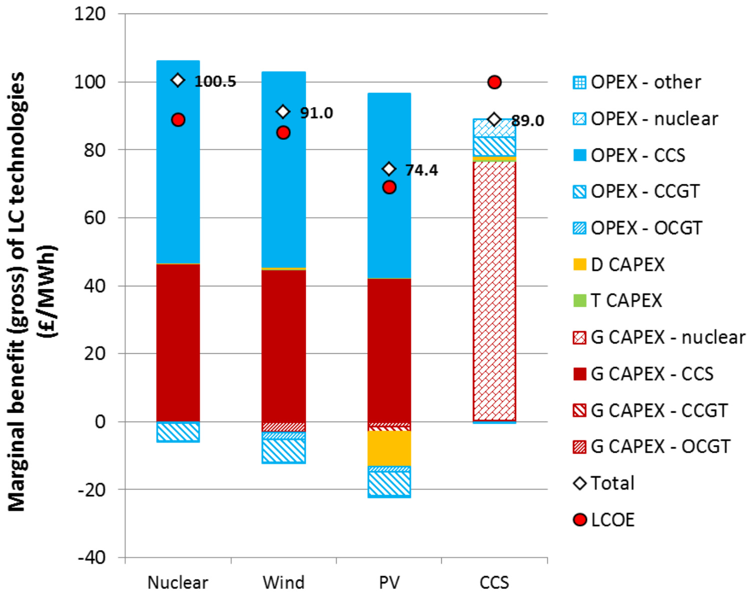


Figure B.19. Marginal system benefits of nuclear, wind, PV and CCS in Method 3 studies (50 g/kWh core scenario, solar-dominated)

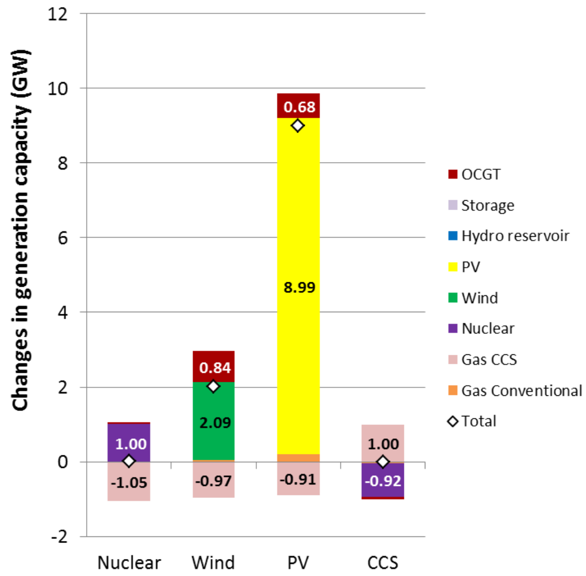


Figure B.20. Changes in UK generation capacities in Method 3 studies (50 g/kWh core scenario, solar-dominated)

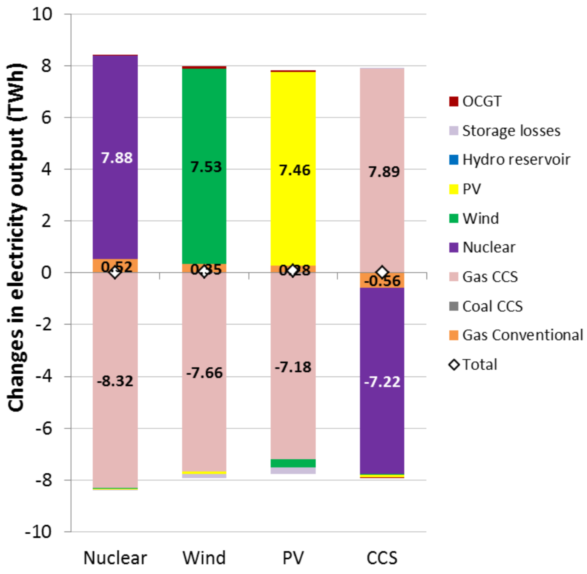


Figure B.21. Changes in UK generation outputs in Method 3 studies (50 g/kWh core scenario, solar-dominated)

B.2.4. 10 g/kWh scenario (2050)

Components of system integration costs, changes in generation capacity and changes in generation output for Methods 1 and 2 applied to the 10 g/kWh scenario are presented in Figure B.22, Figure B.23 and Figure B.24, respectively.

Components of system integration costs, changes in generation capacity and changes in generation output for Method 3 applied to the 10 g/kWh scenario are presented in Figure B.25, Figure B.26 and Figure B.27, respectively.

