# OPTIONS FOR LOW-CARBON POWER SECTOR FLEXIBILITY TO 2050

A report to the Committee on Climate Change

October 2010

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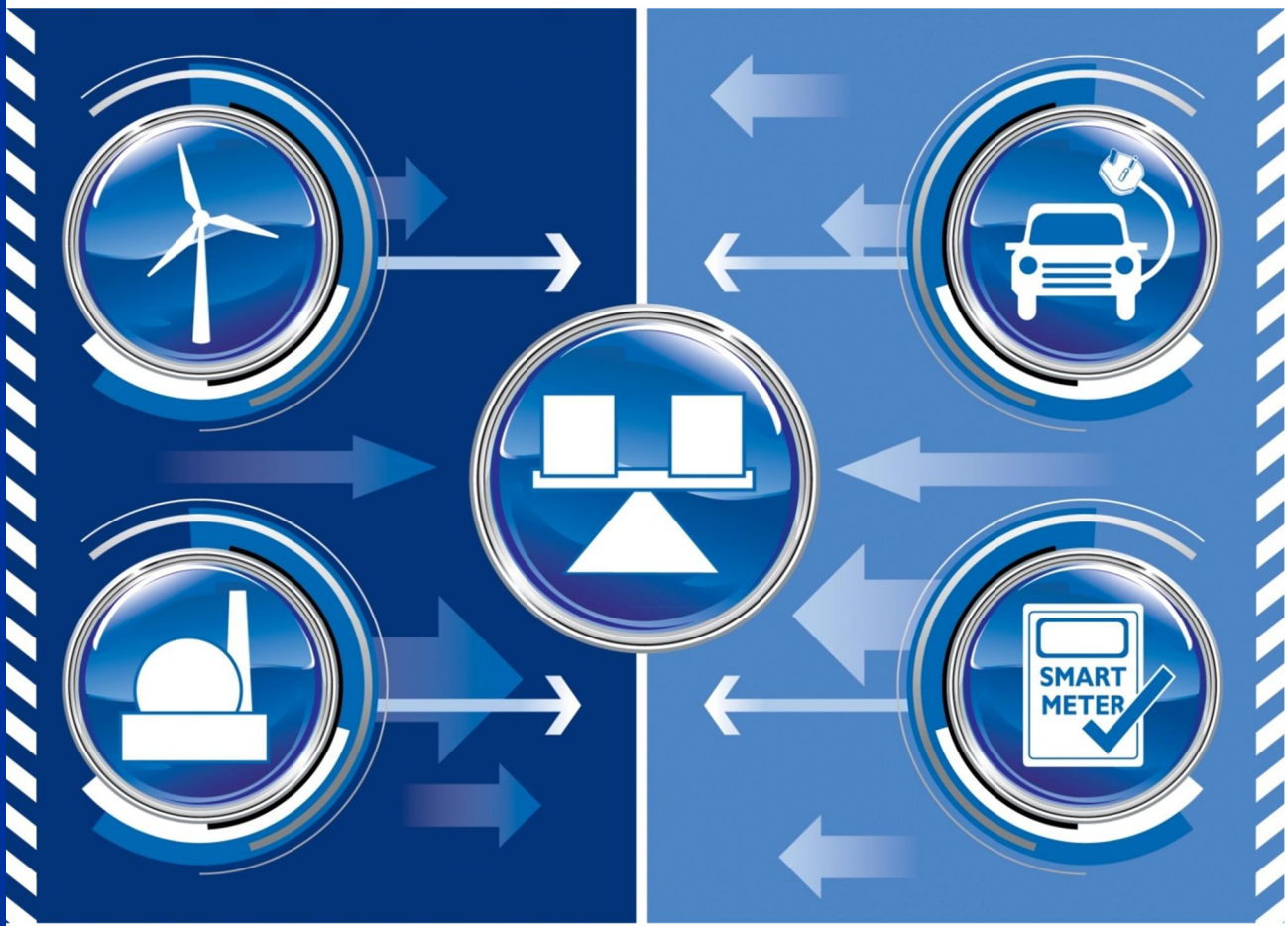

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# EXECUTIVE SUMMARY

## Introduction

The Committee on Climate Change (CCC) has identified decarbonisation of electricity generation as key to the UK achieving its 2050 target of an 80% reduction in greenhouse gas emissions from 1990 levels.

A low-carbon generation sector would mean future electricity markets very different to those of today. Instead of unabated coal-fired and gas-fired power stations dominating the generation mix, there would be large amounts of low marginal cost (and hence price insensitive) plant, including a significant amount of intermittent wind generation.

Several studies, including work by Pöyry[1], have suggested that it will be increasingly difficult to match generation and demand. Insufficient flexibility in the system may limit the amount of low-carbon generation that can be deployed without undermining other Government policy goals, such as security of supply.

At the same time, large electrification of the heat and transport sectors is expected, particularly from the late 2020s onwards in support of the 2050 emissions target, potentially exacerbating the situation further.

Figure 1 shows the dispatch pattern for non-intermittent generation in one winter week modelled for 2030 assuming identical weather patterns to 2000 repeated themselves. It illustrates how the future interaction between demand and variations in wind output could lead to big changes in the dispatch pattern for non-intermittent generation (shown in the bottom chart).

It also shows the variability in demand, which is higher during the week than at weekends, and higher during the day than at night. It is also much higher in the winter than in the summer, driven by increased demand for heating and lighting.

During the week shown, the output from wind is close to zero for a couple of days before then increasing to nearly 100% of installed capacity. When low wind coincides with high demand as during the daytime periods between 24 January and 26 January, significant amounts of peaking plant must be run. When high wind output coincides with low demand (summer, weekends and overnight), then some nuclear and CCS coal generation must operate below full output. Indeed nearly the entire CCS coal fleet is forced to shut down for the whole of 29 January in this particular example.

Interactions as described above are complex and multidimensional and poorly understood at the moment, despite their importance.

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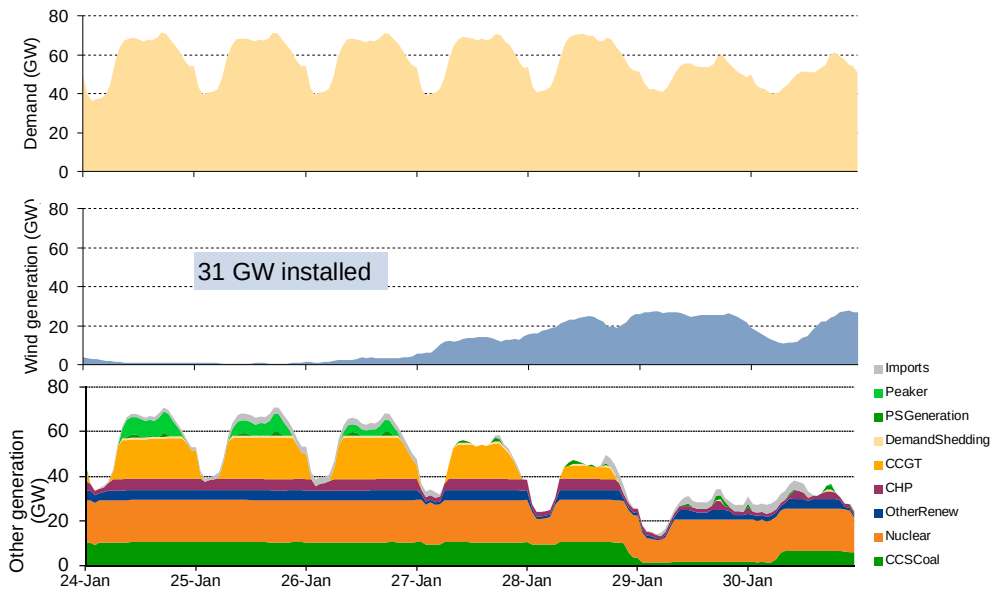
1 'Impact of intermittency. How wind variability could change the shape of British and Irish electricity markets. Summary report', Pöyry Energy Consulting. July 2009.

**Figure 1 – Dispatch and demand in 2030[2]**




## Objectives

Given the complexity of these important issues and their long-term nature, the CCC commissioned Pöyry Energy Consulting to characterise the potential options for flexibility from different parts of the electricity system; and make detailed, quantitative assessments of how greater flexibility could help meet long-term carbon targets.

Furthermore, the CCC wanted the study to inform discussions for the fourth carbon budget period in 2023-2027 by improving the understanding of the prospects for greater flexibility. In particular, the CCC wanted to understand the implications of the timing and magnitude of electrification. During the late 2020s, the electricity sector is expected to be decarbonised towards an average carbon intensity of 100g/kWh (of demand) or below, with progress to be made in earnest on the electrification of heat and transport.

## Approach

We assessed a reference case and three alternative flexibility packages against a set of counterfactuals (or possible low-carbon worlds) to allow for uncertainty about future developments. In practice, significant differences emerged in the mix of requirements for flexibility in each counterfactual.

The first pair of counterfactuals tested how changes in demand would affect flexibility in 2030:

- **Counterfactual 1** (CF 1) has an electricity demand mix similar to today; and
- **Counterfactual 2** (CF 2) is consistent with the low-carbon pathways set out by the CCC, in which there is electrification of transport and, in particular, heat by 2030.

2 Assuming that the weather of 2000 is repeated.

The second pair of counterfactuals explored the impact of the availability of CCS technology on the flexibility challenge for a 2050 system in which there had been widespread electrification of heat and transport:

- **Counterfactual 3** (CF 3) has a diverse generation mix mainly consisting of nuclear, wind, CCS coal and CCS gas; and
- **Counterfactual 4** (CF 4) has no CCS generation technology which means that the generation mix is heavily reliant on wind and nuclear.

Compared to the 2030 assumptions shown in Figure 1, electricity demand has nearly doubled and wind capacity has grown to more than 40GW, which increases the system management challenges in these two cases.

In all four counterfactuals, flexibility in both supply and demand in the reference cases was limited to the flexibility of generation and customers that we observe today. Consequently, most of the flexibility was provided by gas-fired generation. We then tested the three alternative flexibility packages, based on the following themes, against each counterfactual:

- **Flexible generation** – ex-ante time of use tariffs smooth the expected demand profile with 'real-time' flexibility being provided by nuclear and CCS generation that can operate more flexibly than in the reference case;
- **Imported flexibility** – ex-ante time of use tariffs smooth the expected demand profile with 'real-time' flexibility being provided by expansion in the capacity of interconnection and bulk storage, and more flexible operation of CHP generation; and
- **Active demand side** – active (or dynamic) management of demand, primarily from heating and transport, provides greater system flexibility.

Table 1 summarises how each sector (generation, demand, interconnection and storage) contributes to each flexibility package. Green boxes denote a strong contribution, amber boxes identify a weak contribution and red boxes show where there is no contribution at all.

**Table 1 – Summary of different flexibility packages[3]**

| Flexibility packages | Generation | Demand | Interconnection and storage |
|---|---|---|---|
| Flexible generation | More flexible nuclear and CCS | Ex-ante ToU tariffs smooth demand | As in reference case |
| Imported flexibility | More flexible district heating CHP | Ex-ante ToU tariffs smooth demand | More interconnection More storage |
| Active demand side | As in reference case | 'Real-time' response from demand | As in reference case |

3 In all three packages, it was possible to deload wind (and wave) generation if required to balance supply and demand.

Outputs from our wholesale electricity model *Zephyr* were used to assess the flexibility packages in the following areas:

- carbon intensity of the power generation sector;
- security of electricity supply;
- total generation cost; and
- total system cost.

We adjusted the capacity mix for non-renewable generation to reflect the relative commercial attractiveness of different types of plant in 2030 and 2050. We took into account physical constraints on new build by 2030 and 2050 but did not model the investment pathways or market arrangements required to reach these capacity levels.

## Conclusions

Our conclusions fall into four areas – requirements for flexibility, options for flexibility, impact of greater low-carbon flexibility and policy implications. Each is summarised in the following sections and then discussed in more detail in the report.

The key messages are:

- electrification, particularly for space heating, would make demand much more variable across the year and (without some form of demand side management) during the day;
- higher levels of wind generation will generally increase the range and unpredictability in the need for non-intermittent generation across the year;
- electrification of heat and transport greatly increases the potential for demand side response;
- demand side response and bulk storage can shift demand within-day but storage constraints make them much less effective over longer periods;
- flexibility over timescales of more than a couple of days is expected to be primarily provided by generation, with the high capital costs of low-carbon generation meaning that even with increased low-carbon flexibility 10-15GW of gas-fired peaking capacity is required in 2050 (although emissions are limited by its very low load factors);
- greater flexibility reduces generation costs and emissions whilst maintaining security of supply, with the savings increasing at higher levels of intermittent generation and electrification of heat and transport;
- the effect of flexibility on overall system cost is inconclusive given uncertainty about level and allocation of non-generation costs;
- price signals and incentives must encourage provision of flexibility from all sources, not just generation;
- policy-makers must take into account how low-carbon flexibility would increase the requirements for flexibility in other parts of the whole energy system, particularly energy transportation networks; and
- the delivery of improved flexibility by 2030 needs decisions to be taken in the short-term for most but not all of the flexibility options.

### *Requirements for flexibility*

It will be harder to match generation and demand in a low-carbon system with high levels of intermittent generation, more variable sources of demand, and baseload low-carbon generation. As a result, increased system flexibility is needed over a range of different timescales.

Table 2 summarises the impact of electrification of heat (using heat pumps) and higher levels of wind generation on the variability and predictability of the requirement for non-intermittent generation (as proxied by the level of demand net wind).

In summary, electrification tends to have a much stronger impact on variability than on predictability. Although wind generation displays some average patterns within-year, its key feature is that these average patterns are not a very good predictor for the observed level.

The more stable the level of demand net wind across the whole year, the greater the amount of non-intermittent generation (such as nuclear, CCS coal and CCS gas) that would be expected to be able to operate at high annual load factors. Because the capital costs of low-carbon are typically high and the variable costs are low, the investment returns are very sensitive to the achieved annual load factor.

For the reference cases for both 2050 worlds, at least 50GW of non-intermittent generation could be required to operate at annual load factors below 50%, which would undermine deployment of low-carbon generation.

**Table 2 – Impact of electrification and high wind on patterns of demand net wind**

| Period | Electrification of heat (without demand side response) | Higher wind penetration |
|---|---|---|
| Annual | Increased variability across the year because of increased heating demand in winter and at early evening peak;<br>electrical efficiency of heat pumps is also reduced at lower temperatures | Increased variability across the year (as shown by the range in hourly figures for demand net wind being greater than range in demand alone) |
| Seasonal (monthly averages) | Increased seasonal variation because winter months have increased heating demand and lower electrical efficiency of heat pumps | Dampens seasonal variation (on average) because wind output is greater in winter |
| Day to day | Increased variability (and reduced predictability) driven by day to day variations in temperature | Increased variability and reduced predictability; much of the existing day to day variation in demand is driven by predictable shifts between business days and non-business days |
| Hour to hour | Increased variability because increases demand at evening peak (which is largely predictable) | Uncertain impact on variability and reduced predictability |

### *Options for flexibility*

There are many potential sources of low-carbon flexibility even by 2030. These differ in a number of key characteristics (as summarised in Table 4) – quantity, speed, duration, availability throughout the year and cost.

