Whole-system cost of variable renewables in future GB electricity system

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Background

With nearly half of UK's generation capacity expected to retire in the build up to 2030, the UK's electricity system is facing exceptional challenges in the coming decades. Replacing this generation capacity will for the most part need to be achieved with low-carbon electricity generation technologies if we are to meet our carbon emission reduction targets and this will need to be done whilst maintaining security of supply. The UK's electricity sector is in particular expected to deliver significant reductions in its carbon emissions by 2030, which will require increasing deployment of low-carbon generation technologies such as renewables, nuclear, biomass, carbon capture and storage, etc. In the context of the Contracts for Difference (CfD) mechanism, which allocates payments to low-carbon generators, there is a question over whether selecting technologies solely based on their levelised cost would deliver decarbonisation at the lowest overall cost. Generally, variable renewable generation technologies would impose certain types of costs on the wider system, for example through the need for more back-up capacity and balancing services (although all generation options may imply some system costs).

There are two key factors which may reduce the ability of the system to accommodate the combination of inflexible low-carbon generation and variable renewables:

- *Increase in system balancing requirements*: Reserve requirements will increase due to higher generation output fluctuations and consequently higher forecasting errors associated with high RES penetrations. At the same time, given that wind and solar PV represent non-synchronous power sources that tend not to contribute to system inertia[1], the overall system inertia will decrease during periods of high variable renewable output. When combined with an increased size of largest generator loss in line with the expected capacities of future nuclear generators, this will lead to higher requirements for primary frequency regulation. The importance of frequency regulation in the future GB system is hence expected to increase dramatically.

- *Limited flexibility of present system*: At present, flexibility is provided by conventional gas and coal generators, which are typically characterised by a limited amount of frequency control they can provide and a relatively high minimum stable generation. Both of these features may represent limiting factors for the amount of renewable generation that can be accommodated in the system. Conventional generation technologies with significantly enhanced flexibility are already available, but the lack of appropriate market signals has so far suppressed their deployment. In this context, energy storage technologies and demand-side response could also significantly enhance system flexibility.

[1] It is noted that onshore and offshore wind turbines have the technical capability to provide "synthetic inertia" through the adoption of advanced control schemes that enable the release of their kinetic energy into the grid during a contingency. Nevertheless, current regulatory framework does not require wind generators to provide inertial response to the system.

The operating cost (OPEX) associated with delivering energy is expected to decrease going forward as the result of very low operating cost of most Low-Carbon Generation Technologies (LCGTs); this in contrast with typically high investment cost (CAPEX) associated with building low-carbon generation capacity. At the same time, the cost associated with the provision of ancillary services is likely to increase driven by both increased requirements for frequency regulation as well as the cost of managing variability of renewables. This is illustrated in Figure E.1, which presents the magnitude of cost associated with the provision of 1) energy and 2) ancillary services related to reserve and response provision for two systems – one with 10 GW of wind, which corresponded to the UK's total wind capacity in 2013, and another one with 50 GW, which is closer to the expected wind capacity in 2030.[2] The figure shows that the energy production cost would drop by nearly 50%, while the cost associated with providing reserve and response services would increase by an order of magnitude. At the same time the share of reserve and response cost in the total operating cost will increase from about 1-2% to more than 25%. Note that these costs have been estimated based on today's carbon and energy prices; imposing higher carbon prices would increase the total cost, however the relative proportions of energy and ancillary service costs would remain the same.

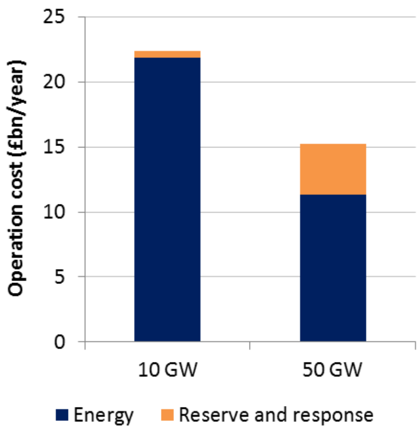

Figure E.1. Operating cost associated with energy and reserve and response services for different wind penetration levels

The *whole-system cost* (WSC) of any generation technology can be expressed as the sum of the *levelised cost of energy* (LCOE) of that technology and the corresponding *system integration costs* (SICs), where the latter refers to additional cost at the system level required to securely integrate a unit of generation technology. Understanding and quantifying the SICs of various low-carbon generation technologies (LCGTs) is therefore critically important in the context of the expected future decarbonisation of the British electricity system. SICs of generation technologies include various types of costs that are imposed on the system by adding generation capacity, but which are not necessarily or wholly included in the capital or operating cost estimates of these technologies. Examples of SIC components include:

[2] Note that none of the two illustrative cases correspond exactly with any of the scenarios presented later in the report, however they are representative of the GB system with current level of wind generation and the future system with significantly expanded wind capacity.

- *Increased balancing cost* associated with: a) increased requirements for system reserve due to higher uncertainty of variable renewable generation output, and b) increased requirements for fast frequency regulation (response) due to reduced system inertia as well as larger maximum generating unit size.

- *Network reinforcements* required in interconnection, transmission and distribution infrastructure (e.g. transmission reinforcement to connect remote wind resources).

- *Increased backup capacity cost* due to limited ability of e.g. variable renewable technologies to displace "firm" generation capacity needed to ensure adequacy of supply.

- *Cost of maintaining system carbon emissions*, as the addition of certain technologies may cause the overall emission performance of the system to deteriorate, requiring that additional low-carbon capacity is installed to maintain the same level of carbon emissions.

Some of these components, such as increased balancing or network cost are already reflected to some extent in current charges imposed on generators, such as the balancing payments (BSUoS), or transmission and distribution charges (TNUoS and DUoS). Nevertheless, these charges are not fully cost-reflective[3]. Some of the above components such as the backup capacity are not currently included in LCOE assessments in any form whilst other components such as constraint payments are completely imposed on distributed generators through the bilateral conditional grid connection agreements which include provision for uncompensated constraint.

Understanding the WSC of technology requires the quantification of SICs in addition to the cost of building and operating low-carbon generation capacity, i.e. their Levelised Cost of Electricity (LCOE). SIC therefore represents a critical input into planning for a cost-effective transition towards a low-carbon electricity system, enabling the development of policies and procurement mechanisms that consider both private and wider system costs of different technologies. This study seeks to quantify and examine in detail the SIC of low-carbon generation technologies such as nuclear, biomass, variable renewable generation technologies, with particular focus on onshore and offshore wind, in the context of the future, largely decarbonised UK electricity system. The report also focusses on quantifying the total system cost of the future UK system where the emphasis is expected to shift towards low-carbon technologies with generally high investment cost but low operating cost.

This report, however, does not consider existing market arrangements or dynamics. It does not for instance account for the part of SIC that might already be paid for by generators through market arrangements such as BSUoS charges or Grid connection agreements or as part of discounts embedded with Power Purchase Agreements to reflect imbalance risk.

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3 For a more detailed discussion on the issue, see a recent study prepared by NERA Economic Consulting and Imperial College London for the Committee on Climate Change: "System integration costs for alternative low carbon generation technologies – policy implications", available here: https://www.theccc.org.uk/publication/system-integration-costs-for-alternative-low-carbon-generation-technologies-policy-implications/.

Methodology

This report quantifies the *relative integration cost* reflecting the difference between the system externalities of pairs of LCGTs, with nuclear power chosen to represent the benchmark LCGT against which the relative SIC of other LCGTs (wind, solar and biomass) are quantified. The choice of nuclear as the benchmark technology is somewhat arbitrary but is motivated by nuclear being a baseload LCGT and enables other LCGTs to be compared against the same reference technology. The interpretation of relative SIC compared against nuclear generators should be that if the SIC for a given LCGT is higher than its corresponding LCOE cost advantage against nuclear, this suggests that a unit of this technology has a higher whole-system cost i.e. provides a lower net marginal benefit to the system than a unit of nuclear capacity (and vice versa).

Different components of SIC are incurred in different segments of the electricity system, such as generation, transmission or distribution infrastructure, or are a part of system operation and balancing cost. Therefore, the quantitative framework applied to evaluate the SIC is based on the whole-system modelling approach (WeSIM model), with the ability to simultaneously make investment and operation decisions with hourly time resolution, while capturing the interactions between different time scales as well as across different asset types in the electricity system. At the same time the model can also consider a broad range of flexible technologies such as energy storage or demand-side response (DSR). In this study the WeSIM model was applied to the interconnected GB electricity system while also considering two neighbouring systems: Ireland and Continental Europe (CE). Important feature of the model is in the ability to impose carbon emission target while ensuring that the security of supply standards are met.

Instead of focusing on quantifying the components of SIC separately (e.g. only the additional balancing or additional network cost), this study quantifies the whole-system impact of adding a unit of LCGT into an electricity system while maintaining a given carbon intensity target. The method adopted to quantify the SIC assumes nuclear power as the benchmark LCGT, and is based on *optimised replacement*, assuming that 1 GW of nuclear capacity is removed from the system, while the model is allowed to optimally increase the capacity of another LCGT (e.g. wind or solar) while at the same time maintaining the same overall GB system emissions. No change in the capacities of other LCGTs is allowed in this method; the model is only allowed to adjust conventional capacity if cost-efficient. Similarly, the volumes of energy storage, DSR and interconnection in SIC studies (i.e. when optimising the system where 1 GW of nuclear is replaced by another LCGT) are also kept constant at the counterfactual scenario level.[4]

Changes in total system cost, excluding the investment and operation cost (i.e. LCOE) of the pairs of technologies involved in the substitution (e.g. removed nuclear and added wind capacity), are divided by the annual output of the added low-carbon technology to establish its relative SIC against nuclear power in £/MWh. Also, in this method any cost of LCGT capac-

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[4] If the volumes of flexible options are allowed to be cost-optimally adjusted in SIC studies together with conventional generation capacities, this could result in a lower observed change in total system cost. In that context the integration cost results in this study represent conservative estimates of SIC of LCGTs.

ity added in excess of the energy-equivalent[5] volume is factored into the total cost differential between the original system and a given SIC study. This also means that any cost associated with curtailing LCGT output during periods of oversupply is included in the SIC.

Scenarios and assumptions

Power system scenarios cover the period between 2015 and 2030, with a single scenario covering years 2015, 2020 and 2025, and a range of seven 2030 scenarios with varying level of system flexibility or alternative low-carbon generation mixes. A number of sensitivity studies have also been done in addition to the core scenarios. All scenarios assume a significant expansion of low-carbon generation capacity (primarily nuclear, wind and PV). The scenarios assumed a certain level of targeted carbon intensity for the electricity system; in the basic set of studies this target was set at 100 g/kWh in 2030, although sensitivity studies have been run with the 50 g/kWh target as well (which could be used as an indication of system circumstances around year 2035).

The following core scenarios were considered in 2030:

1. *Mid Flexibility ("Mid Flex")*: Central scenario with high wind deployment, reaching up to 31 GW of offshore and 20 GW of onshore wind in 2030. This scenario has moderate levels of nuclear (8.2 GW), assuming the addition of 4.5 GW of new capacity by 2030, and 20 GW of PV capacity. It also has a moderately high deployment level of flexible options: 10 GW of new distributed storage, 50% of DSR uptake and 11.3 GW of interconnection capacity.

2. *Low flexibility ("Low Flex")*: Same as Mid Flex, but with less ambitious deployment of flexible options: 5 GW of new storage, 25% DSR uptake and 10 GW of interconnection.

3. *Modernisation*: Same as Mid Flex, but with a range of measures to improve system operation (concerning wind predictability, capability to provide ancillary services etc.).

4. *High flexibility ("Mega Flex")*: Scenario with similar generation mix as the Mid Flex, but with enhanced flexibility i.e. higher storage (15 GW) and interconnection capacity (15 GW) and greater DSR uptake than the Mid Flex (100%).

5. *Onshore Capped*: Scenario with no new onshore wind deployment beyond today's level (dropping to around 8 GW by 2030 due to decommissioning), but compensated by a more intensive expansion of offshore wind until 2030. Nuclear and PV capacity are at the Mid Flex level.

6. *Nuclear Centric*: This represents a theoretical alternative technological solution to a high variable LCGT mix for achieving the UK's decarbonisation agenda. Whilst a

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[5] Energy equivalence here means that the removed and added capacities are capable of providing the same nominal annual output (e.g. if the annual utilisation of nuclear is 90% and that of offshore wind is 43%, then it would take about 2.1 GW of wind capacity to produce the same output as 1 GW of nuclear).

more ambitious nuclear expansion in this scenario (16.4 GW in 2030) seems unachievable to deliver from today's perspective, this scenario nevertheless offers a useful benchmark to assess the cost-effectiveness of an energy mix with high levels of variable LCGT. The scenario therefore has slower wind development (up to 21 GW of offshore and 12.5 GW of onshore wind, compared to 5.1 GW of offshore and 9 GW of onshore today).

7. *No progress ("No Flex")*: Same as Mid Flex, but with no new storage, zero DSR uptake and low interconnection capacity and is broadly reflecting today's situation. Although largely theoretical, this scenario nevertheless offers a useful benchmark to assess the benefits of flexibility.[6]

Each scenario had a set of LCOE assumptions specified for different technologies. These were mostly based on DECC's most recent generation cost projections from December 2013. However, given that this data is becoming outdated, alternative assumptions have been used for certain technologies to reflect emerging evidence of reduction in the cost of that technology.

Projected demand for years 2015 to 2030 used in the study has been based on the CCC scenarios. The baseline demand in this scenario remains broadly stable, with a slowly declining trend beyond 2020. The uptake of electrified transport and heating in the domestic sector on the other hand is projected to increase from about zero today to around 21 TWh and 9 TWh, respectively in 2030.

Most scenarios in 2030, with the exception of No Flex, envisaged improvements in system flexibility. New energy storage was assumed to be available, reaching the capacity of 5-15 GW in 2030. The uptake of demand-side response (DSR) was also assumed to increase rapidly, from around zero in 2020 to between 25% and 100% of its theoretical potential in 2030. The DSR potential is quantified based on previously developed bottom-up models of different flexible demand categories; four categories were considered in the model: electrified transport, electrified heating, smart appliances and industrial and commercial DSR. Finally, the interconnection capacity was projected to increase from the existing 4 GW to 10-15 GW in 2030.

The starting seven 2030 scenarios and those assumed for years 2015-2025 were used as a basis to produce final counterfactual scenarios to be used for SIC studies. This was done by cost-optimising conventional generation capacity in the system (e.g. to ensure sufficient security of supply) as well as reducing offshore wind capacity while maintaining the carbon intensity at 100 g/kWh.

6 The likelihood that the UK electricity system decarbonisation is not accompanied by further deployment of flexible options (energy storage, DSR and interconnection) is perceived to be very small. The smart meter rollout and recent increase in battery storage capacity on the system combined with the results of Enhanced Frequency Response (EFR) tenders suggest that we are already on track to go far beyond this scenario. However, this scenario was analysed to provide a reference point i.e. a worst-case scenario against which the other scenarios can be compared.

Total system cost

The total annual system cost was first quantified across all scenarios, to estimate the overall cost performance including investment and operating cost between different scenarios.[7] All 2030 systems included a significant amount of new LCGT capacity required to meet the 100 g/kWh target; given the high investment cost and low operating cost typically associated with LCGTs, the investment cost in low-carbon generation dominates the total system cost, and its share gradually increases between 2015 and 2030.

The overall system cost in 2030 is by far the highest in the No Flex scenario, while the Low and Mid Flex scenarios deliver savings of about £3.5bn/year and £4.0bn/year, respectively, over the No Flex scenario. Further improvements in flexibility in Modernisation and Mega Flex scenarios deliver savings of about £4.2bn/year, although this figure does not include the cost of increased DSR deployment in the Mega Flex scenario, nor any cost of improved system operation in the Modernisation scenario.

It is evident that achieving the 100 g/kWh target in 2030 cost-effectively by using relatively high shares of variable renewables would require moderate improvements in system flexibility. Scenarios with modest levels of flexibility already deliver substantial cost savings over the No Flex scenario because they require *less low-carbon generation to meet the carbon target*, less conventional generation to meet the security criterion and less distribution CAPEX due to reduced peak loading driven by the utilisation of distributed storage and DSR. These savings are only slightly offset by the additional cost of storage and interconnection.

It is worth noting that already in the Low Flex scenario, which is broadly half way between the No Flex and Mid Flex scenarios in terms of flexibility deployment, the net system cost savings amount to about 80% of those found in the Mid or Mega Flex scenarios. Therefore, even moderate improvements in system flexibility have the potential to deliver significant savings when compared to the No Flex scenario i.e. to the system with no flexibility improvement from today's situation (noting again that the cost of DSR or modernised system operation is not included in total system cost estimates; however, as these improvements are not necessarily scenario-driven, this assumption does not undermine the comparison between scenarios). On the other hand, increasing the system flexibility beyond the Mid Flex level appears to yield very modest additional savings.[8]

System Integration Cost

By applying the whole-system assessment framework it was possible to not only quantify the total SIC, but also to disaggregate it into key components: generation, transmission and dis-

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[7] Note that this calculation of total system cost did not include the cost of currently existing transmission and distribution asset base. These estimates are therefore primarily intended to provide a relative measure of economic performance of different scenarios when compared to each other. Furthermore, these cost estimates do not include any cost associated with DSR deployment or the cost of implementing the improved measures and practices in the Modernisation scenario.

[8] Lower level of flexibility seems sufficient to deliver bulk of the savings given the focus on 2030 and 100 g/kWh carbon intensity in this study. However, as demonstrated in our earlier studies (e.g. the CCC report) higher RES penetrations i.e. more ambitious carbon targets would require higher levels of flexibility. This is also demonstrated in the sensitivity studies for 50 g/kWh carbon intensity carried out in this report.

tribution investment cost (CAPEX) as well as operating cost (OPEX) associated with different generation technologies. Given that the SIC results refer to relative integration cost of LCGTs when compared against nuclear generators, the interpretation of SIC should be that if the SIC for a given LCGT is higher than its corresponding LCOE cost advantage against nuclear, this suggests that a unit of this technology has a higher whole-system cost i.e. provides a lower net marginal benefit to the system than a unit of nuclear capacity.

The results of the SIC studies for offshore wind, onshore wind and PV across all scenarios are shown in Figure E.2. For each scenario the SIC is broken down into components, which refer to operating cost (OPEX), generation investment (G CAPEX) and transmission and distribution network investment (T CAPEX and D CAPEX). OPEX and G CAPEX categories are further subdivided according to different generation technologies where change in operating and investment cost is observed in the SIC study compared to the counterfactual scenario. Note that the No Flex results are not plotted to scale as they would make the other results less visible.

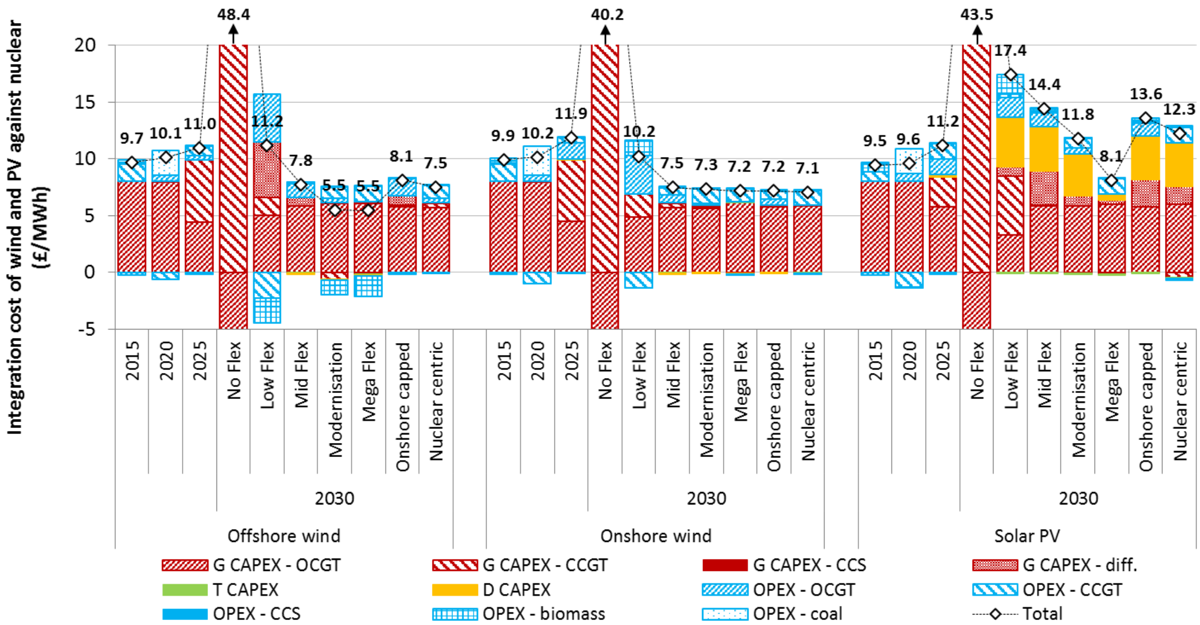

Figure E.2. SIC of offshore wind, onshore wind and solar PV compared to nuclear across all scenarios

In each scenario the replacement of nuclear with offshore or onshore wind or PV had a positive (net) G CAPEX component, which is predominantly a result of investing in additional OCGT and CCGT capacity to maintain security of supply given the low capacity value of wind and PV. In 2030 scenarios the component "G CAPEX – diff." starts to appear in SIC; this component refers to the extra capacity of offshore/onshore wind or PV that had to be added in excess of the energy-equivalent capacity in order to meet the 100 g/kWh emission target.

Replacement of nuclear with offshore or onshore wind or solar PV also triggers changes in operating cost of thermal generators in varying proportions, driven by the additional requirements for ancillary services (reserve and response) arising from increased wind and PV capacity, as well as the seasonality of wind and PV output profiles. The exact magnitude of additional operating cost is the result of the composition of thermal generation mix in a given scenario and the combination of fuel and carbon prices across time.

Interestingly, despite the SIC of offshore and onshore wind gradually increasing between 2015 and 2025, the integration cost in 2030 (except in the No Flex scenario) is at the same level as in 2025 or lower. Similarly, the SIC of PV also remains similar or even reduces in some 2030 scenarios compared to the 2015-2025 values. This reduction in SIC is primarily driven by significant improvements in flexibility between 2025 and 2030 assumed in most of the scenarios (i.e. rapid deployment of energy storage, DSR and interconnection).[9]

The SIC of solar PV across different scenarios between 2015 and 2025 is very similar to the SIC of offshore and onshore wind (i.e. around £10-12/MWh); however, in 2030 the SIC of PV becomes considerably higher. This is particularly driven by a higher distribution CAPEX component across all 2030 scenarios. High distribution investment arises as the result of increased reversed flows in distribution networks, which require reinforcement of the grid. There is also a noticeable component of additional PV investment to maintain emissions (G CAPEX – diff.), as the seasonal variation of PV generation output in the UK is exactly the opposite of system demand variations: high PV output in summer coincides with low system demand and vice versa. Hence, the generation displaced by an incremental PV capacity is likely to be less carbon-intensive than average, meaning that carbon benefits of additional PV would be lower than those of removed nuclear output and consequently more PV capacity would be needed to maintain the 100 g/kWh intensity.

To illustrate the relationship between the assumed LCOE values and calculated SIC for variable renewables against nuclear generation, Table E.1 contrasts the projected LCOE evolution for these technologies and their Whole-System Costs (WSC) across different scenarios.[10] As indicated by green-coloured cells in the table, the WSC of all three variable RES technologies is lower than the LCOE of nuclear in all 2030 scenarios except No Flex, where due to the lack of flexibility the SIC of wind and PV is several times higher than in all other scenarios. The only exception to the above statement is the WSC of offshore wind in the Nuclear Centric scenario, where due to zero LCOE advantage over nuclear the similar level of SIC as in other scenarios makes the WSC of offshore wind higher than for nuclear.

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[9] It is possible to conceive a situation where due to sudden improvements in future flexibility some generation capacity, in particular flexible peaking capacity installed in earlier years to provide sufficient firm capacity, becomes redundant as its role is taken over by e.g. energy storage and DSR. Nevertheless, in a scenario with a gradual improvement of flexibility over time the likelihood of ending up with a significant volume of stranded generation assets is considered to be relatively small.

[10] Given that SIC of LCGTs were quantified against nuclear, this could be interpreted as implicitly assuming that SIC of nuclear is zero. Nevertheless, the impact of the size of largest generator loss is not factored into the SIC of nuclear.

Table E.1. LCOE, SIC and whole-system costs of variable renewables and nuclear in 2030 (in £/MWh, real 2015 prices)

Scenario name	**No Flex**	**Low Flex**	**Mid Flex**	**Moderni-sation**	**Mega Flex**		**Onshore capped**	**Nuclear centric**
				LCOE				
Nuclear	90	90	90	90	90		90	80
Offshore wind	75	75	75	75	75		70	80
Onshore wind	60	60	60	60	60		60	60
Solar PV	65	65	65	65	65		65	65
				SIC vs. nuclear				
Offshore wind	48.4	11.2	7.8	5.5	5.5		8.1	7.5
Onshore wind	40.2	10.2	7.5	7.3	7.2		7.2	7.1
Solar PV	43.5	17.4	14.4	11.8	8.1		13.6	12.3
				Whole-System Cost (WSC)				
Offshore wind	**123.4**	**86.2**	**82.8**	**80.5**	**80.5**		**78.1**	**87.5**
Onshore wind	**100.2**	**70.2**	**67.5**	**67.3**	**67.2**		**67.2**	**67.1**
Solar PV	**108.5**	**82.4**	**79.4**	**76.8**	**73.1**		**78.6**	**77.3**

Sensitivity analyses

Further sensitivity studies focused on the following scenario aspects:

- *Retiring biomass*: Absence of biomass in the system requires more offshore wind in counterfactual scenarios to keep the carbon emissions at 100 g/kWh. Higher RES penetration in turn results in a generally increased SIC of offshore and onshore wind and solar PV compared to the core scenarios.

- *More ambitious carbon intensity target*: The counterfactual scenarios for 2030 with 50 g/kWh carbon intensity were constructed by adding a required amount of offshore wind to the original scenarios. This group of scenarios is useful to understand the dynamics of going beyond the 100 g/kWh mark and can therefore serve as a proxy for the challenges that we will be facing beyond 2030. The results of SIC studies for these scenarios reveal that in the Mid Flex and Onshore Capped scenarios, where the share of wind in meeting annual demand exceeds 55%, the SIC of both offshore wind and PV becomes substantially higher than in 100 g/kWh scenarios, as much more than energy-equivalent amount of wind or PV needs to be added to maintain carbon emissions, making the integration of wind and PV in those scenarios extremely inefficient. On the other hand, in scenarios with higher flexibility (Modernisation, Mega Flex) or lower starting wind capacity (Nuclear Centric) the level of SIC is comparable to that in the 100 g/kWh scenarios. These results suggest that a highly decarbonised scenario with high penetration of variable RES needs a high level of flexibility to be efficient.

- *Variations in system flexibility*: In addition to central (Medium) flexibility assumptions in core scenarios, further flexibility levels have been considered for the Base Case scenario: Low and High in 2020 and 2025, in addition to the already introduced No Flex, Low Flex, Mid Flex and Mega Flex scenarios in 2030. The results of quantitative studies confirm that increasing system flexibility can significantly reduce SIC of variable RES, with the reduction becoming particularly prominent in 2025 and

2030. For illustration, moving from No Flex to High flexibility (or Mega Flex) can reduce the SIC of offshore wind about 4 times in 2025 and 8 times in 2030.

- *Impact of largest unit size:* If the largest unit size in the 2030 GB system reduces from 1.8 GW to 0.5 GW, the SIC of variable RES would decrease by about 20%. This share of SIC may be interpreted as arising from the large size of nuclear units, which drives the primary response requirements.

Key observations

Key findings from quantitative studies include:

- Total annualised system cost for the 2030 GB system with the carbon intensity of 100 g/kWh will be driven by system flexibility. Up to £4.7bn/year could be saved by improving system flexibility from today's level; most of these savings are already achievable with moderately enhanced flexibility.

- A moderate improvement of system flexibility already brings the cost of the system down by £3.5bn/year, while at the same time reducing SIC of wind from more than £40/MWh down to around £11/MWh in the 2030 horizon. This level of SIC combined with the LCOE assumptions makes both offshore and onshore wind cost-effective compared to nuclear generation.