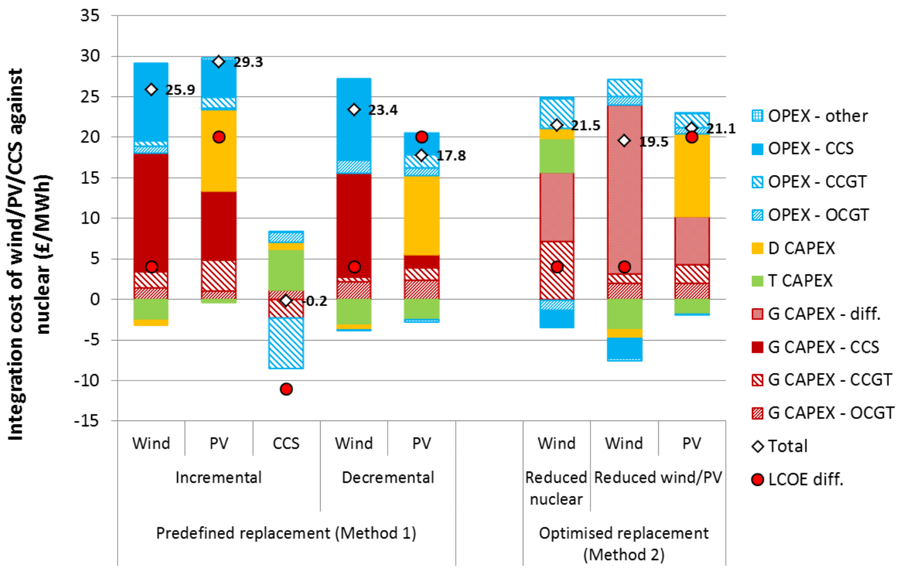


Figure B.22. Relative integration cost of wind, PV and CCS against nuclear in all Method 1 and 2 studies (10 g/kWh scenario)

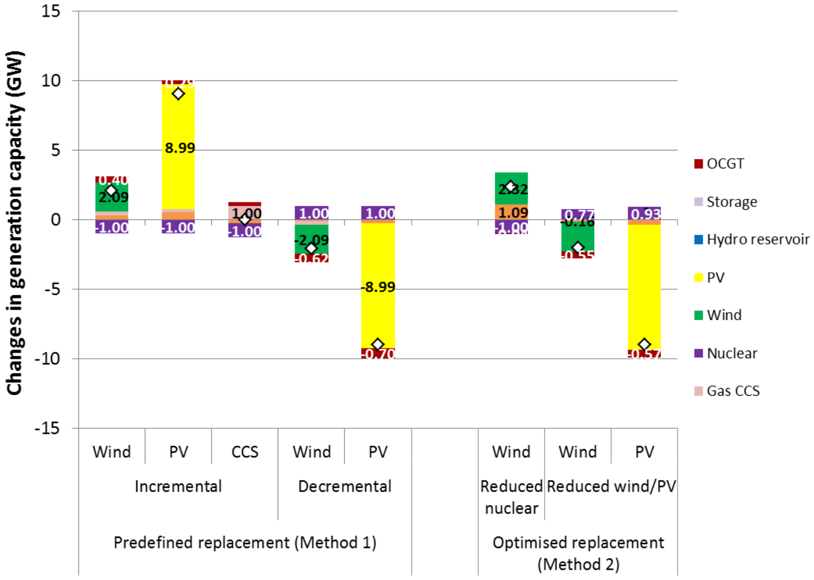


Figure B.23. Changes in UK generation capacities in all Method 1 and 2 studies (10 g/kWh scenario)

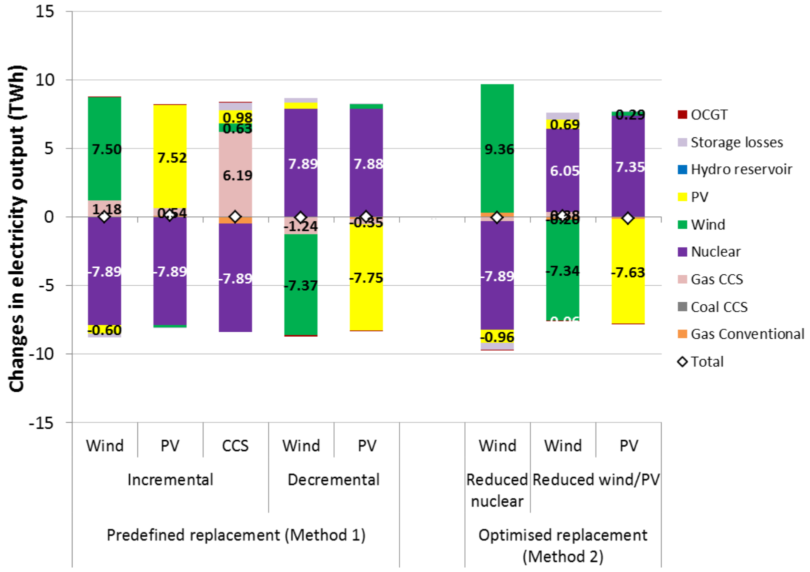


Figure B.24. Changes in UK generation outputs in all Method 1 and 2 studies (10 g/kWh scenario)