Electrification of heat and transport would greatly increase the potential for shifting demand, particularly between different hours in the same day. However, questions remain about delivery of this potential in practice. Furthermore, the within-day flexibility provided often mitigates the problem of increased variability of demand resulting from electrification rather than balancing variations in wind.

By providing greater scope for daily electricity demand to vary, bulk storage, interconnection and electric vehicles can play a greater role in provision of flexibility over several days; although flexibility is likely to be provided in bursts rather than being sustained throughout the whole period.

Over even longer timescales (weeks or months), flexibility may be provided by back-up power station capacity. The barriers to the provision of this back-up capacity by low-carbon generation are primarily economic rather than technical as a result of high capital costs. A comparison of the levelised costs of different low-carbon generation suggests that CCS gas would be best suited (economically) to operating at lower annual load factors.

For each source of flexibility, delivering the flexibility discussed in Table 4 will require behavioural changes supported by the investments required to provide them with the ability to change their behaviour. This could include for example, investment in an interconnector with Norway in the 'imported flexibility' package or in smart infrastructure in the 'active demand side' package.

There remains uncertainty about the detailed technical performance capability of the low-carbon generation (primarily nuclear and CCS) that will be deployed in 2030 and 2050. This means that some improved flexibility beyond the reference case could be expected in an optimistic view of the future. However, simply waiting (and hoping) for a good out-turn is unlikely to be sufficient to deliver the level of flexibility considered in this study, given the importance of the choices that are made in the design and construction phases.

## Table 3 – Overview of strengths and weaknesses of each option for flexibility

| Flexibility source | Strengths (in 'flexible' mode) | Weaknesses (in 'flexible mode') |
|---|---|---|
| **Nuclear** | Reduction in minimum stable generation to 25% provides access to significant flexibility (i.e. can vary output by up to 75% of installed capacity)<br>Maintenance scheduling can be used to match seasonal variations | Economic barriers to provision of long-term flexibility<br>If plant is required to shut-down, it cannot restart for minimum of 48 hours<br>Uncertain how repeated ramping up and down would affect safety cost, operating lifetime and maintenance costs |
| **CCS coal and CCS gas** | Suited to medium-length periods of flexibility (e.g. at least 6 hours) such as turning off overnight or use of storage solutions<br>Maintenance scheduling can be used to match seasonal variations<br>IGCC may be faster source of flexibility | Economic barriers to provision of long-term flexibility by coal plants<br>Uncertain how repeated ramping up and down would affect safety cost, operating lifetime and maintenance costs<br>Uncertainty about technology development<br>Not suited to dealing with large hour to hour oscillations<br>IGCC flexibility restricted to within-day as hydrogen storage capabilities may be limited to 12 hours |
| **District heating CHP** | Can provide within-day flexibility, particularly in winter | Variable potential as linked to heating demand<br>Not assumed to be on the system in 2050<br>Flexibility limited by storage capability |
| **Interconnection with SEM and/or NW Europe** | Flows driven by wind differentials, so help to offset wind conditions in GB, even over extended periods<br>NWE link gives access to large market | Flows not driven by relative levels of demand net wind<br>Flows could exacerbate extreme situations in GB<br>Flexibility from SEM limited by small market size |
| **Interconnection with Norway** | Effectively provides access to storage outside GB, which can help to balance system over periods of several days | Competition from other European markets for access<br>Cannot provide seasonal flexibility |
| **Bulk storage** | Can provide flexibility across a number of days | Provision of multi-day flexibility is periodic rather than constant<br>Needs increase in GWh of storage capacity per GW of output to avoid becoming energy constrained |
| **Hydrogen production through electrolysis** | Absorbs excess supply, particularly over extended periods of low demand in summer<br>Reduces carbon intensity of other energy sectors | Constrained by the level of daily gas demand by 2050 when technology is available<br>Most useful in summer when gas demand is low, which limits magnitude of flexibility available |
| **Ex-ante tariffs** | Effective at flattening within-day demand profile (which is helpful for networks), especially when heating demand is high | Largely limited to within-day smoothing.<br>Unresponsive to 'unexpected' changes in demand and/or wind |
| **Active management of heating load** | Effective at within-day smoothing of requirement for non-intermittent generation, particularly in winter.<br>Storage may be easier to deliver in the non-residential sector | Flexibility potential much lower in summer<br>Flexibility largely limited to within-day because of size limitations and energy losses from storage.<br>Uncertainty about extent to which storage will be deployed alongside heat pumps by 2030<br>Fuel switching only available as transitional option |
| **Active management of EV load** | Potential to shift demand across days, which is enhanced by fuel switching.<br>Flexibility potential more consistent across year | Uncertainty about behaviour and infrastructure<br>Limited deployment by 2030<br>EV to grid not displace thermal plant in practice |
| **Active management of wet appliance load** | Help within-day smoothing of need for non-intermittent generation<br>Potential consistent across year | Limited magnitude and duration of flexibility potential as typically can only shift within-day at most |

### *Impact of greater low-carbon flexibility*

Increased flexibility helps to increase the load factor and installed capacity of low-carbon plant, primarily nuclear, at the expense of gas-fired (unabated) generation. This reduces the carbon intensity of the power generation sector compared to the reference cases.

The sole exception is in the 2030 world with electrification when active demand side response is so effective at reducing peak capacity requirements that there is less scope for new build of low-carbon plant.

The three flexibility packages reduce total generation costs from the reference cases by a similar amount – by 5-10% in 2030 and by 10-15% in 2050. The increased savings in 2050 reflect the high level of peaking capacity in the reference cases – 28GW in the world with CCS (CF 3) and 35 GW in the world without CCS (CF 4).

Even though greater flexibility reduced generation costs, the modelling results suggest that this may not result in lower wholesale electricity prices. This is because prices in the future, as at present, may be strongly influenced by marginal, as opposed to average, costs of generation.

The UK Government are planning to consult in autumn 2010 on the Electricity Market Reform (EMR) package. This consultation is expected to provide more information on the future design of the electricity market, including the drivers of wholesale electricity prices. This should improve the understanding of how future consumers may be able to capture the benefits of improved flexibility.

Although generation costs represent the majority of the system costs evaluated in this study, the impact of increased flexibility on total system costs is inconclusive. This reflects the degree of uncertainty about the level of non-generation costs and the extent to which they should be attributed to the provision of flexibility (such as the deployment costs for smart metering) as opposed to other benefits (such as improved billing processes).

Of the non-generation costs, electricity distribution network costs vary the most between the different low-carbon worlds (or counterfactuals) and between the different flexibility packages. This reflects the fact that electrification and demand side response may both push up distribution costs by increasing peak demand at the lower levels of the distribution network (e.g. from heating, transport and residential appliances).

Although other areas, such as transmission, are a relatively small part of the overall total systems costs, they can have a big impact on the ability of the system to physically deliver the investment required to deliver decarbonisation.

### *Policy implications*

Policy, market and regulatory arrangements must support the delivery of an appropriate mix of flexibility to meet the needs of a low-carbon future. These arrangements must take into account the investment and operational incentives for different potential sources of flexibility. For example, commercial arrangements must encourage the responsiveness of interconnectors to dynamically changing levels of demand net wind. This will be helped by continued support for development of more effectively integrated European electricity markets.

A number of options rely on shifting electricity demand between different periods – bulk storage, demand side response and to a certain extent, interconnection. If additional revenue streams are introduced that could reduce the sharpness of energy price signals between periods (e.g. capacity payments), then policy-makers must consider how these

revenue streams can be accessed by parties outside the generation sector. Otherwise, there is the risk of distorting the incentives for provision of flexibility in favour of generation.

In many cases, the provision of appropriate incentives will not be enough on its own to deliver the flexibility required because the scale of practical delivery is very challenging. Policies design to support provision of flexibility must consider barriers and risks associated with delivery, as well as attempt to minimise overall system costs. These barriers and risks include:

- the scale of physical investment required – for example, delivering flexible nuclear power stations at the same time as an aggressive new build programme;
- the speed of technology improvements needed – delivering flexible CCS generation at the same time as commercially deploying the technology for the first time;
- the delivery of behavioural responses – engaged consumers will be vital for delivering demand side response; and
- becoming locked into undesirable pathways – many of the assets in the electricity system are long-lived which means that decisions in the short-term can have persistent long-term effects.

Heat and transport accounts for the vast majority of the increase in movable demand. However, if there is not sufficient delivery of demand side response, electrification may worsen rather than alleviate the problem of adequate flexibility making demand more peaky. Therefore, in planning the pathways for decarbonisation and electrification, policymakers should take into account the consequences of electrification for the supply of and demand for flexibility in the power system.

It may be possible to mitigate the impact of electrification on system peak demand by using ex-ante tariffs to shift electricity demand for heating (assuming storage is in place) and transport to periods of low demand. However, this would not help to meet unexpected variations in wind (or in demand), which would require dynamic response from the demand side. This type of response are likely to be increasing important in supporting higher levels of wind deployment, as ex-ante tariffs respond to expected patterns which would become increasingly less relevant.

Storage is required to shift electricity demand for heating over time, which could be very useful for system flexibility particularly within-day. However, a parallel study for the CCC[4] suggests that although technically feasible in most cases, the costs of investment in storage alongside residential heat pumps would not be supported by the assumed differential between off-peak and peak prices. If storage is seen an important source of system flexibility, policy-makers will need to consider how best to overcome the key barrier of the initial investment in heat storage – once storage is in place, the costs of using it are relatively small.

This study has focused on the demand for and supply of flexibility in the electricity sector. Provision of power system flexibility would in many instances increase the requirements for flexibility in other parts of the whole energy system, particularly for transportation networks for electricity, gas and CCS.

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4 'Decarbonising Heat: Low-Carbon Heat Scenarios for the 2020s. Report for the Committee on Climate Change', June 2010, NERA and AEA.

Therefore, policy makers should be mindful that increases in electricity system flexibility can be accommodated by other parts of the energy supply chain. For example, smoothing peak national demand for generation could conflict with smoothing peak demand on distribution networks. There could be particularly acute issues at a local network level if response is largely limited to clusters of customers with electric heating and transport.

For a number of the flexibility options considered in the study, there are some important decision points in the short-term:

- Nuclear – if flexibility is not adequately addressed as part of the current design process (which will affect most, if not all, of the plants expected to be on the system by 2030), flexible response in 2030 may come at a greater costs in terms of performance and operational lifetime.
- CCS – there is expected to be limited emphasis on flexibility for plants commissioning before 2030 as emphasis will be on commercial deployment.
- Interconnection – support should continue for the development of more integrated European markets. However, the expected lead time for the interconnection capacity considered in the study means that action is not needed in the short-term to deliver it the capacity by 2030.
- Bulk storage – the planning and logistical challenges of delivering increased bulk storage capacity suggests that significant preparatory work would need to be started in the near term.
- Heat storage (demand) – policy-makers will need to decide the extent to which additional incentives or requirements will be placed on the delivery of storage alongside heat pumps as part of the design of the electrification programme.
- Distribution networks (demand) – distribution networks will need to be significantly upgraded to support electrification, given long lead times and long asset lives, with clarity needed on how demand side response is expected to be used (e.g. to smooth network flows or to balance variations in intermittent generation).
- Smart infrastructure (demand) – the smart infrastructure (including meters) rolled out in the next few years will still be in place by 2030. Given the increasing importance of active demand side response (as opposed to ex-ante tariffs) at higher levels of wind penetration, then the capability for dynamic response may need to be built in even if its additional short-term benefits (compared to ex-ante tariffs) are relatively limited.

# 1. INTRODUCTION

## 1.1 Introduction

This report sets out the results of a study carried out by Pöyry Energy Consulting, the leading European energy consultancy, on behalf of the Committee on Climate Change (CCC). Excel files containing the key input assumptions and results set out in this report have been provided to the CCC.

Pöyry has led the research, analysis and interpretation of findings in this study. Its project team consisted of staff from Pöyry Energy (Oxford) Ltd along with expert advisors on nuclear and thermal generation drawn from the engineering arm of the Pöyry group, and an Associate, Dr Mark Barrett, who provided expertise on demand side issues.

CCC has overseen the project through regular discussions and four project meetings involving Pöyry and the Steering Group, which includes representatives from DECC and one of the power sector champions from the CCC, Jim Skea. The CCC has also provided assumptions in a number of areas, most notably in the composition of annual electricity demand for each of the four low-carbon worlds (or 'counterfactuals').

### *1.1.1 Structure of this report*

This report is structured as follows:

- Chapter 1 summarises the structure and conventions of this report;
- Chapter 2 sets out the objectives of the study, and in particular why power system flexibility is of interest to the CCC;
- Chapter 3 explains Pöyry's approach to the analysis including the assessment of different flexibility packages against different reference cases, and the modelling methodology;
- Chapter 4 describes the drivers and mix of requirements for flexibility in the low-carbon electricity systems of 2030 and 2050;
- Chapter 5 sets out the key characteristics of the different sources of flexibility for the power system, covering generation, interconnection, bulk storage and demand;
- Chapter 6 describes the performance of the three different flexibility packages;
- Chapter 7 discusses the implications for policymakers emerging from the study; and
- Annex A provides detailed data tables covering common input assumptions, installed capacity, generation, emissions and costs.

## 1.2 Conventions

Where tables, figures and charts are not specifically sourced they should be attributed to Pöyry Energy Consulting. All money is shown in real 2009 money unless otherwise stated.

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# 2. OBJECTIVES OF THE STUDY

Electricity supply and demand are both expected to become more variable and more unpredictable as the GB energy system moves towards a low-carbon future over the next forty years. Several analytical studies, including work by Pöyry[5], suggest that it would be increasingly difficult to match electricity supply and demand without improvements in flexibility.

As a result, the Committee on Climate Change (CCC) is interested in understanding how more flexible demand, storage, interconnection and/or low-carbon generation could contribute to an affordable, secure and low-carbon electricity supply in Great Britain[6].

The CCC has commissioned Pöyry Energy Consulting to characterise and carry out a detailed quantitative assessment of the options for flexibility from different parts of the electricity system.

This study is designed to inform discussions for the fourth carbon budget period in 2023-2027 by improving the understanding of the prospects and challenges for delivery of greater flexibility in the power system. In particular, the CCC is using this study to better understand the implications of the timing and magnitude of electrification of heat and transport, which is expected to happen rapidly from the mid-2020s onwards. At the same time, the electricity sector would need to reach an average carbon intensity of no higher than 100g/kWh of demand by 2030.