- According to the LCOE assumptions adopted in the study, despite the positive SIC the whole-system cost of offshore and onshore wind and PV (i.e. the sum of their LCOE and SIC) still makes them more attractive than nuclear in the majority of 2030 scenarios with modest or high flexibility levels.

- The SIC of wind and PV generation greatly depends on system flexibility as well as on the overall energy mix (i.e. the penetration of variable RES, largest generating unit size, the level of inflexible generation etc.) and is therefore a function of the assumed system evolution. As illustrated in Figure E.3 on the example of SIC values obtained for onshore wind, higher VRES penetrations yield a higher SIC, but the magnitude and the rate of this increase depends greatly on the level of enhancements in system flexibility that accompanies the expansion of VRES i.e. on the volume of deployed flexible options such as DSR, storage and interconnection. The figure identifies trend lines for four different rates of deployment of flexibility (No, Moderate, Fast and Maximum progress). In the case of inflexible system ("No progress") levels the SIC increases sharply already at low wind penetration levels; conversely, with higher flexibility ("Moderate" or "High progress") SIC remains at moderate levels even at significantly higher VRES penetrations.

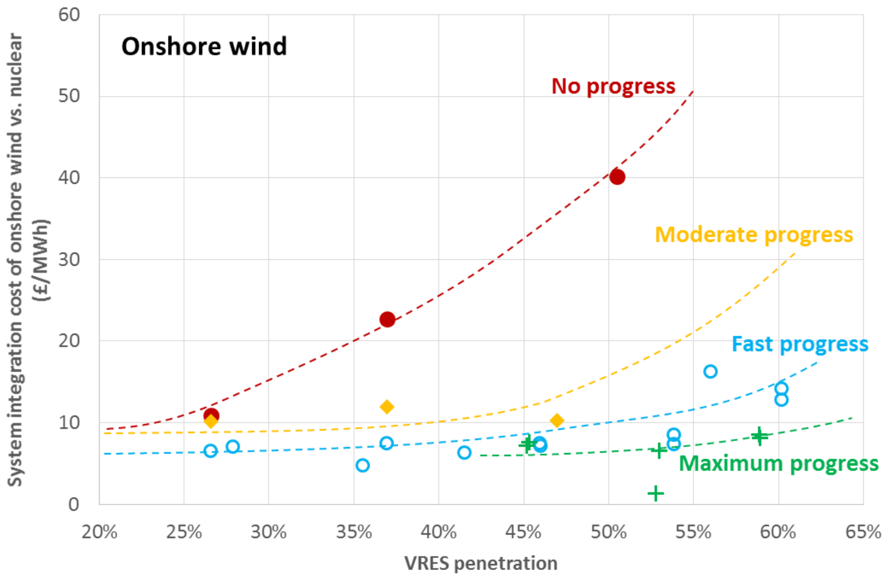

Figure E.3. SIC of onshore wind as function of total wind penetration

- System integration costs of variable renewables remain at a relatively low level even at penetration levels that are 3 times higher than today, provided there is only a modest improvement in system flexibility (such as through deployment of modest amount of energy storage and/or DSR).

- SIC of offshore and onshore wind in 2030 (when compared against nuclear power) is found to be around £5-9/MWh across the medium to high flexible scenarios analysed in the study. The majority of this cost (over 80% for flexible 2030 scenarios) is associated with the requirement to build sufficient firm (back-up) capacity when wind is added to the system, in order to maintain the same level of security of supply. A smaller part of SIC of wind is associated with increased operating cost resulting from increased requirement for balancing services triggered by added wind capacity and it is possible that this results in some double counting as generators are, at least partially, exposed to these costs.

- SIC of solar PV generation in 2030 is slightly higher than for offshore wind, and varies within the £10-15/MWh range with medium flexibility assumptions. When compared to offshore wind, it contains an additional component associated with distribution investment cost, given that large volumes of PV, especially if they are not installed uniformly across GB (as assumed in the study), may trigger distribution network reinforcement to deal with increased reverse power flows i.e. electricity being injected back into the distribution grid.

- Despite an increasing penetration of variable renewables between 2015 and 2030, SIC of wind and PV can be maintained at a relatively stable level (or even lower in some scenarios) provided that sufficient amount of flexible options is deployed. This occurs because the impact of increasing RES penetration and larger inflexible plant, creating an upward pressure on SIC, is counteracted by the opposing impact of improved flexibility i.e. increased volumes of energy storage, DSR and interconnection.

- Sensitivity studies carried out for 2030 scenarios with a more ambitious carbon target of 50 g/kWh suggest that the integration cost of variable RES would increase, driven primarily by higher RES penetration required to meet the lower emission target. In some instances, like in the Mid Flex and Onshore Capped scenarios where the penetration of wind exceeds 55% of annual electricity demand, any integration of further wind capacity becomes costly. Such high levels of wind require further improvements in system flexibility or operation practices, such as those assumed in Modernisation or Mega Flex scenarios.

1. Introduction

1.1. Background

With nearly half of UK's generation capacity expected to retire in the build up to 2030, the UK's electricity system is facing exceptional challenges in the coming decades. Replacing this generation capacity will for the most part need to be achieved with low-carbon electricity generation technologies if we are to meet our carbon emission reduction targets and this will need to be done whilst maintaining security of supply. Meeting the fourth carbon budget (2023-27) will require that emissions are reduced by 50% on 1990 levels in 2025. The decarbonisation of electricity supply is also driven by the EU Renewables Directive, 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 deployment of low-carbon generation technologies such as renewables, nuclear, biomass, carbon capture and storage, etc. Despite the output variability that is a feature of some (primarily renewable) low-carbon technologies, the decarbonised electricity system will need to continue to operate at the same levels of security of supply that are considered acceptable today.

One of the key challenges associated with decarbonisation is to ensure that electricity remains affordable to consumers i.e. that the transition towards a low-carbon electricity supply is achieved at the lowest possible cost for the society. This implies that it is critical to go beyond the pure LCOE estimates of individual low-carbon technologies and take into account their whole-system costs when considering detailed operation and design of a power system with high share of low-carbon generation. In that context, this work aims to provide evidence that will contribute towards the delivery of a secure and decarbonised power sector at least cost to consumers.

1.2. Concept of system integration costs of generation technologies

Understanding and quantifying the *system integration costs* (SICs) of various low-carbon generation technologies (LCGTs) is important in the context of delivering a secure decarbonised power sector at least cost in line with the legally binding 2050 decarbonisation targets and security of supply imperatives. SICs of generation technologies (also sometimes referred to as *system externalities*) include various types of costs that are imposed on the system by added generation capacity, but which are not included in the capital or operating cost estimates of these technologies. Examples of SIC components include:

- *Increased balancing cost* associated with: a) increased requirements for system reserve due to higher uncertainty of variable renewable generation output, and b) increased requirements for fast frequency regulation (response) due to reduced system inertia.

- *Network reinforcements* required in interconnection, transmission and distribution infrastructure (e.g. transmission reinforcement to connect remote wind resources or distribution network upgrade to cope with increased reverse power flows triggered by high volume of distributed solar PV installations).

- *Increased backup capacity cost* due to limited ability of e.g. variable renewable technologies to displace “firm” generation capacity needed to ensure adequacy of supply.

- *Cost of maintaining system carbon emissions*, as the addition of certain technologies may cause the overall emission performance of the system to deteriorate, requiring that additional low-carbon capacity is installed to maintain the same level of carbon emissions.

Some of these components, such as increased balancing or network cost may already be reflected to some extent in current charges imposed on generators, such as the balancing payments (BSUoS), or transmission and distribution charges (TNUoS and DUoS). Nevertheless, it has been argued that these charges may not be fully cost-reflective[11], while on the other hand some of the above components such as the backup capacity are not currently included in LCOE assessments in any form.

The quantification of SICs 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, enabling the development of policies and procurement mechanisms that consider both private and wider system costs of different technologies. It also has to be noted that some components of system integration costs are faced by generation plant owners in the market (such as e.g. the impact of location on transmission charges), but many of them are not.

1.3. Challenges of integrating low-carbon generation

There are two key factors which may reduce the ability of the system to accommodate the combination of inflexible low-carbon generation and variable renewables.

First, the expansion of variable renewables will lead to a significant increase in system balancing requirements in a low-carbon power system. Reserve requirements will increase due to higher generation output fluctuations and consequently higher forecasting errors associated with high RES penetrations. This is particularly relevant for wind generation, which is generally more difficult to predict than solar PV output. At the same time, given that solar PV and wind represent non-synchronous power sources that tend not to contribute to system inertia, the overall system inertia will decrease causing system frequency to fluctuate faster and more widely during frequency incidents such as those caused by a sudden loss of generation.[12]

[11] For a more detailed discussion on the issue, see a recent study prepared by NERA Economic Consulting and Imperial College London for the Committee on Climate Change: “System integration costs for alternative low carbon generation technologies – policy implications”, available here: https://www.theccc.org.uk/publication/system-integration-costs-for-alternative-low-carbon-generation-technologies-policy-implications/.

[12] It is noted that onshore and offshore wind turbines have the technical capability to provide “synthetic inertia” through specifically designed control algorithms that ensure that in the event of a significant frequency drop their kinetic energy is extracted and injected into the grid. Nevertheless, current regulatory framework does not require wind generators to provide inertial response to the system.

Lower system inertia would in turn lead to higher requirements for primary frequency regulation. The value of frequency regulation in the future GB system is hence expected to increase. The need for reserve capacity and frequency regulation is also dependent on the size of the largest credible generator loss in the system which would be the driven by deploying new very large nuclear power stations.

Second, the present electricity system is characterised by relatively limited flexibility, mostly provided by conventional gas and coal generation. Today's generators are typically characterised by a limited amount of frequency control they can provide and a relatively high minimum stable generation, and both of these features may represent limiting factors for the amount of renewable generation that can be accommodated in the system. Conventional generation technologies with significantly enhanced flexibility are already available, but the lack of appropriate market signals has so far suppressed their deployment. Similarly, energy storage technologies and demand-side response could also significantly enhance system flexibility. It is important to mention that a tender for Enhanced Frequency Response (EFR) was recently developed by National Grid to bring forward new technologies that support the decarbonisation of the energy industry by providing a fast response solution to system volatility. In contrast to traditional frequency response delivered by conventional generation within ten seconds, new class of technologies will enable the delivery of this response in under a second.

The operating cost associated with delivering energy is expected to decrease going forward as the result of very low operating cost of most LCGTs. At the same time, the cost associated with the provision of ancillary services is likely to increase substantially, driven by both increased requirements for frequency regulation as well as the cost of managing the fluctuations in variable LCGT output. Similarly, the volume of the capacity market is expected to increase as historical generators retire and need to be replaced by more new capacity. The increasing prominence of ancillary service and capacity markets should create opportunities for flexible providers such as energy storage and DSR. Previous analysis by the authors shows that the proportion of total system operating cost that can be attributed to ancillary service provision would increase from about 2% today to more than 25% in the 2030 horizon, driven by rapidly changing energy mix.

A more detailed discussion of challenges associated with the integration of variable renewables is provided in Chapter 7, where a range of solutions is also described.

1.4. Key objective

In the context of the above, the main objective of this study is to first establish the likely level of total system cost in the 2030 horizon across different scenarios, and then quantify and examine in more detail the SIC of low-carbon generation technologies such as nuclear, biomass, variable renewable generation technologies, with particular focus on onshore and offshore wind, in the context of the future, largely decarbonised UK electricity system.

For more details 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.

2. Methodology for quantifying whole-system costs of low-carbon technologies

Most of the previous approaches to quantifying SICs focused on quantifying individual components of SIC. All of these methods calculated the *absolute integration cost* i.e. the cost associated with a single technology that is added to the system. Nevertheless, there is at present no commonly accepted method to quantify SIC, as different definitions have their own issues with robustness or accuracy.

This report therefore focuses on quantifying the *relative integration cost* reflecting the difference between the system externalities of pairs of LCGTs. This approach ensures a robust calculation approach while at the same time indicating relative merits of different LCGTs from the whole-system perspective. In the studies presented in the report nuclear power is selected as the counterfactual LCGT, against which the relative SIC of other LCGTs (wind, solar and biomass) are quantified. The choice of nuclear as the benchmark technology is somewhat arbitrary; however, this choice does not affect the differences between relative SICs quantified for other LCGTs (such as e.g. between the SICs of wind and PV generation).

2.1. Whole-system assessment of electricity systems

Different components of SIC are incurred in different segments of the electricity system, such as generation, transmission or distribution infrastructure, or are a part of system operation and balancing cost. Therefore, the quantitative framework applied to evaluate the SIC is based on the whole-system modelling approach i.e. the WeSIM model[13]. This model has the ability to simultaneously make investment and operation decisions with high (hourly) time resolution, while capturing the interactions between different time scales (investment vs. short-term operation) as well as across different asset types in the electricity system (e.g. generation vs. network). At the same time the model can also consider various flexible technologies such as energy storage or demand-side response (DSR). A distinct characteristic 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 detailed description of the model can be found in the Appendix.

In this study the WeSIM model was applied to the interconnected GB electricity system that was represented with four transmission nodes within GB and two neighbouring systems: Ireland and Continental Europe (CE), with the latter representing the entire interconnected European system. In order to simulate cost-efficient outcomes across Europe, the model was set up to optimise the operation of the entire European system, taking into account interconnection capacities between systems. Two further important features endogenously included in the model are the capability to impose a given carbon emission constraint for each system, as well as ensure sufficient generation capacity is built in each system to meet the security of supply standards.

[13] D. Pudjianto, M. Aunedi, P. Djapic, G. Strbac, "Whole-Systems Assessment of the Value of Energy Storage in Low-Carbon Electricity Systems", *IEEE Transactions on Smart Grid*, vol:5, pp. 1098-1109, (2013).

2.2. Valuation of flexible options in future systems

As part of the whole-system assessment framework employed in this analysis, there are four main categories of flexible options that were considered: (i) demand-side response (DSR), (ii) flexible generation technologies, (iii) network solutions such as investing in interconnection, transmission and/or distribution networks, and (iv) the application of energy storage technologies.[14]

Our previous study[15] found that in the absence of alternative flexible balancing technologies the scale of the balancing challenge in the future GB electricity system would increase very significantly beyond 2030, with substantial investment needed in additional generation, transmission and distribution assets to achieve the carbon emission targets while ensuring security of supply. Lack of flexibility significantly limits the system's ability to integrate high volumes of variable renewable energy sources (VRES): the same study demonstrated that up to 30% of electricity theoretically available from VRES may need to be curtailed in 2050 if no flexible options are deployed. VRES curtailment may become necessary to balance the system, e.g. during periods of low demand, high renewable output, and high output of inflexible units such as nuclear plants, or conventional generators that have to be synchronised in order to provide ancillary services. Curtailment of VRES will obviously have an adverse impact on the carbon intensity of electricity supply given that the system effectively spills zero-carbon renewable output. Additionally, curtailment of VRES would not necessarily be predicated by a cost imperative, indicating that VRES is likely to be cheaper to curtail than the alternative such as nuclear plant.

It is therefore essential to study various system flexibility levels as one of the key determinants of the system's ability to cost-effectively integrate VRES generation. Flexibility is hence included as a key parameter in subsequent SIC studies as it is evident that flexibility can greatly reduce the SIC of VRES, particularly in future development scenarios with high shares of renewable generation.

2.3. Method for calculating SIC

The *whole-system cost* (WSC) of any generation technology can be expressed as the sum of the LCOE of that technology and the corresponding SIC:

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

The cost terms in the above expression are typically expressed in monetary units per unit of energy produced (e.g. in £/MWh). All generation technologies will potentially have a SIC although for some technologies and systems this value may become negative (i.e. the technology may provide a system integration benefit). There is currently no widely accepted con-

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14 Details on how these different flexible options have been included in the whole-system modelling framework can be found in the recent CCC study: Imperial College London, "Value of Flexibility in a Decarbonised Grid and System Externalities of Low-Carbon Generation Technologies", report for the CCC, October 2015.

15 Imperial College London and NERA Economic Consulting, "Understanding the Balancing Challenge", report for DECC (2012).

sensus regarding the exact definitions of various components of SIC and their interactions, and the methods for evaluating and allocating these costs vary considerably.[16]

In contrast to the approaches that quantify the components of SIC separately, such as e.g. by considering only additional balancing or additional network cost without looking at their interaction, this report quantifies the whole-system impact of adding a unit of LCGT in a given system scenario while maintaining a given carbon intensity target. The approach presented here quantifies each of the components of SIC that result from the system cost-optimally adapting to the addition of LCGT across all cost categories. As an example, if there is a significant volume of DSR present in low-voltage (LV) distribution grid, and wind capacity is being added to the system requiring a higher volume of balancing services to be provided, it may be opportune to invest into reinforcing the distribution network in order to enable the system to access flexible DSR resource at the distribution level so that this flexibility can be used to reduce balancing cost at the national level. These interactions and trade-offs would be highly difficult to capture when quantifying SIC components separately.

In terms of the allowed response of the system to the addition of a unit of LCGT, we establish a method to quantify the *relative System Integration Cost* that adopts nuclear power as the benchmark LCGT, and is based on *Method 2* elaborated in the earlier CCC study. The theoretical relationship between the relative SIC of technology 1 compared to technology 2, their WSCs and LCOEs can be expressed as follows:[17]

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

Method 2, based on *optimised replacement*, assumes that 1 GW of nuclear capacity is removed from the system, while the model is allowed to optimally increase the capacity of another LCGT (e.g. wind or solar) while at the same time maintaining the same overall GB system emissions. No change in the capacities of other LCGTs is allowed in this method; the model is only allowed to adjust conventional capacity (CCGT and OCGT) if cost-efficient.

Changes in total system cost, excluding the investment and operation cost (i.e. LCOE) of the pairs of technologies involved in the substitution (e.g. removed nuclear and added wind capacity), are divided by the annual output of the added low-carbon technology to establish its relative SIC against nuclear power in £/MWh. Also, in this method any cost of LCGT capacity added in excess of the energy-equivalent[18] volume is factored into the total cost differential between the original system and a given SIC study.

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16 An early meta-study comparing different approaches to quantifying the cost of integrating wind in the UK power system was carried out by the UK Energy Research Council: "The Costs and Impacts of Intermittency – An assessment of the evidence of the costs and impacts of intermittent generation on the British electricity network", March 2006.

17 Note that this equation represents the theoretical relationship between whole-system costs, LCOEs and SICs. The actual calculation method deployed in the study is elaborated in Section 3.6.2.

18 Energy equivalence here means that the removed and added capacities are capable of providing the same nominal annual output (e.g. if the annual utilisation of nuclear is 90% and that of offshore wind is 43%, then it would take about 2.1 GW of wind capacity to produce the same output as 1 GW of nuclear).

3. Scenarios and assumptions

This chapter sets out the scenarios and other assumptions used to estimate the SIC of a range of low-carbon generation technologies. Scenarios cover the period between 2015 and 2030, with a single core scenario for years 2015, 2020 and 2025, and multiple scenarios for 2030 with varying degrees of flexibility as well as different low-carbon generation portfolios. This study also includes a broad range of sensitivity analyses.

Given the decarbonisation agenda of the UK energy policy, all scenarios assume a significant expansion of low-carbon generation capacity (i.e. nuclear and renewable, and to a lesser extent CCS capacity) between today and 2030. Also, the scenarios assumed a certain level of targeted carbon intensity for the electricity system; in the basic set of studies this target was set at 100 g/kWh in 2030, although sensitivity studies have been run with the 50 g/kWh target as well.

3.1. Description of scenarios

A range of future development scenarios have been selected for this analysis based on the Sponsors' input, drawing upon recent DECC, CCC and National Grid scenarios. The time horizon covered by the scenarios is until 2030. The following main scenarios are considered in 2030:

1. *Mid flexibility ("Mid Flex")*: Central scenario with high wind deployment, reaching up to 31 GW of offshore and 20 GW of onshore wind in 2030[19]. This scenario has moderate levels of nuclear (8.2 GW), assuming the addition of 4.5 GW of new capacity by 2030, and 20 GW of PV capacity. It also has a moderately high deployment level of flexible options: 10 GW of new storage, 50% of DSR uptake and 11.3 GW of interconnection capacity.

2. *No progress ("No Flex")*: Same as Mid Flex, but with no new storage, zero DSR uptake and low interconnection capacity. With the regulated role out of smart meters and significant cost benefits for any flexible system, this scenario should be seen as a useful benchmark that informs the benefits of flexibility rather than as a viable scenario.

3. *Low flexibility ("Low Flex")*: Same as Mid Flex, but with less ambitious deployment of flexible options: 5 GW of new storage, 25% DSR uptake and 10 GW of interconnection.

4. *Modernisation*: Same as Mid Flex, but with a range of measures to improve system operation (concerning wind predictability, capability to provide ancillary services etc.).

[19] Note that, as explained later, in the basic set of scenarios the offshore wind capacity was optimally reduced to reach the given carbon intensity target (100 g/kWh).

5. *High flexibility ("Mega Flex")*: Scenario with similar generation mix as the Mid Flex scenario, but with enhanced flexibility i.e. higher storage (15 GW) and interconnection capacity (15 GW) and greater DSR uptake than the Mid Flex (100%).

6. *Onshore Capped*: Scenario with no new onshore wind deployment beyond today's level[20] (around 8 GW), but compensated by a more intensive expansion of offshore wind (up to 39 GW) until 2030. Nuclear and PV capacity are at the Mid Flex level.

7. *Nuclear Centric*: This represents a theoretical alternative technological solution to a high variable LCGT mix for achieving the UK's decarbonisation agenda. Whilst a more ambitious nuclear expansion in this scenario (16.4 GW in 2030) seems unachievable to deliver from today's perspective, this scenario nevertheless offers a useful benchmark to assess the cost-effectiveness of an energy mix with high levels of variable LCGT. The scenario therefore has slower wind development (up to 21 GW of offshore and 12.5 GW of onshore wind, compared to 5.1 GW of offshore and 9 GW of onshore today).

The Mid Flex scenario is also backtracked to include years 2015, 2020 and 2025, and is also referred to as "Base Case" in those years. Other scenarios only referred to 2030 (although sensitivity studies on system flexibility were also carried out for 2020 and 2025, as explained in Section 6.3).

3.2. Assumptions on generation technologies

3.2.1. Generation capacity

Table 3.1 provides an overview of the assumed starting generation capacities across all scenarios. Generation mixes for No Flex, Low Flex, Modernisation and Mega Flex scenarios were the same as in the Base Case scenario.

[20] This scenario reflects the uncertain future evolution of offshore wind in light of the recent closure of the Renewables Obligation (RO) to onshore wind capacity in Great Britain that took effect on 12 May 2016.

Table 3.1. Generation capacity assumptions across scenarios (in GW)

Scenario name	Basecase 15	Basecase 20	Basecase 25	Mid Flex*	Onshore capped	Nuclear centric
Year	**2015**	**2020**	**2025**	**2030**	**2030**	**2030**
Nuclear	9.4	8.9	7.9	8.2	8.2	16.4
Gas CCGT**	29.3**	29.3**	18.0**	16.0**	16.0**	16.0**
Coal	18.7	10.9	-	-	-	-
Gas CCS	-	-	0.5	0.5	0.5	0.5
Onshore	9.0	13.2	16.6	20.0	8.0	12.5
Offshore***	5.1	10.2	16.2	31.0***	39.0***	21.0***
Solar	8.8	12.8	16.4	20.0	20.0	20.0
Biomass	4.0	3.4	3.4	3.4	3.4	3.4
Hydro	1.5	1.5	1.5	1.5	1.5	1.5
Pumped st.	2.8	2.8	3.7	3.7	3.7	3.7

Notes:
* The same starting generation mix as in Mid Flex scenario was also assumed in No Flex, Low Flex, Modernisation and Mega Flex scenarios.
** CCGT capacity in the table represents the legacy capacity that would be in place without any new CCGT plants. The model was allowed to build more CCGT if cost-effective.
*** In the core scenario runs the offshore wind capacity in 2030 was subject to cost-optimal reduction while meeting the system-level carbon target of 100 g/kWh.

As indicated in the table, capacities of certain technologies were modified by the model when finding a least-cost solution. CCGT capacity was optimised on top of the capacity of current generators that will still be in operation until 2030. With offshore wind capacity, the capacity was reduced in a cost-optimal fashion in order to meet the 100 g/kWh target in 2030.[21] In the modelling OCGT generation is used as a proxy for peaking capacity that may be required to enforce the security of supply criterion, as the low capital cost and high utilisation cost of OCGT are representative of a typical peaking unit. In reality OCGT could be replaced with distributed reciprocating engines, CCGTs, storage or DSR if these where perceived as cheaper or more desirable alternatives. .

3.2.2. Capacity factors

Table 3.2 sets out the assumptions on achievable capacity factors for different generation technologies across time. Note that all 2030 scenarios had the same capacity factor assumptions. All other technologies (e.g. conventional plant) had their utilisation factors determined by the model as the result of optimisation.

[21] According to preliminary studies carried out, without this reduction the Base Case system would be able to achieve carbon intensities of below 60 g/kWh, i.e. would over-deliver on the carbon target due to abundant low-carbon generation capacity.

Table 3.2. Maximum[22] capacity factors of generation technologies across scenarios

Year	**2015**	**2020**	**2025**	**2030**
Nuclear*	66%	66%	73%	90%
Gas CCS	90%	90%	90%	90%
Onshore wind	30%	30%	30%	30%
Offshore wind	47%	47%	47%	47%
Solar	11%	11%	11%	11%
Biomass**	75-90%	75-90%	75-90%	90%

Notes:
* Nuclear capacity factors in different years are based on historical data on the utilisation of existing plant combined with the expected utilisation of new nuclear units.
** Biomass generation in years 2015, 2020 and 2025 had a specified *minimum* utilisation of 75% in our studies, as it would otherwise see very low utilisation due to high operating cost in the absence of support mechanisms.

The evolution of nuclear capacity factors over time is a blend of relatively lower utilisation achieved by currently existing plants (some of which have technical issues that prevent them from operating at full output) and high utilisation (~90%) of new nuclear units.

Capacity factors of onshore and offshore wind are based on the Sponsors' estimates, while the PV utilisation is taken from the 2015 version of DECC's energy projections[23]. These capacity factors have been supported by regional hourly output profiles for wind and PV generators, which Imperial have developed in previous analyses. The hourly RES output profiles were further differentiated according to four GB regions used in the modelling, so that for instance an onshore wind generator in Scotland has a higher utilisation factor than onshore wind located in South England. Conversely, the utilisation of PV generation is higher in the south than in the north of Great Britain. Figure 3.1 presents the normalised output duration curves for UK-representative wind and PV profiles used in the study.

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22 Maximum in the context of wind and PV generation refers to maximum achievable load factor; if there is curtailment of variable RES output, the actual utilisation of these technologies could be lower.

23 Department of Energy and Climate Change, "Updated energy and emissions projections: 2015", available at: https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2015.

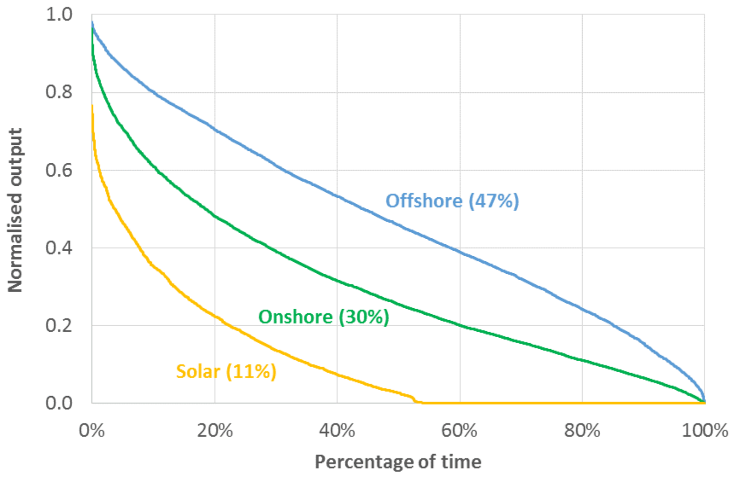

Figure 3.1. Assumed normalised output duration curves for offshore wind, onshore wind and solar PV for Great Britain

3.2.3. Geographical distribution of generation capacity

Given the representation of the GB electricity system with four regions, the assumed breakdown of RES capacity, as well as nuclear and conventional capacity, followed the existing generation portfolio as well as expectations regarding future installations of generation capacity. Table 3.3 specifies the relative shares used in the study for onshore, offshore and PV capacity in each of the modelled GB regions.