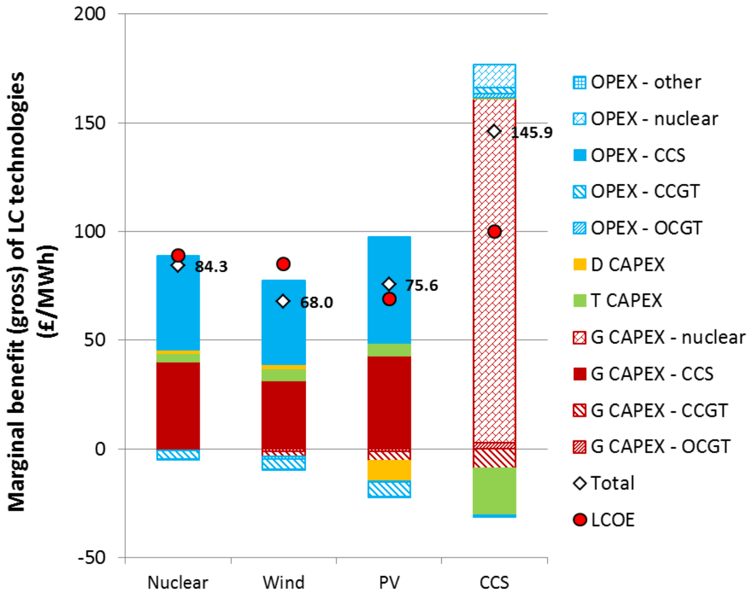


Figure B.25. Marginal system benefits of nuclear, wind, PV and CCS in Method 3 studies (10 g/kWh scenario)

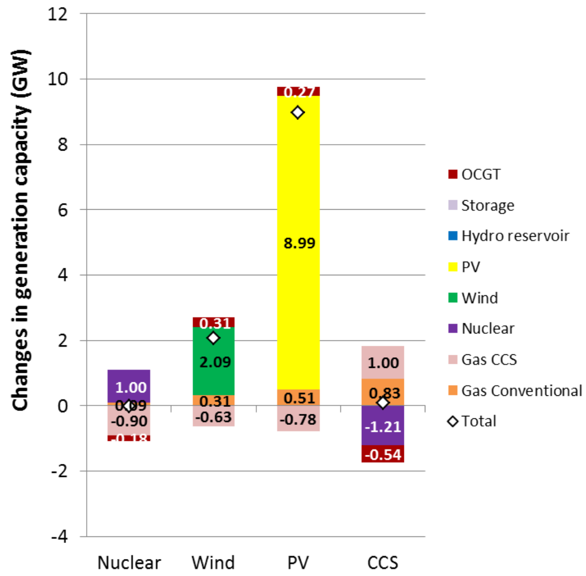


Figure B.26. Changes in UK generation capacities in Method 3 studies (10 g/kWh scenario)

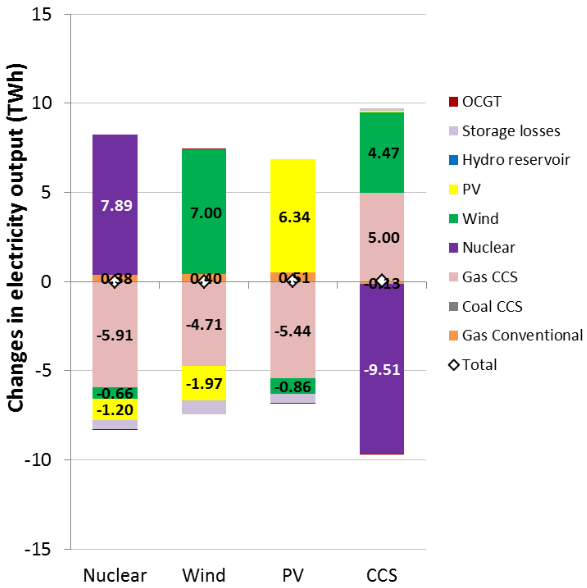


Figure B.27. Changes in UK generation outputs in Method 3 studies (10 g/kWh scenario)

B.2.5. 100 g/kWh scenario with no new nuclear

Components of system integration costs, changes in generation capacity and changes in generation output for Methods 1 and 2 applied to the 100 g/kWh scenario with no new nuclear are presented in Figure B.28, Figure B.29 and Figure B.30, respectively.

Components of system integration costs, changes in generation capacity and changes in generation output for Method 3 applied to the 100 g/kWh scenario with no new nuclear are presented in Figure B.31, Figure B.32 and Figure B.33, respectively.