The report contains a detailed quantitative assessment of the performance of different options for the sources of power system flexibility in 2030 and 2050. Therefore, it contributes to the debate on moving to a low-carbon energy future but does not quantitatively assess all issues involved in such a transition. For example, it does not explore the impact on gas distribution networks of decarbonisation of heat through electrification. This could affect the flexibility that can be provided by gas distribution networks, for example to support fuel switching in heating.

The remainder of this chapter discusses the context for this study, in particular the reasons for increased interest in the delivery of flexibility within the GB electricity system.

## 2.1 Delivery of a low-carbon energy system

The CCC provides advice to the UK government on climate change issues, including progress towards the UK's 2050 target of an 80% reduction in greenhouse gas emissions from 1990 levels. The CCC has identified decarbonisation of the electricity generation sector alongside electrification of heating and transport as being key to the delivery of the 2050 emissions target.

The expectation is that a decarbonised generation sector would lead to future electricity markets being very different to those of today. Instead of unabated coal-fired and gas-fired power stations dominating the generation mix, the market is expected to contain large amounts of low-carbon generation, such as nuclear, wind, CCS coal and CCS gas.

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5 'Impact of intermittency. How wind variability could change the shape of British and Irish electricity markets. Summary report', July 2009, Pöyry Energy Consulting.

6 Although the CCC is responsible for providing advice to the UK Government , the CCC limited the scope of this study to Great Britain, in order to cover the single electricity market that is currently governed by the BETTA market arrangements.

High capital costs and lower variable costs make these technologies more price-insensitive, with wind generation also being intermittent.

At the same time, the electrification of heat[7] and transport would increase the variability of electricity demand. This is because heat demand is more strongly determined by weather conditions and hence is more variable across the year than existing sources of electricity demand. On the other hand, electrification also provides opportunities for greater flexibility through the storage associated with heat and transport.

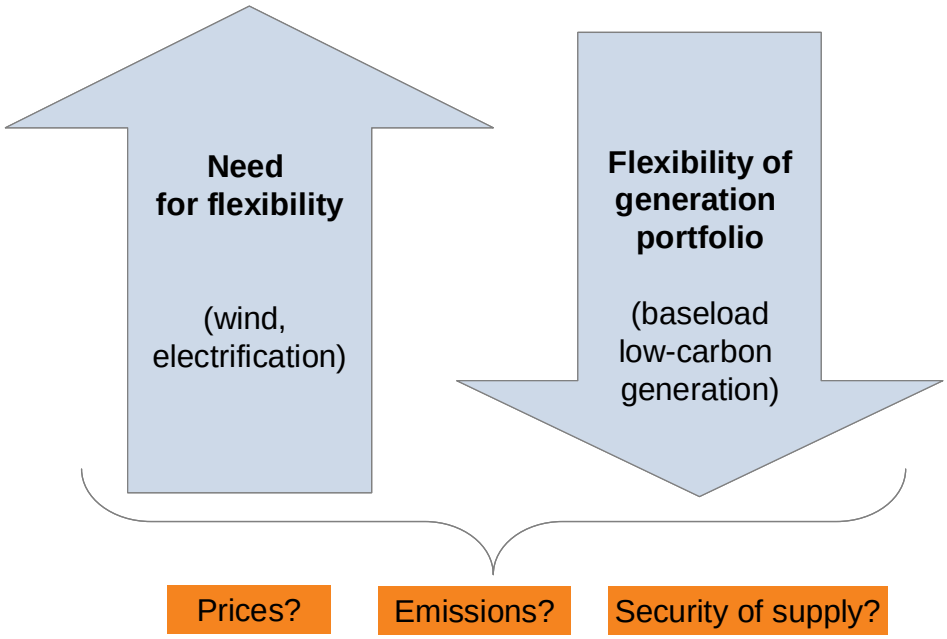
## 2.2 Implications for flexibility

Power system flexibility is needed to help match generation and demand over a range of timescales, which stretch from reserve and response over very short periods to the annual level of supply and demand.

The deployment of more variable forms of generation, primarily wind, coupled with more variable demand would increase the need for flexibility. This may coincide with reduced supply of flexibility as low-carbon generation, such as wind, nuclear, CCS coal and CCS gas plants, replace unabated gas and coal-fired generation. This situation is summarised in Figure 2 with the need for flexibility growing at the same time as the generation fleet, currently a key source of flexibility, becomes less price-sensitive.

This would increase the challenge of matching electricity supply and demand. At worst, this could lead to more frequent events in which supply is unable to meet demand. Even if it is possible to maintain security of supply at the desired level, this may incur much higher costs in an inflexible system.

**Figure 2 – Changes in demand and supply of flexibility**




7 Electrification of heating is assumed to take place in industrial and commercial sectors, as well as residential sector.

Many forms of low-carbon generation, such as biomass, CCS and nuclear generation, have high capital costs. Consequently, the investment case is typically based on achieving high load factors. If greater seasonality in demand reduces average annual load factors for these technologies, this would hinder deployment of these plants in support of the low-carbon targets.

Similarly, large amounts of CCS and nuclear plant could deter investors in further wind generation. This is because in an inflexible system, high wind periods are likely to be associated with very low prices whilst the highest prices are found in low wind periods. This would reduce the price that the wind generation would be able to capture, hence undermining the investment case.

### *2.2.1 Provision of flexibility from unabated gas-fired generation*

At the moment, gas-fired plants (without CCS facilities) are normally seen as the main source of flexibility for the power system. However, the continued reliance on flexibility from unabated fossil-fuel generation may not allow the power generation sector to reach a carbon intensity of close to zero by 2050. The CCC has suggested that this is the level of carbon intensity in the GB power generation sector needed to meet the overall emissions target for the UK.

Furthermore, there remains a wide range of views about the long-term impact of flexing gas-fired plants. While manufacturer guarantees provide some safety net, they also tend to limit the number of starts per year and, they are unlikely to cover more than the first two or three years. So reliance on gas plant flexibility alone is unlikely to be sensible, particularly as gas plant would be unable to deal with situations of excess generation when generation from price insensitive plant is greater than electricity demand. In addition, potential benefits of a more diverse mix of sources of flexibility could include a reduction in the impact on the power system of any interruptions in the gas system or rises in gas prices.

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# 3. APPROACH

The study is centred on the detailed quantitative assessment of different flexibility packages against four different low-carbon worlds (or 'counterfactuals'). This required a number of preliminary steps, such as the characterisation of different options for flexibility, and the modelling of a baseline (or 'reference case') for each counterfactual.

This chapter sets out the approach taken for the assessment, which was carried out using the wholesale electricity model *Zephyr* that Pöyry Energy Consulting developed for use in its intermittency study in 2009. The demand side modelling capability of *Zephyr* was further enhanced for use in this study.

## 3.1 Low-carbon worlds

The first step was to develop a set of counterfactuals (or possible low-carbon worlds), two for 2030 and two for 2050, against which to assess each flexibility package. This provided allowed the evaluation of the different packages to take account of uncertainty about future developments.

Two counterfactuals tested how the changes in electricity demand would affect the flexibility challenge in 2030:

- **Counterfactual 1** has a demand mix similar to today; and
- **Counterfactual 2** is consistent with the low-carbon pathways set out by the CCC (and by DECC[8]), in which there is electrification of transport and, in particular, heat by 2030.

The other two counterfactuals test the sensitivity of the flexibility challenge to the development of CCS technology by 2050:

- **Counterfactual 3** has a diverse generation mix mainly consisting of nuclear, wind, CCS coal and CCS gas; and
- **Counterfactual 4** has no CCS generation, which means that the generation mix is heavily reliant on wind and nuclear.

Figure 3 shows the composition of final electricity demand in each of the counterfactuals, as provided by CCC as inputs into the modelling[9]. It highlights the difference between Counterfactuals 1 and 2 in the extent of the electrification of heat (residential, commercial and industrial), and of transport (EVs, PHEVs) that is assumed to have occurred by 2030.

Electrification would lead to big changes in the level, pattern and variability of electricity demand. These two counterfactuals therefore allow us to test how demand developments could ease or worsen the flexibility challenge. In Counterfactual 1, the share of electricity demand taken by heating (non-heat pumps) and EVs is 12%, below the current level of around 18%. This is the result of improvements in energy efficiency for heating and the absence of significant EV penetration. The deployment of heat pumps in residential and non-residential sectors in Counterfactual 2 (in addition to existing heating demand from non-heat pump sources) pushes the share of heating and EV in electricity demand up to 27%.

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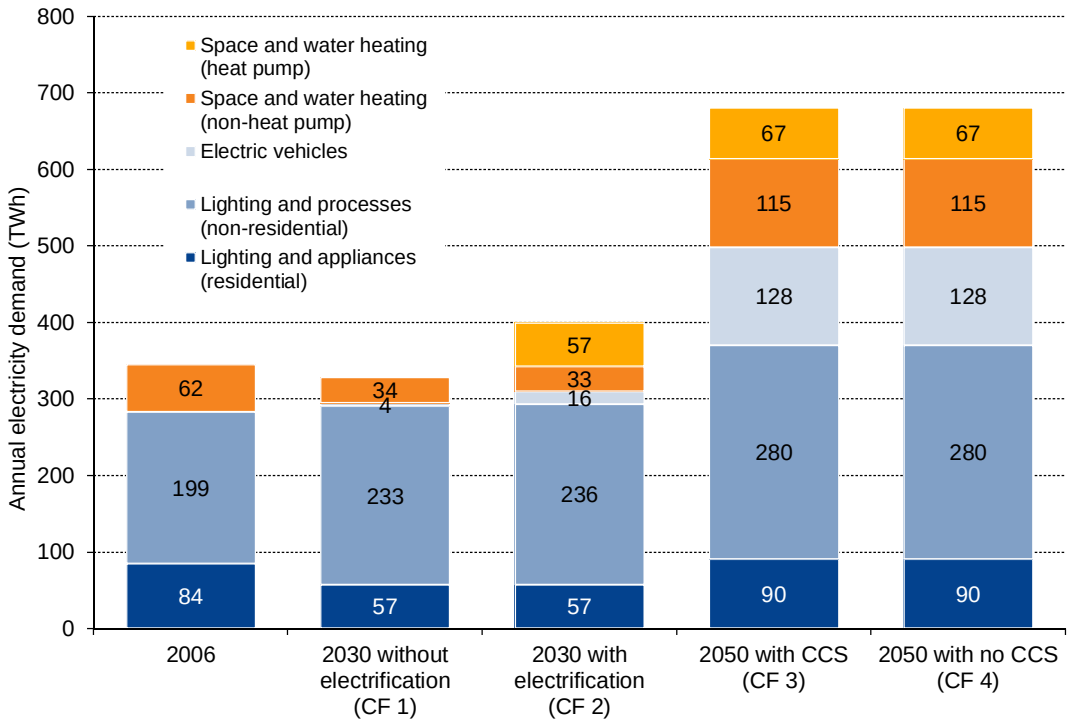
8 '2050 Pathways Analysis', Department of Energy and Climate Change, July 2010.

9 Further details on these assumptions are contained in Section 3.1.1.

Both counterfactuals for 2050 share the assumption of the widespread electrification of heat and transport (and industry), which results in a near doubling of electricity demand from current levels. Heating and EVs account for 46% of electricity demand.

**Figure 3 – Annual final electricity demand in the four counterfactuals** (TWh)




Source: Historic – DECC publications, Counterfactuals – Committee on Climate Change

Counterfactuals 3 and 4 test uncertainty on the supply side, in relation to the development of CCS technology. In Counterfactual 3, CCS coal and CCS gas contribute to a diverse low-carbon generation mix. The assumed absence of CCS technology in Counterfactual 4 means that decarbonisation relies much more heavily on the deployment of wind and nuclear. This facilitates closer examination of the challenges and opportunities of accommodating high levels of wind and nuclear.

The design of these low-carbon worlds by the CCC was designed to explore the impact on the electricity system of a number of key exogenous assumptions based on its work in other areas. These included the annual mix of electricity demand, the roll-out of different solutions in the heat sector[10] and the transport sector, and the volume of deployment of different types of renewables. Therefore, these assumptions were not flexed in the modelling work in this study (beyond the differences embodied in the counterfactuals). It would be possible for future modelling work to consider, if appropriate, the impact of a different set of values for these assumptions, e.g. lower wind capacity and higher solar deployment.

10 For example, a focus on the deployment of individual heat pumps rather than CHP and/or district heating solutions.

### 3.1.1 Reference cases

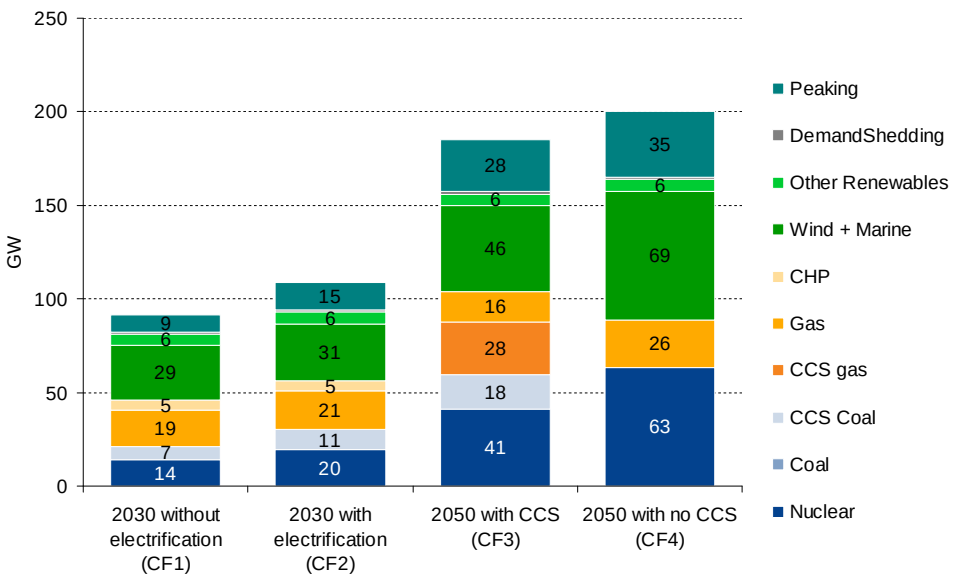
For each low-carbon world (or counterfactual), a reference case was developed to provide a baseline for the evaluation of the different flexibility packages. Flexibility in both supply and demand in the reference cases is limited to the flexibility of generation and customers that we observe today.