Table 3.3. Geographical distribution of RES capacity across GB regions

GB region	Onshore	Offshore	Solar
Scotland	66%	14%	5%
North England and Wales	13%	39%	5%
Midlands	5%	13%	25%
South England and Wales	16%	34%	65%

In our whole-system modelling it is possible to differentiate distributed energy resources (distributed generation, distributed storage or DSR) according to the types of networks where they are connected, and quantify the resulting impact of distributed technologies on distribution networks at different voltage levels. Therefore, in addition to the above breakdown, we have further assumed that 25% of installed PV capacity was connected at low voltage (LV), while 75% was connected at the high voltage (HV) level.[24]

[24] This is broadly in line with the recent statistics on PV deployment in Great Britain. For instance, at the end of April 2016 about 74% of GB PV capacity had the rated power of more than 10 kW (see e.g. DECC, "Solar Photovoltaics Deployment in the UK", April 2016, https://www.gov.uk/government/statistics/solar-photovoltaics-deployment).

3.2.4. Cost assumptions

The levelised cost of energy (LCOE) assumptions for different technologies were mostly based on DECC's 2013 generation cost update.[25] There is strong evidence, even from the Government itself, that this data set is outdated; we have therefore used alternative cost data sources for certain technologies where available, as specified in Table 3.4 below. The assumptions in different scenarios follow the rationale where e.g. higher deployment of offshore wind or nuclear generation leads to a reduction in cost of the technology.

Table 3.4. LCOE assumptions for selected technologies across scenarios (in £/MWh, real 2015 prices)

Scenario name	Basecase 15	Basecase 20	Basecase 25	Mid Flex	Onshore capped	Nuclear centric
Year	2015	2020	2025	2030	2030	2030
Nuclear	93	93	90	90	90	80
Gas CCS	-	-	122	123	123	123
Onshore wind[26]	75	65	60	60	60	60
Offshore wind[27]	133	106	80	75	70	80
Solar[28]	101	86	75	65	65	65
Biomass	108	108	108	108	108	108

LCOE assumptions in No Flex, Low Flex, Modernisation and Mega Flex scenarios were identical to those made for the Mid Flex scenario.

3.3. Demand assumptions

Projected demand for years 2015 to 2030 used in the study has been based on the CCC sectoral scenario for the electricity sector[29], which supported the drafting of the Fifth Carbon Budget. The baseline (Other) demand in this scenario is projected to remain broadly similar, with a slowly declining trend beyond 2020. On the other hand the uptake of electrified trans-

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25 DECC, "Electricity generation costs", July 2013, available at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/223940/DECC_Electricity_Generation_Costs_for_publication_-_24_07_13.pdf.

26 Sources:
1) Renewable UK, "Onshore Wind Cost Reduction Taskforce Report", April 2015, http://www.renewableuk.com/en/publications/reports.cfm/Onshore%20Wind%20Cost%20Reduction%20Taskforce%20Report
2) Policy Exchange, "Powering Up: The future of onshore wind in the UK", 2015, http://www.policyexchange.org.uk/images/publications/powering%20up.pdf

27 Source: BVG Associates, "Approaches to cost reduction in offshore wind", report for the CCC, 2015, https://www.theccc.org.uk/publication/bvg-associates-2015-approaches-to-cost-reduction-in-offshore-wind/.

28 Sources:
1) KPMG, "UK solar beyond subsidy: the transition", report for REA, July 2015, http://www.r-e-a.net/upload/uk-solar-beyond-subsidy-the-transition.pdf.
2) Solar Trade Association, "Cost reduction potential of large scale solar PV", November 2014, http://www.solar-trade.org.uk/wp-content/uploads/2015/03/LCOE-report.pdf.

29 Climate Change Committee, "Sectoral scenarios for the fifth carbon budget – Technical report", November 2015, https://www.theccc.org.uk/publication/sectoral-scenarios-for-the-fifth-carbon-budget-technical-report/.

port and heating in the domestic sector is projected to increase from about zero today to around 21 TWh and 9 TWh, respectively. The evolution of demand is provided in Table 3.5.

Table 3.5. Projected electricity demand between 2015 and 2030 (in TWh)

Year	**2015**	**2020**	**2025**	**2030**
Domestic Heat (HP)	0.6	2.1	5.0	9.0
Electric Vehicles	0.1	1.3	7.0	21.0
Losses	26.0	26.0	26.5	27.0
Other	302.3	305.1	302.6	298.0
Total	**329**	**335**	**341**	**355**

A single projection was made for each year, therefore all 2030 scenarios had the same demand assumptions.

3.4. Flexibility assumptions

3.4.1. Deployment of flexible options

Key assumptions regarding the assumed deployment of flexible options across different scenarios are given in Table 3.6. Onshore Capped and Nuclear Centric scenarios are omitted as they had the same flexibility assumptions as the Mid Flex scenario.

Table 3.6. Deployment of flexible options across scenarios

Scenario name	**Basecase 15**	**Basecase 20**	**Basecase 25**	**No Flex**	**Low Flex**	**Mid Flex***	**Moderni-sation****	**Mega Flex**
Year	**2015**	**2020**	**2025**	**2030**	**2030**	**2030**	**2030**	**2030**
New storage (GW)	0	0.2	2	0	5	10	10	15
DSR	0%	0%	25%	0%	25%	50%	50%	100%
Interconnection (GW)	4.0	7.5	11.3	7.5	9.9	11.3	11.3	15.0

* Onshore Capped and Nuclear Centric scenarios had the same flexibility assumptions as the Base Case.
* The Modernisation scenario had the same deployment of storage, DSR and interconnection as the Base Case, but included improved system operation practices as detailed in Section 3.4.2.

New *energy storage* (in addition to the projected capacity of pumped storage in Table 3.1) is assumed to be available in distributed form similar to battery storage. Its capacity is increased from broadly zero today to between 0 and 15 GW in 2030 scenarios. It was further assumed that new storage would be sufficiently fast-responding to be able to provide frequency response to the system operator.[30] The assumed duration of energy storage (i.e. the ratio between the maximum energy stored and installed power) was 5 hours, so that for instance 5 GW of storage capacity was assumed to be able to store 25 GWh of energy.

30 This is in line with recent developments of new ancillary service products by National Grid, such as Enhanced Frequency Response that requires sub-second response times; this service is primarily targeting battery providers.

The uptake of *demand-side response (DSR)* is assumed to increase from around zero in 2020 to 50% in 2030 in the Base Case scenario. The 2030 DSR uptake varied between 0% in the No Flex to full uptake in the Mega Flex. The DSR potential is quantified based on our previous bottom-up modelling of different flexible demand categories, which considered how they perform their actual functions while exploiting the flexibility that may exist without compromising the service delivered to end users. In our modelling we differentiated between four types of potentially flexible demand:

- *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.

The above assumptions correspond to 100% DSR uptake i.e. represent the maximum achievable potential. The actual DSR availability is scaled down according to the assumed DSR uptake level (e.g. the 50% DSR uptake assumes that only half of the theoretical potential is realised).

Interconnection capacity is projected to increase from the current 4 GW to 11.3 GW in 2030 (Mid Flex), assuming the realisation of currently approved and planned interconnection projects. Available interconnection capacity was varied across different flexibility scenarios, from 7.5 GW in No Flex to 15 GW in the Mega Flex scenario.

3.4.2. Improved system operation in Modernisation scenario

There is a number of different possibilities as to how the system operation practices in the future may become more flexible and more efficient, in particular with respect to the management of wind generation. In this report we have modelled several of these improvements that were deemed of particular interest, but this by no means implies these are the only possibilities.

The improvements in system operation assumed in the Modernisation scenario included:

- *Wind generators being able to provide synthetic inertia and frequency response*
  Wind installations are normally realised through non-synchronous generation technologies, which cannot provide inertia unless equipped with advanced control schemes. Although theoretical solutions are available in scientific literature, wind generators are currently not required to provide system inertia. With higher wind penetrations, it may become opportune to improve the control of wind generators to enable them to contribute to system inertia similar to conventional plant that they are likely to displace in future electricity mix.

- *Wind generators being able to provide reserve when curtailed*
  In the future system with high wind penetration it may become necessary to occasionally curtail wind or PV output in situations of excess available energy and low demand. Curtailed renewable output may in those situations be used to provide reserve services to the system operator and potentially replace reserve provided by conventional units. More generally, wind generators that can access reserve and balancing markets may choose to curtail their output whenever the value of reserve or balancing service exceeds the value obtained from the wholesale market. This option is not utilised today given the current market structure and low frequency of curtailment events, but it may become more commonplace in future.

- *Improved forecasting of wind*
  There is continuous improvements in wind forecasting techniques which may eventually lead to reduced reserve requirements, as the forecasting error which the system operator needs to be able to resolve would become lower and hence require less reserve service to be procured.

- *Ability to procure frequency response services via interconnectors*
  This option is also not commonly used in today's systems, but with increased frequency response requirements it may become beneficial to use interconnection capacity not only to enable energy exchanges, but also to facilitate trading of balancing services.

3.5. Other assumptions

3.5.1. Carbon intensity target

In this study we imposed an explicit carbon intensity target of 100 g/kWh in 2030 across the main set of scenarios. No carbon target was specified for 2015, 2020 or 2025. The 100 g/kWh target is often considered as an appropriately ambitious intermediate decarbonisation goal on the pathway to achieve the 2050 carbon reduction target.[31]

As explained later in the report, we also analysed the performance of the system in an additional set of sensitivity studies that assumed a more ambitious 2030 target of 50 g/kWh.

3.5.2. Fuel and carbon prices

Summary of fuel and carbon price assumptions over the study period is given in Table 3.7.

Table 3.7. Projected fuel and carbon prices between 2015 and 2030

Year	**2015**	**2020**	**2025**	**2030**
Coal ($/tonne)	57.3	66.3	79.1	83.2
Gas (p/therm)	37.5	28.8	36.9	45.0
Carbon (£/t)	5.9	6.6	22.6	47.1

[31] See for instance the CCC Fifth Carbon Budget.

The key source for fuel and carbon price projections is DECC's 2015 update of energy and emissions projections[32]. Coal and carbon[33] price projections follow the Reference price scenario, while the gas price evolution is taken from the Low Prices scenario[34].

3.5.3. System security assumptions

The GB system in our modelling was required to maintain sufficient firm capacity margin over peak demand to ensure that the specified reliability standard is complied with. The reliability criterion used is the Loss of Load Expectation (LOLE), which was limited at 3 hours per year[35]. The appropriate level of LOLE is directly linked to the Value of Lost Load (VOLL) that the customers are assumed to place on having their demand met. This relationship is rather complex as VOLL generally depends on customer type, size, location, time of day etc. however it is normally assumed that VOLL is in the order of several thousand pounds (at present VoLL at £17,000/MWh is used in the Capacity Market). With the rollout of smart meters and higher DSR uptake levels the flexibility in terms of shifting demand or providing system services will increase significantly, however, it is likely that the customers will still place a very high value on the inflexible part of their demand.

With high levels of heating demand electrification the peak demand would become even more sensitive to the severity of cold winter conditions. In the study we assumed that peak demand would correspond to a normal (i.e. average) winter rather than the coldest 1-in-20 winters (as was assumed in some of the previous system studies). In practice, assuming a 1-in-20 cold winter would result in a higher system peak demand and hence higher requirement for peaking (OCGT) capacity. A large proportion of this capacity would be very seldom used i.e. would be characterised by very low utilisation factors. Nevertheless, having this capacity available and therefore ensuring a sufficient capacity margin is necessary to maintain the security of supply. Our previous studies have shown that assuming a higher peak demand driven by extreme winter weather would have no material impact on SIC of LCGTs, which is the core objective of this study.

3.5.4. Interaction with neighbouring systems

In order to ensure that the GB system is largely self-reliant, and to avoid distorting the system carbon intensity evaluation when importing or exporting significant volumes of electricity, we further impose an *energy neutrality* constraint for the GB system. This means that energy flows over interconnectors with neighbouring systems 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 on an annual basis.

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32 DECC, "Updated energy and emissions projections: 2015", https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2015.

33 Carbon price projection assumed is the one applicable for Industry and Services. This is the projection for traded carbon price under the EU Emissions Trading Scheme.

34 This approach was taken in light of the recent significant drop in gas prices.

35 The LOLE of 3 hours is consistent with the level of security targeted in the British Capacity Mechanism.

The topology of the system used in the study requires that assumptions on generation, demand etc. are also made for the two neighbouring systems (Ireland and Continental Europe). We therefore assume the generation and demand background for the European system that reflects the decarbonisation and RES expansion resulting from recent European climate change policies[36]. Decarbonisation of heating and transport is assumed to evolve at similar proportions to those assumed for the GB system. Also, the assumed DSR uptake in Europe is consistent with the DSR uptake in Britain. The assumed carbon and fuel prices in GB were also assumed to apply in the rest of Europe.

3.6. Optimisation set-up for scenarios and SIC studies

This section explains how we constructed the counterfactual scenarios based on initial scenario assumptions in Table 3.1, and later used these counterfactual as a foundation for running SIC studies.

3.6.1. Counterfactual scenarios

Starting from the scenarios specified in Table 3.1, the counterfactuals were established by optimising the following components of the scenarios:

- OCGT capacity was optimised from zero. Note that OCGT in this context as used as proxy for flexible peaking capacity. If there was another technology with lower investment cost (such as e.g. gas reciprocating engines), then it could be substituted for OCGT in subsequent discussion.

- CCGT capacity was optimised from the minimum level for each year as specified in Table 3.1.

- In 2030 scenarios, subject to carbon target, the offshore wind capacity was allowed to reduce as part of the optimisation while the model was required to meet the 100 g/kWh carbon intensity target.

- In all scenarios that envisage new storage capacity (see Table 3.6) this capacity was optimally allocated between five[37] GB regions, as well as between different distribution network types (urban, rural or intermediate) in each region.

- In all scenarios the model was allowed to add more interconnection capacity (at a cost) if cost-efficient.[38]

The summary of model outputs in terms of added or reduced capacities in counterfactual scenarios is provided in Table 3.8 for years between 2015 and 2030 (with the Base Case scenario

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[36] Imperial College London, NERA Economic Consulting, DNV GL, "Integration of Renewable Energy in Europe", June 2014, https://ec.europa.eu/energy/sites/ener/files/documents/201406_report_renewables_integration_europe.pdf.

[37] In terms of distribution network and demand representation, London was considered as a separate, fifth region. In terms of transmission topology, London was embedded within the South England and Wales region.

[38] This was allowed to ensure feasibility of model runs. As shown later in the report, in a large majority of cases the model did not add any new interconnection capacity.

included for 2030), and in Table 3.9, where the capacities are reported across different 2030 scenarios.

Table 3.8. Capacity of optimised technologies in counterfactual Base Case scenarios between 2015 and 2030 (in GW)

Scenario name	**Basecase 15**	**Basecase 20**	**Basecase 25**	**Mid Flex**
Year	**2015**	**2020**	**2025**	**2030**
OCGT	8.1	19.6	29.9	30.0
New CCGT*	-	0.1	3.9	0.1
Offshore wind	5.1	10.2	16.2	22.2
*Reduced wind***	-	-	-	*-8.8*

Notes:
* CCGT capacity added on top of the capacity in Table 3.1.
** Reduction compared to the initial capacity in Table 3.1.

Note that in the No Flex scenario the model was used to optimally add CCS capacity, as the original capacities of wind and other LCGTs was insufficient to meet the 100 g/kWh target.

Table 3.9. Capacity of optimised technologies in 2030 counterfactual scenarios (in GW)

Scenario name	**No Flex**	**Low Flex**	**Mid Flex**	**Moderni-sation**	**Mega Flex**		**Onshore capped**	**Nuclear centric**
OCGT	41.7	38.2	30.0	30.1	20.2		30.0	21.9
New CCGT*	9.3	1.6	0.1	0.1	-		0.1	0.1
Offshore wind	31.0	23.1	22.2	21.7	21.5		29.9	11.3
*Reduced wind***	-	*-7.9*	*-8.8*	*-9.3*	*-9.5*		*-9.1*	*-9.7*
Added CCS	2.1	-	-	-	-		-	-

Notes:
* CCGT capacity added on top of the capacity in Table 3.1.
** Reduction compared to the initial capacity in Table 3.1.

Along with the capacities i.e. investment decisions, all model runs for counterfactual scenarios also provided optimal decisions with respect to operation of the system, resulting in a certain level of operating cost associated with the use of fuel and the resulting carbon emissions.

3.6.2. System Integration Cost studies

With the counterfactual scenarios established as shown in Table 3.8, the system integration cost studies were set up in line with the approach described in Section 2.3, i.e. using the following steps:

- 1 GW of nuclear capacity was removed from each counterfactual scenario, and an energy-equivalent amount of another LCGT added to retain the same nominal amount of low-carbon electricity available in the system.[39] Given that the utilisation of nuclear portfolio varied across different years, the energy-equivalent capacities also changed

[39] The energy-equivalent capacity in GW to replace 1 GW of nuclear is simply the inverse of the ratio of the achievable utilisation factors of a given LCGT and nuclear, as specified in Table 3.2.

as specified in Table 3.10. Note that one SIC study is required for each scenario and each of the four LCGTs.

Table 3.10. Energy-equivalent capacity additions for different LCGTs (in GW) when removing 1 GW of nuclear power

Year	**2015**	**2020**	**2025**	**2030**
Offshore wind	1.40	1.40	1.55	1.91
Onshore wind	2.33	2.33	2.58	3.18
Solar PV	5.93	5.93	6.56	8.09
Biomass	0.88	0.88	0.97	1.00

- For each 2030 scenario, the system was required to maintain the 100 g/kWh carbon intensity target following the replacement of nuclear with another LCGT. The model was allowed to add *further LCGT capacity* (above the energy-equivalent amount) if needed to keep the emissions at 100 g/kWh.

- The model was also allowed to re-optimise OCGT and new CCGT capacity, as well as all decisions regarding system operation. Capacities of all other LCGTs, interconnection and storage were kept constant.

- The difference in total system cost (investment in generation and network infrastructure plus operating cost) before and after the replacement is then interpreted as the *relative integration cost* between nuclear and a given LCGT. It has to be noted that this cost difference should not include the LCOEs associated with the energy equivalent capacities of nuclear and the other LCGT that replaces it; however, any investment cost associated with installing additional LCGT capacity above the energy-equivalent volume is calculated into the cost difference as it arises from the lower ability of the system to absorb the LCGT in question. If the cost of the system after replacement was higher, the LCGT in question had a positive SIC (and vice versa). Dividing the cost differential with the replaced annual nuclear output finally provides us with the measure of relative integration cost of each LCGT compared to nuclear, expressed in £/MWh.

To make results comparable and consistent, all capacity additions and removals imposed in the SIC studies were assumed to occur in South of GB.

4. System Integration Costs of low-carbon technologies

This chapter discusses the results of quantitative case studies to determine SIC of LCGTs when a small amount of them is added to the system. The broad range of scenarios analysed demonstrates that the integration cost of LCGTs is a function of the system they are being added to, heavily dependent in particular on the volume of low-carbon capacity already present in the system and flexibility level in the system. The results of SIC studies presented here are disaggregated across key components: generation, transmission and distribution investment cost (CAPEX) as well as operating cost (OPEX). G CAPEX and OPEX components are further broken down by technologies to identify where different components of integration cost originate.

As discussed before, the SIC results presented in this chapter refer to relative integration cost of LCGTs when compared against nuclear generators. To aid comparison, the assumed LCOE differentials (i.e. cost advantages) of different LCGTs against nuclear are also referred to in the text. 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.

4.1. Counterfactual scenarios

Section 3.6.1 explained how the counterfactual scenarios used in this study have been obtained, i.e. which variables were optimally determined by running the WeSIM model. This section provides more details on the results of these counterfactual scenarios, specifically the generation capacity portfolios, generator outputs and capacity factors across different years and scenarios.

4.1.1. Optimised generation portfolios

As explained earlier, in all 2030 scenarios the model was used to optimally add peaking (OCGT[40]) and CCGT capacity, while at the same time removing offshore wind capacity while still being able to meet the 100 g/kWh carbon intensity target. The exception to this was the No Flex scenario, where the volume of LCGTs was not sufficient to deliver the 100 g/kWh intensity, so the model was used to add CCS capacity to meet the carbon target. Capacities of other generation technologies were given as part of scenario assumptions. Generation mix in 2015 was constructed so as to reflect the currently existing GB generation portfolio.

Figure 4.1 presents the composition of the counterfactual generation mixes obtained across Base Case scenarios between 2015 and 2030. As evident from the figure, the 2030 scenarios assume a gradual decline in coal capacity, accompanied by a rapid increase in low-carbon generation, particularly wind and PV. The Base Case scenarios also feature a steadily increasing energy storage capacity compared to today's levels. Finally, the capacity of peaking i.e.

[40] As noted earlier, the role of peaking capacity assumed by OCGT in this study could be taken on by another generation or storage technology should its cost be considered more attractive than that of OCGT generation.

back-up OCGT units is expected to increase significantly, driven by low capacity value of variable RES generation.

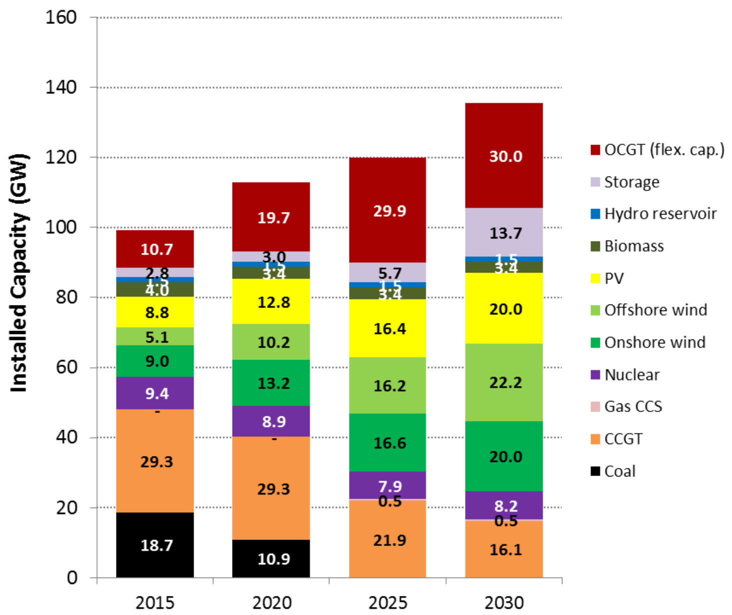

Figure 4.1. Counterfactual GB generation portfolios across Base Case scenarios between 2015 and 2030

Any coal capacity in the GB power system is projected to retire before 2025, which is in line with the present trends of coal plant closures driven by environmental legislation. As for the CCGT generation, about 16 GW is expected to be in operation by 2030 (after discounting the capacity scheduled to close until 2030). Nuclear capacity similarly follows the announced closure dates of existing plants as well as the expectations with respect to the construction of new nuclear units by 2030 (the Nuclear Centric scenario envisages this commitment schedule for new nuclear units to be expedited compared to the rest of the scenarios). Following from the recent changes in government's policy towards CCS, its capacity does not feature significantly in these scenarios: only 500 MW is expected to be commissioned around 2025.

Clearly, the composition of the 2015 generation portfolio is somewhat different from the actual GB generation mix, which is the result of simplifying the generation mix across all scenarios. Nevertheless, these discrepancies should have little if any impact on the levels of SIC quantified in the study.

Figure 4.2 presents the counterfactual generation portfolios across all 2030 scenarios considered in the study. The first five scenarios are characterised by increasing system flexibility (i.e. increasing storage and DSR uptake). Enhancing flexibility steadily reduces the need for backup capacity in the form of OCGT, while also allowing the system to meet the 100 g/kWh target with less LCGT capacity. As an example, moving from No Flex to Low Flex requires 2.1 GW less CCS capacity and 7.9 GW less offshore capacity to meet the carbon target, given that reduced RES curtailment levels enabled by improved flexibility allow that the carbon target is achieved with lower overall low-carbon capacity. In the most ambitious scenario in terms of flexibility, Mega Flex, as much as 9.5 GW of offshore wind could be removed (and thus significant investment cost avoided) while still achieving the 100 g/kWh carbon intensity. Another effect of enhanced flexibility is that less CCGT capacity is required, given that the utilisation of the conventional generation fleet also improves with the deployment of flexible options.

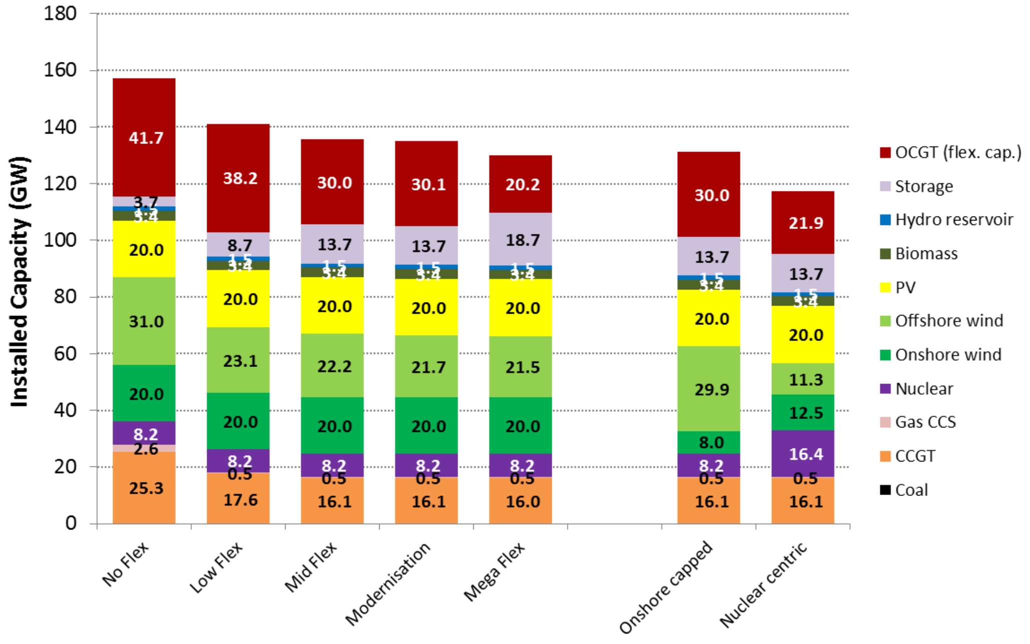

Figure 4.2. Counterfactual GB generation portfolios across 2030 scenarios

The remaining two scenarios, Onshore Capped and Nuclear Centric, have a slightly different mix of LCGT in line with their starting capacity mixes (the former has more offshore and less onshore wind than the Mid Flex scenario, while the latter has less wind overall and more nuclear capacity).

4.1.2. Annual energy production and utilisation factors

The annual output from generation technologies across the Base Case scenarios between 2015 and 2030 is illustrated in Figure 4.3. As with the generation capacities, the model outputs reflect the trend of increasing wind and PV output, with a reduction in coal and CCGT production. Relative position of coal and CCGT generation in the merit order, and consequently their annual output, are driven by the assumed evolution of gas, coal and carbon prices. In 2015, the full load operating cost of coal are lower than for CCGT; the situation is reversed in 2020.

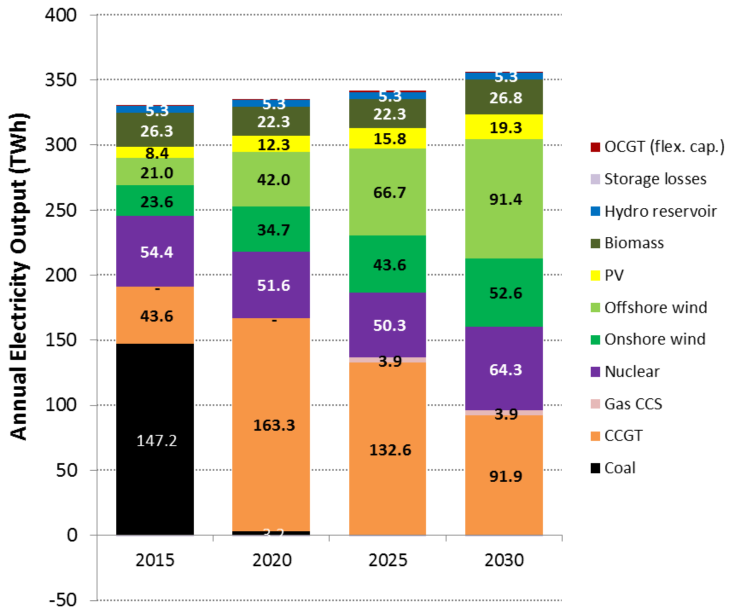

Figure 4.3. Annual outputs of GB generators across Base Case scenarios between 2015 and 2030

Figure 4.4 illustrates the generation outputs across the counterfactual 2030 scenarios with varying flexibility and generation mixes. The share of annual electricity demand met by wind generation increases to about 40% in most 2030 scenarios (with the exception of Nuclear Centric). In the same scenarios, when all renewable technologies are added together (wind, PV, biomass and hydro), their share in meeting the electricity demand reaches around 55%. It can be observed that in the No Flex scenario the capacity factors of wind and PV are lower than in other scenarios due to significant output curtailment (in the order of 10% of annually available energy).