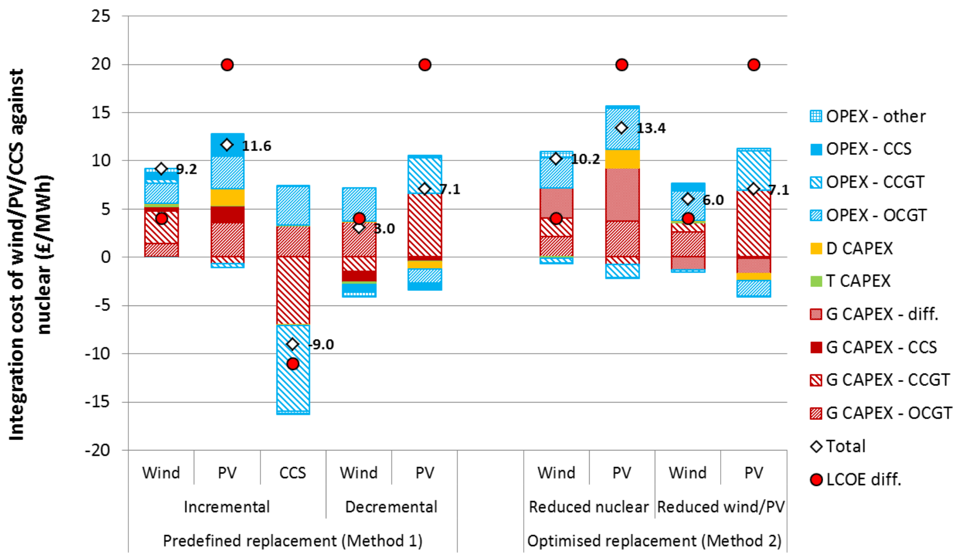


Figure B.28. Relative integration cost of wind, PV and CCS against nuclear in all Method 1 and 2 studies (100 g/kWh scenario with no new nuclear)

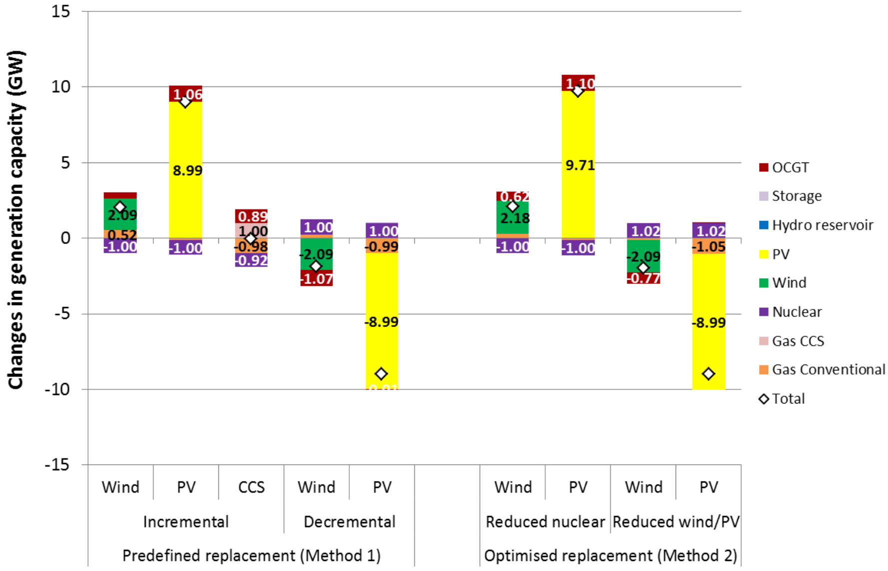


Figure B.29. Changes in UK generation capacities in all Method 1 and 2 studies (100 g/kWh scenario with no new nuclear)

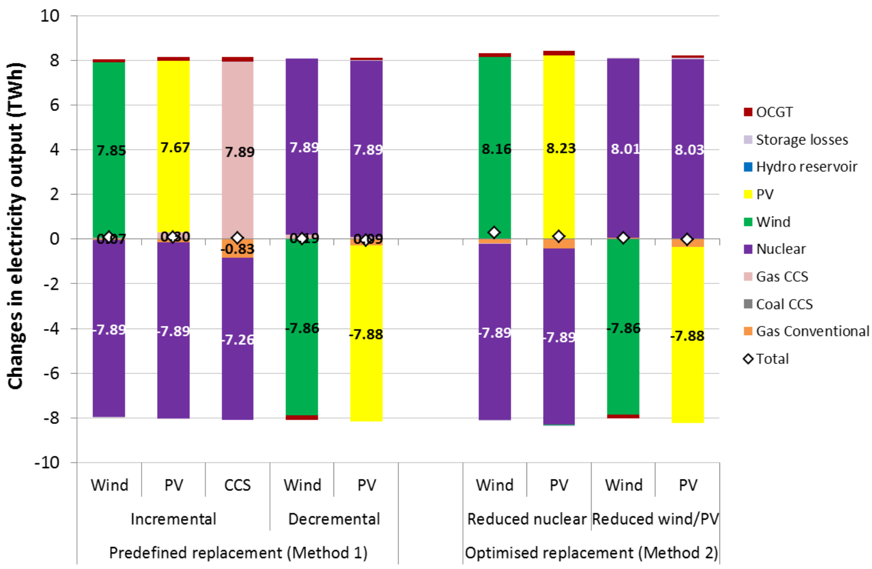


Figure B.30. Changes in UK generation outputs in all Method 1 and 2 studies (100 g/kWh scenario with no new nuclear)