To help produce these reference cases, CCC provided assumptions on electricity demand, fuel prices and generation costs, along with initial views on the installed capacity mix. A number of *Zephyr* modelling runs were then used to develop the final capacity mix, based on a number of constraints such as:

- limit on average carbon intensity of power generation – around 80-90g$CO_2$/kWh of demand in 2030 and close to zero in 2050;
- security of supply – ceilings on expected energy unserved (EEU) of around 2GWh of in 2030 and around 4GWh in 2050, with the difference reflecting the fact that annual electricity demand was about twice as high in 2050 than in 2030.
- profitability of investment in different types of generation – which determined whether investment decision was consistent with the internal rate of return (IRR) achieved by each plant; and
- development of a diverse low-carbon generation mix, as far as possible within the constraints of the counterfactual assumptions.

We have adjusted the capacity mix for non-renewable generation to reflect the relative commercial attractiveness of different types of plant in 2030 and 2050. We have taken into account physical constraints on new build by 2030 and 2050 but we have not modelled the investment pathways or market arrangements required to reach the capacity levels. The final capacity assumptions for each reference case are shown in Figure 4.

**Figure 4 – Generation capacity in the reference cases** (GW)

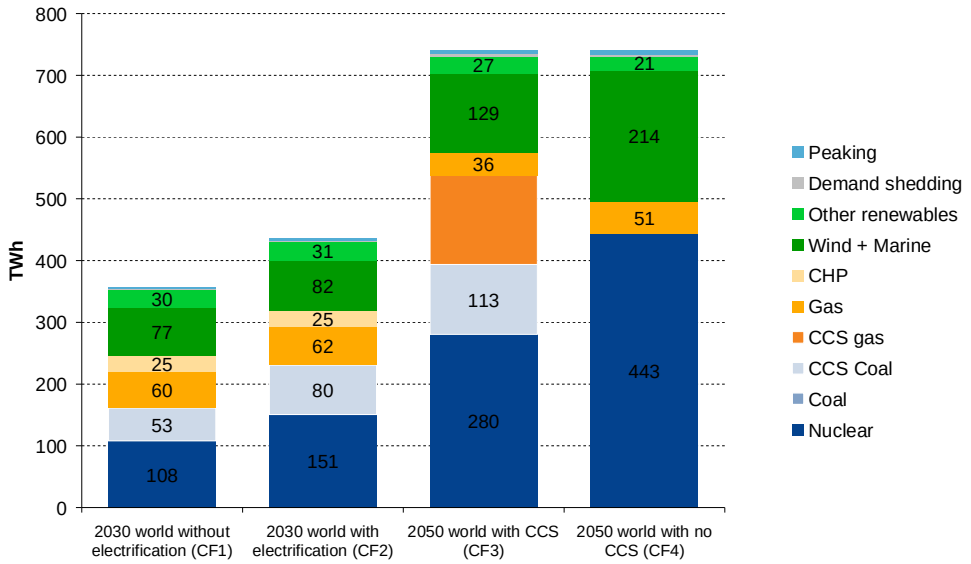



Source: Committee on Climate Change and Pöyry Energy Consulting analysis

Figure 5 illustrates that high annual load factors mean that non-intermittent low-carbon technologies, such as nuclear and CCS plants, play a much bigger role in the generation

mix than in the capacity mix. At the other end of the scale, peaking plant makes a minimal contribution to annual generation (in fact, barely showing up on Figure 5) even though they account for around 10-15% of installed capacity. This means that shaving the peak requirement for non-intermittent generation would primarily reduce capital costs through avoided investment in these type of plants rather than operating costs.

**Figure 5 – Annual generation in the reference cases** (TWh)




In all four reference cases, there was assumed to be:

- 3.3GW of interconnection between Great Britain and North West Europe (including France and Netherlands);
- 0.9 GW of interconnection between Great Britain and the Single Electricity Market (SEM) in Ireland; and
- bulk storage with capacity and operating characteristics kept at current levels (for further details, see Section 5.5).

## 3.2 Flexibility packages

Required to match generation with demand, power sector flexibility can be provided by:

- varying the operating pattern of non-intermittent low-carbon generation, as encapsulated in our **'flexible generation'** package;
- using intermediate technologies, such as interconnectionor storage, alongside CHP to accommodate any imbalance between supply and demand, as covered by our **'imported flexibility'** package; or
- changing the pattern of demand in response to 'real-time' variations in the requirement for non-intermittent generation, as covered by our '**active demand side**' package.

Table 4 summarises how each sector (generation, demand, interconnection and storage) contributed to each flexibility package. Green boxes denote a strong contribution, amber

boxes identify a weak contribution and red boxes show where there was no contribution at all.

The scope of this study meant that the packages were designed to isolate as far as possible the contribution that could be made by different parts of the electricity supply chain. To develop an optimal flexibility package, assessments would be needed of packages that had a more balanced mix across the three sectors.

**Table 4 – Summary of different flexibility packages[11]**

| Flexibility packages | Generation | Demand | Interconnection and storage |
|---|---|---|---|
| Flexible generation | More flexible nuclear and CCS | Ex-ante ToU tariffs smooth demand | As in reference case |
| Imported flexibility | More flexible district heating CHP | Ex-ante ToU tariffs smooth demand | More interconnection More storage |
| Active demand side | As in reference case | 'Real-time' response from demand | As in reference case |

In all three packages, it is assumed that smart meters have been deployed, which allow (at least) the use of hourly time of use tariffs set in advance to smooth the (expected) pattern of demand. Some but not all potentially flexible demand responds to these tariffs, which provides the fixed demand profiles used in the 'flexible generation' and 'imported flexibility' packages.

To deliver each of the packages set out in Table 4, appropriate incentives will be needed to change the behaviour of market players as well as investment to provide them with the ability to change their behaviour. This could include for example, investment in an interconnector with Norway in the 'imported flexibility' package or in smart infrastructure in the 'active demand side' package.

There remains uncertainty about the detailed technical performance capability of the low-carbon generation (primarily nuclear and CCS) that will be deployed in 2030 and 2050. This means that some improved flexibility beyond the reference case could be expected in an optimistic view of the future. However, simply waiting (and hoping) for a good outturn is unlikely to be sufficient to deliver the level of flexibility considered in this study, given the importance of the choices that are made in the design and construction phases (as discussed further in Section 5.3.1).

## 3.3 Assessment criteria

There are two key elements to the study – the characterisation of different sources of power system flexibility, and the detailed quantitative assessment of the performance of various flexibility packages against the four counterfactuals. In the characterisation of options, we have concentrated on looking at the type of flexibility provided and how it compares to the different types of flexibility required by the system.

11 In all three packages, it was possible to deload wind (and wave) generation if required to balance supply and demand.

The assessment of performance must relate to the impact on the delivery of the Government's energy policy goals, which can be summarised as the delivery of a low-carbon, secure and affordable energy supply[12]. Greater flexibility could help towards meeting these goals in a number of different ways:

- lowering need for peak capacity, be it generation or network;
- improving system utilisation and system management;
- reducing number of starts and amount of part-loading for generation;
- decreasing cost of provision of reserve and response; and
- dampening volatility in wholesale electricity prices, which would feed into lower perceived risk (and hence cost of capital) for investments in low-carbon generation.

We have captured these effects through four specific quantitative measures:

- **carbon intensity of the power generation sector,** which must be at least comparable to the level in the reference case for each counterfactual (80-90gCO2/kWh of demand in 2030, close to zero in 2050);
- **security of electricity supply**, which must be at least comparable to the level in the reference case for each counterfactual (with total expected energy unserved of around 2GWh in 2030 and approximately 4GWh in 2050 based on a much higher level of electricity demand – these figures exclude the impact of network failures);
- **total generation cost** (covering investment and operating costs) for delivering the low-carbon generation mix; and
- **total system cost**, which captures the cost of investing in and operating supporting infrastructure and networks.

These measures are based on modelled outputs from *Zephyr*, which also produces many other useful outputs, such as the hourly dispatch pattern for non-intermittent generation.

## 3.4 Modelling platform

The quantitative assessment is based on the outputs of our wholesale electricity model *Zephyr,* which captures the interaction between variable supply and variable demand. Developed for use in Pöyry's intermittency study for GB and Ireland[13], this model has been subsequently refined through a number of further studies. In particular, we have developed the demand side modelling capability for use in this study.

Figure 6 provides an overview of this unparalleled modelling platform backed by a wealth of historical data on wind, availability and demand profiles.

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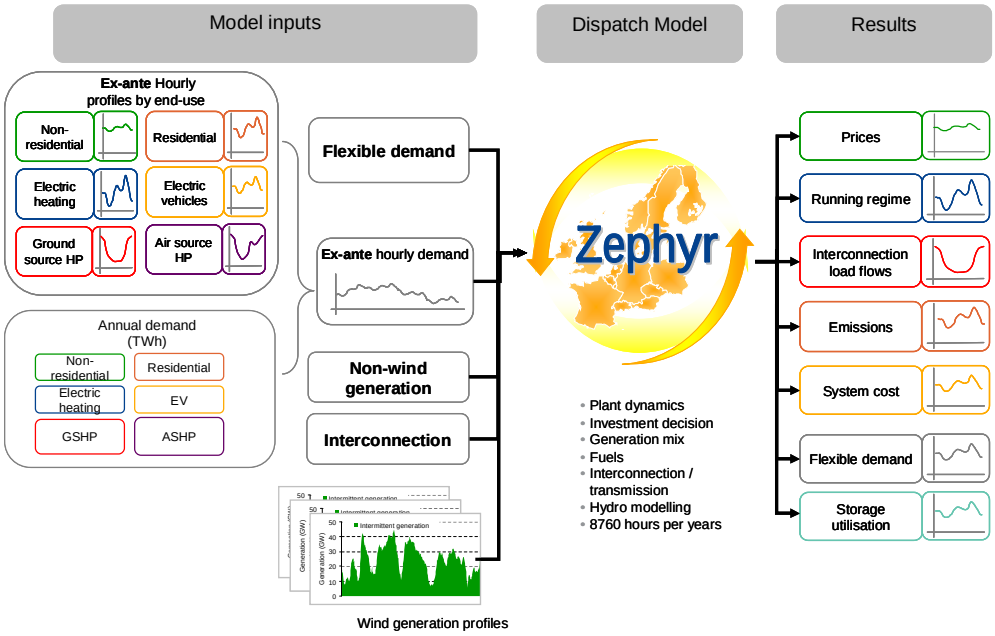
12 This study is focused on the flexibility of the power system. Therefore, the study has not taken into account some of the direct benefits and costs of the electrification of heat and transport, such as the impact on overall carbon intensity of energy and the cost of roll-out of electric vehicles.

13 'Impact of intermittency. How wind variability could change the shape of British and Irish electricity markets. Summary report', July 2009, Pöyry Energy Consulting.

## Figure 6 – Overview of Zephyr




Based on a mixed integer linear programming platform[14], *Zephyr* simulates the dispatch of each unit on the GB and Irish systems for each hour of every day – a total of 8,760 hours per year.

This allows us to optimise to find the least cost solution for meeting hourly electricity demand (including any fixed flows across interconnectors) in the model accounting the sum of variable costs (including fuel and carbon), the costs of starting plant and the costs of part-loading. The options available to the model include the following:

- changing the dispatch of non-intermittent generation (such as nuclear and/or CCS and subject to plant dynamics);
- changing flows across the interconnectors (where these have not been pre-determined);
- changing the input or output from bulk storage (subject to constraints on reservoir volumes etc);
- changing the dispatch of flexible electricity demand units (e.g. electric vehicles) whilst meeting the specified energy requirements (e.g. provide enough electricity to satisfy driving demand);
- reducing the level of intermittent generation (e.g. spilling or deloading wind), for example to avoid shutting down a nuclear plant and incur the cost of restarting it later – it is not possible to increase output from intermittent generation; and
- failing to meet demand, which is measured as the amount of expected energy unserved.

14 Zephyr has been run in this study in what is known as 'relaxed mode', whereby the full mixed integer problem is approximated by continuous variables. Starts and part loading is still optimised subject to the constraints on plant dynamics.

The model also accounts for minimum stable generation and minimum on and off times, which allows more realistic operational simulation of plant such as large coal or nuclear sets. Once running, these plants must remain on for a certain number of hours, or, once shut down, cannot restart for a long period.

For each future year that is modelled, nine iterations are carried out, which represent the wind, availability and demand profiles for the historical years 2000-2008. This means that for any given future year, a total of 78,840 prices are created (8,760 x 9), giving a comprehensive representation of possible interactions between wind, availability and demand. The prices that result from the model are the result of the interaction of supply and demand in any given hour.

Generation from wind is based on 2.8 million hourly wind speed records at 35 locations across the UK and RoI plus an offshore site using 'reanalysis' of wave data, which are converted to generation using an aggregated power curve. The Anemos European Wind Atlas was the source of wind data for the North West Europe region, which was used to calculate border flows.

The key features of Zephyr which ensures it provides quantitative modelling and analysis of the highest quality are:

- **Annual demand and availability** – hourly profiles of demand are generated based on historical demand patterns as well as weather pattens that would affect new sources of demand such as heat pumps. Each annual profile is used in a separate Monte Carlo iteration. Thus peaks and troughs in demand would occur at different times in different iterations.
- **Wind, wave and tidal generation profiles** – to ensure a consistent set of input data for wind generation, we worked with the UK Met Office to define 28 sites across GB that offer an accurate representation of future wind generation in the UK. These points were chosen to represent sites where there is likely to be significant wind turbine deployment in the next 20 years based on known applications and licensing areas determined by the government.
- **Prices consistent with new entry decisions** - to calculate the system marginal price, the model assesses the variable costs of the most expensive set operating at any point in time, inclusive of start-up and part loading costs. A value of capacity is added which reflects either the fixed year on year costs of keeping sufficient plant open to ensure that demand is met in peak periods, or in circumstances in which there is an impending shortage of capacity, the cost of bringing forward new entry. Annual fixed costs and new entry costs are not included in Zephyr itself, but we iterate new build and/or value of capacity based on these to produce a set of wholesale prices that are consistent with the new entry decision for thermal plant.
- **Plant dynamics** – plant availability based on historical profiles (by plant type) for several individual years[15]. This includes scaling for different properties (maximum output, minimum on and off time, minimum stable generation etc) estimated from historical MEL data. For Pumped Storage (PS) capacity we modelled a maximum generation, a maximum pumping, maximum and minimum reservoir levels, and the contribution of PS to reserve and response.
- **Active demand units** – the model includes three categories of active demand units; heating, electric vehicles and residential washing units.

15 For new entrant plants, the within-year availability profiles were amended in response to the changing patterns of demand in 2030 and 2050, compared to historic data.

### 3.4.1 Reserve and response

Short-term unpredictability, particularly about plant availability, affects the reserve requirement for the electricity system. Reserve has three components:

- primary frequency response (up to 30 seconds after unplanned outage);
- secondary frequency response (30 seconds to 30 minutes after an unplanned outage); and
- reserve (30 minutes to 4 hours).