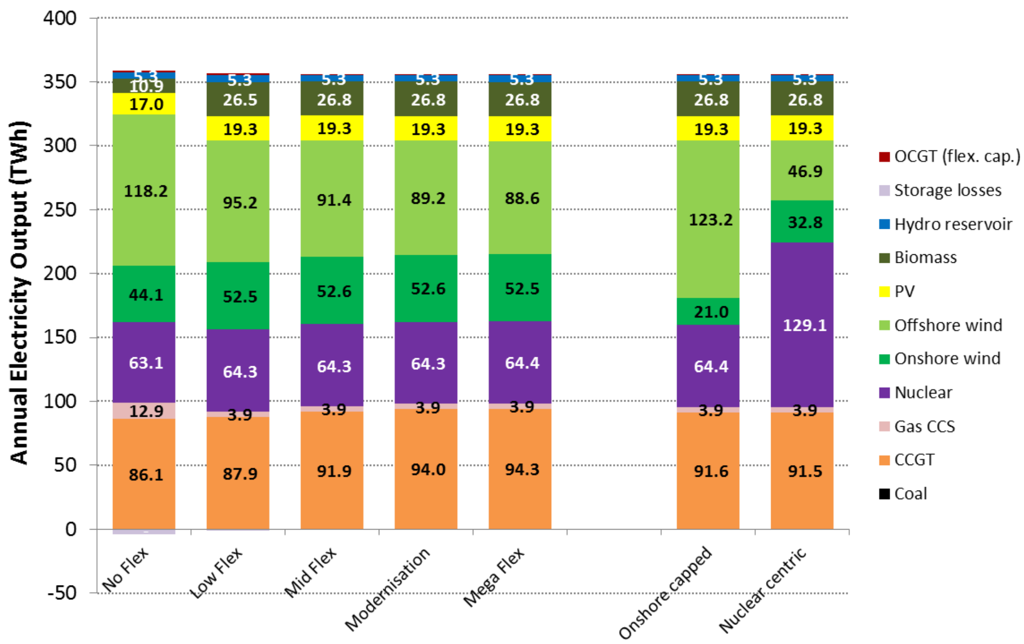

Figure 4.4. Annual outputs of GB generators across 2030 counterfactual scenarios

Annual utilisation of generation technologies in counterfactual Base Case scenarios over the period 2015-2030 is given in Table 4.1. Note that the actual observed utilisation factors of renewable technologies, nuclear and CCS generation are bounded by the assumed achievable capacity factors specified in Section 3.2.2. The last row of the table also provides the observed carbon intensity of GB electricity supply across scenarios (note that in 2030 it has been explicitly constrained to 100 g/kWh).

Table 4.1. Annual utilisation of generation technologies in counterfactual Base Case scenarios between 2015 and 2030

Scenario name	**Basecase 15**	**Basecase 20**	**Basecase 25**	**Basecase**
Year	**2015**	**2020**	**2025**	**2030**
Coal	90.0%	3.4%	-	-
CCGT	17.0%	63.6%	69.2%	65.5%
CCS	-	-	89.7%	90.0%
Nuclear	66.0%	66.0%	73.0%	90.0%
Offshore wind	47.0%	47.0%	47.0%	47.0%
Onshore wind	30.0%	30.0%	30.0%	30.0%
PV	11.0%	11.0%	11.0%	11.0%
Biomass	75.0%	75.0%	75.0%	90.0%
Hydro	41.4%	41.4%	41.4%	41.4%
OCGT	0.0%	0.1%	0.4%	0.1%
CO_2 intensity (g/kWh)	*429.9*	*202.0*	*150.8*	*100.0*

Similarly, Table 4.2 contains the utilisation factors of generation technologies for all 2030 scenarios. It is interesting to note that with no added flexibility the utilisation of PV and wind becomes considerably lower than their nominal capacity factors due to output curtailment. In the No Flex scenario we observe that about 7% of offshore wind, 12% of PV and 16% of onshore wind output gets curtailed. As flexibility improves, the utilisation of RES reaches the maximum level (already occurring at Low Flex level), while at the same time the utilisation of more efficient conventional plant (CCGT) increases.

Table 4.2. Annual utilisation of generation technologies across counterfactual scenarios in 2030

Scenario name	**No Flex**	**Low Flex**	**Mid Flex**	**Moderni-sation**	**Mega Flex**		**Onshore capped**	**Nuclear centric**
Year	**2030**	**2030**	**2030**	**2030**	**2030**		**2030**	**2030**
Coal	-	-	-	-	-		-	-
CCGT	38.9%	56.9%	65.2%	66.7%	67.1%		65.0%	65.0%
CCS	57.5%	90.0%	90.0%	90.0%	90.0%		90.0%	90.0%
Nuclear	88.2%	90.0%	90.0%	90.0%	90.0%		90.0%	90.0%
Offshore wind	43.5%	47.0%	47.0%	47.0%	47.0%		47.0%	47.0%
Onshore wind	25.2%	30.0%	30.0%	30.0%	30.0%		30.0%	30.0%
PV	9.7%	11.0%	11.0%	11.0%	11.0%		11.0%	11.0%
Biomass	36.7%	88.9%	90.0%	90.0%	90.0%		89.9%	90.0%
Hydro	41.4%	41.4%	41.4%	41.4%	41.4%		41.4%	41.4%
OCGT	0.3%	0.4%	0.1%	0.0%	0.0%		0.2%	0.0%
CO_2 intensity (g/kWh)	*100.0*	*100.0*	*100.0*	*100.0*	*100.0*		*100.0*	*100.0*

4.1.3. Total system cost comparison across 2030 scenarios

The assumptions on electricity demand in 2030 were the same across all five 2030 scenarios; however, these scenarios differed greatly in the assumed level of flexibility as well as in their generation portfolios (i.e. the mix of low-carbon generation technologies). It is therefore of interest to analyse the whole-system costs across different scenarios to estimate how they compare against one another in terms of the cost required to achieve the 100 g/kWh decarbonisation target in 2030.

For that purpose, in Table 4.3 we compare the total annual system cost across all 2030 scenarios. The annual system cost is broken down into the following components: 1) generation investment cost, disaggregated into low-carbon and other i.e. conventional; 2) generation operating cost (OPEX), disaggregated into low-carbon and other; 3) investment cost of storage assets; 4) investment cost of interconnection; and 5) incremental transmission and distribution investment cost. Note that in this calculation the whole-system cost does not include the cost of currently existing transmission and distribution asset base. These estimates are therefore primarily intended to provide a relative measure of economic performance of different 2030 scenarios when compared to each other.

In our estimates of annualised total system cost, the LCOE i.e. investment and operating cost assumptions for different technologies were as specified in Section 3.2.4. A single LCOE assumption was applied to each technology i.e. there was no distinction between generators of the same technology despite possible differences in age etc. The forecasted annualised investment cost of pumped storage hydro capacity in 2030 was assumed to be £196/kW/year, while for new distributed battery storage the assumed cost for the purpose of this calculation was £67.4/kW/year.[41] The assumed cost of submarine interconnector cables was

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[41] Assumptions were based on a recent Carbon Trust study on energy storage: Carbon Trust and Imperial College London, "Can storage help reduce the cost of a future UK electricity system?", March 2016.

£96/MW/km/year (the assumed lengths of different interconnection links was adjusted to take into account the cost of substations and any onshore transmission grid reinforcements). Given a number of uncertainties associated with estimating the cost of DSR deployment[42], this cost is not included in the total annual cost calculation.[43] For a similar reason, the cost estimate of the Modernisation scenario does not include the cost of implementing the improvements in system operation practices.

Table 4.3. Total annual system cost by component in counterfactual 2030 scenarios (in £m/year)

	No Flex	Low Flex	Mid Flex	Moderni-sation	Mega Flex		Onshore Capped	Nuclear Centric
Gen. CAPEX (low-C)	23,988	20,865	20,589	20,427	20,375		20,786	20,446
Gen. CAPEX (other)	4,329	3,445	2,919	2,919	2,457		2,919	2,539
OPEX (low-C)	1,873	2,442	2,448	2,443	2,439		2,449	3,034
OPEX (other)	4,189	4,142	4,124	4,121	4,115		4,127	4,038
Interconnection CAPEX	491	612	678	678	856		678	678
Transmission CAPEX	0	0	0	0	0		0	0
Distribution CAPEX	791	307	189	188	175		189	186
Storage CAPEX	691	1,028	1,364	1,364	1,701		1,364	1,364
Total	**36,352**	**32,841**	**32,312**	**32,141**	**32,118**		**32,512**	**32,285**
Savings vs. No Flex	-	*3,512*	*4,040*	*4,211*	*4,234*		*3,840*	*4,067*

All 2030 systems include a significant amount of low-carbon generation capacity required to meet the 100 g/kWh target. Given that low-carbon generation technologies tend to be characterised by high investment cost and low operating cost, the investment cost of low-carbon generation dominates the total system cost, accounting for about 60% of the total. At the same time the generation CAPEX of conventional generators is 5-9 times lower. Operating cost in all except the Low Flex scenario accounts for just over a fifth of total cost, and within that category broadly a third is associated with the OPEX of low-carbon generators (mostly nuclear, CCS and biomass as wind and PV have near-zero operating costs), while the rest is the OPEX of conventional gas generation.

The storage CAPEX category is also significant given the relatively large assumed volume of storage being available in the system (13.7 GW in total in the Mid Flex and 18.7 GW in the Mega Flex scenario). Interconnection investment cost is also visible but does not exceed 2-3% of the total system cost. In terms of transmission network investment, virtually no additional investment is required into the key GB transmission corridors.[44] Finally, the incremental investment in distribution grid for flexible scenarios (Mid Flex and above) is just be-

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42 As an example of an attempt to estimate the cost of DSR while considering the uncertainty of its future evolution, see e.g. Imperial College London, Carbon Trust, "An analysis of electricity system flexibility for Great Britain", report for DECC, October 2016.

43 It may be argued that because the enabling technology (smart meters) is mandated under all scenarios, and pricing DSR is a complex task, it can be assumed that the cost of DSR is price-neutral across the scenarios i.e. that differences between scenarios provide a valid estimate of total system cost differentials.

44 Note that due to aggregated representation of GB transmission network used in the modelling, this would not capture the cost of any local network reinforcements or replacements.

low the £200m mark. In scenarios with lower flexibility, however, the distribution CAPEX increases considerably, almost doubling in the Low Flex scenario and more than quadrupling in the No Flex scenario.

The total level of annualised system cost is also presented graphically in Figure 4.5 for all 2030 scenarios, as well as for the period 2015-2025. Total system cost between 2015 and 2025 is lower than in 2030 as the result of lower low-carbon generation capacity as well as lower annual demand level.

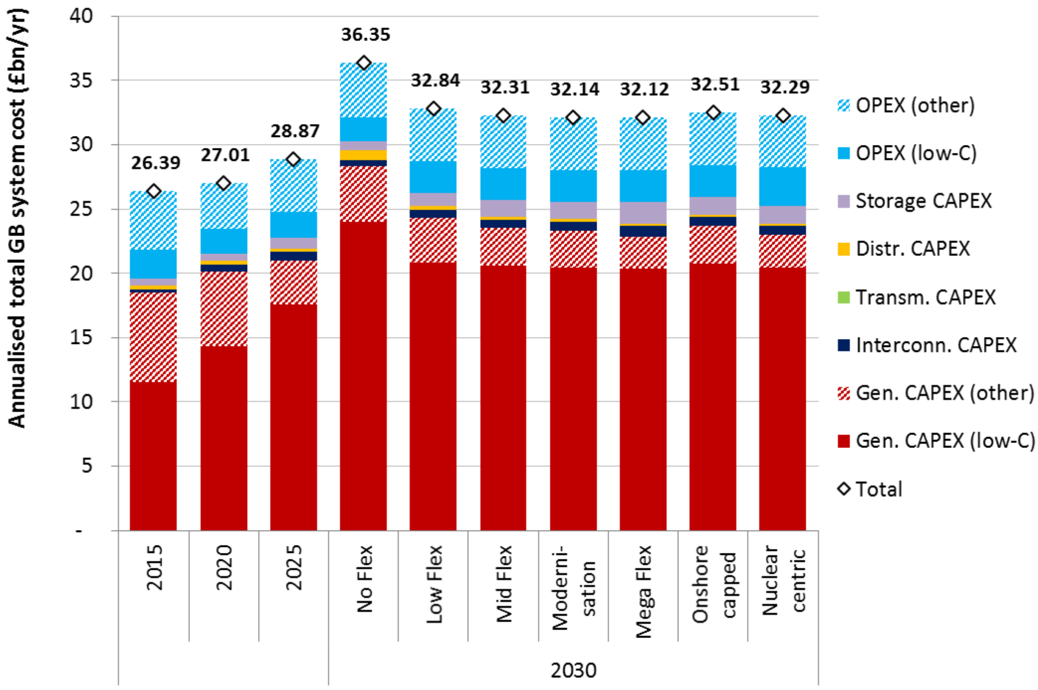

Figure 4.5. Total annual system cost in counterfactual scenarios

Unsurprisingly, the overall system cost in 2030 is the highest in the Low Flex scenario, while the enhancement of flexibility delivers savings of up to £4.2bn/year. Figure 4.6 further disaggregates the cost differentials between 2030 scenarios and the No Flex scenario into individual components.

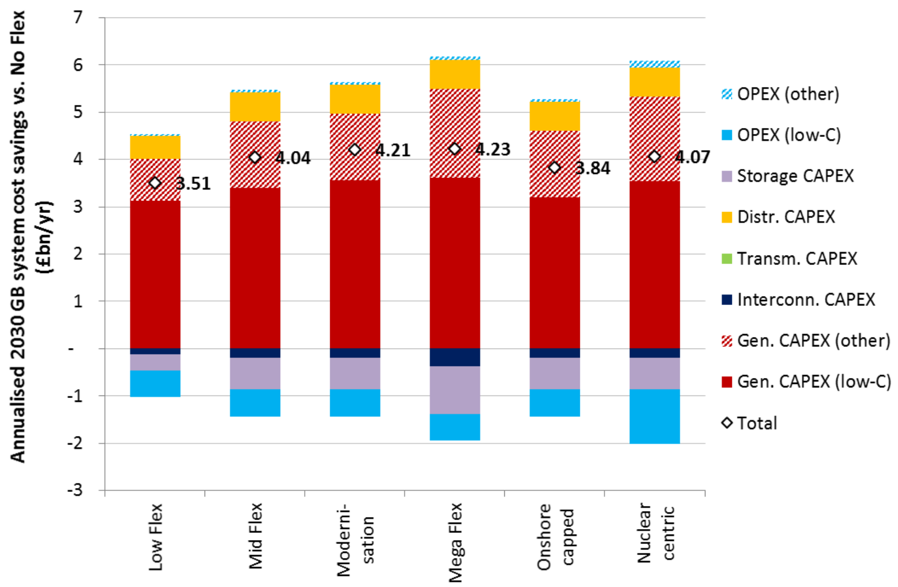

Figure 4.6. Annual system cost savings in 2030 counterfactual scenarios compared to No Flex scenario

It is evident that achieving the 100 g/kWh target in 2030 using relatively high shares of variable renewables would be far more cost-efficient if accompanied by at least moderate improvements in flexibility. The medium-flexible scenarios (Mid Flex, Onshore Capped and Nuclear Centric) outperform the No Flex scenario by about £3.8-4.1bn/year even after the cost of additional flexibility (with the exception of DSR) is taken into account. Key cost savings categories are low-carbon generation CAPEX (resulting from lower offshore wind capacity and no requirements for additional CCS), conventional generation CAPEX (due to less CCGT and OCGT capacity being required to meet the security criterion) and distribution CAPEX (as distribution peak loading is mitigated by distributed storage and DSR). A relatively small fraction of these gross savings (just over 20%) is offset by the additional cost of storage, interconnection and increased low-carbon OPEX (due to better utilisation of biomass output and higher nuclear output in the Nuclear Centric scenario).

It is further interesting to note that already in the Low Flex scenario, which is broadly half way between the No Flex and Base Case scenarios in terms of flexibility deployment, the system cost savings amount to about 80% of those found in the medium-flexible scenarios. Therefore, even moderate improvements in system flexibility have the potential to deliver significant savings over the scenario with no flexibility improvements. Increasing flexibility further may result in diminishing (although still present) marginal benefits.

Again, it should be noted that the above cost savings do not include the cost of increased DSR deployment in the Mega Flex scenario, nor do they take into account any cost potentially associated with the measures to improve system operation in the Modernisation scenario.

Finally, we note that the total system cost in those years was between £5.9bn/year (in 2015) and £3.4bn/year (in 2025) lower than in the 2030 Mid Flex, which is the combined effect of lower low-carbon generation capacity as well as lower annual demand.

4.2. Technology-specific integration costs

This section discusses the results of System Integration Cost studies based on the approach laid out in Section 3.6.2. All SIC studies are based on a marginal addition of LCGT capacity accompanied with a marginal removal of nuclear capacity. To ensure a like-for-like replacement, the nominal annually available output of added LCGT and removed nuclear capacity is kept equal. Following the replacement of nuclear with another LCGT the system is allowed to readjust itself by finding a new set of optimal decisions on system operation and on investment in selected generation technologies.

The SIC of a given LCGT is evaluated by dividing the change in total system cost with the volume of replaced low-carbon output. The unique feature of our whole-system modelling approach allows for a component-by-component disaggregation of the cost differential, enabling the identification of which sectors and technologies are the key contributors to changes in investment and operation cost.

4.2.1. Offshore wind

The results of the SIC studies for offshore wind are shown in Figure 4.7 for the Base Case scenarios between 2015 and 2030[45], and in Figure 4.8 for all 2030 scenarios. For each scenario the SIC is broken down into components, which refer to operating cost (OPEX), generation investment (G CAPEX) and transmission and distribution network investment (T CAPEX and D CAPEX). OPEX and G CAPEX categories are further subdivided according to different generation technologies where change in operating and investment cost is observed in the SIC study compared to the counterfactual scenario.

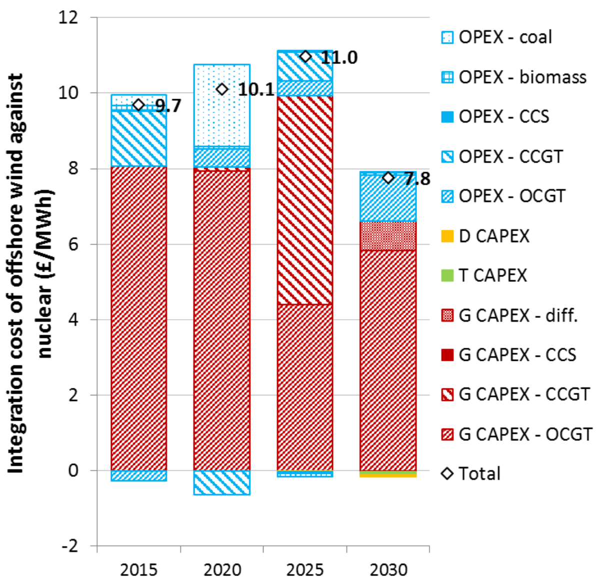

Figure 4.7. SIC of offshore wind compared to nuclear in Base Case scenarios between 2015 and 2030

45 The Mid Flex scenario is used in this and subsequent sections to make comparisons between 2030 and earlier years.

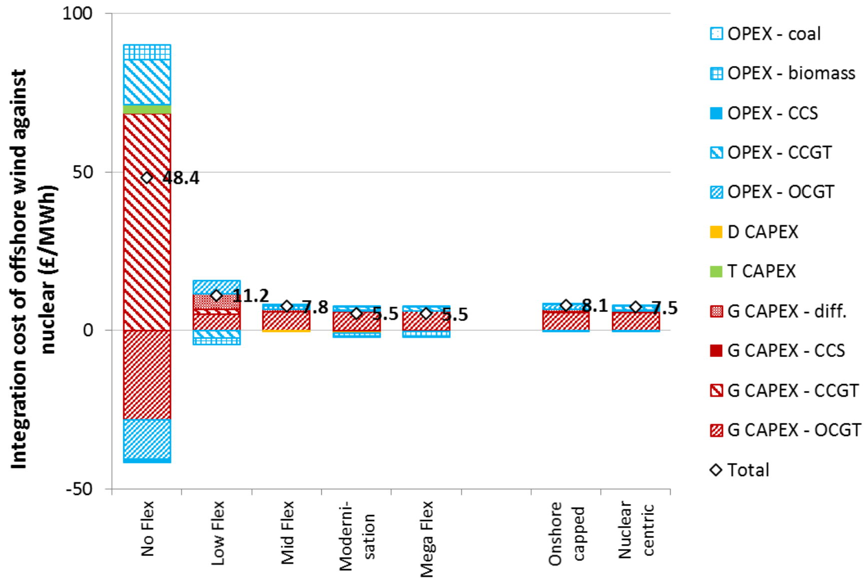

Figure 4.8. SIC of offshore wind compared to nuclear across different 2030 scenarios

Both figures show that in each scenario the replacement of nuclear with wind capacity has a positive (net) G CAPEX component, which is predominantly a result of investing in additional OCGT and CCGT capacity. The requirement to firm up added wind with conventional capacity results from the low capacity value (i.e. low derating factor) of wind in terms of contributing to secure capacity margin in the system. In the 2030 scenarios it is also possible to observe a component "G CAPEX – diff." in the SIC; this component refers to the extra capacity of an LCGT (offshore wind in this case) that had to be added in excess of the energy-equivalent capacity in order to meet the 100 g/kWh emission target.[46]

Replacement of nuclear with offshore wind also triggers changes in operating cost of thermal generators in varying proportions, driven by the additional requirements for ancillary services (reserve and response) arising from increased wind capacity, as well as the seasonality of offshore wind output profile, which tends to be higher over winter and autumn months than during summer, making it better aligned with the seasonal variations in system demand than the largely flat output profile of nuclear generators. The exact change in operating cost is the result of the composition of thermal generation mix assumed to exist in a given scenario, as well as the combination of gas, coal and carbon prices across time.

It is further interesting to note that while the SIC of offshore wind increases between 2020 and 2025, the integration cost in 2030 is lower than in 2025. This reduction in SIC is primarily driven by significant improvements in flexibility between 2025 and 2030 assumed in the scenarios (see Section 3.4.1 for detailed assumptions on flexibility). Nevertheless, as demonstrated in Figure 4.8, in the No Flex scenario the SIC would be significantly higher, around £48/MWh, indicating a very low ability of the system to cost-effectively integrate RES generation.

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46 This is in line with the method chosen to quantify System Integration Cost, see Section 2.3.

Another point to note is that in 2030 scenarios with higher flexibility (e.g. in Base Case in Figure 4.7) there is a noticeable component of SIC associated with distribution network investment (D CAPEX), which may appear counterintuitive at first given that new offshore wind sites would obviously connect at transmission level. The reason for this effect is the whole-system approach to system optimisation: the distributed storage resource, assumed to exist in significant volumes in all 2030 scenarios, now shifts the utilisation of its flexibility slightly away from minimising distribution network loading (and the associated investment cost savings) towards supporting the management of added wind resource. The ability to capture such trade-offs represents a unique feature of our modelling approach and the WeSIM model.

To get a measure of how the whole-system costs of nuclear and offshore wind compare when their investment and operation cost is taken into account, it is beneficial to compare differences in LCOE against the SIC obtained through running the model for various scenarios. According to the LCOE assumptions in Section 3.2.4, the cost of offshore wind is projected to drop over time, while the cost of nuclear would remain relatively stable (with some reduction envisaged in the Nuclear Centric scenario). Given that the analysis shows that SIC of offshore wind also varies across scenarios, the relationship between the whole-system cost of nuclear and offshore wind will also change as function of the scenario.

Table 4.4 and Table 4.5 summarise the projected LCOE evolution for nuclear and offshore wind and contrast the LCOE differentials to the relative SIC of offshore wind quantified across different scenarios.

Table 4.4. LCOE differentials between offshore wind and nuclear compared to SIC in Base Case between 2015 and 2030 (in £/MWh)

Scenario name	**Basecase 15**	**Basecase 20**	**Basecase 25**	**Mid Flex**
Year	**2015**	**2020**	**2025**	**2030**
	LCOE			
Nuclear	93	93	90	90
Offshore	133	106	80	75
Difference	*-40*	*-13*	*10*	*15*
	SIC			
Offshore vs. nuclear	**9.7**	**10.1**	**11.0**	**7.8**

Table 4.5. LCOE differentials between offshore wind and nuclear compared to SIC across 2030 scenarios (in £/MWh)

Scenario name	**No Flex**	**Low Flex**	**Mid Flex**	**Moderni-sation**	**Mega Flex**		**Onshore capped**	**Nuclear centric**
	LCOE							
Nuclear	90	90	90	90	90		90	80
Offshore	75	75	75	75	75		70	80
Difference	*15*	*15*	*15*	*15*	*15*		*20*	*0*
	SIC							
Offshore vs. nuclear	**48.4**	**11.2**	**7.8**	**5.5**	**5.5**		**8.1**	**7.5**

From Table 4.4 we observe that between 2015 and 2025 the SIC of offshore wind is higher than its cost advantage (if any) over nuclear, and this is indicated by red cell shading. In the 2030 Mid Flex scenario, however, both SIC and LCOE of offshore wind reduce sufficiently to make its whole-system cost lower than that of nuclear (indicated by green cell colour). Table 4.5 shows that with the exception of No Flex and Nuclear Capped scenarios, in all other scenarios the SIC of offshore wind is lower than its cost advantage over nuclear, resulting in a lower whole-system cost of wind.

4.2.2. Onshore wind

The results of the SIC studies for onshore wind are shown in Figure 4.9 for the Base Case between 2015 and 2030, and in Figure 4.10 for all 2030 scenarios.

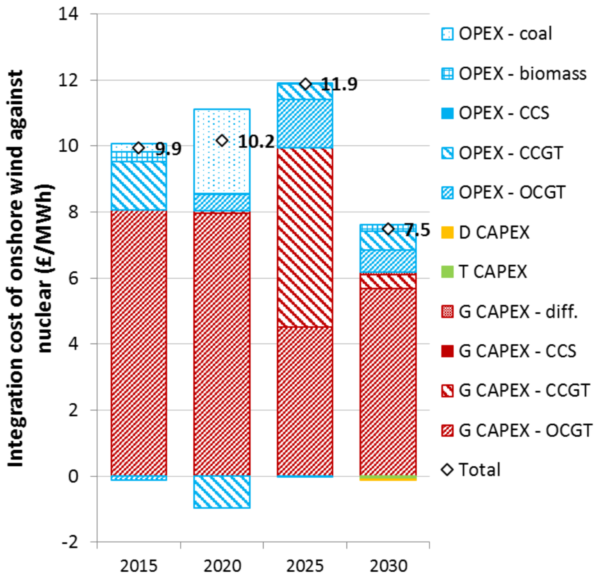

Figure 4.9. SIC of onshore wind compared to nuclear in Base Case scenario between 2015 and 2030

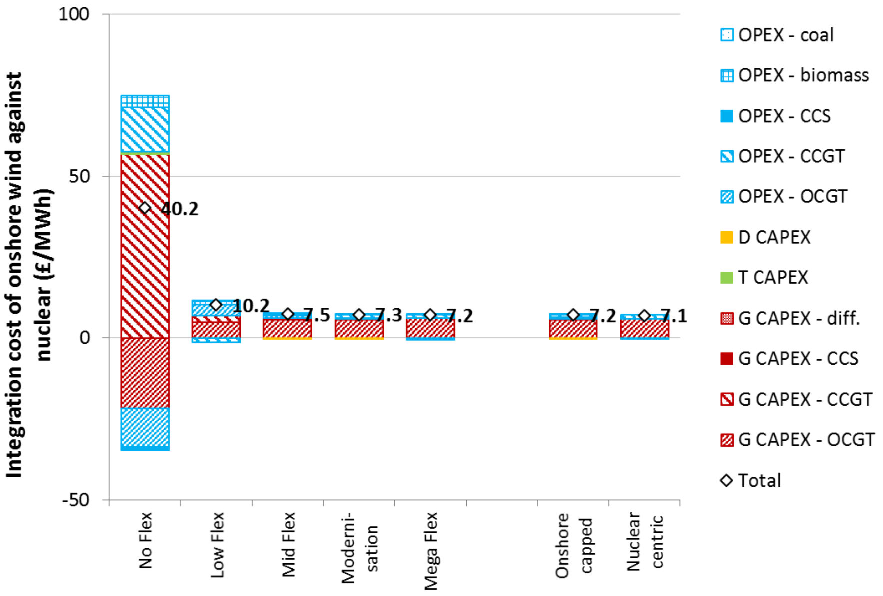

Figure 4.10. SIC of onshore wind compared to nuclear across 2030 scenarios

The magnitude of SIC before 2030 is very similar as for offshore wind. In 2030 we again observe a very high SIC in the No Flex scenario, driven by high RES output curtailment. Scenarios with lower onshore capacity (Onshore Capped and Nuclear Centric) result in a slightly lower SIC than for offshore wind, while on the other hand the SIC in Modernisation and Mega Flex scenarios is slightly higher than for offshore wind. Nevertheless, generally speaking there are no great differences between the SIC of onshore and offshore wind.