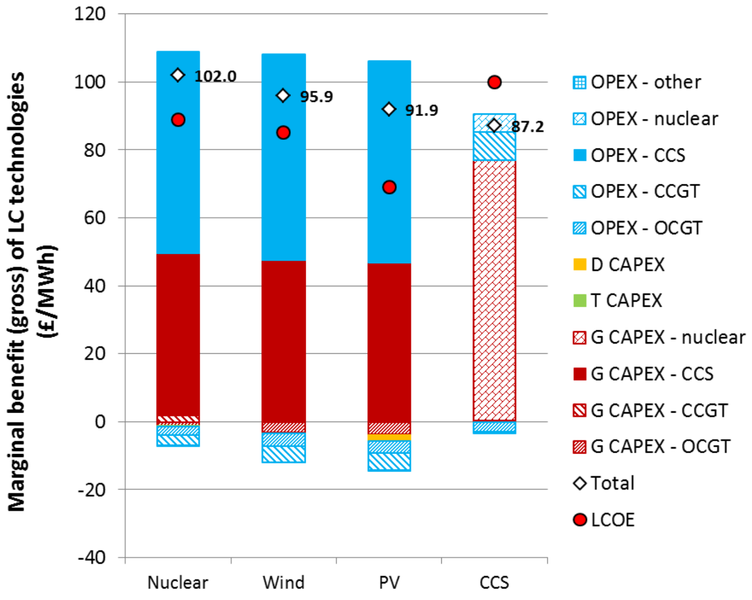


Figure B.31. Marginal system benefits of nuclear, wind, PV and CCS in Method 3 studies (100 g/kWh scenario with no new nuclear)

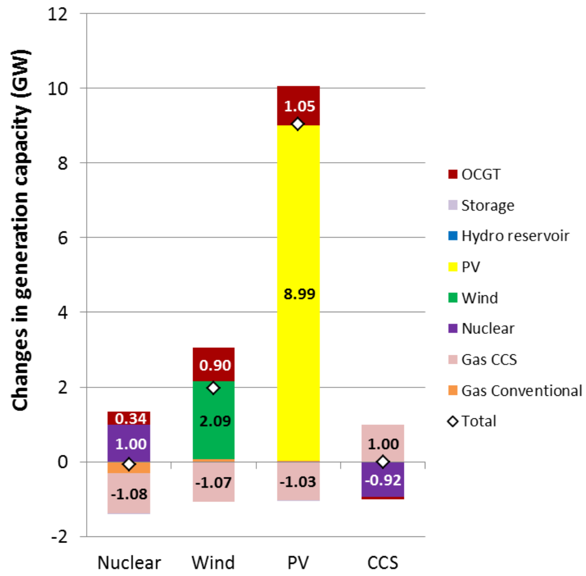


Figure B.32. Changes in UK generation capacities in Method 3 studies (100 g/kWh scenario with no new nuclear)

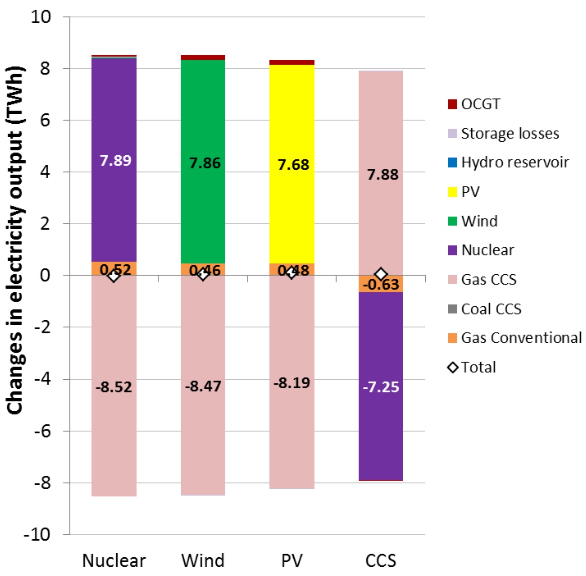


Figure B.33. Changes in UK generation outputs in Method 3 studies (100 g/kWh scenario with no new nuclear)

Appendix C. Overview of the methodology for whole-system analysis of electricity systems

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 *Whole-electricity System Investment Model* (WeSIM), 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.

C.1. 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 C.1); 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.

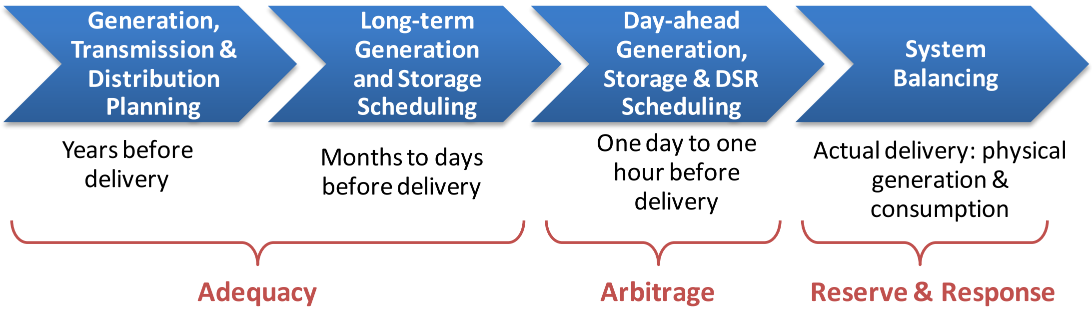


Figure C.1. Balancing electricity supply and demand across different time horizons