We assume that sufficient primary frequency response is provided in line with technical requirements for generation plants. For secondary frequency response and for reserve, we have used formulae to determine the ex-ante level of reserve required to be held by the system, which can be determined in a constrained run of the model, which looks at a number of factors such as hot plants, headroom available and OCGTs that are not running. However, we do not model the actual deployment of reserve as there are no unexpected outages within the modelling framework.

## 3.5 Modelling inputs

There are five broad categories of input into the Zephyr model:

- **Fuel and carbon prices** – based on assumptions published by DECC.
- **Electricity demand** – annual electricity demand (TWh) provided by the CCC with demand profiles based on Pöyry analysis, as described in Section 3.5.5.1.
- **Generation plant characteristics** – technical and economic plant assumptions in the reference cases were based on assumptions provided by DECC[16].
- **Border assumptions** – these can take two forms, either exogenous assumptions about flows which drive border prices, or assumed border prices which are used to determine flows. We used the the first approach for the interconnectors with the SEM and with NW Europe and the second approach for the Norwegian interconnector.
- **Demand characteristics** – the two main types of demand inputs are fixed electricity demand profiles (from inflexible demand), and flexibility characteristics of active demand side units (which provide flexible demand).

Chapter 5 provides a detailed overview of the flexibility characteristics assumed for generation, interconnection, bulk storage and demand.

### 3.5.1 Fuel and carbon prices

The fuel price assumptions were based on Scenario 2 (Timely Investment, Moderate Demand) from a January 2010 DECC publication on fossil fuel prices[17]. As this only provides assumptions out to 2030, we held the 2050 price constant at the 2030 level.

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16 We have based the characteristics of the peaking generation based on our understanding of the LMS100 plant, which is a GE design.

17 'Valuation of energy use and greenhouse gas emissions for appraisal and evaluation' January 2010, DECC.

The assumed fuel prices (all real 2008 money) were as follows:

- Oil – $90/barrel (Brent Crude);
- Gas – 74p/therm (NBP); and
- Coal – $80/tonne (ARA).

These were converted into sterling using an exchange rate of $1.56:£1, in line with assumptions made in DECC's published guidance on fuel prices.

Our assumed carbon prices were based on DECC guidance from July 2009, which set out an assumed carbon price of £70/t$CO_2$ in 2030 and £200/t$CO_2$ in 2050[18].

### 3.5.2 Annual electricity demand

The CCC provided the figures for annual electricity demand in 2030 and 2050, which were described in Section 3.1. *Zephyr* uplifts electricity demand to take account of network losses when calculating the requirement for generation and imports.

### 3.5.3 Generation characteristics

We used DECC assumptions (based on data sourced from a study undertaken for DECC by Mott MacDonald entitled 'UK Electricity Costs Update') for generation plant characteristics where possible to ensure consistency with other work being undertaken by the CCC and/or DECC. Where it was not possible to use the DECC assumptions, we have used our own assumptions derived from our experience in modelling the GB electricity market.

The CCC provided an initial view on the installed capacity mix for each reference case. However, installed capacity for non-intermittent generation was adjusted through a number of model runs, based on the investment returns achieved and the need for capacity to meet peak demand.

### 3.5.4 Border assumptions

Any model must have a geographical boundary, beyond which assumptions must be made about the operation of the 'outside world'. *Zephyr* was developed to cover Great Britain and Ireland. However, for this project, we limited the modelling to Great Britain in line with the counterfactual information provided by the CCC. Therefore, we had to make border assumptions for input into *Zephyr* with respect to

- the Single Electricity Market in Ireland (**SEM**);
- the North West European electricity market including France, Netherlands and Belgium **(NW Europe**); and
- Norway.

There are three key components to the modelling of the interconnectors – capacity, flexibility of operation (on an hourly basis) and determinants of flow (both direction and magnitude).

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18 'Carbon Valuation in UK Policy Appraisal: A Revised Approach', July 2009, Climate Change Economics, Department of Energy and Climate Change.

In all reference cases and flexibility packages, it is assumed that there are no technical restrictions of the ability of the interconnector to operate flexibly on an hourly resolution (i.e. it can swing freely from hour to hour).

#### *3.5.4.1 Capacity*

In all four reference cases, there was assumed to be 3.3GW of interconnection between Great Britain and NW Europe, and 0.9GW of interconnection between Great Britain and the SEM. This was based on existing links and projects under development, such as the BritNed interconnection between GB and the Netherlands. The capacity of the interconnector with Norway is set to zero in all four reference cases.

Interconnection is only expanded in the 'imported flexibility' package, with capacity of the interconnectors reaching (in both 2030 and 2050):

- 1.9GW with the SEM;
- 6GW with North West Europe; and
- 2.5GW with Norway.

#### *3.5.4.2 Determination of interconnector flows*

There were two options for determining interconnector flows because explicitly modelling other European countries was outside the scope of this study. The options were either to fix flows as an exogenous input into the *Zephyr* optimisation process or to let *Zephyr* use assumed border prices to optimise flows. We used the first approach for the interconnections with SEM and NWE, and the second form for the Norwegian interconnection.

The net flows across each interconnector were assumed to be zero [19] – i.e. annual imports equal annual exports on average across the nine Monte Carlo years. This has the effect on requiring generation in GB to completely meet electricity demand in GB (including network losses). Setting net flows to zero allowed the study to focus on the role of the interconnectors in providing flexibility, rather than letting them reduce annual carbon emissions by simply displacing (annual) generation in GB.

The hourly flows across the interconnectors with the SEM and with NW Europe are assumed to be driven by differences in the hourly wind load factor between GB and the relevant market. This reflects the fact that although the precise capacity mix in 2030 and 2050 is not modelled, swings in wind are assumed to be an important determinant of the balance between demand and supply in these markets.

This means that for example, when ‘wind load factor’ is higher in GB than in the SEM, GB would export to the SEM. Consequently, these two interconnectors can only provide limited flexibility for the British system – they are responsive only to wind and not to demand net wind. If wind is high in GB but higher in the foreign zone, then the interconnector would flow into GB worsening a potential excess supply situation. This means that additional capacity only helps to the extent that the flows were already helping to balance the wind.

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[19] It also reflects that there is no certainty (or existing contractual arrangements) in relation to the annual level of net flows across these interconnectors.

Figure 7 shows the limited extent to which wind load factors in GB are correlated with those in NW Europe. A negative correlation would offer the most scope for flexibility, and so the pattern in

Figure 7 suggests that the NW Europe interconnector would only provide limited flexibility, and could even make things worse at times.

**Figure 7 – Correlation of wind load factors in Great Britain[20] and NW Europe**


Source: Wind data for GB based on Met Office data, NWE wind data based on Anemos data

The Norwegian generation mix is expected to contain significant amounts of flexible hydro generation out to 2050. The capacity of the Norwegian interconnector in the 'imported flexibility' scenario is 2.5GW, which compares to current installed hydro capacity in Norway of 28GW (with the potential to be much higher according to projections). This allows the flows across the Norwegian interconnector to be responsive to changes in the price level in GB, subject to two main constraints outlined below.

Although the Norwegian interconnector is effectively providing access to pumped storage, we do not model any limits of the size of the storage capacity, given the relatively small size of the link compared to the capacity available in Norway. However, to avoid the model treating Norway simply as a very large sink for the GB system (and as a result, possibly over-optimising), we assumed that there is a zero net flow across the Norwegian

20 Load factor for GB wind based on mix of offshore and onshore wind capacity in 2050 world with CCS (CF 3).

interconnector over a month[21] (i.e. to prevent the GB system importing from Norway continuously for two months which would require very large storage capacity in Norway). As imports and exports were assumed to balance over a month[22], the flexibility of the Norwegian link can only provide flexibility within a single month.

Norway is also expected to be an important source of flexibility for other electricity markets in North West Europe. Therefore, we imposed an assumptions that imports from Norway are restricted when GB is exporting over the NWE link (i.e. wind is relatively low in North West Europe and hence the Continent may also be importing from Norway which reduces the availability of Norwegian storage to the British market).

### 3.5.5 Demand modelling

There are two key components to the modelling of demand – production of ex-ante (fixed) demand profiles and the characterisation of active demand units.

The reference cases provide a baseline against which to measure the impacts of providing increased flexibility. Therefore, the reference case was based on demand profiles before any (additional) load smoothing measures had been applied, and the only active load management was the voluntary load loss described in Section 3.5.3.

The fixed demand profiles used in the reference cases were modified in each of the flexibility packages, either through use of system tariffs or through active load management as part of the optimisation process.

#### 3.5.5.1 Demand profiles in reference cases

Table 5 summarises the source of the demand profiles used for each demand category in each Monte Carlo year in the reference cases. The categories are consistent with the breakdown of the annual demand figures provided by the CCC.

We assumed that the overall mix of electricity demand for space and water heating remains at current levels – however, the mix varies by technology in line with guidance from the CCC[23]:

- ASHP provides space heating only;
- GSHP provide 50% of water heating that would normally be provided by electric heating; and
- non-heat pump heating provides the residual mix of space and water heating.

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21 This is consistent with the assumption that there are zero net flows over the year, and reflects the absence of any certainty about the seasonal pattern of flows across the Norwegian interconnector.

22 This means that in the modelling, GB exports to Norway when the wholesale electricity price in GB is lower than the monthly average price in GB (and vice versa).

23 This refers to the space and water heating provided by the specified heat technology (i.e. the actual heat pump). An alternative but equivalent approach would be to assume that each heating system provides the current mix of space and water heating, where a heating system is made up of heat pumps and/or non-heat pump technologies. For example, in the assumptions set out in the bullet points, non-heat pump heating (with a constant coefficient of performance of 1) would provide hot water in buildings where an ASHP is providing space heating.

The mix of electricity demand required for space and water heating will depend on the mix of end-use heat demand for space and water, as well as the relative electrical efficiencies for the technologies providing space heating and the technologies providing hot water.

End-use demand for space heating is much more seasonal than the demand for water heating, because it is more strongly linked to external temperatures. Therefore, the profile of heating demand across the year would be affected by the mix of space and water heating, which would itself be influenced by relative improvements in energy efficiency for each type of heating.

**Table 5 – Construction of demand profiles in reference case**

| Demand category | Source of sample profile | Production of Monte Carlo profile |
|---|---|---|
| Residential (excluding heat and electric vehicles) | Class 1 demand profile (as used in settlement) | Adjustments made to sample demand profile in line with 'unexplained' variations in historical demand profile |
| Non-residential (excluding heat and electric vehicles) | Analysis of historical demand profile | Adjustments made to sample demand profile in line with 'unexplained' variations in historical demand profile |
| Heating (non-heat pump) in residential and I+C sectors | The within-day profile, which followed sample heat demand profiles if no storage, or E7 type profile if storage was assumed in reference case[24] | Daily heating demand was based on a structural pattern of demand around which variations were driven by deviations in wind speed and temperature from seasonal levels, drawing on analysis from Pöyry's gas intermittency study[25] |

### *3.5.5.2 Demand profiles after smoothing by ex-ante tariffs*

The demand profiles used in the 'flexible generation' and 'imported flexibility' packages were smoothed in response to ex-ante tariffs. Given the amount of potentially flexible demand, particularly by 2050, we could not just use current time of use tariff structures such as E7, which would have led to overnight demand peaks.

We assumed that the ex-ante tariffs would shift demand from peak periods to periods of low demand, based on the average demand pattern for each of our fifteen sample days – a working day, a Saturday and a Sunday for five periods of the year[26]. We assumed transport demand could be shifted between days to some extent (e.g. into the weekend) but that heating and residential (washing) demand could only shift to another hour within the same day.

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24 Different within-day heat demand profiles and daily heating demand profiles were used for the residential and non-residential sectors.

25 'How wind generation could transform gas markets in Great Britain and Ireland. A multi-client study. Public summary', June 2010, Pöyry Energy Consulting.

26 The five periods of the year were winter, spring, summer, high summer, and autumn.

Therefore, the tariffs would smooth the average demand profiles, particularly a the sample day[27]. Indeed, the amount of movable demand in 2050 means that only a proportion of it has to be used to fill in demand troughs in order to produce a flat expected within-day profile. This was not possible for the 2030 cases, particularly where there was no electrification (CF 1) and hence relatively little flexible demand.

The ex-ante tariffs cannot shift demand in response to changes in wind levels or temperature-driven deviations in heating demand from the sample demand. This requires the real-time load management capabilities assumed in the 'active demand side' flexibility package.

#### *3.5.5.3 Active demand units*

The study assumed that in all of the counterfactuals, there was approximately 1 GW of voluntary demand response. This was consistent with previous CCC studies with the following combinations of prices and quantities[28]:

- 760 MW reduction at £100/MWh;
- 170 MW reduction at £200/MWh; and
- 60 MW reduction at £500/MWh.

In addition, we expanded the scope of *Zephyr* to take account of movable demand from three categories of active demand units – heating (both residential and non- residential), electric vehicles and residential washing appliances.

The movable demand was allocated to a number of different units, as summarised in Table 6. These assumptions and constraints were then used by *Zephyr* to optimise the operation of these units, with the restriction that the underlying profile of energy demand must be met.

For units with storage (heating and transport), this restriction was implemented by reducing the amount of electricity in storage in line with the underlying energy demand profile. Storage is separately managed for different users (e.g. electricity in storage for residential ASHPs cannot be used to meet electricity demand from residential GSHPs or from non-residential ASHPs). The optimisation of the use of heat storage also took into account thermal losses in storage, and variations in the coefficient of performance of ASHPs across the year (which changes the amount of electricity demand required to provide a particular level of heating demand).

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27 A further development in this approach would be to use ex-ante tariffs to shift the fixed demand profile to flatten the expected demand net wind profile. This would require further analysis and the development of assumptions about expected wind output on a sample day basis – the wind profile pattern will vary by reference case as it is affect by the mix of onshore and offshore wind. This analysis was not possible in this project given constraints on time and resources.

28 Figures are based on 'Estimation of Industrial Buyers' Potential Demand Response to Short Periods of High Gas and Electricity Prices', 2005, Global Insight.

**Table 6 – Modelling assumptions and constraints for active demand units**

| Type of demand unit | Energy demand profile | Charging rate | Availability for charging | Min on time | Storage capacity | Minimum storage levels | Rate of energy loss | Fuel switching capability | Returning electricity to grid |
|---|---|---|---|---|---|---|---|---|---|
| **Domestic washing appliance** | Residential demand profile determines daily demand | Determined by energy demand as no storage capability | Available during 12 hour period (either overnight or during day) | 2 hours | No storage capability assumed as shifting end use energy demand | No | No storage | No | No |
| **Heating** | Heating demand profiles | Capacity can be filled in about 4 hours | All times | None (1 hour) | Based on 25-30 hours of average demand | No | 1% per hour | Boiler – variable cost of gas (inc CO2) | No |
| **Electric vehicles** | Driving profile with three user categories (high, medium, low) | Battery filled in 4-5hours for dedicated EV, 3-5hours for hybrid | Three periods – overnight, daytime or 24 hour | None (1 hour) | Battery range of 100-120km for dedicated EV; 60km for hybrids | By end of charging period, 1.5 days of average use | No losses | PHEV – variable cost of petrol (inc CO2) | 50% of charging rate; round trip efficiency of 75% (EV) and 50% (PH) |

## 3.6 Modelling outputs

As described in Section 3.3, the following quantitative assessment criteria were used in this study:

- carbon intensity of the power generation sector;
- security of electricity supply;
- total generation cost; and
- total system cost.