Table 4.6 and Table 4.7 compare the assumed LCOE cost differentials of onshore wind and nuclear with the SIC results in order to establish in which scenarios is the whole-system cost of onshore wind lower than that of nuclear. Given that the assumed LCOE of onshore wind is considerably lower than the cost of nuclear (by up to £30/MWh), the whole-system cost of onshore wind is more competitive than nuclear in almost every scenario considered, with the exception of the extreme No Flex scenario in 2030, where the SIC of onshore wind takes a very high value.

Table 4.6. LCOE differentials between onshore wind and nuclear compared to SIC in Base Case between 2015 and 2030 (in £/MWh)

Scenario name	**Basecase 15**	**Basecase 20**	**Basecase 25**	**Mid Flex**
Year	**2015**	**2020**	**2025**	**2030**
	LCOE			
Nuclear	93	93	90	90
Onshore	75	65	60	60
Difference	*18*	*28*	*30*	*30*
	SIC			
Onshore vs. nuclear	**9.9**	**10.2**	**11.9**	**7.5**

Table 4.7. LCOE differentials between onshore wind and nuclear compared to SIC across 2030 scenarios (in £/MWh)

Scenario name	No Flex	Low Flex	Mid Flex	Moderni-sation	Mega Flex		Onshore capped	Nuclear centric
	LCOE							
Nuclear	90	90	90	90	90		90	80
Onshore	60	60	60	60	60		60	60
Difference	*30*	*30*	*30*	*30*	*30*		*30*	*20*
	SIC							
Onshore vs. nuclear	**40.2**	**10.2**	**7.5**	**7.3**	**7.2**		**7.2**	**7.1**

4.2.3. Solar PV

The SIC of solar PV is given in Figure 4.11 for the Base Case scenario between 2015 and 2030, and in Figure 4.12 for all 2030 scenarios.

While the SIC in 2015, 2020 and 2025 is very similar as for onshore and offshore wind, in 2030 the integration cost is considerably higher than the SIC of wind. This is particularly reflected in the higher distribution CAPEX component across all 2030 scenarios. High distribution investment arises as the result of increased reversed flows in distribution networks, which require reinforcement of the grid. There is also a noticeable component of additional PV investment to maintain emissions (G CAPEX – diff.), as the seasonality of PV generation is exactly the opposite of system demand: high PV output in summer coincides with low system demand and vice versa. Hence, the generation displaced by PV is likely to be less carbon-intensive than average, meaning that carbon benefits of additional PV would be lower than those of removed nuclear output and consequently more PV capacity would be needed to maintain the 100 g/kWh intensity. Note also that the PV capacity is not assumed to be uniformly dispersed across GB; a much higher installation density is foreseen in the south of the country.

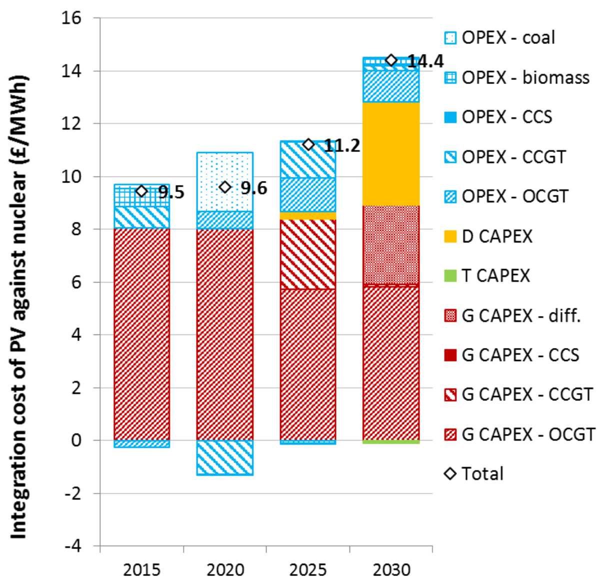

Figure 4.11. SIC of solar PV compared to nuclear in Base Case scenario between 2015 and 2030

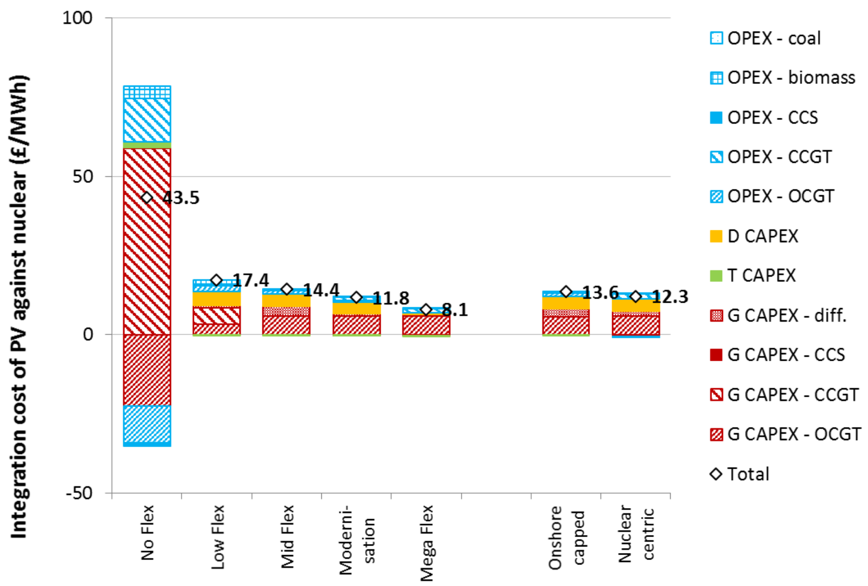

Figure 4.12. SIC of solar PV compared to nuclear across 2030 scenarios

As with offshore and onshore wind, the SIC in the No Flex scenario is found to be very high, above £40/MWh. This is again the consequence of high curtailment: about 25% of the PV output added in the SIC study is curtailed. The system establishes the same CO_2 intensity by replacing a significant volume of OCGT with CCGT capacity.

The enhanced flexibility i.e. additional storage and DSR in the Mega Flex scenario manage to almost completely eliminate the SIC component associated with distribution investment cost. In general, however, the SIC of PV tends to be higher in 2030 than for both onshore and offshore wind. On the other hand, because the assumed LCOE of solar PV in 2030 was relatively low (£15/MWh lower than nuclear in Nuclear Centric and £25/MWh in all other scenarios), in all scenarios except No Flex solar PV is competitive with nuclear when its whole-system cost is considered.

Table 4.8 and Table 4.9 compare the LCOE assumptions for solar PV and nuclear with the numerical results for SIC of solar PV generation. The tables suggest that from 2025 onwards the whole-system cost of solar PV becomes more competitive than that of nuclear, or in other words that its cost advantage over nuclear exceeds its SIC. The only exception to this is again the No Flex scenario, where the SIC of solar PV (similar to offshore and onshore wind) has a value of over £40/MWh.

Table 4.8. LCOE differentials between solar PV and nuclear compared to SIC in Base Case between 2015 and 2030 (in £/MWh)

Scenario name	**Basecase 15**	**Basecase 20**	**Basecase 25**	**Mid Flex**
Year	**2015**	**2020**	**2025**	**2030**
		LCOE		
Nuclear	93	93	90	90
Solar PV	101	86	75	65
Difference	*-8*	*7*	*15*	*25*
		SIC		
Solar PV vs. nuclear	**9.5**	**9.6**	**11.2**	**14.4**

Table 4.9. LCOE differentials between solar PV and nuclear compared to SIC across 2030 scenarios (in £/MWh)

Scenario name	**No Flex**	**Low Flex**	**Mid Flex**	**Moderni-sation**	**Mega Flex**		**Onshore capped**	**Nuclear centric**
				LCOE				
Nuclear	90	90	90	90	90		90	80
Solar PV	65	65	65	65	65		65	65
Difference	*25*	*25*	*25*	*25*	*25*		*25*	*15*
				SIC				
Solar PV vs. nuclear	**43.5**	**17.4**	**14.4**	**11.8**	**8.1**		**13.6**	**12.3**

4.2.4. Biomass

Finally, the SIC of biomass generation is depicted in Figure 4.13 for the Base Case studies between 2015 and 2030, and in Figure 4.14 for all 2030 scenarios. Given that biomass represents a flexible form of renewable generation, and unlike wind and PV does not increase the volume of required ancillary services, its integration costs are correspondingly lower, and in some scenarios even become negative. In the majority of scenarios the absolute magnitude of SIC of biomass is rather low, with the results being in the range ±£2/MWh. In the No Flex scenario the SIC of biomass drops to -£7/MWh, as the operation of biomass plant is expected to be more flexible than nuclear.

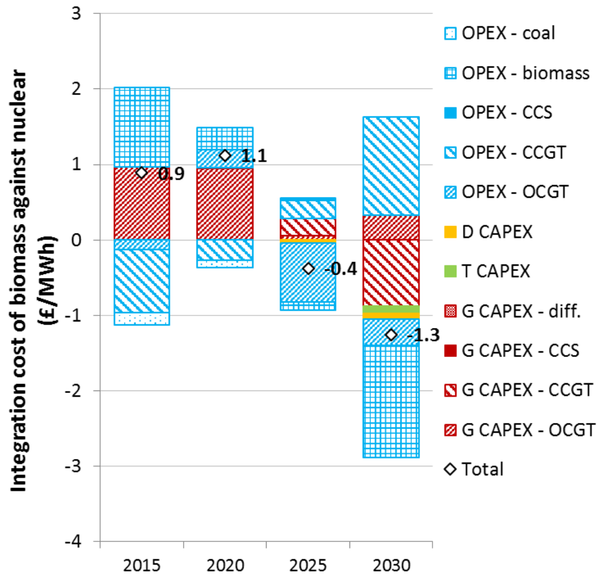

Figure 4.13. SIC of biomass compared to nuclear Base Case scenario between 2015 and 2030

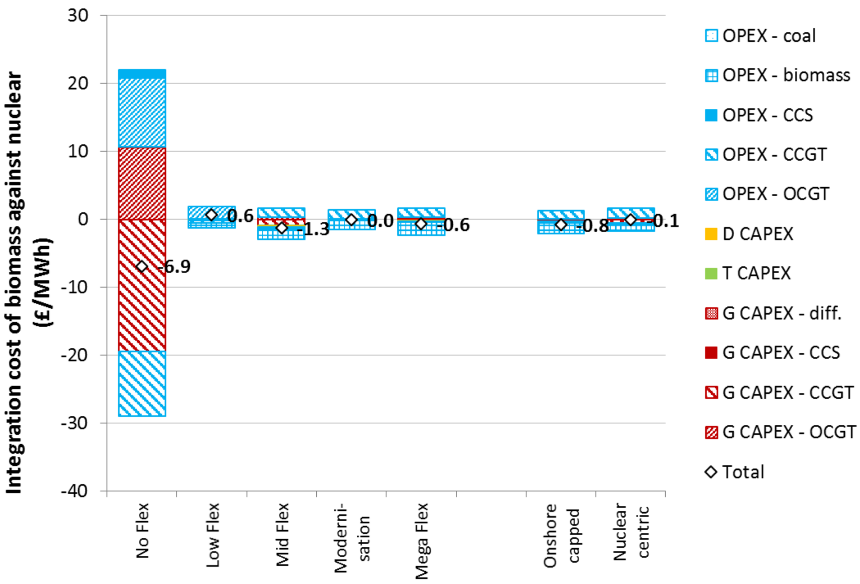

Figure 4.14. SIC of biomass compared to nuclear across 2030 scenarios

Low SIC of biomass indicates that its whole-system benefits are similar to those of nuclear, so the comparison between the whole-system costs of the two technologies provides a very similar outcome to the comparison of their LCOEs. Table 4.10 and Table 4.11 compare the LCOEs of nuclear and biomass with the SIC results presented above. Despite very low, or sometimes even negative SIC of biomass, its higher LCOE assumption than nuclear results in a whole-system cost of biomass that is higher than that of nuclear in all scenarios and in all years.

Table 4.10. LCOE differentials between biomass and nuclear compared to SIC in Base Case between 2015 and 2030 (in £/MWh)

Scenario name	**Basecase 15**	**Basecase 20**	**Basecase 25**	**Mid Flex**
Year	**2015**	**2020**	**2025**	**2030**
		LCOE		
Nuclear	93	93	90	90
Biomass	108	108	108	108
Difference	*-15*	*-15*	*-18*	*-18*
		SIC		
Biomass vs. nuclear	**0.9**	**1.1**	**-0.4**	**-1.3**

Table 4.11. LCOE differentials between biomass and nuclear compared to SIC across 2030 scenarios (in £/MWh)

Scenario name	**No Flex**	**Low Flex**	**Mid Flex**	**Moderni-sation**	**Mega Flex**		**Onshore capped**	**Nuclear centric**
				LCOE				
Nuclear	90	90	90	90	90		90	80
Biomass	108	108	108	108	108		108	108
Difference	*-18*	*-18*	*-18*	*-18*	*-18*		*-18*	*-28*
				SIC				
Biomass vs. nuclear	**-6.9**	**0.6**	**-1.3**	**0.0**	**-0.6**		**-0.8**	**-0.1**

5. Illustration of key aspects of hourly system operation

In this chapter we provide several examples of hourly system operation for selected situations that are typical for the system. The examples presented are taken from the Mid Flex scenario for 2030.

5.1. Impact of flexible options on residual demand

One of the key advantages of flexible options, in particular energy storage, DSR and interconnectors, is the ability to modify the residual demand profile seen by the generators in the system. A flatter demand profile requires lower use of high-cost peaking plants, while at the same time maximising the utilisation of baseload plant characterised by low marginal costs. For the example of the Mid Flex scenario in 2030, Figure 5.1 shows how the original load duration curve (LDC) is modified by the model through optimised use of three flexible options (storage, DSR and interconnection).

The original demand profile in 2030 (before and DSR actions) had a peak of 71.3 GW, corresponding to the highest value on the ‘Original demand’ curve in Figure 5.1. The way WeSIM ensures sufficient capacity margin is to build the required firm capacity so that the Loss of Load Expectation (LOLE) parameter does not exceed 3 hours per year. In practice, for a thermal system without any DSR or storage, this results in the capacity margin of approximately 20% over the system peak.

In the No Flex scenario (see Section 3.6.1) the model adds 41.7 GW of flexible peaking (OCGT) capacity. When this is added to the volume of other firm capacity (CCGT, CCS, nuclear, biomass, hydro and storage), the total firm capacity in the system totals about 86 GW, or around 20% above the peak demand of 71.3 GW. In the Mid Flex scenario on the other hand, the combined effect of DSR, additional storage and interconnection is that only about 20 GW of flexible peaking capacity is required in the system to maintain the same level of security of supply, i.e. to keep the LOLE at 3 hours per year.

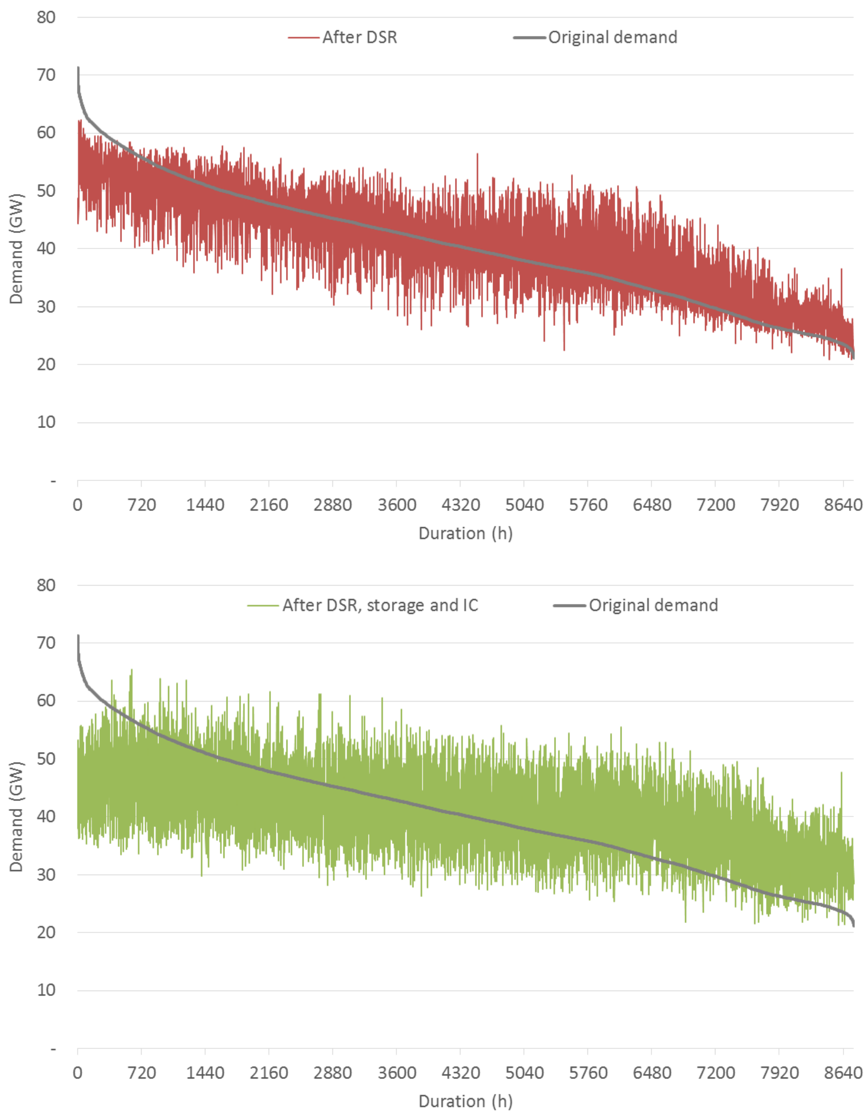

Figure 5.1. Synchronised load duration curves for system demand before and after optimising the use of DSR, energy storage and interconnection

The curves shown in Figure 5.1 are synchronised in the sense that once the LDC of the original demand is constructed, each corresponding data point plotted on the modified demand curve occurred at the same time as the original demand point with a given time coordinate. As expected, the shape of the demand curve changes to improve efficiency of electricity generation: high peaks in the original demand curve are reduced, while the low-demand periods see an increase in demand.

The same demand curves are plotted again in Figure 5.2 without retaining the synchronicity, i.e. by simply ordering the modified demand curve points in descending order. As expected, the shape of the LDC becomes flatter with additional flexibility. It is nevertheless interesting to note that after applying all three flexible options the peak demand ends up being slightly higher than after applying just DSR. This is because the system optimises the use of flexibility to minimise system cost, so the resulting demand profile is also adapting to fluctuations in the output of variable RES technologies (wind and solar). The new peak in modified demand (occurring at a different point in time than the original peak) is likely to coincide with periods of high renewable output.

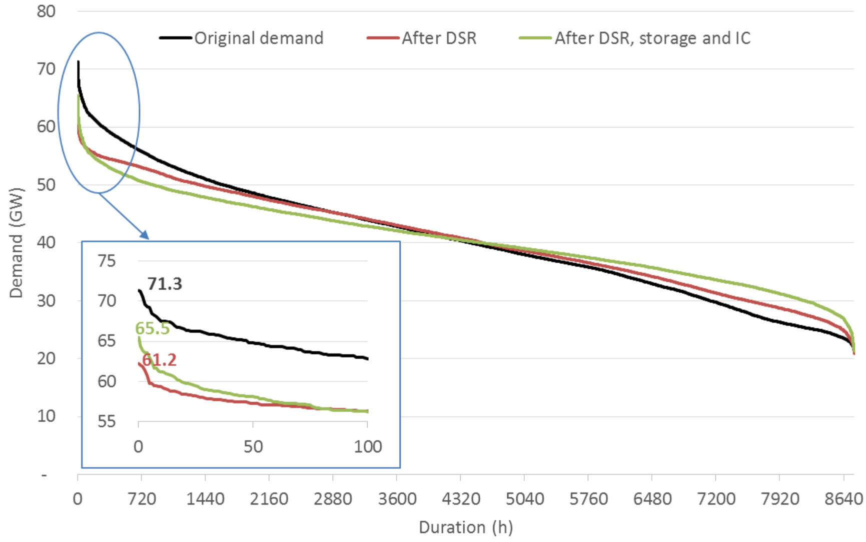

Figure 5.2. Non-synchronised LDCs for system demand before and after optimising the use of DSR, energy storage and interconnection

To illustrate the effect of flexibility on net demand LDC, Figure 5.3 shows the LDC for net demand before and after applying flexible options. It is evident that without flexibility the net demand would occasionally become negative, necessitating RES output curtailment. In the presence of flexible options however, the modified net demand curve is maintained well above zero and is much more evenly balanced between periods of low and high net demand.

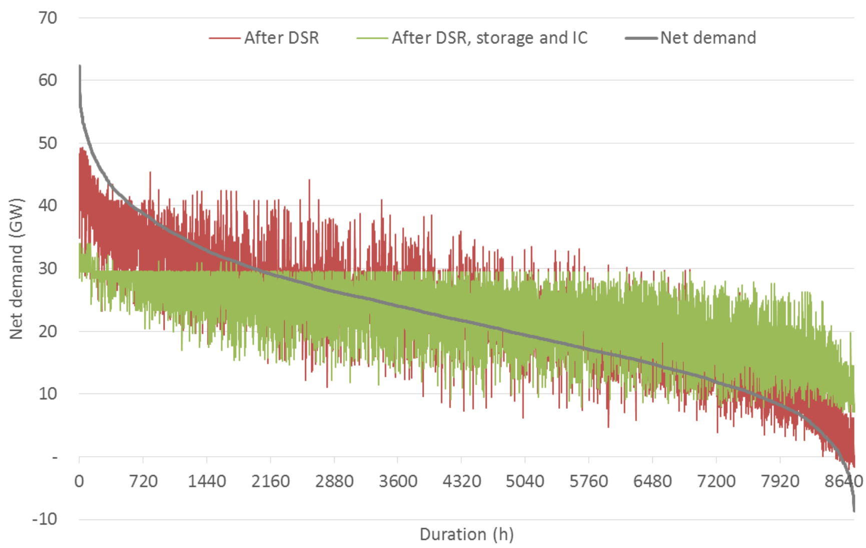

Figure 5.3. Synchronised net demand LDCs before and after optimising the use of flexible options

It is interesting to observe that for most of the year the modified net demand profile is capped at about 30 GW, which is only exceeded during a small number of hours (ca. 50) coinciding with peak demand hours. This occurs because the model is trying to maximise the utilisation of firm capacity represented by nuclear, CCS, biomass, hydro and CCGT generation (totalling around 30 GW). On infrequent occasions when the 30 GW of generation output has to be exceeded due to very high original demand, the model utilises high marginal cost OCGT generators that are otherwise providing backup.

The role of flexibility in ensuring a more efficient operation of generation resources is even more evident from Figure 5.4, which represents non-synchronised net demand LDCs. Deployment of DSR, storage and interconnection enables the peak net demand value seen by conventional generators to drop from 62.3 GW to just 33.9 GW. On the other end of the spectrum, the minimum value of net demand increases from -8.6 GW (i.e. from a situation with an excess RES output potentially necessitating curtailment) to 7.1 GW. The 30 GW threshold is easily discernible from the post-flexibility net demand LDC, suggesting that in this scenario (i.e. with the relevant assumptions made on demand, low-carbon and conventional generation capacities and flexible options deployment) not more than 30 GW of mid-merit (i.e. non-peaking) plant is required to cover the demand in all but a small number of peak demand hours.

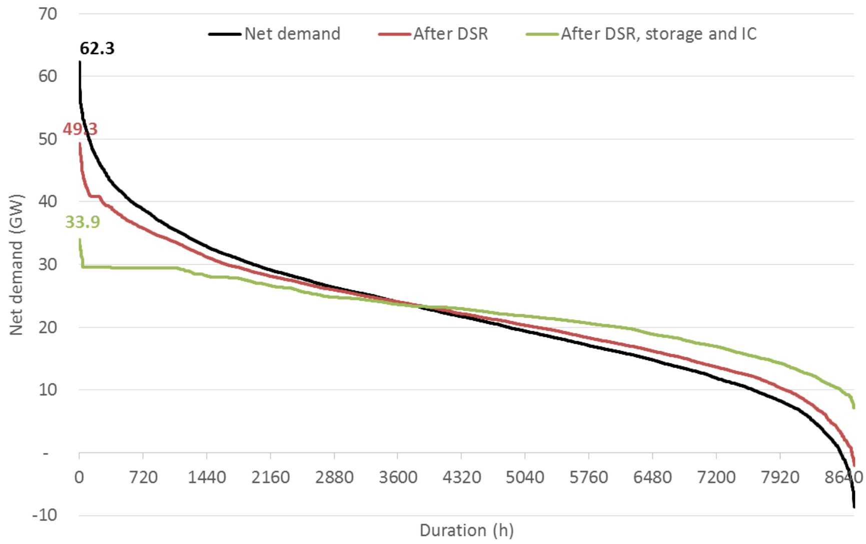

Figure 5.4. Non-synchronised net demand LDCs before and after optimising the use of flexible options

In order to further clarify the role of flexible peaking capacity, we note that the maximum utilisation of non-renewable generation in 2030 (according to the green curve in Figure 5.4) is 33.9 GW, or when deducting CCGT, CCS, nuclear, hydro and biomass output, this implies the maximum utilisation of OCGT generation capacity at the level of 4.4 GW. This is considerably lower than the 21.8 GW installed by the model, so one might question the need to install a seemingly excessive amount of peaking plant. However, the system operation simulated in WeSIM is deterministic, and does not explicitly include the simulation of plant outages. This is why WeSIM (as documented in detail in the Appendix) uses a separate set of constraints to ensure that sufficient generation capacity margin is maintained to guarantee the ability of the system to supply demand in all but 3 hours per year (on average). The model therefore adds peaking capacity that would mostly not be used with a perfect (deterministic) forecast, but is on the other hand crucial to ensure the ability of the system to cope with probable outages of generating units at the assumed level of LOLE of 3 hours.

Increasing the allowed level of LOLE would inevitably result in a lower level of required capacity margin, reducing the need to add peaking capacity to the system.[47] Nevertheless, the impact on the level of SIC associated with VRES technologies, being the key focus of this study, is unlikely to change materially as the result of relaxed security of supply criterion.

5.2. Winter vs. summer system operation

In Figure 5.5 we illustrate how the system operates on an hourly basis for a winter week in January (results are from the 2030 Mid Flex scenario). The chart shows the hourly output of all generation technologies as well as the utilisation of storage, net interconnection flows and the impact of DSR on residual demand profile.