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

In order to capture these effects and in particular trade-offs between different flexible technologies, it is critical that they are all modelled in a single integrated modelling framework. In order to meet this requirement we have developed *WeSIM*, 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 WeSIM has been extensively tested in previous projects studying the interconnected electricity systems of the UK and the rest of Europe.[78] An advantage of WeSIM 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 synergies between different applications of distributed storage in supporting intermittency management at the national level and reducing necessary reinforcements in the local distribution network.

78 WeSIM 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.

C.2. WeSIM problem formulation

WeSIM 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 WeSIM model structure is given in Figure C.2.

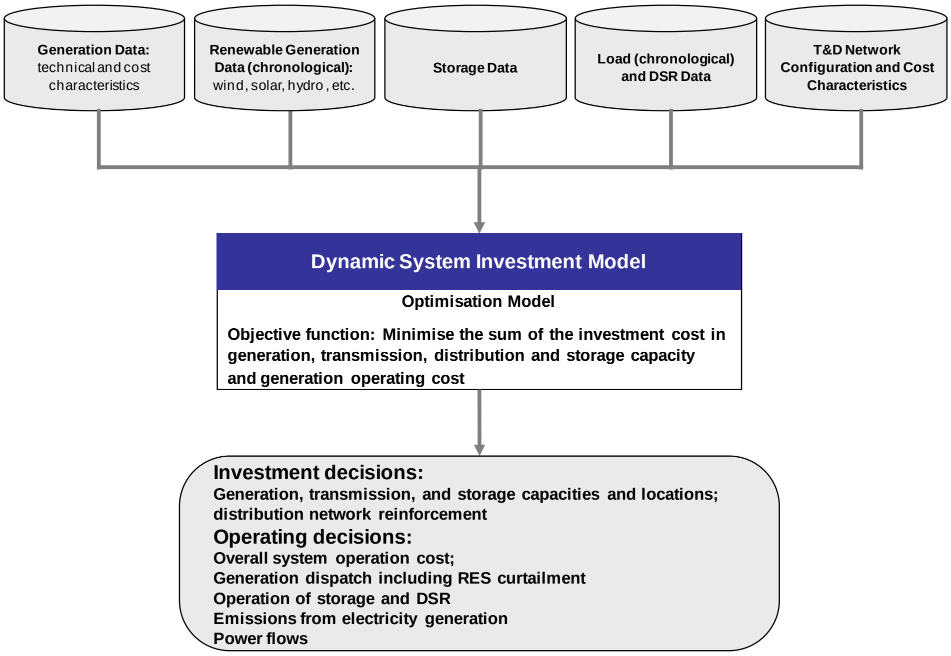


Figure C.2. Structure of the Whole-electricity System Investment Model (WeSIM)

The objective function of WeSIM 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[79] 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. WeSIM 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 order to take into account the impact of having less inertia during low demand and high renewable output conditions, the WeSIM's formulation has been enhanced by including additional constraints that dictate the minimum response requirements to meet the RoCOF specification, the minimum frequency at the nadir point, and the steady state frequency deviation from the nominal frequency as illustrated in Figure C.3.

[79] 4 hours is generally the maximum time needed to synchronize a large CCGT plant.

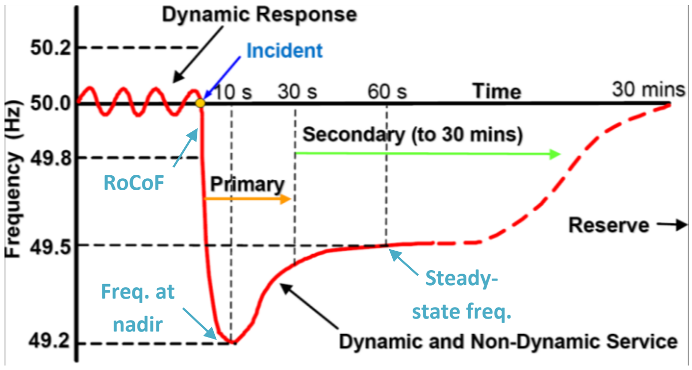


Figure C.3. System frequency evolution after a contingency (source: National Grid)

In WeSIM, frequency response can be provided by:

- Synchronised part-loaded generating units.
- Interruptible charging of electric vehicles.
- A proportion of wind power being curtailed.
- A proportion of electricity storage when charging
- Smart refrigeration.

While reserve services can be provided by:

- Synchronised generators
- Wind power or solar power being curtailed
- Stand-by fast generating units (OCGT)
- Electricity storage
- I&C flexible demand
- 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 WeSIM.[80,81] 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.