The carbon intensity of the power generation sector and the security of electricity supply are direct outputs of the *Zephyr* modelling process. Where customers switch away from electricity to using alternative fuels for heating or transport (as part of the optimisation process), then the carbon dioxide emissions from the substitute fuel are included in total power sector emissions.

Table 7 and Table 8 describe the construction of the other two assessment criteria – total generation cost (covering investment and operating costs) and total system cost.

Table 7 highlights that the variable costs (carbon, start-up and no-load, VOWC and fuel) are taken directly from *Zephyr, which* produces hourly dispatch patterns for each plant on the system. The capacity-related costs (FOWC, capex) are derived from the inputs into *Zephyr* rather than the outputs from the model. However, the iterative process means that the capacity assumptions are themselves informed by previous modelling runs.

**Table 7 – Calculation of generation costs**

| | | |
|---|---|---|
| **Carbon costs** | Product of CO2 price and level of CO2 emissions from generation fleet (including from substitute fuels in fuel switching) | Direct from Zephyr |
| **Start-up and no-load costs (SUNL)** | **Fuel and maintenance costs of starting and part-loading plant (from Zephyr)** + balancing costs (from National Grid estimates of increases in balancing costs with different volumes of wind). | Partly from Zephyr |
| **Variable other work costs (FOWC)** | Non-fuel costs of plant that vary strictly with output (including maintenance not related to number of starts) | Direct from Zephyr |
| **Fixed other work costs (FOWC)** | Annual fixed costs of plant (salaries, rates etc.) | Not direct Zephyr output |
| **Fuel costs** | Sum across all fuel types of the product of fuel price and level of fuel burn from generation fleet (including use of substitute fuels in fuel switching) | Direct from Zephyr |
| **Capex** | Levelised capex of all plant on the system, assuming discount rate of 10% pre-tax real and economic lifetime. | Not direct Zephyr output |

**Table 8 – Calculation of annual system cost**

| | |
|---|---|
| **Smart meters/grids** | Based on ENSG Smart Grid Road Map for 'quantity load management' package. Based on cost of basic smart meter roll out (DECC) for reference case and all other packages |
| **CCS infrastructure** | Cost of pipelines and offshore investment for CCS, assumed to be around £500/kW for CCS coal and £300/kW for CCS gas<br>CCS infrastructure sized to meet maximum capacity of CCS plants even if they operate at low load factors. |
| **Electricity distribution costs** | Uprated from current levels pro -rata with change in peak demand |
| **Electricity transmission costs** | Levelised network investment based on 6.25% discount rate and 40 years.<br>Onshore network reinforcement calculated from network flow data and peak demand data from Zephyr<br>Offshore reinforcement based on offshore wind build. |
| **Interconnection** | Sum of £400m + £1m perGW per km |
| **Storage** | Based on cost of existing pumped storage facilities |
| **Wholesale market costs** | Based on mixture of Zephyr inputs and outputs |

### *3.6.1 Impact on wholesale prices*

Nuclear and CCS plants are assumed to be the main options for baseload new entry because the capacity of other low-carbon forms of generation is largely fixed (such as wind, wave and biomass). As a result, TWA wholesale prices are driven by the long-run marginal cost (LRMC) of nuclear and CCS plants. This means that wholesale market costs and TWA wholesale prices may not move in the same direction.

The LRMC of generation is determined by:

- fuel and carbon costs;
- variable non-fuel costs;
- annual fixed costs;
- capital investment costs;
- assumed hurdle rate (i.e. cost of capital, or target IRR); and
- annual load factor (if LRMC is to be expressed in £ per MWh).

As part of the modelling process, we compare the achieved IRR of the plant (based on its modelled revenues) with its target IRR. If a technology achieves a return above its target, it suggests that it would be profitable for more of that plant to be built. Such an event encourages more plant into the market, which then decreases the IRR (and load factors) back towards the target level.

Therefore, higher load factors for low-carbon plant (as a result of improved system flexibility) may not be necessarily sustainable – they may simply allow more of it to be built which then drives down the average load factor.

The shape of wholesale prices would be determined by the assumptions about the recovery of fixed and capital costs. In order to support the construction of peaking generation, we assumed a capacity payment was made – this would reduce the range of

prices across the year (because very low load factor plants do not need to make all their money in a couple of periods) but makes the profile of prices sensitive to how that capacity payment is spread across the year (e.g. related to either the observed capacity margin or demand, or following a fixed ex-ante profile).

It is assumed that wholesale prices can only be used to recover the cost of generation. Therefore, the non-generation costs shown in Table 8 would either feed through into retail prices (possibly via network price controls) or would be borne as investment costs by customers.

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# 4. REQUIREMENTS FOR FLEXIBILITY

Flexibility helps to match generation to demand over a range of timescales stretching from the provision of capacity at the year-ahead stage to meeting within-hour requirements for reserve and response. This chapter presents a number of different measures that in combination help to illustrate the requirements for flexibility in different low-carbon worlds with:

- higher levels of intermittent generation, such as wind;
- more variable sources of demand, particularly for heating; and
- other forms of low-carbon generation, such as nuclear and CCS, wanting to run at or close to baseload.

The combination of these three factors means that increasingly any average measure of the requirement for flexibility only tells part of the story. The *Zephyr* model goes beyond the average to provide insight into the combination of circumstances that put particular strain on the system. This could range from:

- meeting large hour on hour swings in requirement for non-intermittent generation;
- coping with several days of high demand net wind as result of still weather conditions;
- dealing with high levels of wind generation at times of low demand; and
- accommodating large seasonal variations in peak demand levels.

This means that we can look not just at how flexibility can reduce peak capacity requirements but how also flexibility can change the running patterns of different generation plant over an entire year, thereby changing the investment case for low-carbon generation.

This chapter first discusses the key drivers of the required mix of flexibility in the low-carbon energy future, before presenting different measures of the requirement for flexibility over different time periods.

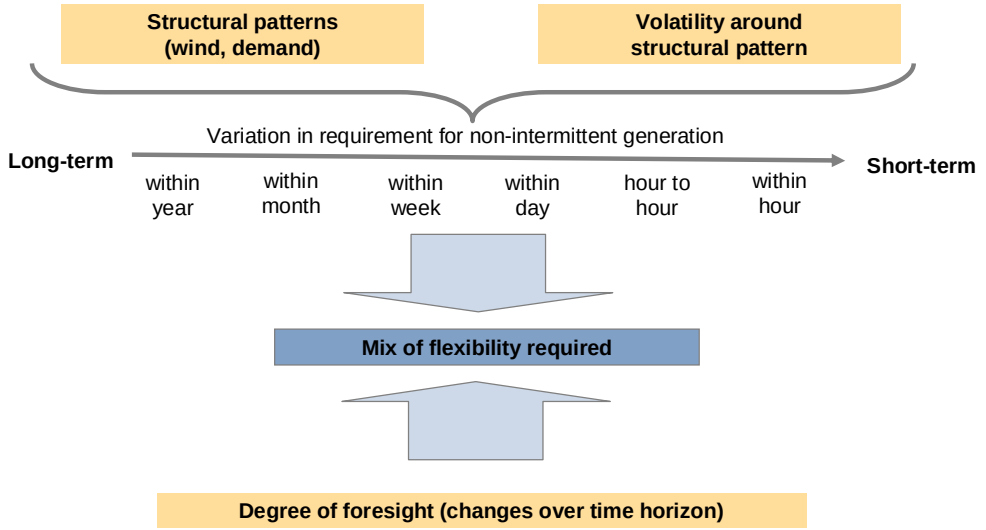
## 4.1 Drivers of flexibility

There are three key drivers of flexibility within the power system:

- compatibility of structural (i.e. typical) patterns of demand and generation;
- random deviations from structural profile of demand and generation; and
- degree of foresight of deviations from expected profile.

Figure 8 shows how these factors combine to produce flexibility requirements over a range of timescales. This illustrates that the flexibility challenge is not just restricted to the ability to change supply and/or demand quickly as duration is also important.

**Figure 8 – Drivers of requirement for power system flexibility**




### *4.1.1 Structural pattern of demand*

The structural profile of electricity demand can be considered over three key timescales – within-day, within-week (i.e. working day versus non-working day) and the monthly profile. The overall electricity demand profile is a weighted composite of the profiles of electricity demand from different end uses such as entertainment, industrial processes, cooking (or catering), lighting, refrigeration and cooling, heating and transport. The contribution of each of these end uses to overall electricity demand varies over time (during the day, between days, and across the year).

The overall electricity demand profile has the following key features:

- **Significant variation in demand across the day** – the exact shape of the within-day demand profile varies according to the day of the week and the time of the year. Typically, demand is lowest overnight with peak demand occurring in the early evening. There is normally a secondary peak in the morning at about 8am.
- **Demand is higher on working days rather than non-working days** – residential electricity demand is a much higher proportion of overall demand on non-working days and itself has a different profile with less pronounced morning and evening peaks.
- **Demand is higher in winter than in summer** – this is driven by a number of factors, including higher demand for lighting and heating. At the moment, the low penetration of space cooling means that demand is at its lowest in summer months.

Electrification of heat and transport, combined with a decarbonised electricity generation sector, is seen as being key to delivering a low-carbon energy system. Earlier this year, the Department of Energy and Climate Change (DECC) set out six low-carbon pathways to 2050 – all assume a significant degree of electrification of heating and transport[29].

29 '2050 Pathways Analysis', Department of Energy and Climate Change, July 2010.

For most end uses, the electricity demand profiles are determined by the underlying energy demand profile. For example, changes in the electricity demand profile for lighting are driven by changes in the timing of sunset across the year. Where storage is available, such as for heating or for electric vehicles, energy demand can be decoupled from electricity demand. This leads to greater flexibility (and uncertainty) in the electricity demand profile, particularly within-day.

Table 9 shows how different types of demand are influenced by weather. It illustrates how, in particular, more electric heating would increase variability of electricity demand by linking it more strongly to temperature[30] and to wind. Where demand increases with wind, this would help to offset the variability of wind generation, but the gap between electricity demand and wind output would be wide on cold and still days. This impact is worse for heat pumps because their coefficient of performance is also inversely linked to the difference between internal and external temperatures. This can be seen most clearly in the 2030 world with electrification (CF 2), where heat pumps play the largest role in any of the four counterfactuals.

**Table 9 – Impact of weather on demand by category**

| | Wind speed | Temperature | Sunshine |
|---|---|---|---|
| Transport | 0 | ? | ? |
| Space cooling | -ve | +ve | +ve |
| Space heating | +ve | -ve | -ve |
| Water heating | +ve? | -ve? | -ve? |
| Refrigeration/cooling | -ve | +ve | +ve |
| Cooking/catering | 0 | -ve? | 0 |
| Lighting | 0 | 0 | -ve |
| Motive power, Washing, Entertainment, Processes, Computing | ? | ? | ? |

30 Heat pumps could also be used to facilitate space cooling, which would create a positive correlation between electricity demand and temperature in summer months.

There are two reasons why electricity demand from electric vehicles may change as a result of variations in wind speed, temperature and/or sunshine. The first is a change in the driving pattern and the second is a change in the distance achieved per kWh of charge (which will vary from day to day around an underlying seasonal pattern). For this study, it was agreed with the CCC that electricity demand from vehicles would be assumed to be spread evenly across the year.

Electrical power will be diverted to the car heating systems in cold weather and to powering air-conditioning units in warm weather. Consequently, there would be a non-linear relationship between outside temperature and the distance achieved per kWh of charge, which would depend on a number of factors including the relative efficiency of heating and cooling systems, level of desired inside temperature, and where the car is parked (e.g. in a garage or not). There has been much less detailed quantitative analysis carried out on the daily pattern of use of heating and cooling systems in cars, as opposed to buildings. As a result, it was not possible to establish a sufficiently robust relationship between temperature and electricity vehicle demand within the scope of this study.

Sunshine will affect the electrical demand from vehicles in two ways – through the use of headlights and then through the use of cooling to offset the warming effects of direct sunshine (beyond just temperature-driven cooling). Just as in the home, changes in the timing of sunrise and sunset over the year will affect the demand for lighting for vehicles. The challenge is to map the available data on daily and weekly driving patterns to the hourly pattern of driving demand for different types of users. For example, for a high user who drives almost entirely in daylight hours, the impact of additional headlight use on electricity demand may be proportionately small. In contrast, a low user who uses their car for the daily commute may do most of their driving in winter in the dark, which could make additional headlight use proportionately more important than for a high user. This study did not attempt to produce a robust relationship between sunshine[31] and electricity demand from vehicles.

### *4.1.2 Structural pattern of generation*

Typically, the generation fleet has been dominated by plant that can largely follow the pattern of demand. However, in the future, an increasing proportion of the generation mix could find it more difficult to operate in this way, either because of:

- economics – high capital costs mean that the plant is best suited to operating at or close to baseload (e.g. nuclear plants, CCS plants); or
- variable availability of ‘energy source’ – for example, wind availability is variable throughout the year.

In theory, a strong positive correlation between the structural profiles of wind output and demand could reduce the requirement for extra generation capacity, particularly if peak wind generation coincides reliably with peak demand. In practice, however, there is only a weak relationship between wind and demand. Figure 9 compares wind generation and demand in each hour for the reference case for the 2030 world with electrification (CF 2). This shows no clear relationship between demand and wind in each hour. High wind levels occur frequently both at periods of peak demand and at periods of low demand. Similarly, output from wind is close to zero at hourly demand levels ranging from 25GW to nearly 70GW, which nearly covers the full range of demand across the whole year.