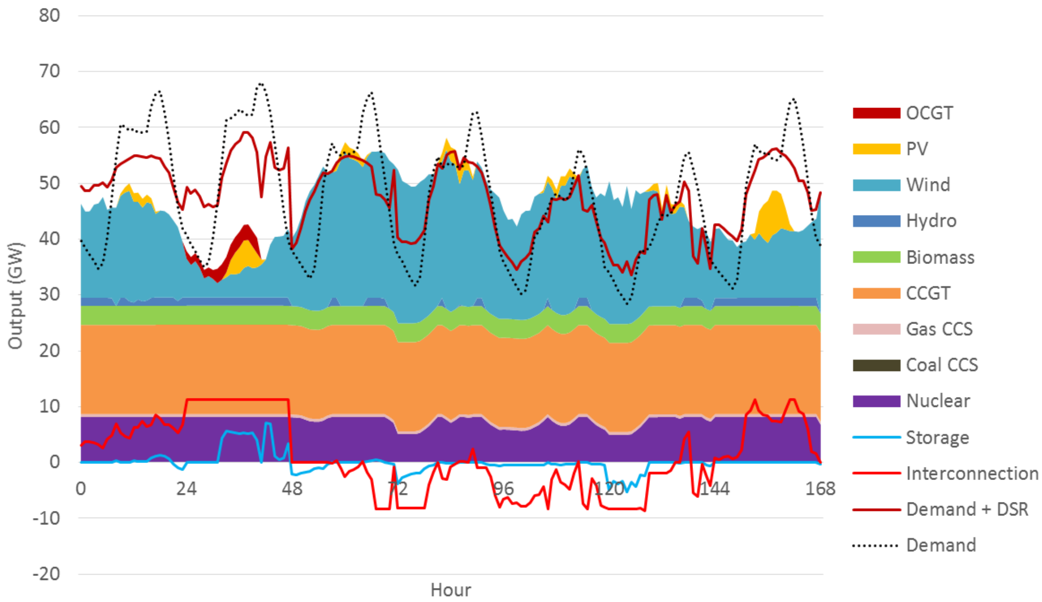

Figure 5.5. Hourly system dispatch for a winter week in 2030 (Mid Flex)

During the week depicted in the chart, wind output during the second day drops to a very low level (with about 2.5 GW being the lowest output during that day). The system responds to the combination of low RES output and high demand by maximising the imports via interconnectors as well as discharging energy storage during key hours of that day. As this is still insufficient to meet the demand, the model also utilises some OCGT capacity to provide electricity during Day 2. One can also note that when wind output increases again starting from Day 3, the model starts exporting electricity to neighbouring systems, while also taking the opportunity to recharge energy storage.

During a typical summer week, depicted in Figure 5.6, the system is faced with much lower demand requirements, while the output of variable RES generators (including solar PV that provides peak output during summer) can be substantial. The model therefore minimises the

47 A very rough calculation shows that if LOLE was increased from 3 to 6 hours per year, the system in 2030 would need about 4 GW less peaking capacity.

use of thermal generators, while at the same time exporting large volumes of electricity to other systems. This is particularly visible on Days 2 and 6.

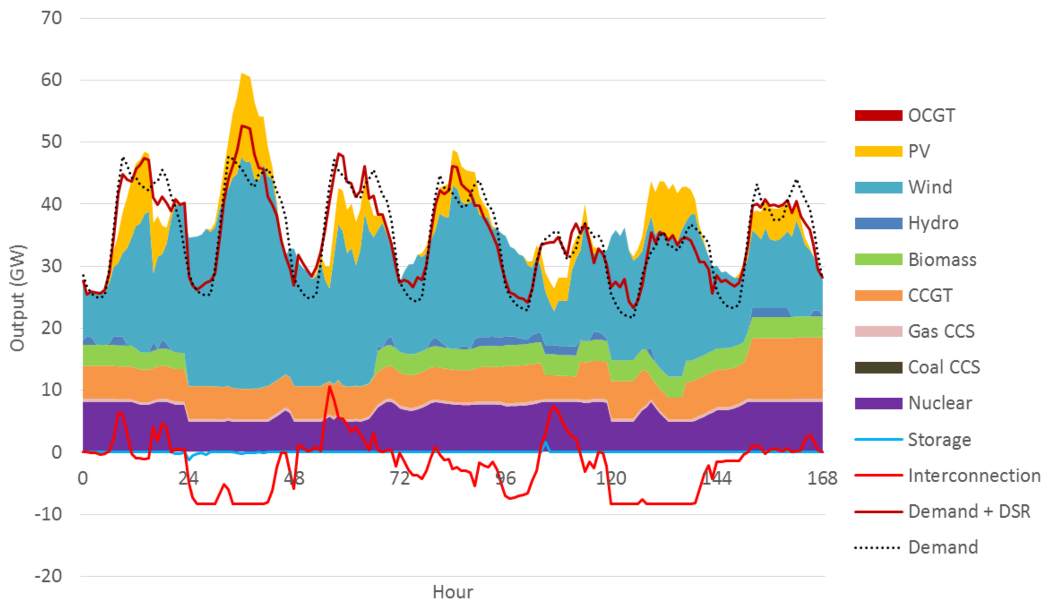

Figure 5.6. Hourly system dispatch for a summer week in 2030 (Mid Flex)

The output of biomass units is reduced to zero during Days 2 and 3 to manage excess available electricity in the system. Note that biomass generation is utilised at about 90% load factor annually despite having a higher operating cost than e.g. CCGT units. This occurs as the result of the imposed carbon constraint (100 g/kWh) that requires high biomass output in order to meet the target.

Note that in the studies nuclear generators were assumed to be operate more flexibly than they do in the current GB power system. Nuclear units were allowed to reduce output to 60% of their minimum output level, while maintaining the annual capacity factor of 90% in 2030. With today's operation practices, where nuclear units tend to remain as close as possible to the maximum output with the exception of periodic maintenance periods, it is likely that there would be more frequent curtailment of VRES output. However, without additional analysis it is not possible to state with certainty in which direction the SIC of VRES would change as the result of less flexible nuclear operation.

6. Sensitivity analysis

This chapter summarises the results of sensitivity analyses where a number of core assumptions have been modified to investigate the impact of these variations on system integration cost of renewable generation.

6.1. Impact of retiring biomass before 2030

Biomass generation, in particular when associated with conversion of existing coal-fired plants, is currently seen as a viable option for decarbonising the UK electricity supply in the medium term. Nevertheless, there are concerns around the sustainability of biomass sources.[48] It is therefore of interest to assess the impact on SIC of renewable technologies of the assumption that instead of 3.4 GW of biomass capacity assumed across all 2030 scenarios, there would not be any biomass generators in operation in 2030.

As shown in Table 4.2, the utilisation of biomass in all 2030 scenarios except No Flex is very close to the maximum (90%), despite a relatively high operating cost (around £70/MWh). This follows from the 100 g/kWh carbon target imposed in 2030 scenarios and the fact that biomass output was assumed to be zero-carbon, so the model maximised its utilisation. Given that the 2030 scenarios were optimised for offshore wind capacity, it was more cost-efficient to remove a unit of offshore wind capacity than to reduce the utilisation of biomass, despite its variable cost being higher than e.g. the cost of CCGT.

Because of the setup of the scenarios, where a cost-optimal volume of offshore wind is chosen to meet the 100 g/kWh target, reduction of low-carbon output from biomass will require more offshore wind in the system to maintain the same level of carbon emissions. With everything else kept equal, one would expect that SIC of e.g. offshore wind would increase if the volume of offshore wind in the scenario increases at the expense of biomass generation.

In the first step the model was run to establish the counterfactual cases for the five 2030 scenarios, in particular to determine the optimal volumes of offshore wind capacity that can be removed from the system while maintaining the 100 g/kWh carbon intensity, similar to the counterfactual scenario construction described in Section 3.6.1. Table 6.1 specifies the optimised volumes of generation technologies and interconnection across the five 2030 scenarios without biomass (this table is equivalent to Table 3.8, which specified optimal volumes for the core scenarios).

48 For a more detailed discussion of the issue see e.g. DECC's report "Life Cycle Impacts of Biomass Electricity in 2020" (July 2014), the U.S. Natural Resources Defense Council's issue brief "Think Wood Pellets are Green? Think Again" (May 2015), or the Greenpeace report "Fuelling a BioMess: Why Burning Trees for Energy Will Harm People, the Climate and Forests" (October 2011), providing a view from the Canadian perspective.

Table 6.1. Optimised capacities of technologies in 2030 counterfactual scenarios without biomass (in GW)

Technology	***Scenario***				
	Mid Flex	**Onshore capped**	**Nuclear centric**	**Modernisation**	**Mega Flex**
OCGT	33.6	33.6	25.5	33.6	23.9
New CCGT*	-	-	-	0.1	0.1
Offshore wind	29.0	36.7	18.0	28.3	28.1
*Reduced wind***	*-2.0*	*-2.3*	*-3.0*	*-2.7*	*-2.9*
New interconnection	-	-	-	-	-

Notes:
* CCGT capacity added on top of the capacity in Table 3.1.
** Reduction compared to the initial capacity in Table 3.1.

By comparing Table 6.1 with Table 3.8, it is evident that much less offshore wind has been removed from the starting generation mixes, which is expected given the requirement to maintain carbon emissions following the removal of biomass from the generation portfolio. Instead of 8.8-9.6 GW of offshore wind that could be removed in the core scenarios, the absence of biomass in the 2030 mix allowed only 2 to 3 GW of offshore wind to be removed from the starting generation mixes for the same emission intensity level. The absence of biomass is also reflected in the increased volume of peaking OCGT capacity, added by the model to maintain the same level of firm capacity i.e. to ensure sufficient capacity margin in the system.

The quantitative results for SIC across the 2030 scenarios without biomass are shown in Figure 6.1 for the four analysed renewable technologies.

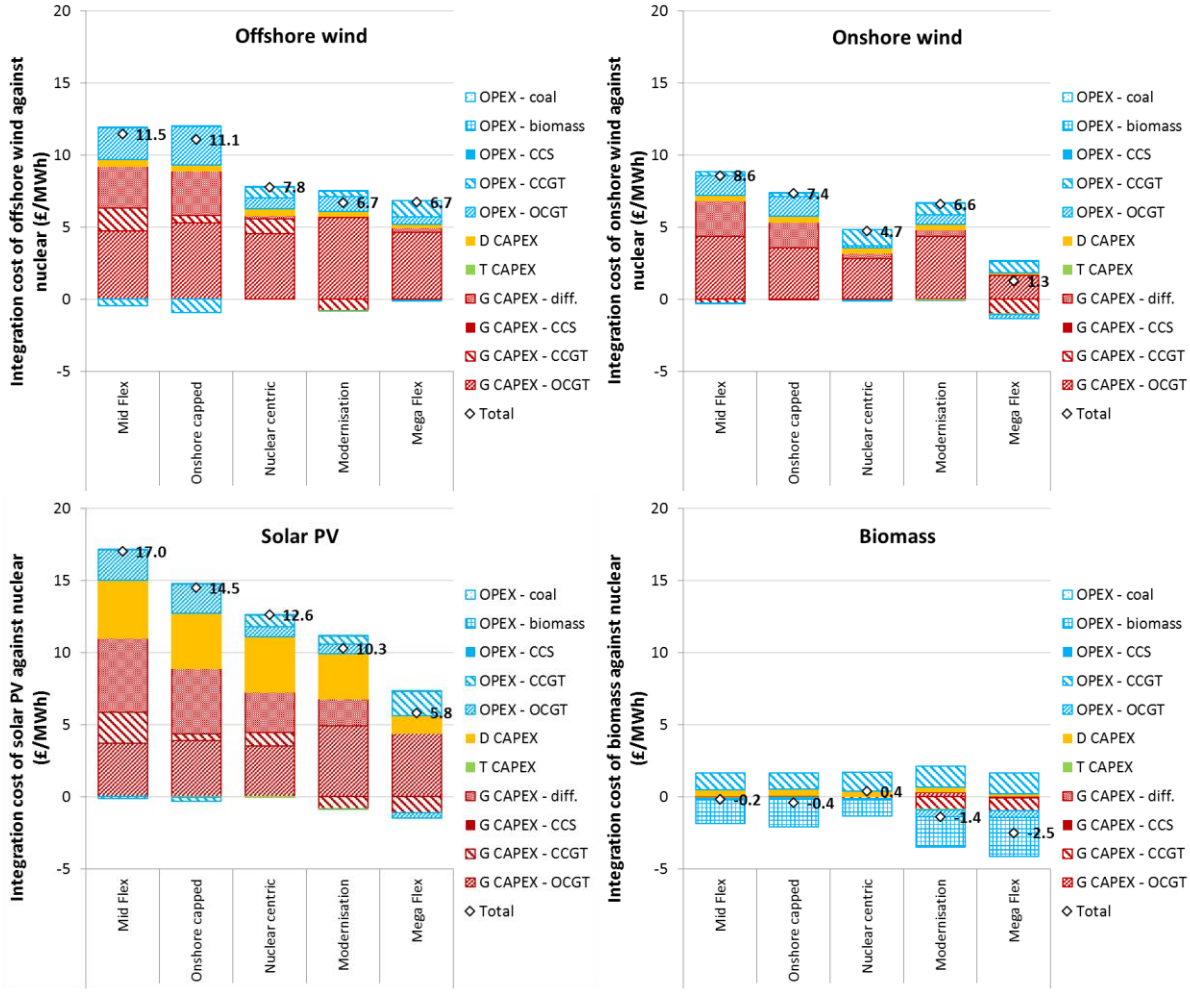

Figure 6.1. SIC of LCGTs for 2030 scenarios without biomass

With the removal of biomass from the 2030 system the SIC of offshore wind and solar PV generation generally increases compared to the core scenarios. This is not unexpected given the increased penetration of variable RES in scenarios without biomass, and higher baseline RES penetration gives rise to an increased cost of integrating the next marginal amount of RES generation. At the same time the SIC of biomass tends to decrease slightly, although it had already been found to be at fairly low levels in the core scenarios.

6.2. Impact of more ambitious carbon target in 2030

Another set of sensitivity studies analysed the impact of adopting a more ambitious carbon reduction target, so that the carbon intensity of electricity supply in 2030 reduces to 50 instead of 100 g/kWh. In analogy to the approach to constructing five counterfactual scenarios for 100 g/kWh (where offshore wind capacity was optimally reduced while meeting the carbon target), the 50 g/kWh scenarios for 2030 have been constructed by *adding* the necessary volume of offshore wind to meet the carbon target. An additional scenario has also been constructed from the Mid Flex scenario where the 50 g/kWh target is not met by adding offshore wind but by adding CCS capacity.

Table 6.2 summarises the key capacity additions in the five 2030 scenarios necessary to reach the 50 g/kWh carbon intensity. The table suggest that in Nuclear Centric, Modernisation and Mega Flex scenarios, which are characterised by either very high flexibility or moderate wind deployment levels, only about 2.2-2.5 GW of additional offshore wind capacity would be necessary to meet the 50 g/kWh target. In the two scenarios with high wind capacity and medium flexibility level, Mid Flex and Onshore Capped, it is necessary to install 3.2-3.6 GW of additional offshore wind to comply with the 50 g/kWh limit, but it also becomes necessary to install additional interconnection capacity between GB and mainland Europe, in the amount of 5-6 GW.

Table 6.2. Optimised capacities in 2030 counterfactual scenarios when meeting 50 g/kWh target (in GW)

Technology	Scenario					
	Mid Flex	Onshore capped	Nuclear centric	Modernisation	Mega Flex	Mid Flex (CCS)
OCGT	30.1	30.0	21.9	30.0	20.2	28.1
New CCGT*	-	0.1	-	-	0.1	-
Added wind**	3.6	3.2	2.2	2.4	2.4	-
Added CCS**	-	-	-	-	-	1.9
New interconnection***	5.1	6.1	-	-	-	-

Notes:
* CCGT capacity added on top of the capacity in Table 3.1.
** Compared to the initial capacity in Table 3.1.
*** Compared to the deployment level in Table 3.6.

The results of SIC studies for the 50 g/kWh scenarios are shown in Figure 6.2 for offshore and onshore wind and PV. An immediate observation is that in Mid Flex and Onshore Capped scenarios the SIC of both wind and PV becomes dramatically higher, about 2-3 times higher than the SIC found in 100 g/kWh scenarios. In these two scenarios the SIC of wind and PV is dominated by the excess wind or PV capacity added on top of the energy equivalent amount to keep the system emissions constant.

As an illustration, in the Mid Flex scenario, instead of replacing 1 GW of nuclear with the energy-equivalent 1.9 GW of offshore wind, the model in fact adds 3.4 GW i.e. almost double the equivalent amount. This occurs because the integration of wind and PV generation in those scenarios becomes challenging in the context of retaining the same carbon intensity: the addition of e.g. wind in SIC studies displaces a significant amount of low-carbon output of biomass[49], which requires additional wind capacity to be added in order to maintain system carbon emissions. Only with 3.4 GW of additional offshore wind capacity does the model manage to balance the system with 50 g/kWh carbon intensity. This inability to efficiently integrate VRES generation also indicates that purely increasing wind capacity beyond about 50 GW with the level of flexibility assumed in the Mid Flex scenario may not be the best

[49] Displacement of biomass output is observed despite the reduction of nuclear capacity by 1 GW. The reason for this is that the added wind capacity that is energy-equivalent to 1 GW of nuclear produces the same output on average; however the wind output fluctuates so that when it is higher than 1 GW it would displace biomass despite there being 1 GW less of nuclear generation. When wind output is lower than the average on the other hand, the missing energy cannot be provided by increased biomass output as biomass will be constrained by its installed capacity.

strategy to decarbonise electricity supply and that an improved flexibility may be required to accompany wind.

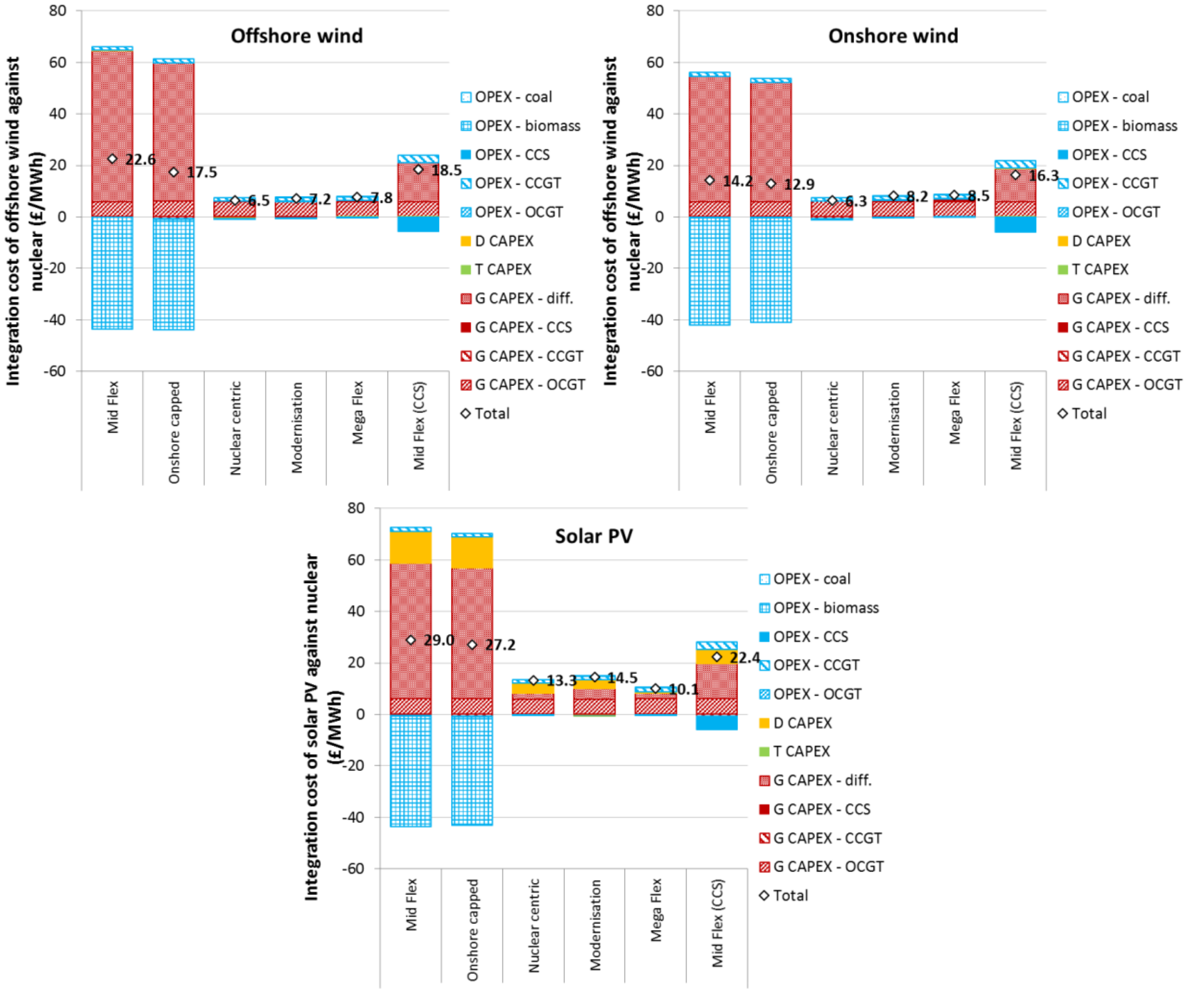

Figure 6.2. SIC of offshore wind, onshore wind and PV in 2030 scenarios achieving 50 g/kWh carbon intensity

On the other hand, in scenarios with higher flexibility (Modernisation, Mega Flex) or lower starting wind capacity (Nuclear Centric) the level of SIC is comparable to that in the 100 g/kWh scenarios.

It is also interesting the compare the LDCs of net demand (system demand reduced by wind and PV output in each time interval) for 100 and 50 g/kWh Mid Flex scenarios, to illustrate the effect of increasing wind capacity on the resulting demand shape seen by conventional generators. This is presented in Figure 6.3, which shows the net demand LDCs for 50 and 100 g/kWh Mid Flex scenarios before and after applying flexible options (DSR, storage and interconnection) to the net demand profile. In order to reach the 50 g/kWh target, this scenario has 12.4 GW more of installed offshore wind capacity than the 100 g/kWh scenario. This is particularly reflected in a very low minimum value on the net demand LDC, which drops to -20 GW (as opposed to 9 GW for the 100 g/kWh case). Although this does not result in significant curtailment of wind output due to relatively high system flexibility, it does lead to the curtailment of output of another low-carbon technology (biomass in this case).

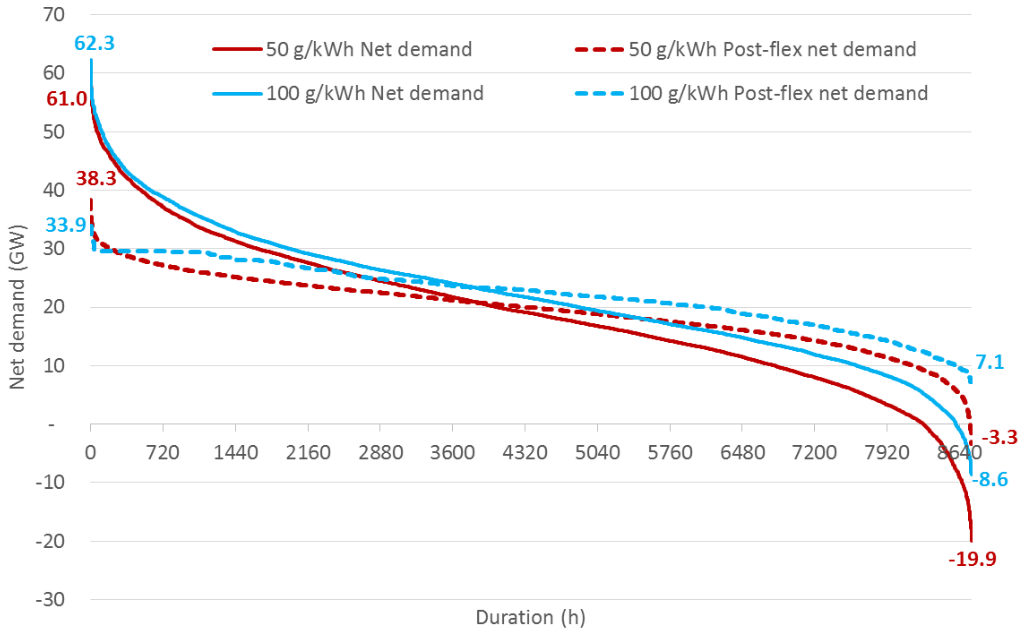

Figure 6.3. Non-synchronised net demand LDCs in 100 and 50 g/kWh Mid Flex runs before and after applying flexible options

Finally, in the Mid Flex scenario with CCS optimally added rather than offshore wind, the SIC of wind and PV becomes similar to the levels observed in Mid Flex and Onshore Capped scenarios. In the case of PV the SIC in this scenario is actually lower than the integration cost in Mid Flex scenario with 50 g/kWh target imposed by installing additional wind capacity. An implication of this is that there may be merit in considering a certain amount of CCS as part of the low-carbon generation mix thus ensuring flexibility on the generation side.

6.3. Impact of system flexibility

Our previous studies, such as the recent CCC study, demonstrated the critical role of flexible options such as energy storage and DSR in cost-effective integration of variable renewables. A high level of flexibility in the system may help to manage the integration cost and keep it at an acceptable level. Although varying flexibility was a prominent feature of the analysed scenarios, given the pivotal role of flexibility in supporting cost-effectiveness of VRES integration, an additional set of sensitivity studies was run to evaluate the impact of varying flexibility across the scenarios adopted in this study on SIC of VRES.

Table 6.3 details the variations in flexibility assumptions around the central values assumed in baseline scenarios. Two further flexibility levels have been considered in 2020 and 2025, Low and High. In 2030, in addition to the Mid Flex and Mega Flex scenarios, two lower flexibility levels were analysed (as already defined previously in Section 3.1):

- *Low Flex*: same starting generation mix as Mid Flex, but with less new storage (5 GW instead of 10 GW), lower DSR uptake (25% instead of 50%) and less interconnection capacity (10 GW). As in the other five counterfactual scenarios, the 100 g/kWh target was attained by reducing offshore wind; this scenario allowed for 7.9 GW of offshore wind to be removed (as opposed to 8.8 GW in Mid Flex).

- *No Flex*: same starting generation mix as Mid Flex, but with zero new storage and zero DSR uptake, as well as slower interconnection deployment (7.5 GW). In this scenario no offshore wind could be removed as even with the original portfolio of LCGTs the system could not achieve 100 g/kWh. The target was therefore achieved by cost-optimally adding CCS capacity to the system, in the amount of 2.1 GW.

Table 6.3. Flexibility assumptions for Low, Medium and High flexibility

Year	2020			2025			2030			
Flex. level	Low	Mid	High	Low	Mid	High	No	Low	Mid	Mega
New storage (GW)	-	0.2	2	-	2	5	-	5	10	15
DSR	0%	0%	25%	0%	25%	50%	0%	25%	50%	100%
Interconnection (GW)	4.0	7.5	7.5	7.5	11.3	11.3	7.5	9.9	11.3	15.0

It is not in the scope of this study to speculate on the likelihood that a given level of flexibility would materialise by 2030. Nevertheless, flexibility levels towards the high level of the spectrum will require coordinated action and policy support starting from today in order to ensure high volumes of flexible options are deployed over the next decade or so.

Figure 6.4 presents the results of SIC studies for offshore wind when flexibility in the Base Case is varied in years 2020-2030 as specified in Table 6.3.