---

80 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.

81 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.

- *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 C.4.

- 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 ($P_{max} – MSG$).

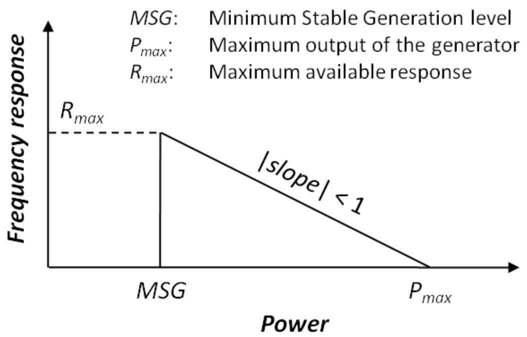


Figure C.4. Provision of frequency regulation from conventional generation

- *Generation:* WeSIM 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. WeSIM 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 WeSIM 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, WeSIM takes into account efficiency losses.

- *Demand-side response constraints* include constraints for various specific types of loads. WeSIM 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 (WeSIM 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. WeSIM 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 renewables (wind and PV), 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.[82] If there is storage in the system,

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

WeSIM may make use its capacity for security purposes if it can contribute to reducing peak demand, given the energy constraints.

WeSIM allows for the security-related benefits of interconnection to be adequately quantified.[83] Conversely, it is possible to specify in WeSIM 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 WeSIM for the purpose of studying balancing technologies are:

- UK is *self-sufficient* in terms of capacity, i.e. there is no contribution from other regions to the capacity margin in the UK and vice versa. 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.

- UK is *energy-neutral*. This means that the net annual energy import / export is zero. This allows UK to import power from and export to Europe / Ireland as long as the annual net balance is zero. In other words, the UK 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 UK.

C.3. System topology

The configuration of the interconnected GB electricity system used in this study is presented in Figure C.5. Given that the GB transmission network is characterised by North-South power 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, WeSIM 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 C.5 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.

---

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

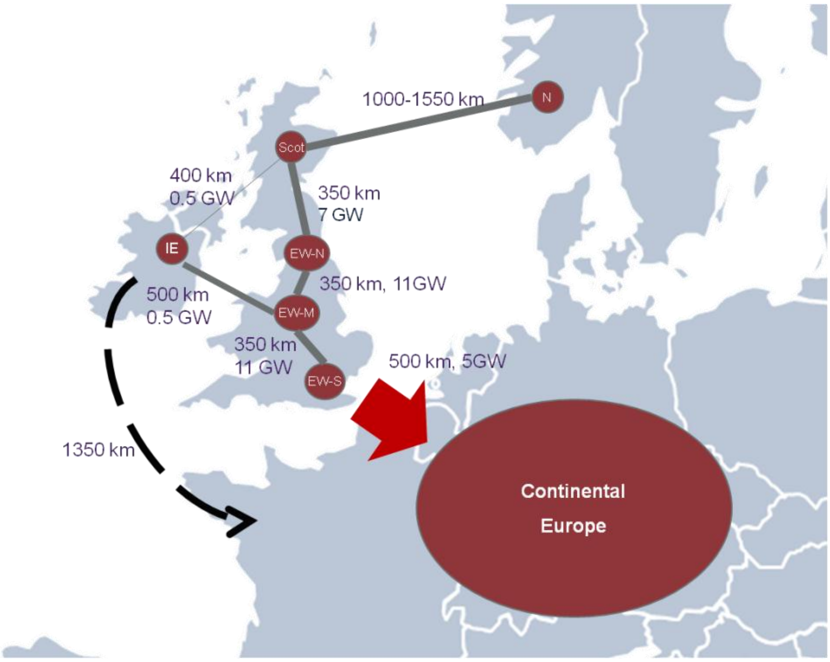


Figure C.5. System topology used for studying the value of flexible balancing technologies

C.4. 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. 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 WeSIM to perform an overall system cost assessment.

Examples of different consumer patterns / layouts that can be created by specifying the desired layout parameters [84] are shown in Figure C.6 for different urban, rural and intermediate layouts. Parameters of representative networks are calibrated against the actual GB distribution systems.[85] [86]

---

84 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.

85 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.