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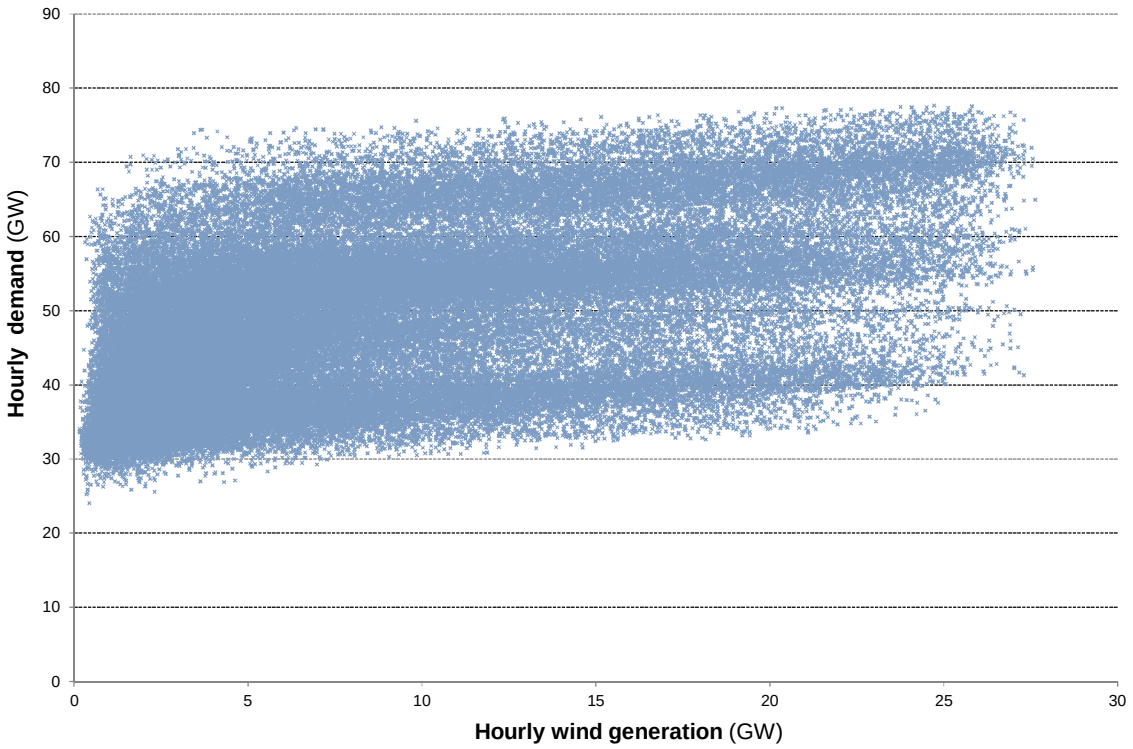
31 Based, for example, on hourly solar irradiation data.

**Figure 9 – Pattern of hourly demand and wind generation**
(GW, Counterfactual 2, reference case)




Below is a summary of average wind patterns according to the same categories as used earlier for demand:

- **Average output from onshore wind farms does vary across the day (**Figure 10) – output increases during the day before dropping off again overnight. Peak wind generation in the mid-afternoon broadly coincides with peak demand in the early evening. The timing of peak generation moves between seasons, with autumn and winter exhibiting peaks at earlier times of the afternoon, while spring and summer periods exhibit peaks in capacity factor later in the afternoon.
- **The average level of output is broadly stable within-day for offshore wind farms** (Figure 10) – this reflects the greater stability in sea temperatures compared to land temperatures.
- **There is no difference in average wind patterns on working days and weekends.**
- **Higher and more consistent wind speed regimes are seen in winter than in summer** (Figure 11).

**Figure 10 – Average within-day profile of wind generation**
(% load factor, Counterfactual 2, reference case)

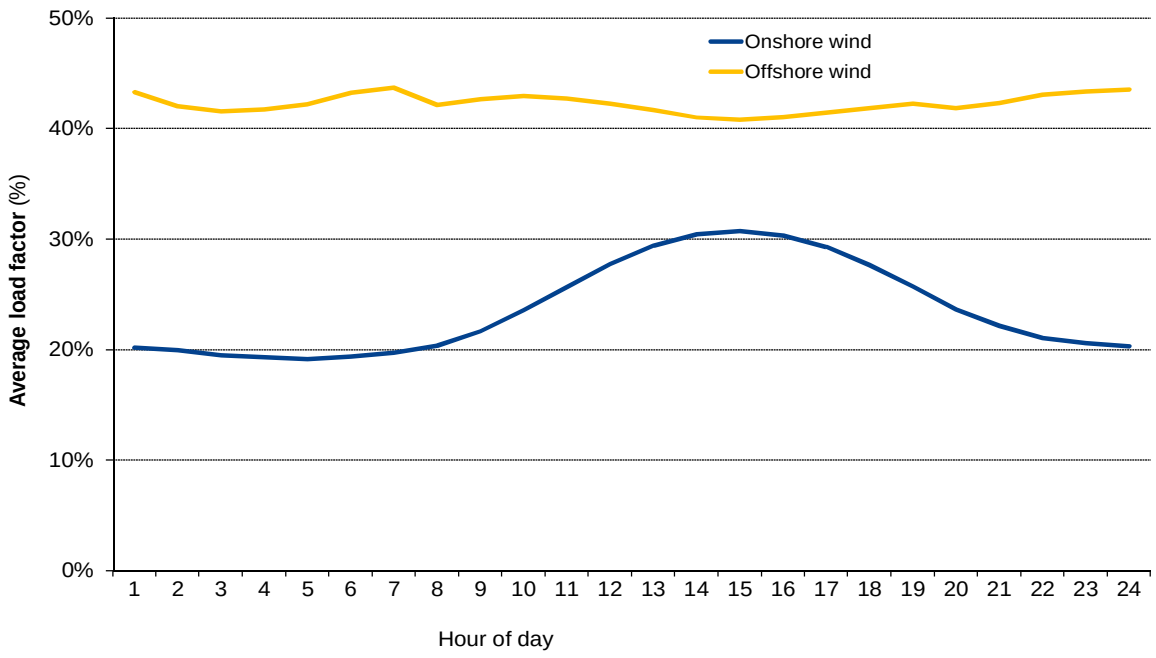
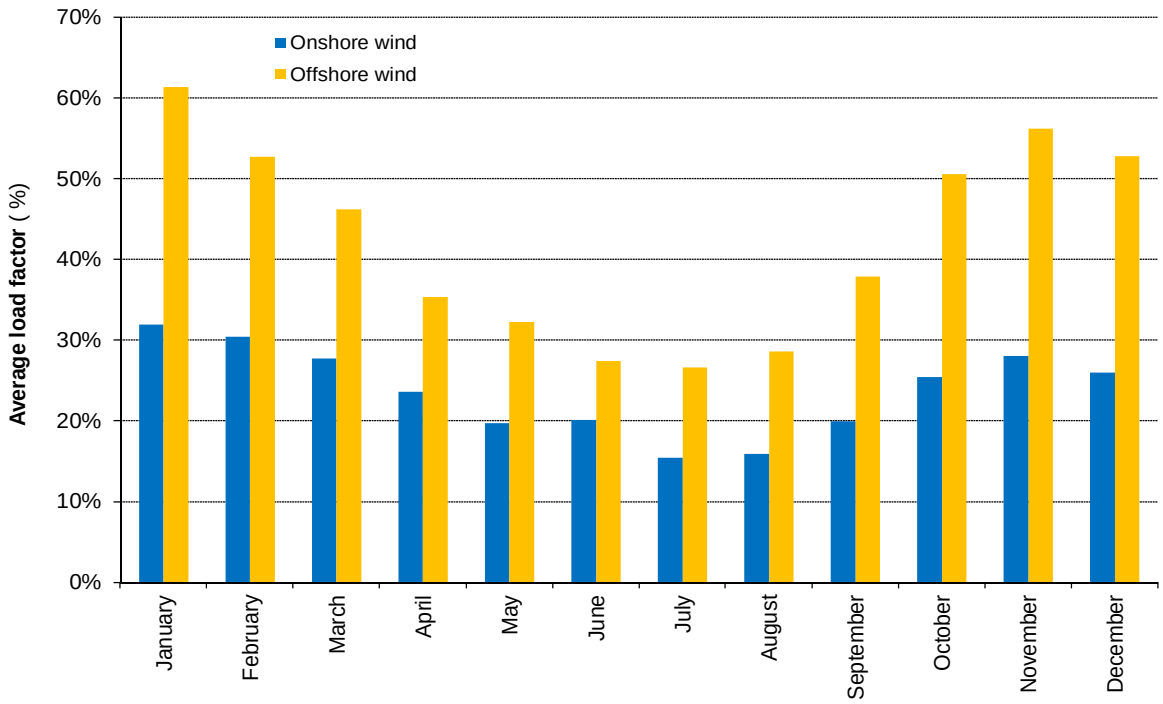



**Figure 11 – Average monthly load factor for wind generation**
(% load factor, Counterfactual 2, reference case)



The fall in wind speed overnight and the higher levels of wind generation in the winter suggests that on average, increased wind deployment would at least partially offset the higher demand from heating. However, the significant variation in the wind away from its structural profile means that the average picture only tells part of the story.

### 4.1.3 Deviations from structural profile

The electrification of heating would increase the variability of demand away from its structural profile because demand becomes much more strongly linked to weather conditions that are variable, compared to for example the predictable changes in lighting-up time over the year.

Monthly average temperatures can be used to project average monthly demand but there are significant within-month temperature variations. Consequently, the coldest spell of the year may not be in the same month every year and may well not be in the coldest month of the year.

At the same time, although an underlying pattern can be identified for wind output, it exhibits significant variations away from this pattern. In comparison, for thermal plant, forecast errors are normally the result of forced outages which typically account for only a small proportion of installed thermal capacity at any one time. Furthermore, the outages of thermal plant tend to be extended so that availability of an individual plant tends to be digital (i.e. on or off). In contrast, the level of availability of a wind farm varies along an analogue spectrum (i.e. between 0 and 100%).

This means that efforts to improve the match between the structural patterns of demand and generation would at best solve only part of the flexibility challenge as flexibility still needs to be provided to deal with deviations from the structural patterns. For example, an (unexpected) cold, still spell of weather in the winter would reduce wind output but increase heating demand.

At worst, concentrating efforts on aligning the structural profiles (e.g. through using ex-ante demand tariffs to flatten the within-day demand profile) could divert attention from delivering responsiveness to deviations from the structural profile, which become increasingly important as wind penetration grows.

### 4.1.4 Degree of foresight of deviations from structural profile

Better forecasting of deviations from the structural profile of demand and generation would improve the notice that can be given to different sources of flexibility and the degree of certainty about the required duration of the flexibility. This would increase the range of possible sources of flexibility.

For example, storage, whether bulk or demand side, needs to be filled up before it can be used to meet electricity demand. If forecasting of demand net wind improves, then these periods of injection and withdrawal can be much better optimised, which would boost system efficiency.

Different measures could be used depending on whether an unexpected change in demand net wind is expected to be temporary or sustained. A more sustained change may tend to favour flexibility from the turning on or off of generation plant (even with long on and off times) compared to the use of storage which may be able to provide fast response but not a sustained response over several days (because of constraints on storage size).

At present, the evolution of the level of certainty is definitely not linear – for example, forecast wind speeds at the month-ahead stage are little better than at the year-ahead stage. However, they improve rapidly from a few days ahead of the period in question.

## 4.2 Requirements for flexibility

There are a number of drivers to the requirement for flexibility, which are primarily average (or structural) variations in demand and/or wind during a particular period, and magnitude and predictability of deviations from the average pattern (as discussed in Section 4.1).

This section describes the requirement for flexibility in the reference cases, which provide a baseline before the application of any of the flexibility packages. The analysis covers the following timescales as the need for flexibility cannot be captured in a single figure:

- across the whole year;
- from month to month;
- within the week;
- within the day; and
- from hour to hour.

The charts in Section 4.2.1 illustrate the **average range** of the variation in demand and demand net wind within-year, within-month, within-week and within-day. This provides insight into the extent of expected swings in output required from (non-intermittent) generation over the relevant time period.

In general, these show that:

- looking across the whole year, there is a larger range in demand net wind than in demand, with the difference largest at highest penetrations of wind;
- the higher levels of wind output **on average** in winter months and within day (as shown in Figure 10 and Figure 11) mean that the range of demand net wind is smaller than the demand range, when comparing both monthly **averages** and the **average** within-day profile[32]; and
- the range of variations from average figures (which is one aspect of unpredictability) is greater for demand net wind than for demand because of the intermittent nature of wind.

Building on the analysis of ranges, Section 4.2.2 looks in more detail at the relative frequency with which the system has to cope with high or low levels of demand and demand net wind. In general, the more stable the level of demand net wind, the greater the amount of non-intermittent generation, such as nuclear, CCS coal and CCS gas, that would be expected to be able to operate at high annual load factors.

We look at the hourly duration curves for demand (Figure 16), wind (Figure 17) and demand net wind (Figure 18) in each reference case. These show that electrification

32 This is supported by Figure 24 in Section 4.2.5 which shows in more detail the average pattern of demand and demand net wind across the day for the reference case for the 2050 world with CCS (Counterfactual 3).

makes demand peakier, primarily as a result of the electrification of heating demand, which is highest (in the reference case) in winter evenings[33]. At the same time,

the hourly load factor of wind varies between zero and approximately 90%, which means that the range of wind output across the year increases with the amount of installed capacity.

The demand net wind duration curves for both 2050 worlds (CFs 3 and 4) are much steeper than for 2030, and could mean that at least 50GW of non-intermittent generation could be required to operate at annual load factors below 50%. Because the capital costs of low-carbon are typically high and the variable costs are low, the investment returns are very sensitive to the achieved annual load factor. Lower expected load factors could undermine deployment.

The stability of the level of demand and demand net wind is explored in more depth in Sections 4.2.3 and 4.2.4, which analyse changes in demand and demand net wind from hour to hour and day to day (in the 2030 world with electrification). These show the importance of the wind in driving changes in demand net wind between days, particularly once the (predictable) shifts between business days and non-business days are taken into account.

Demand appears to be a much bigger driver of hourly changes in demand net wind because the distribution of the hourly changes look very similar for the two 2050 cases. These have the same level of demand but over 20GW difference in installed wind capacity. However, this does not mean that the predictability of the hourly changes is the same in the two cases.

As shown in Section 4.2.5, (for the reference case for the 2050 world with CCS), the average within-day profile of demand follows a recognisable shape of being low overnight, then rising in the morning before peaking in the evening (even if the exact timing of the peak varies by time of the year). The within-day profile of demand net wind is much more variable than for demand which will reduce the degree of predictability of the hourly changes in demand net wind.

The unpredictability of wind is then highlighted in Section 4.2.6, when we use *Zephyr* outputs to look in more detail at the hourly pattern of demand and demand net wind for two weeks, one in the winter and one in the summer. This provides an insight into predictability through the use of nine different annual profiles for demand, wind and availability.

This shows that variations in hourly demand within the week can be large, with the range of hourly demand figures being more than 20GW in the reference case for the 2030 world with electrification (CF 2). However, these swings follow a regular shape within-day and from day to day (in line with the pattern described in Section 4.1.1), and are accommodated through changes in the operation of CCGTs primarily as well as peakers (which effectively shut down overnight and at weekends).