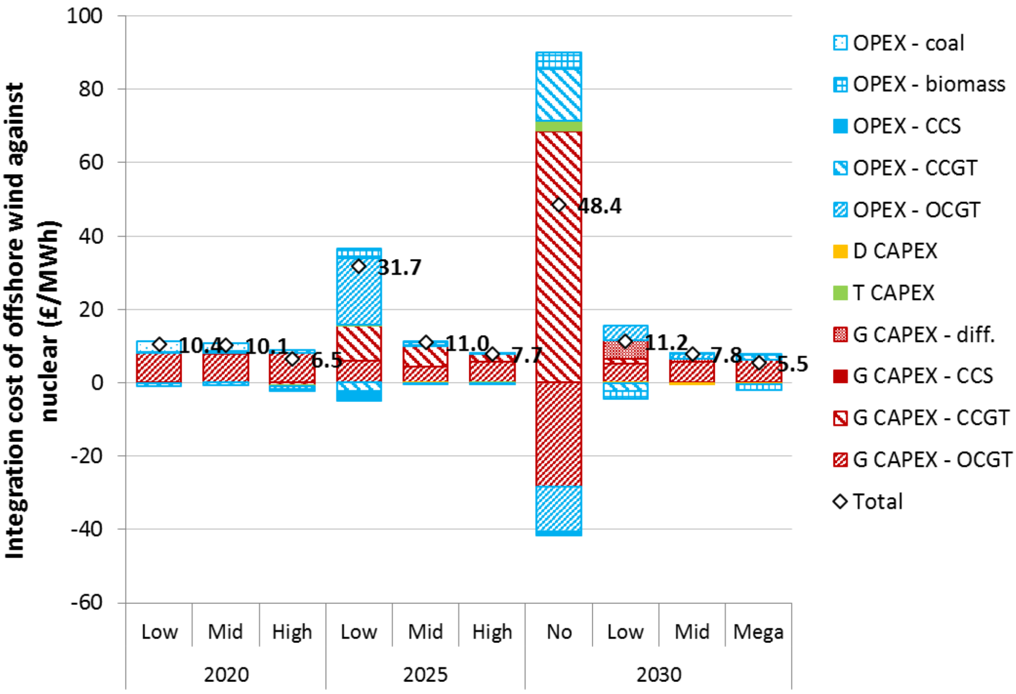

Figure 6.4. SIC of offshore wind in Base Case as function of time and system flexibility

The results confirm that increasing system flexibility can indeed significantly reduce SIC of offshore wind. The reduction becomes particularly prominent in 2025 and 2030 due to higher installed RES capacity. For instance, in 2030 moving from No Flex to High flexibility can reduce the SIC of offshore wind by a factor of 10, while in 2025 the reduction is fourfold. In 2020 the reduction is not that prominent but is still considerable.

These results confirm the overall conclusions from the analysis of total system cost in Section 4.1.3: the integration of variable RES in a system with scarce flexibility would be very costly and inefficient. For instance, the RES curtailment in the counterfactual 2030 No Flex scenario would be as high as 10% overall (ranging between 7% for offshore wind to 12% for solar PV and 16% for onshore wind); however, at the margin i.e. when considering just the added offshore wind capacity in the SIC study the curtailment increases to 20%. Nevertheless, already a moderate improvement of system flexibility brings the SIC of offshore wind down to £10-11/MWh in the 2025-2030 horizon, and this level of SIC combined with the LCOE assumptions still make offshore wind a cost-effective proposition compared to nuclear generation.

Given that it is clear that system flexibility as well as the penetration of variable renewables in the system seem to be the key drivers behind the SIC for VRES technologies. To emphasise this functional relationship, we present the SIC results obtained through a diverse range of case studies presented in this report as a function of VRES penetration in the system, with the level of system flexibility as parameter. The figures are plotted for offshore wind (Figure 6.5), onshore wind (Figure 6.6) and solar PV (Figure 6.7). The groups of SIC results from different scenarios and sensitivities are formed based on the level of improvements in system flexibility as follows:

- *No progress*: Low Flex in 2020 and 2025, No Flex in 2030
- *Moderate progress*: Mid Flex in 2020 and 2025, Low Flex in 2030
- *Fast progress*: High Flex in 2020 and 2025, Mid Flex, Onshore Capped and Nuclear Centric in 2030 (including central scenarios, 50 g/kWh sensitivities and no biomass sensitivities)
- *Maximum progress*: Modernisation and Mega Flex in 2030 (including central scenarios, 50 g/kWh sensitivities and no biomass sensitivities)

To facilitate comparison, these figures also include the SIC results from a recent CCC study[50], which have been inserted in grey colour, matching the marker types for different flexibility levels. Because of differences in assumptions (in particular fuel and carbon costs and generation CAPEX) the CCC results have been adjusted by using the assumptions adopted in this study.

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[50] Imperial College London, "Value of Flexibility in a Decarbonised Grid and System Externalities of Low-Carbon Generation Technologies", report for the CCC, October 2015.

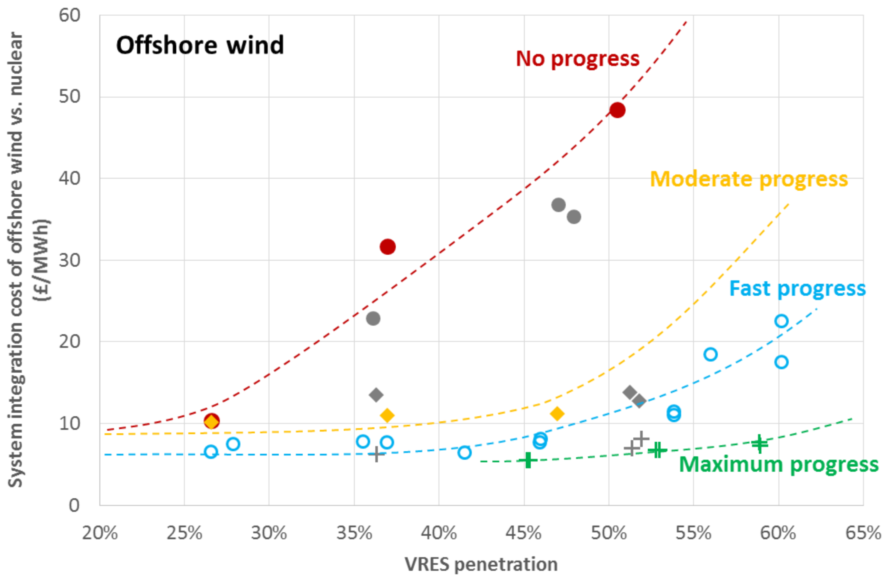

Figure 6.5. SIC of offshore wind as function of VRES penetration and system flexibility

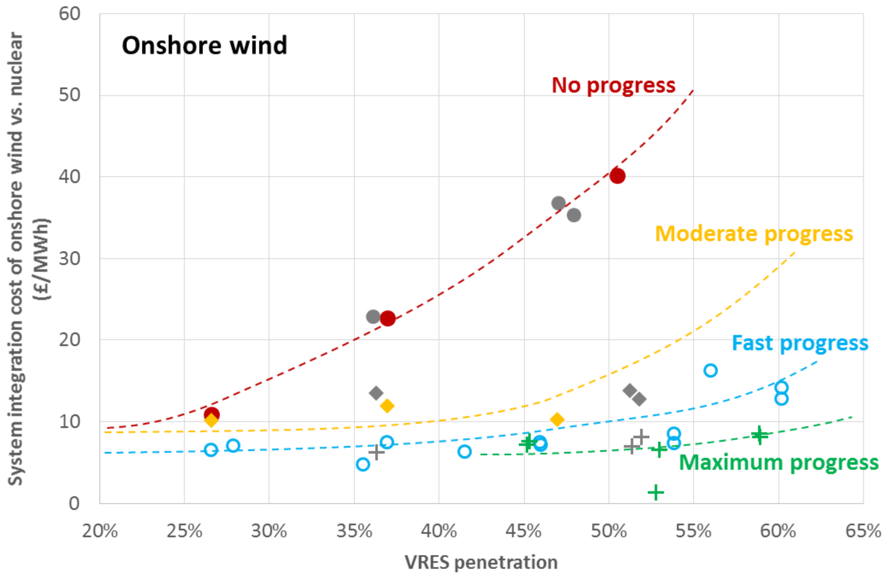

Figure 6.6. SIC of onshore wind as function of VRES penetration and system flexibility

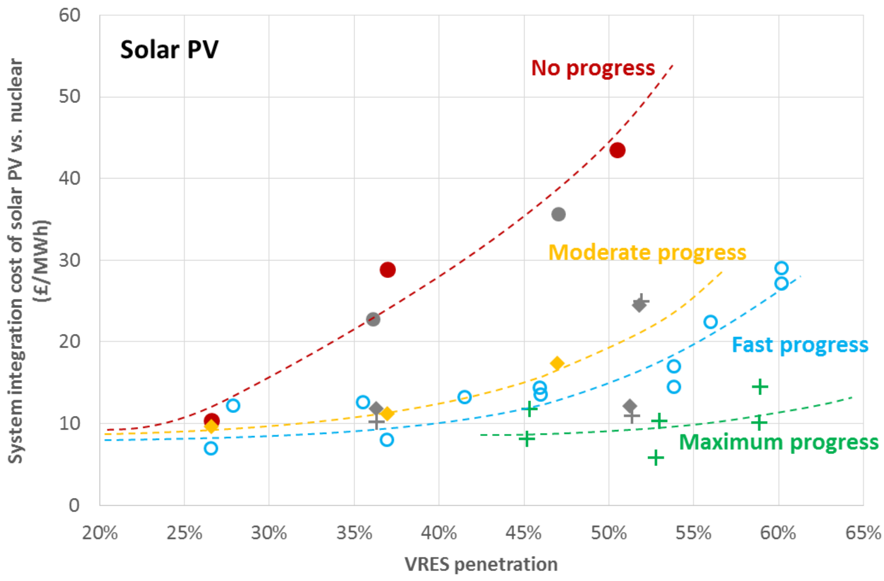

Figure 6.7. SIC of solar PV as function of VRES penetration and system flexibility

A clear finding from these charts is that higher VRES penetrations yield higher SIC values, but the magnitude and the rate of this increase depend greatly on the enhancements in system flexibility that accompanies the expansion of VRES i.e. on the volume of deployed flexible options such as DSR, storage and interconnection. At current flexibility ("No progress") levels the SIC increases sharply already at low wind penetration levels; conversely, with higher flexibility ("Moderate" or "High progress") SIC remains at moderate levels even at significantly higher VRES penetrations reaching 60%. Clearly, in order to ensure the integration of increasing VRES generation at low cost, the system would require a simultaneous increase in the deployment of flexible options – DSR, energy storage and interconnection.

6.4. Impact of largest generator size and relaxed minimum CCGT capacity

In this section we investigate the impact of largest generator size and relaxed minimum CCGT capacity in 2030 on SIC of offshore wind.

The reasoning for sensitivity studies on generator size is that this parameter is critical for determining the volume of primary frequency regulation required to cope with large generator loss: the greater the generator loss, the higher frequency response requirement to capture the frequency deviation within an acceptable range following a large generator loss event. The size of the largest loss relevant for today's system is 1.32 GW, corresponding to the size of the largest nuclear unit (Sizewell B). Nevertheless, future nuclear units (e.g. Hinkley Point C) and interconnectors are expected to be larger in size, and the largest foreseeable loss has therefore recently been increased accordingly to 1.8 GW[51]. This larger unit size was the default assumption used in the 2030 scenarios in this study.

Previous analyses revealed that one of the key drivers behind the additional cost of integrating variable RES output is the expected reduction in system inertia caused by the displacement of conventional synchronous generators by mostly asynchronous RES generation technologies. The cost associated with dealing with reduced system inertia is further exacerbated by the addition of a larger unit, the loss of which needs to be absorbed by the system. In fact the inertia problem would be easier to tackle if all the units in the system were small so that the largest conceivable infeed loss was also of smaller magnitude. Therefore, to investigate the impact of the size of the largest generating unit on the SIC of offshore wind, additional sensitivity studies were run where the size of the largest loss was reduced to 1.32 GW (as in today's system) and 0.5 GW (corresponding to the typical size of thermal units or Small Modular Reactors[52]).

Another sensitivity looked at the impact of relaxing the minimum volume of CCGT generation specified in all 2030 scenarios to be 16 GW. As observed in the counterfactual scenarios, the model very rarely added any CCGT capacity beyond this minimum, which may be interpreted as there being excess CCGT capacity in the system. This sensitivity study therefore relaxed the minimum CCGT capacity constraint and allowed the model to cost-optimise CCGT capacity from zero: instead of 16 GW the optimal capacity chosen by the model was 12.7 GW.

As in the core counterfactual scenarios, the offshore wind capacity in these sensitivity studies was first optimised downwards while meeting the 100 g/kWh target. In the relaxed CCGT sensitivity a marginally lower volume of offshore wind was required (22.1 GW instead of 22.2 GW in Mid Flex scenario), while both cases with lower unit size had an even lower offshore wind volume, 21.7 GW. Therefore, in all of these three sensitivity studies the baseline total annual system was lower than in Mid Flex: the cost was between £142m/year and £157m/year lower with 1.32 GW and 0.5 GW unit sizes, respectively, mainly due to lower wind capacity. In the relaxed CCGT the cost was £171m/year lower, mostly due to lower investment in CCGT capacity. The total system cost levels observed across the three sensitivities are shown in Figure 6.8 against the total system cost in the 2030 Mid Flex scenario.

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[51] See e.g. National Grid: "GSR015: Normal Infeed Loss Risk", Modification Report, August 2014, http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/SQSS/Modifications/GSR015/.

[52] It is considered unlikely that Small Modular Reactor technology would be available at scale before 2030.

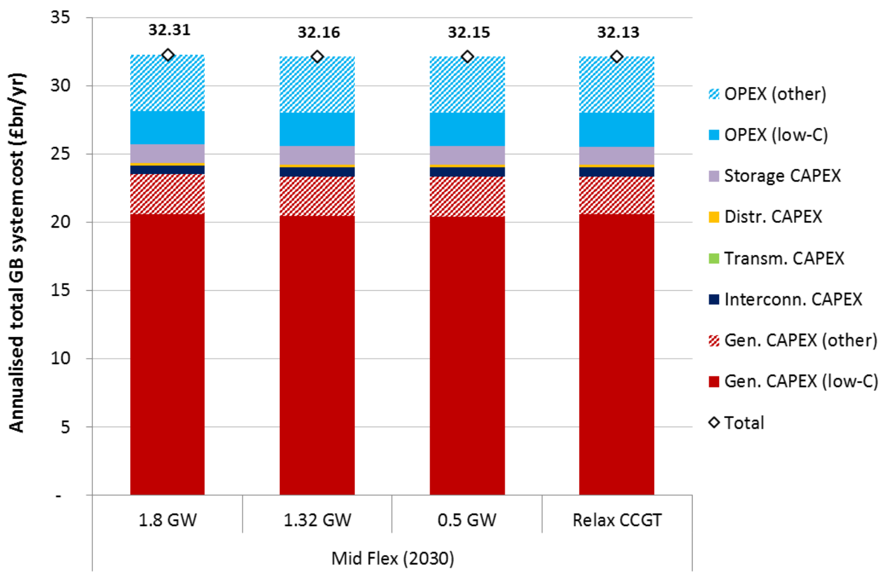

Figure 6.8. SIC of offshore wind in sensitivity studies on largest unit size and relaxed CCGT capacity in Mid Flex scenario in 2030

Figure 6.9 summarises the results of SIC studies for these three sensitivities and compares them against the SIC found in the Mid Flex scenario with the default assumption of 1.8 GW largest unit size.

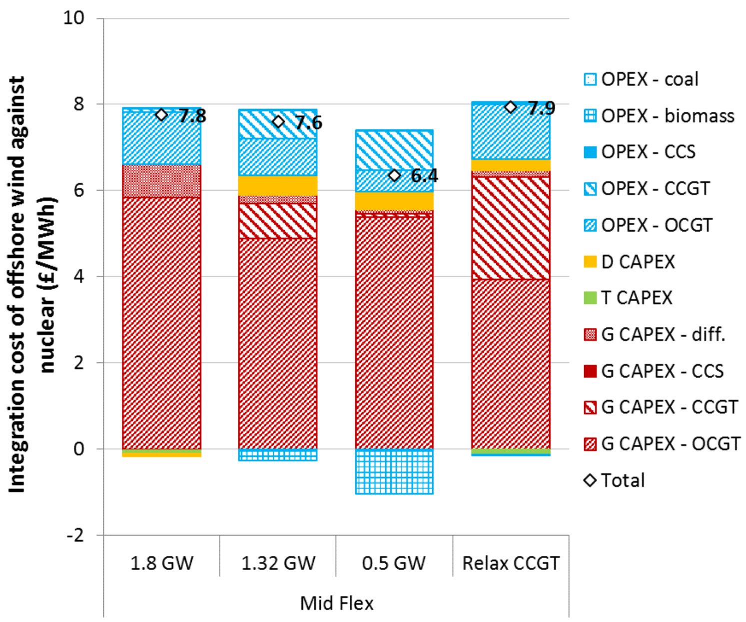

Figure 6.9. SIC of offshore wind in sensitivity studies on largest unit size and relaxed CCGT capacity in Mid Flex scenario in 2030

The impact of reducing the largest unit size to 1.32 GW seems minimal; the CAPEX of excess offshore wind capacity reduces compared to Base Case, but the system installs slightly more CCGT which largely offsets lower wind CAPEX resulting in a very similar level of SIC. With 0.5 GW however there is a visible reduction in SIC from £7.8/MWh to £6.4/MWh, mostly because the biomass plant is utilised less and CCGT more while still meeting the 100 g/kWh target; this is made possible by lower response requirements, allowing the CCGT generators to operate more efficiently and therefore displace some of the higher marginal cost biomass output. It could be expected that the reduction of SIC of offshore wind as a consequence of reducing the largest generator size may be more pronounced in a system with lower flexibility, given that flexible storage and DSR resources allow the system to efficiently cope with higher primary response requirement.

It is also worth mentioning that in the event that new nuclear capacity is not developed in the 2030 horizon, the SIC of VRES technologies may reduce even further, although for exact quantification it would be necessary to specify assumptions on which technologies would replace nuclear in the generation mix.

The impact of relaxed minimum CCGT capacity requirements is also limited, increasing the SIC of offshore wind by only £0.1/MWh. The slight increase in SIC is the result of the system not having excess CCGT capacity in the counterfactual case; therefore more CCGT (and correspondingly less OCGT) is added when increments in offshore wind capacity are made in SIC studies.

7. Modernised system operation

This chapter discusses potential improvements in system operation that could greatly improve the efficiency of VRES integration. Some of these improvements have been modelled as part of Modernisation scenarios.

7.1. Challenges of integrating variable renewables

There are two key factors which may reduce the ability of the system to accommodate the combination of inflexible low-carbon generation and variable 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.[53] 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[54], 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.

[53] 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.

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

However, as the proportion of energy supplied by non-synchronous sources (such as 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).[55] 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 7.1.[56] The requirement for frequency response increases sharply during low demand and high wind conditions.

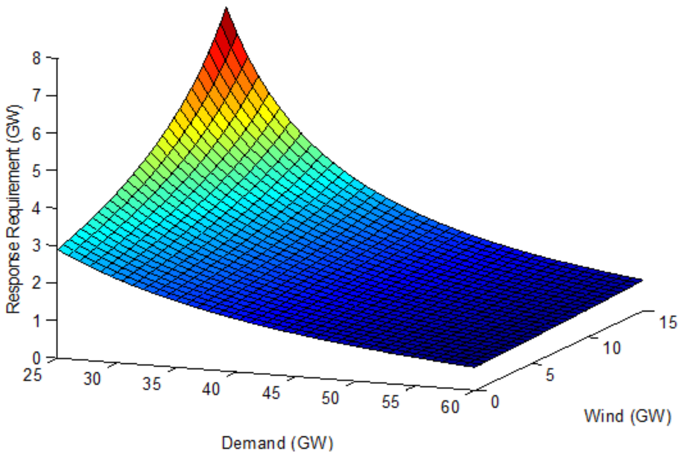

Figure 7.1. Primary frequency response requirement in GB system under different system conditions

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

55 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.

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

minimum stable generation. These two features represent the key limiting factors for the amount of renewable generation that can be accommodated, given that, unless alternative service providers emerge, a 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[57]. 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 system to accommodate cost effectively low-carbon electricity and therefore achieve decarbonisation targets, successively enhancing system flexibility to will be critical. Flexible options considered include:

- **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).

- **Provision of frequency regulation by wind generation –** it is expected that future wind generation technologies will be capable of providing ancillary services, including inertia.

- Deployment of **energy storage** (e.g. battery technologies) **and Demand-side response** would support short-term operation as well as provide primary and secondary frequency response and security of supply and reduce the need for additional back-up generation and network infrastructure reinforcement.

- Increased **interconnection** with mainland Europe.

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[57] 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.

7.2. Market value of energy and ancillary services in future systems

In this section we present several results from previous studies to show the magnitude of expected change in the system operating cost associated with energy delivery and the operating cost associated with ancillary services.

Given that key low-carbon generation technologies such as wind, PV or nuclear have very low operating costs, the operating cost associated with delivering energy is expected to decrease going forward. At the same time, the cost associated with the provision of ancillary services is likely to increase substantially driven by both increased requirements for frequency regulation as well as the cost of managing wind uncertainty. Similarly, the volume of the capacity market is expected to increase several times as new generators start participating in the market. The increasing prominence of ancillary service and capacity markets will create opportunities for flexible providers such as energy storage and DSR to fulfil their commercial potential and contribute to system operation.

Figure 7.2 illustrates this point by providing an estimate of operating cost associated with energy delivery and the cost of providing ancillary services (reserve and response), for two wind penetrations: 1) 10 GW, which is close to today's installed wind capacity, and 2) 50 GW, which is closer to expected wind capacity in 2030. The figure shows that energy cost would broadly drop by 50%, while the cost of ancillary services would increase order of magnitude. The share of ancillary service cost in the total operating cost will increase from about 1-2% to more than 25%. Note that these costs have been estimated based on today's carbon and energy prices; imposing higher carbon prices would increase the total cost, however the relative proportions of energy and ancillary service costs would remain the same.

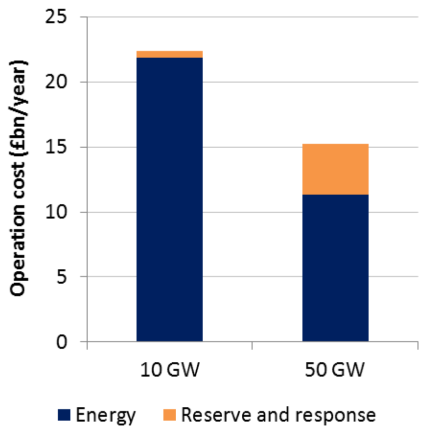

Figure 7.2. Operating cost associated with energy and ancillary services for different wind penetration levels

7.3. Enhancing market and regulatory framework to facilitate deployment of energy storage and DSR

Actual realisation and deployment of flexible options will require significant enhancement of the market and regulatory framework to facilitate the delivery of adequate levels of flexibility.

In the context of DSR and storage, it is important to bear in mind that the method of cost minimisation used in this work is equivalent to assuming that investment decisions are taken in a perfectly competitive market, while in reality, market failures, such as the impact of externalities, inefficient pricing or natural monopoly, mean that the least-cost level of deployment might not take place in practice.

Furthermore, previous analyses have also clearly demonstrated that DSR and storage can bring benefits to several sectors in electricity industry, including generation, transmission and distribution, while providing services to support real time balancing of demand and supply and network congestion management and reduce the need for investment in system reinforcement. These "split benefits" of storage end DSR pose significant challenges for policy makers to develop appropriate market mechanisms to ensure that the investors in storage and DSR are adequately rewarded for delivering these diverse sources of value.

It is not clear whether government policies should incentivise the development and deployment of novel storage technologies, and if so, what sort of mechanisms should be considered, e.g. ranging from subsidies to direct procurement.

7.4. Opportunities and barriers for gas plant of enhanced flexibility

There is expectation that new gas plant will be connected to the UK system to replace coal-based power generation that is being decommissioned. Given the expected growth in variable renewable and inflexible nuclear generation, our analysis demonstrates that it would be beneficial to connect gas plant with enhanced flexibility. The flexibility parameters associated with thermal plants, combined cycle gas plant (CCGT) in particular include:

- *Ramp rates* describe the speed at which the plant can change its output between the minimum and maximum load levels and is generally expressed as percentage of the maximum capacity per minute. Typical maximum ramp rate for the present CCGT plants is around 4%/min.

- *Minimum stable generation* is defined as the lowest level that a plant can continuously operate and is expressed as a percentage of the maximum capacity. Due to the MSG constraint, provision of the synchronized balancing services is inevitably accompanied by the delivery of electricity production, which may lead to a large amount of RES curtailment during low demand and high RES periods. At present, MSG of CCGT plant is limited at around 50%, while the latest design of Alstom CCGT plant is expected to be capable of continuously operating at around 20-30% of nominal power.

- *Frequency response capability* is defined by two parameters, maximum response and response slope. Due to limited inertia capability of RES, the frequency response requirements are expected to increase significantly in the future low carbon systems, leading to a higher demand on the frequency response contribution from thermal plants. Figure 7.3 shows present response characteristics of a CCGT plant as well as potentially enhanced characteristics.

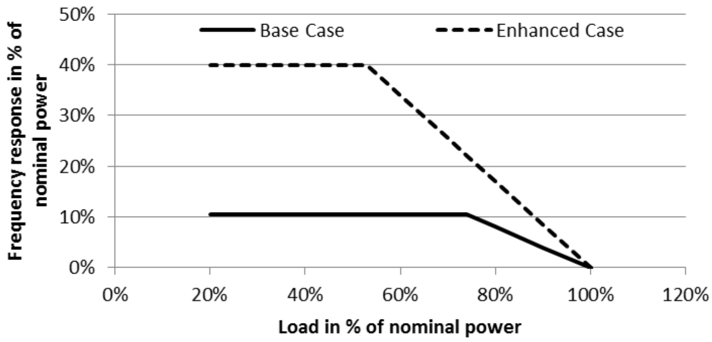

Figure 7.3. Frequency response characteristics of CCGT plant

- *Part-load Efficiency* - is defined as the ratio of the efficiency at part-load operation over the efficiency at full-load operation. As the increased requirements on ramping, operating reserve and frequency response in the future low carbon system, part-load operation of thermal plant will become more common in order to provide these services, leading to a degraded system economic and environmental performance. Significant work has been conducted to enhance the part load efficiency of CCGT plant; improved part-load efficiency curve of CCGT plant are shown in Figure 7.4.

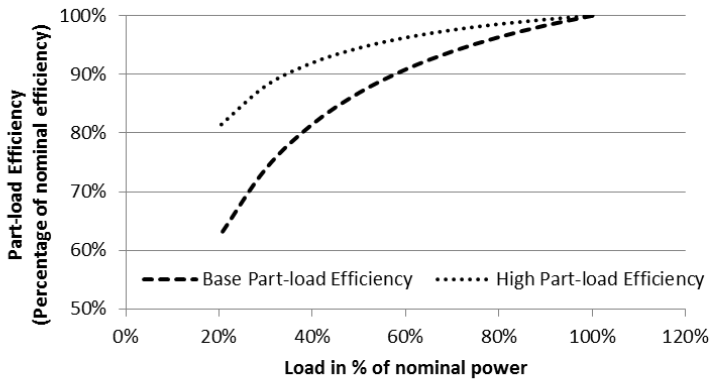

Figure 7.4. Typical part-load efficiency curve of a CCGT plant

- *Start-up Time* - describes the time the plant takes to start generating electricity and this is highly depends on amount of time that elapsed since its last shutdown. Start-up times of conventional CCGT is 2-4 hours while more flexible plant would be synchronised within 50% of this time. In the future, the variability of RES would increase the number of start-ups of thermal plants and the uncertainty of RES would increase the challenge of making start-up decision long time ahead of real-time operation. The start-up decision of a thermal plant with shorter start-up time could be made nearer to real-time operation, which significantly reduces the uncertainty faced by the operator.

The marginal system value of CCGTs with enhanced flexibility is shown in Figure 7.5. The value of the first 5 GW CCGTs with enhanced flexibility is above £1,000/kW, and reduces to £300/kW for the second 5 GW. Given that cost of CCGTs with enhance flexibility will be larger, the market volume for such plant is presented by this figure.

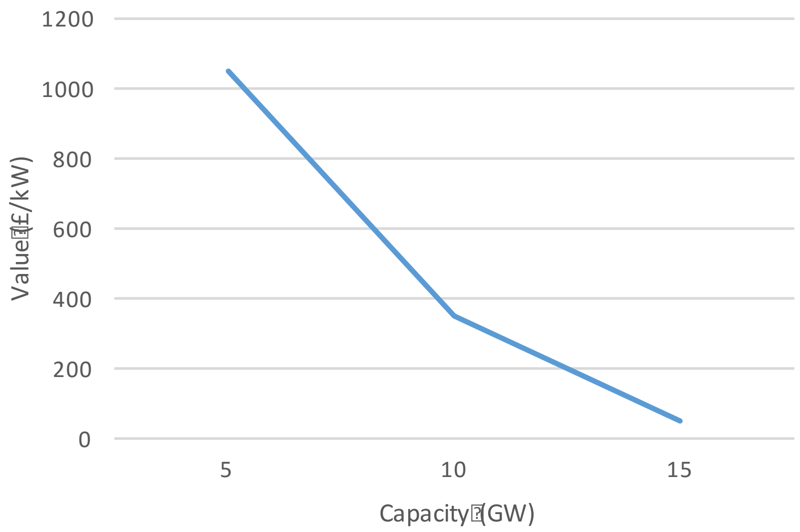

Figure 7.5. Value of flexible generation

Further analysis was carried out to determine the impact of gas plant with enhanced flexibility on the operating patterns of less flexible generation, which is presented in Figure 7.6.