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

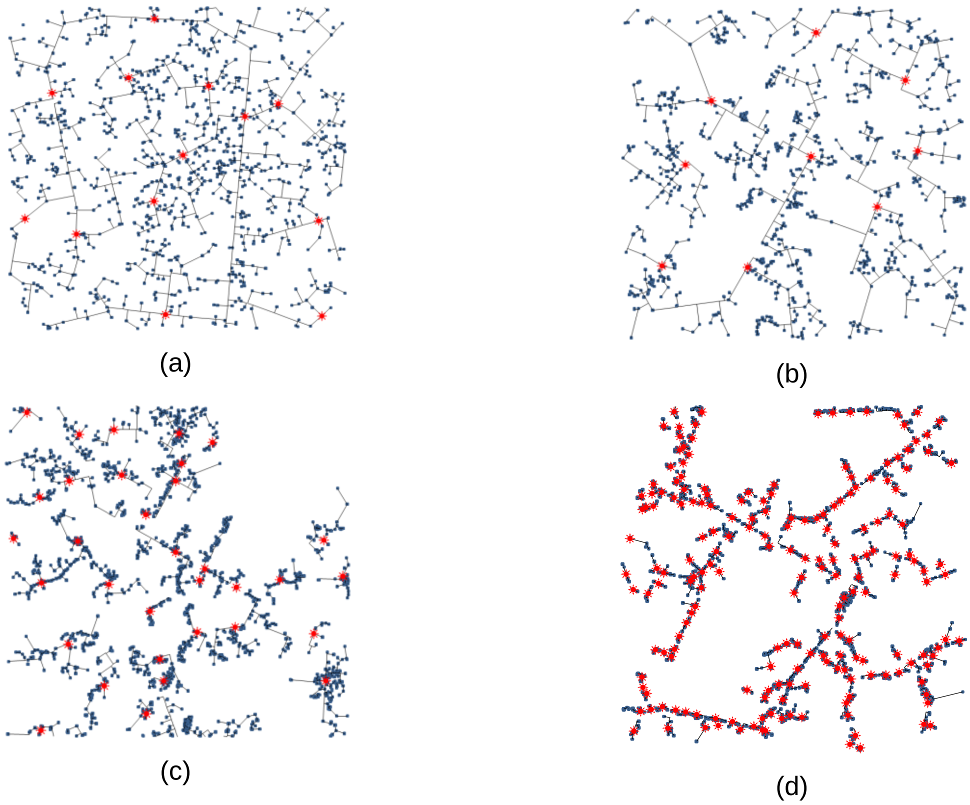


Figure C.6. Examples of generated consumer layouts: a) urban area; b) semi-urban area; c) semi-rural area; and d) rural area. (Blue dots represent consumers, while red stars represent distribution substations.)

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 C.1.

Table C.1. 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 C.2. 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 C.2. 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 C.3 (which closely matches the data presented in Table C.1).

Table C.3. 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.[87] 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 C.4 shows an excerpt from the list of cost items.

87 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 C.4. 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

C.5. 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.[88] 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 various forms of domestic and commercial types of flexible demand.[89,90,91,92,93, 94,95,96]

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

[89] M. Aunedi, G. Strbac, "Efficient System Integration of Wind Generation through Smart Charging of Electric Vehicles", *8th International Conference and Exhibition on Ecological Vehicles and Renewable Energies (EVER)*, Monte Carlo, March 2013.

[90] 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.

[91] 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.

[92] 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*, Vol. 52, pp. 76-84, January 2013.

The following assumptions of *full DSR flexibility* are made in system integration cost studies:[97]

- Electric vehicles: up to 80% of EV demand could be shifted away from a given hour to other times of day;
- Heat pumps: heat storage enables that the 35% of HP demand can be shifted from a given hour to other times of day;
- Smart appliances: demand attributed to white appliances (washing machines, dishwashers, tumble dryers) participating in smart operation can be fully shifted away from peak;
- Industrial and commercial demand: 10% of the demand of I&C customers participating in DSR schemes can be redistributed.

In addition to improving energy management and potentially reducing capacity adequacy requirements due to lower peak demand, these flexible sources are assumed to also be capable of providing frequency response (maintain grid frequency). It is important to stress that the magnitude of demand (and therefore the absolute volume of demand that can be shifted) in each of the above categories changes in time (it is time-specific).

In terms of energy available for shifting in a fully-flexible system, it is assumed the following demand volumes are movable within day:

- EV demand: 15.1 TWh
- Heat pump demand: 9.4 TWh
- Smart appliance demand: 25.4 TWh
- Industrial and commercial loads participating in DSR schemes: 19.0 TWh

---

93 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.

94 M. Aunedi, P. A. Kountouriotis, J. E. Ortega Calderon, D. Angeli, G. Strbac, "Economic and Environmental Benefits of Dynamic Demand in Providing Frequency Regulation", *IEEE Transactions on Smart Grid*, vol. 4, pp. 2036-2048, December 2013.

95 M. Woolf, T. Ustinova, E. Ortega, H. O'Brien, P. Djapic, G. Strbac, "Distributed generation and demand response services for the smart distribution network", Report A7 for the "Low Carbon London" LCNF project: Imperial College London, 2014.

96 Imperial College and NERA Consulting, 2012, "Understanding the Balancing Challenge", analysis commissioned by DECC to support this publication. Please see https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48553/5767-understanding-the-balancing-challenge.pdf

97 An overview of the rationale and evidence behind these assumptions is provided in:
M. Aunedi, F. Teng, G. Strbac, "Carbon impact of smart distribution networks", Report D6 for the "Low Carbon London" LCNF project, December 2014.

Note that in our analysis any demand shifting only occurs within the timeframe of one day i.e. no demand shifting over longer time horizons was considered.