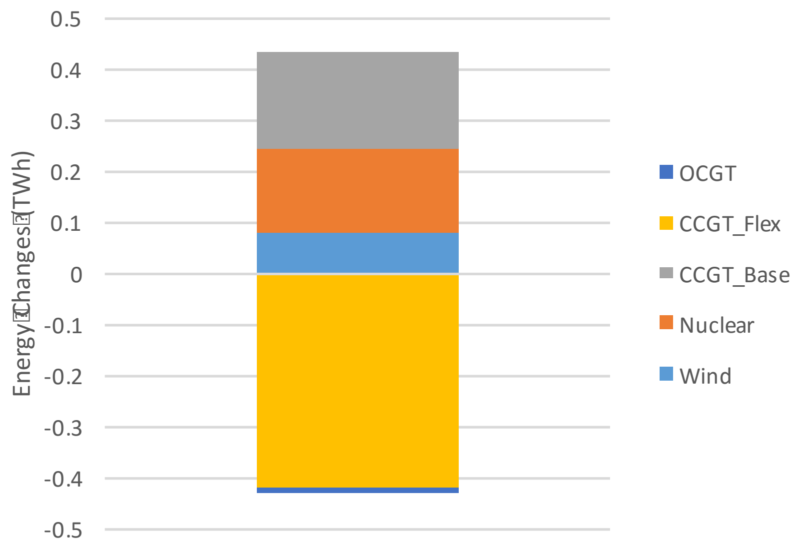

Figure 7.6. Changes in electricity output of generation technologies

Clearly, the presence of CCGT with enhanced flexibility would increase the production of nuclear and wind generation, but also of inflexible CCGTs, making significant cost and emissions benefits. As expected, this would also reduce the energy production of the flexible when compared with inflexible CCGT. Given that the present market rewards energy production rather than flexibility, it is not clear if the investment in flexible generation would materialise, as the investors may not capture system benefits delivered by the flexible plants (that is obviously characterised with higher cost than inflexible). Market designs would need to be developed in order to provide right signal for the market players to invest in flexible generation.

Additional analysis is carried out to assess the value of flexible OCGT in supporting cost effective integration of renewables. As shown in Figure 7.7, the value of flexible generation increases by up to 35%. This demonstrates that requirements for flexibility at a sub trading period level may significantly increase the overall value of flexibility.

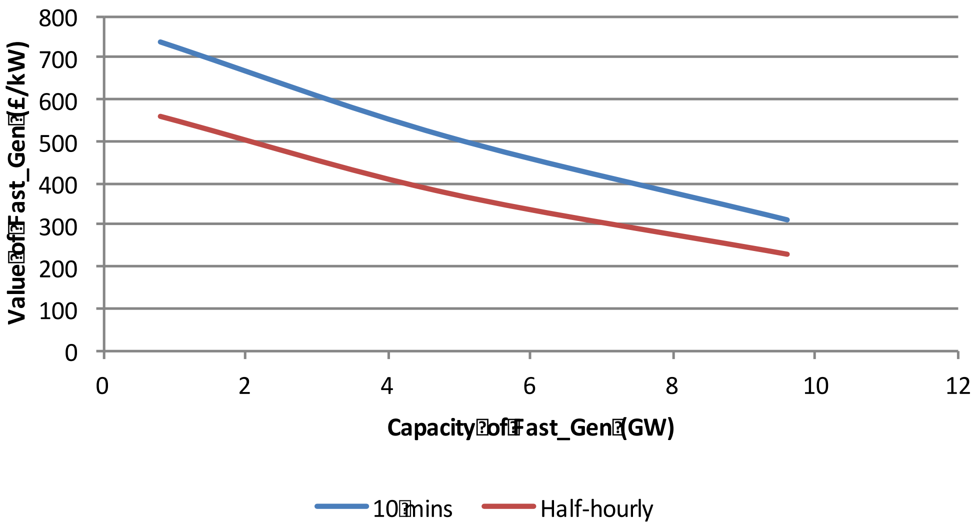

Figure 7.7. Value of flexible generation with 10-minute vs. hourly modelling

Due to the limited governor speed, it currently takes about 10 seconds for thermal plants to deliver primary frequency response. However, variable speed wind turbines are unresponsive to the system frequency.[58] Therefore, as wind generation displaces conventional plants, system inertia provided by rotating mass reduces. This leads to accelerated decline of system frequency after generation outage and requires faster delivery of frequency response from thermal plants.

Figure 7.8 shows the value of frequency response delivered in different speed in 2020 and 2030 system. Importantly, the value of enhanced frequency response becomes much more valuable than primary frequency response, suggesting significant benefits to increase the delivery speed of frequency response from thermal plants.

58 C. Seneviratne and C. Ozansoy, "Frequency response due to a large generator loss with the increasing penetration of wind/PV generation – A literature review", Renewable and Sustainable Energy Reviews, vol. 57, pp. 659–668 (2016).

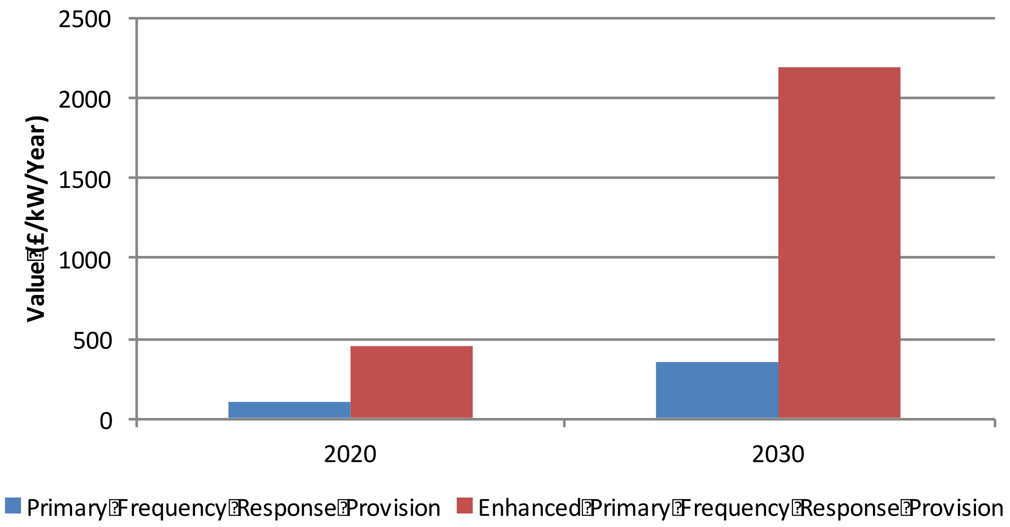

Figure 7.8. Value of primary frequency response and enhanced frequency response

7.5. Enhancing EU market design to facilitate cross-border energy, capacity and reserve trading

Benefits of moving from the current member state-centric to a pan-Europe wide market design would be very significant. Analysis demonstrated that the benefits of fully integrating EU energy and capacity markets would be €12-40bn/year and €7-10bn/year respectively by 2030, while integration of the EU balancing market would save an additional €3-5bn/year. These savings go far beyond the €2.5-4bn/year that the EU has saved through its existing measures to integrate its electricity markets through day-ahead energy arbitrage.

Under high levels of penetration of variable renewable generation, the operating reserve requirements and need for flexibility increase significantly. In particular, the allocation of the reserve portfolio between spinning and standing products is vital to operate a congested network efficiently. This is because the commitment of spinning reserves in areas with significant wind generation can be very costly due to potential wind curtailment events. In such cases, the commitment of standing reserves should be preferred over spinning reserve, even if these are located in neighbouring states and may require reduction in network energy transfers leading to increase in constraints cost. In such cases, the need to access the optimum portfolio of reserves has to be balanced against the need to access low-cost energy sources, leading to the allocation of interconnection capacity between energy delivery and reserve services. Although the question of allocating network capacity between energy and reserve is a key issue, it is not facilitate by the current market coupling arrangements.

In Figure 7.9 below, an example of a two-area system is presented – Area A with significant penetration of renewables (e.g. UK) and Area B with significant penetration of low cost generation, such as nuclear, but also flexible standing generation (e.g. France). If we ignore the reserve requirement, the interconnector capacity will be used for transport of energy from Area B to Area A. However, if the interconnector capacity is optimised between energy and reserve, we observe that flows between the two areas will be radically different.

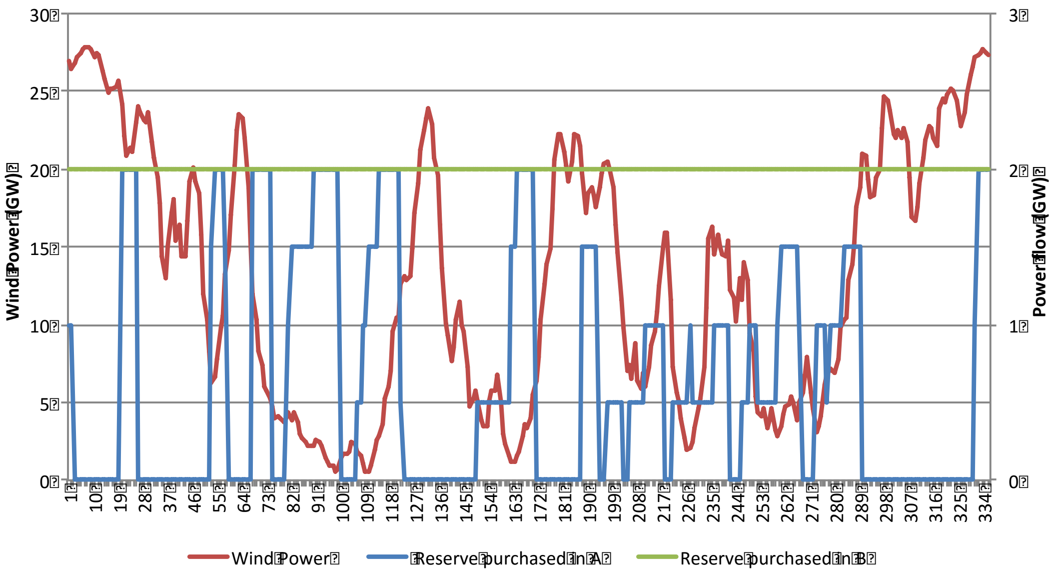

Figure 7.9. Allocation of interconnection capacity between trading energy and reserve services

Clearly, the development of new trading arrangements for sharing reserve between member states would bring significant benefits, particularly to the UK.[59] It will be important to optimise allocation of reserve products across regions, as there are potentially significant benefits of sharing flexibility that can be achieved by shifting the requirements to provide reserve from areas with high renewable production (exporting areas) to areas with low production or demand-dominated areas (importing areas) by making use of cross-border transmission. Furthermore, given the increased diversity in demand and renewable output across interconnected areas, when reserve products are shared across member states, rather than every member state providing reserve services for its own needs, the total reserve requirements are bound to decrease substantially. Recent analysis of the annual operation of the EU system shows that regional sharing of frequency regulation and reserve services using cross-border capacity reduces operating costs by about €3bn/annum, when compared with a policy where each member state provides the services to meet their own requirements. When considering carbon impacts, these benefits can be very significant for the UK.

However, the present market arrangements do not facilitate the optimal allocation of interconnection capacity between energy and reserve services. Transmission capacity in Europe is currently allocated by power exchanges trading energy, while separate institutions deal with reserve and balancing. This is an issue of high priority that should be resolved at the European level through design of efficient market mechanisms to ensure optimal resource sharing across all Member States.

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59 G. Strbac, M. Aunedi, D. Pudjianto, P. Djapic, S. Gammon and R. Druce, *Understanding the Balancing Challenge*, DECC, 2012.

8. Conclusions

In this report we have quantified system integration cost of low-carbon generation technologies across different future development scenarios. Key findings from quantitative studies include:

- Total annualised system cost for the 2030 GB system with the carbon intensity of 100 g/kWh will be driven by system flexibility. Up to £4.2bn/year could be saved by improving system flexibility from today's level; most of these savings are already achievable with moderately enhanced flexibility.

- The SIC of variable RES generation is strongly dependent on system flexibility as well as on the overall energy mix (i.e. the penetration of variable RES) and is therefore a function of assumed system evolution. As illustrated in Figure 8.1 on the example of SIC values obtained for onshore wind, higher VRES penetrations yield a higher SIC, but the magnitude and the rate of this increase depends greatly on the level of enhancements in system flexibility that accompanies the expansion of VRES i.e. on the volume of deployed flexible options such as DSR, storage and interconnection. The figure identifies trend lines for four different rates of deployment of flexibility (No, Moderate, Fast and Maximum progress). At current flexibility ("No progress") levels the SIC increases sharply already at low wind penetration levels; conversely, with higher flexibility ("Moderate" or "High progress") SIC remains at moderate levels even at significantly higher VRES penetrations.

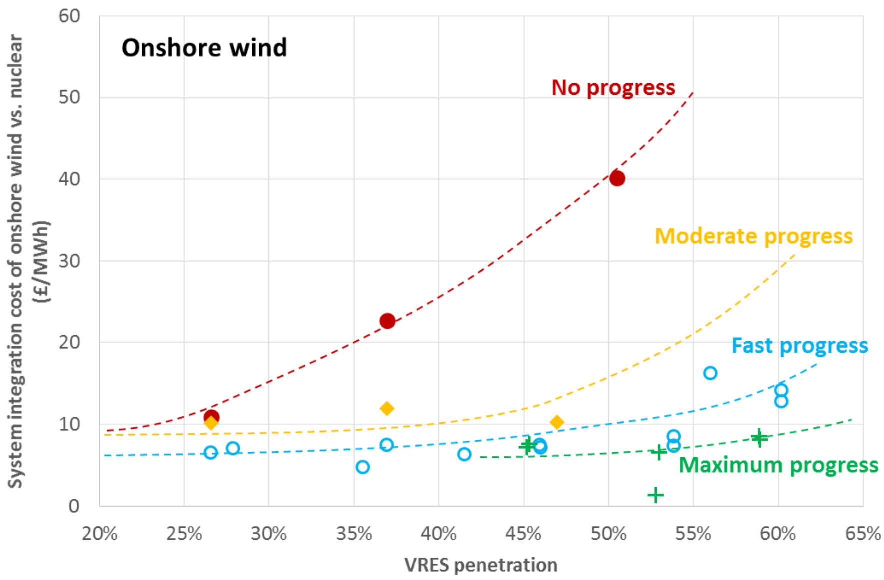

Figure 8.1. SIC of onshore wind as function of wind penetration

- System integration cost of wind and solar PV generation in the 2030 horizon remains at a moderate level provided that the assumed enhancement of system flexibility materialises (i.e. that there is a rapid deployment of energy storage and DSR). In addition to system flexibility, the SIC of variable RES generation is also strongly dependent on the overall energy mix and is therefore a function of assumed system evolution.

- SIC of both offshore and onshore wind in 2030 (when compared against nuclear power) is found to be around £5-9/MWh across the medium to high flexible scenarios analysed in the study. The majority of this cost is associated with the requirement to build sufficient firm (back-up) capacity when wind is added to the system, in order to maintain the same level of security of supply. A smaller part of SIC of wind is associated with increased operating cost resulting from increased requirement for ancillary services triggered by added wind capacity.

- In a system with no added flexibility compared to today's situation, the SIC of variable RES technologies would increase beyond £40/MWh, making it very costly to integrate large penetrations of variable renewables.

- SIC of solar PV generation in 2030 is slightly higher than for offshore wind, and varies within the £10-15/MWh range with medium flexibility assumptions. When compared to offshore wind, it contains an additional component associated with distribution investment cost, given that large volumes of PV, especially if they are not installed uniformly across GB (as assumed in the study), may trigger distribution network reinforcement to deal with increased reverse power flows i.e. electricity being injected back into the distribution grid.

- According to the LCOE assumptions adopted in the study, despite the positive SIC the whole-system cost of offshore and onshore wind and PV (i.e. the sum of their LCOE and SIC) still makes them competitive to nuclear in the majority of 2030 scenarios with at least moderate flexibility (the only exception is Nuclear Centric scenario where nuclear represents a more economical choice given the more favourable LCOE assumptions in that scenario).

- Despite an increasing penetration of variable renewables between 2015 and 2030, SIC of wind and PV can be maintained at a relatively stable level (or even lower in some scenarios) provided that sufficient amount of flexible options is deployed. This occurs because the impact of increasing RES penetration, creating an upward pressure on SIC, is counteracted by the opposing impact of improved flexibility.

- Increasing or reducing system flexibility has a critical impact on the total system cost required to meet the 2030 carbon target, as well as on SIC of variable RES. The integration of variable RES in a system with scarce flexibility would be very costly and inefficient, requiring about £4bn/year more to meet the 100 g/kWh target than in the five core scenarios. Nevertheless, a moderate improvement of system flexibility already brings the cost of the system down by £3.5bn/year, while at the same time reducing SIC of offshore and onshore wind from over £40/MWh down to around £11/MWh in the 2030 horizon. This level of SIC combined with the LCOE assumptions makes offshore and particularly onshore wind cost-effective compared to nuclear generation. Flexibility levels towards the high level of the spectrum will require coordinated action and policy support starting from today in order to ensure high volumes of flexible options are deployed over the next decade or so.

- Sensitivity studies carried out for 2030 scenarios with a more ambitious carbon target of 50 /kWh suggest that the integration cost of VRES would increase, driven primarily by higher RES penetration required to meet the lower emission target. In some instances, like in Mid Flex and Onshore Capped scenarios, where the penetration of wind exceeds 55% of annual electricity demand, any integration of further wind capacity becomes very costly. Such high levels of wind require further improvements in system flexibility or operation practices, such as those assumed in Modernisation or Mega Flex scenarios.

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

In this section we describe our approach and models used to quantify the system integration cost of low-carbon generation technologies in 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.

A.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 A.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.

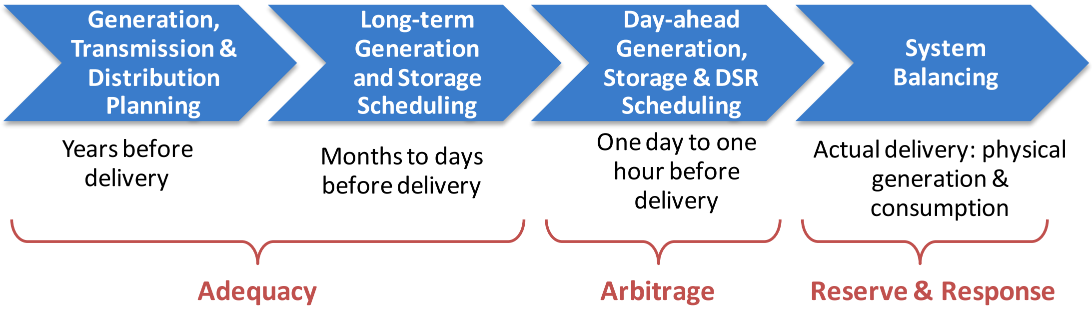

Figure A.1. Balancing electricity supply and demand across different time horizons

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.[60] 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.

[60] 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.

A.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 A.2.

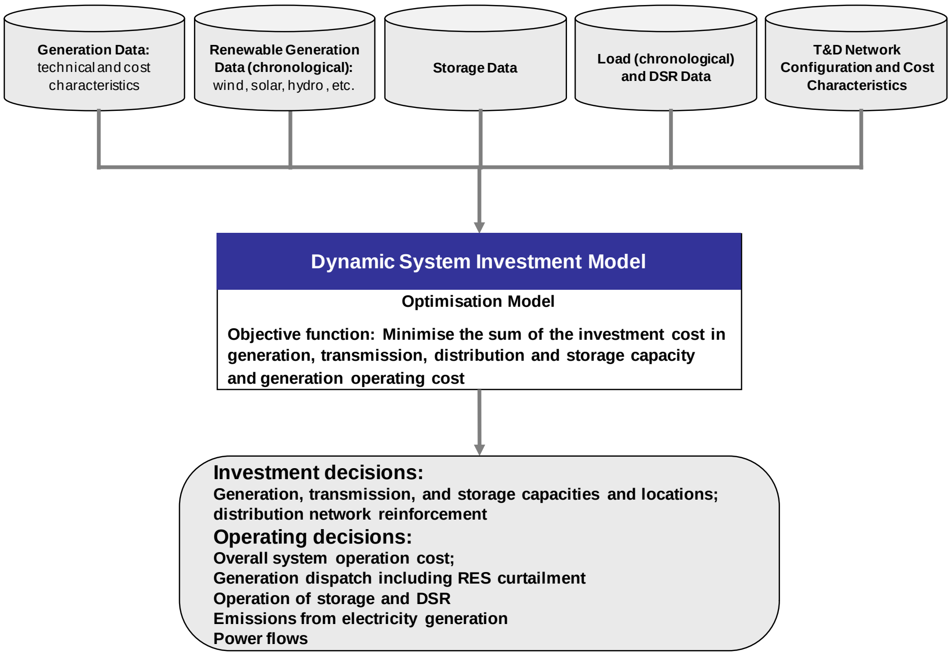

Figure A.2. Structure of the Whole-electricity System Investment Model (WeSIM)

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[61] 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 variable 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 A.3.

[61] 4 hours is generally the maximum time needed to synchronize a large CCGT plant.

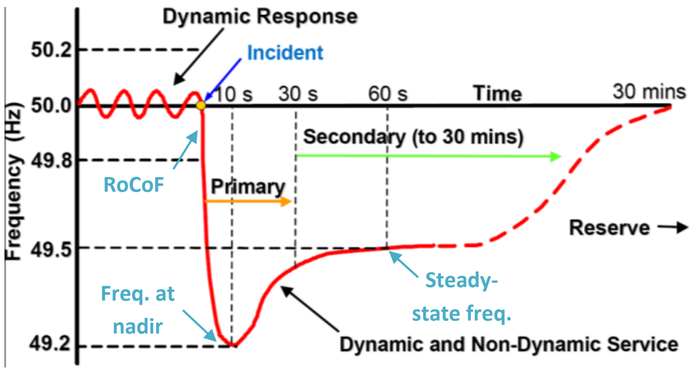

Figure A.3. System frequency evolution after a contingency (source: National Grid)

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.[62,63] 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.

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[62] 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.

[63] 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 A.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 ($P_{max} – MSG$).

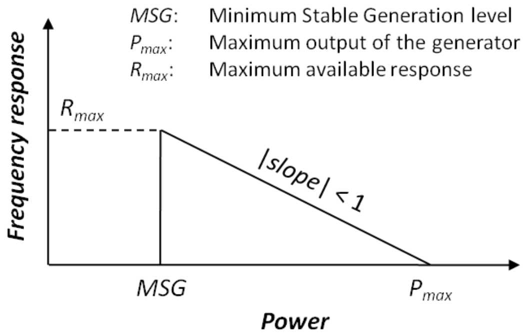

Figure A.4. Provision of frequency regulation from conventional generation

- *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 amounts of variable 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.[64] If there is storage in the system, WeSIM may make use its capacity for security purposes if it can contribute to reducing peak demand, given the energy constraints.

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

WeSIM allows for the security-related benefits of interconnection to be adequately quantified.[65] 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.

A.3. System topology

The configuration of the interconnected GB electricity system used in this study is presented in Figure A.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 A.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.

[65] 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.

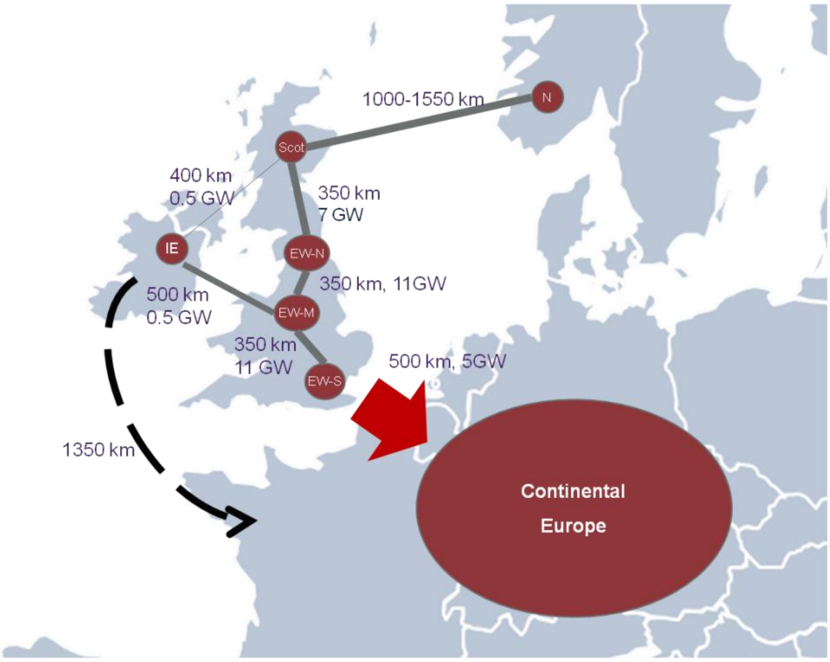

Figure A.5. System topology used for studying the value of flexible balancing technologies

A.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[66] are shown in Figure A.6 for different urban, rural and intermediate layouts. Parameters of representative networks are calibrated against the actual GB distribution systems.[67] [68]

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66 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.

67 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.

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

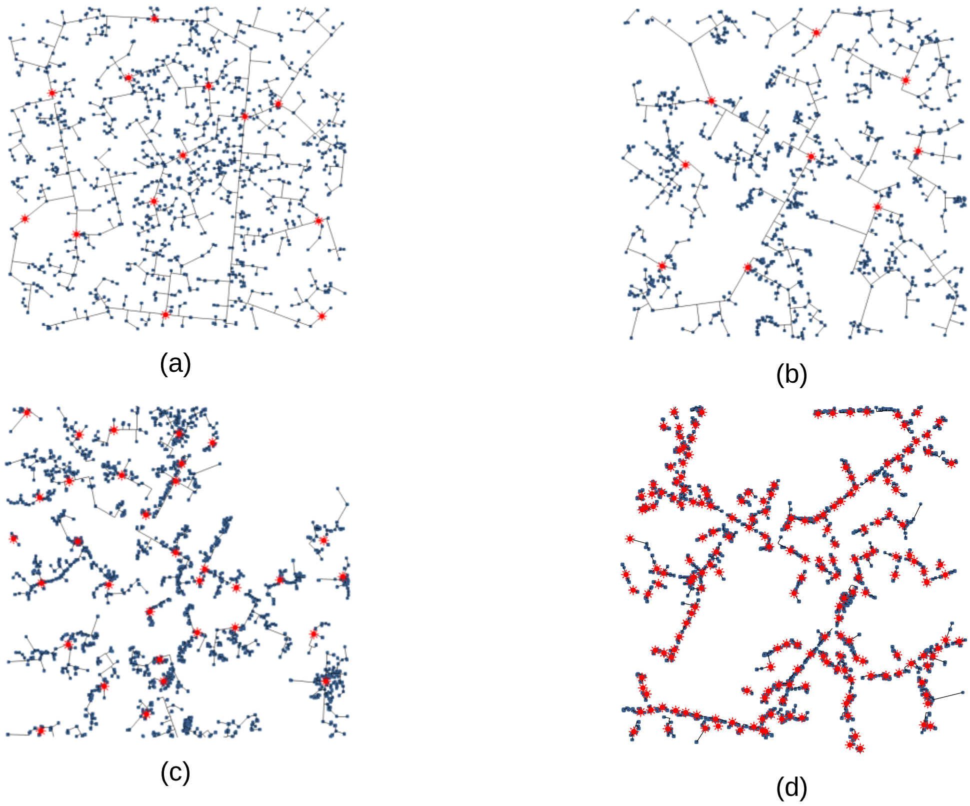

Figure A.6. Examples of generated consumer layouts: a) urban area; b) semi-urban area; c) semi-rural area; and d) rural area. (Blue dots represent consumers, while red stars represent distribution substations.)

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 A.1.

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

Table A.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.[69] 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 A.4 shows an excerpt from the list of cost items.

69 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 A.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

A.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.[70] 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.[71,72,73,74,75,76,77,78]

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

71 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.

72 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.

73 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.

74 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:[79]

- 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

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75 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.

76 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.

77 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.

78 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

79 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.