The pattern of wind output is much more variable across the week, with days of very low wind output followed by days of high wind output. When the wind level increases, this then leads to a reduction in output from low-carbon generation (nuclear and CCS) that is designed to run as baseload plant in the reference cases. Therefore, the variability of

33 In contrast, electricity demand from electric vehicles is assumed to be baseload in the reference case which means that it moves the whole curve upwards and does not affect the slope (or 'peakiness') of the demand duration curve.

wind generation (rather than variability in demand) is the key driver of changes in the day-to-day operation of these plants.

### 4.2.1 Average variations in demand and demand net wind

We start with a set of summary charts for each reference case that show the variation[34] in average demand and requirement for non-intermittent generation (strongly driven by the pattern of demand net wind) measured over different time periods:

- **Range of hourly requirement across all Monte Carlo years (78840 observations)** – the difference between the maximum and minimum hourly figures for demand and for non-intermittent generation across all nine Monte Carlo years, with the range being driven by structural profiles within-year, and deviations from structural profile within-year and between years.
- **Average range of hourly requirement within a Monte Carlo year** – this is derived from the average minimum and maximum hourly figure across the MCs.
- **Range of average hourly figures for each month (12 observations)** –variation in average hourly demand each month shows the importance of structural seasonal variations in driving the range of hourly demands seen within the whole year.
- **Range of average hourly figures for business days, Saturdays and Sundays (3 observations)** – this shows how on average the daily level of demand and demand net wind changes across the week.
- **Range of hourly figures within average day (24 observations) –** this shows the average variation within-day in demand and demand net wind.
- **Deviation of hourly requirements from structural profile (78840 observations)** – this illustrates how far the actual figure for each hour of each Monte Carlo year deviates from the average figure for that hour (based on time of day, day of week and month of year). This highlights how analysis of the average periods only captures part of the picture for flexibility requirements.

Figure 12 shows the variations for the 2030 low-carbon world without electrification (CF 1).

There is a difference of 45GW between the highest and lowest hourly demand seen across all 8 Monte Carlo years. Removing the impact of variations between Monte Carlo years, the average difference between the maximum and minimum demand in a year is 41GW (see second set of columns).

In this counterfactual, heating accounts for just over 10% of electricity demand, which is less than in the current mix. Consequently, there is only limited seasonal variation with a difference of 5GW between average hourly demand in the highest demand month and the lowest demand month. This is smaller than the difference in average demand between a working day and a Sunday (7GW).

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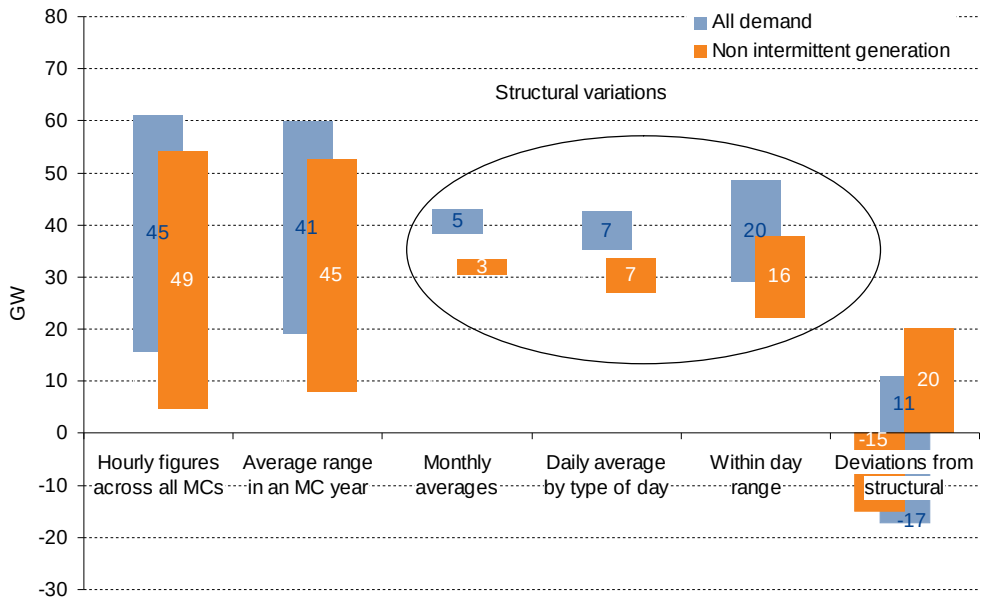
34 The variation is shown as the full range because for the hourly figures (first and last column) is to understand the importance of the low-frequency, extreme events that are going to provide very important challenges for the electricity system with more variable (but potentially less flexible). Where averages are shown for different periods (the middle columns), showing the range illustrates how minimum and maximum levels vary by counterfactual.

Within an average day in the reference case for the 2030 world with electrification, hourly demand can vary by up to 20GW (fifth set of columns). Finally, the deviation from the average demand in a particular hour (based on time of day, day of week and time of year) can be as much as +11GW or -17GW.

**Figure 12 – Variations chart for 2030 with no electrification**
(Counterfactual 1, reference case)




These variation charts also highlight the extent to which the requirement for net intermittent generation is more or less variable than demand alone. As expected, in all cases (first five sets of columns), the top of the orange bar is below the top of the blue bar which means that the maximum requirement for net intermittent generation is lower than maximum demand, For the first two columns, this means that there is some output from wind at times of annual peak demand. For the average measures (columns three to five), the difference between the top of the blue and orange bars show that wind is greater than zero (on average) during the period with maximum demand (be that a month, day or hour).

However, the range of requirements for net intermittent generation across the year is greater than the range of demand (first two sets of columns). As wind output is higher on average in the winter and during the afternoon and early evening (as discussed in 4.1.2), the range of output from non-intermittent generation between months (third set of columns) and within-day (fifth set of columns) is on average a little narrower than the range of hourly demands.

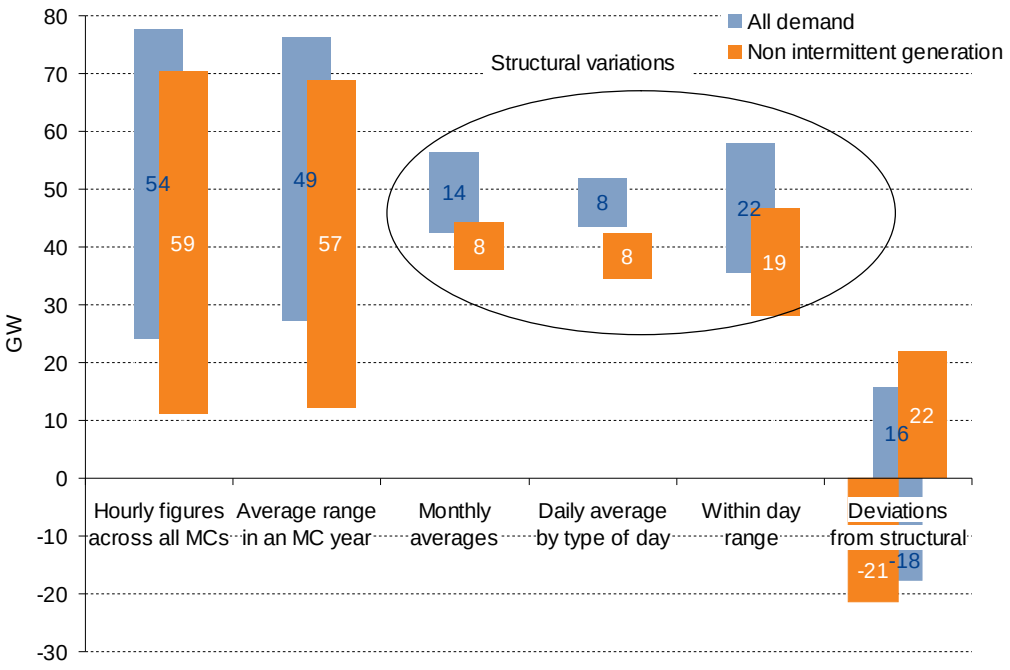
The range in average daily requirement for non-intermittent generation across the week is the same as for demand – this is because the wind output does not vary on average between working days and the weekend. Finally, the deviation from the 'average' requirement for non-intermittent generation is of a similar magnitude to that for demand.

In summary, the relatively low levels of wind and electrification in Counterfactual 1 mean the main variation in requirement for non-intermittent generation is driven by the shape of the within-day demand profile. The variable pattern of wind increases the range of hourly

figures for non-intermittent generation, compared to demand, across the year, but reduces the average variation.

Figure 13 shows the pattern of variations in demand and in non-intermittent generation for a 2030 world with electrification of heat and transport (CF 2). Installed wind capacity is 31 GW, only slightly higher than the 29GW figure in Counterfactual 1.

**Figure 13 – Variations chart for 2030 world with electrification**
(Counterfactual 2, reference case)




The impact of electrification can be seen in the increase in the range of demand, both across the year but also seasonally, with the range in monthly average demand increasing to 14GW, compared to 5GW in Counterfactual 1. This drives an increase both in the range of demand across the year, and in the range of non-intermittent generation.

The two 2050 counterfactuals have the same mix and level of annual demand, which is met by a different generation mix, with Counterfactual 4 having 69GW of wind (and marine) installed compared to 46GW in Counterfactual 3. The variation charts therefore illustrate the impact of higher wind penetration on variations in non-intermittent generation.

Figure 14 and Figure 15 illustrate the magnitude of the flexibility challenges raised by the variability of demand with a high degree of electrification, particularly of heating. The range in average monthly demand is 30GW, double the range in the 2030 world with electrification (CF 2). Within an average day, hourly demand can vary by up to 44GW, which is again twice the range seen in Counterfactual 2.

It was agreed with the CCC that in all four counterfactuals, the electricity demand from vehicles would be assumed to follow a baseload pattern. If the charging profile was peaky (i.e. by being concentrated into periods immediately before and after normal working hours) and seasonal (for example, with heating and headlights in winter increasing electricity consumption for the same mileage), then this would further extend the range of

electricity demands across the year and within-day. The effect would be most marked in the two 2050 cases, which have high electricity demand from vehicles.

Higher levels of wind in Counterfactual 4 dampen the seasonality of the requirement for non-intermittent generation. However, there is no difference in the within-day range, reflecting that most of the additional wind is offshore which has a relatively constant within-day pattern. Also, higher levels of wind are associated with a large range of hourly demands in average year, with the range being 106GW in Counterfactual 4 compared to 103GW in Counterfactual 3. Most strikingly, the high wind world has a much larger range of deviations from average demand (based on hour of day, day of week and time of year), which suggests at least greater unpredictability over a longer forecast horizon. As a prediction based on the time of day, day of week and month of year would only be accurate to within this range of deviations, this highlights how averages may not be a good predictor of actual demand.

**Figure 14 – Variations chart for 2050 world with CCS generation**
(Counterfactual 3, reference case)

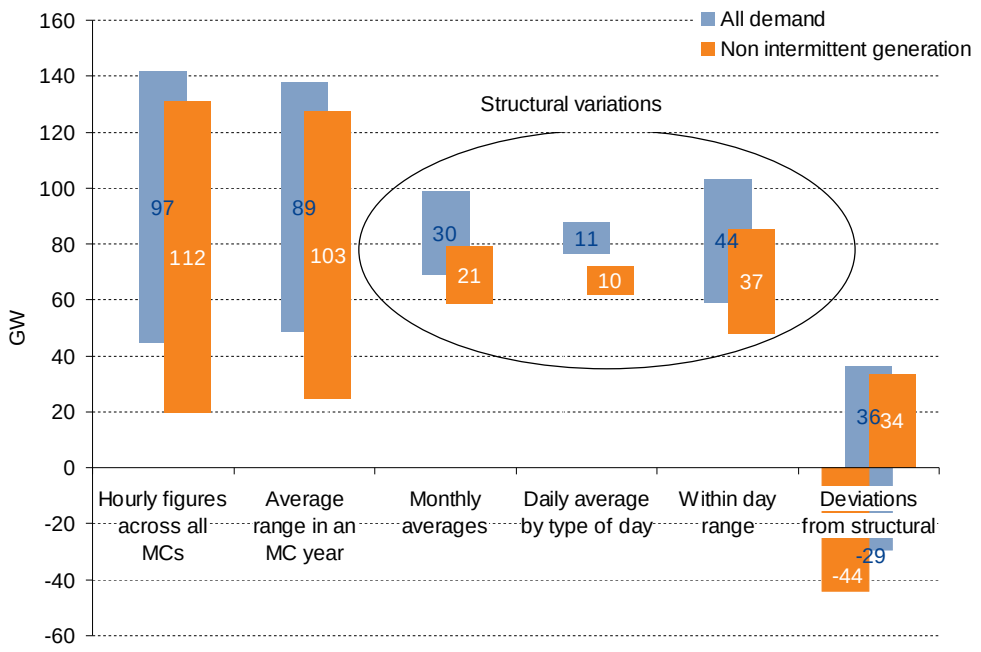
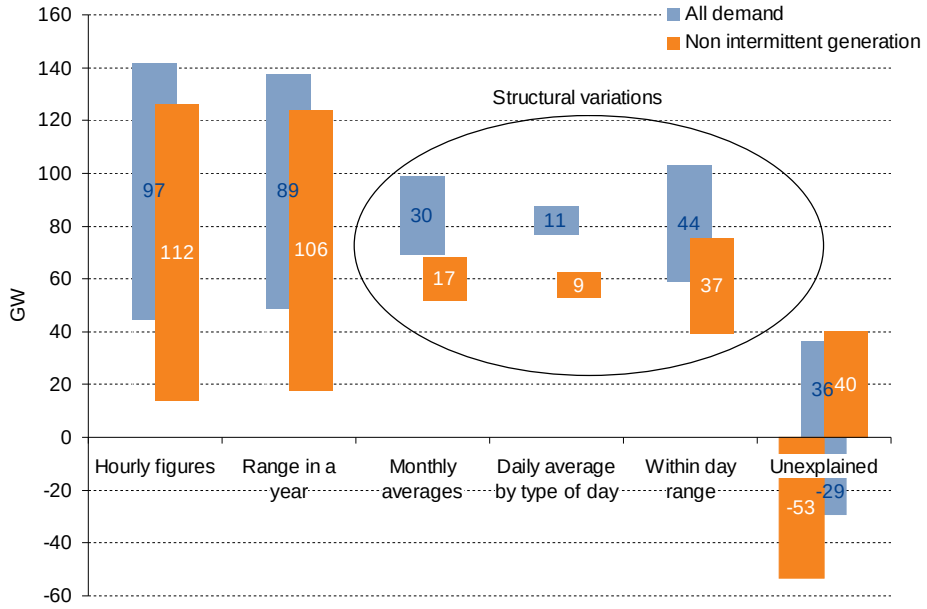


**Figure 15 – Variations chart for 2050 world without CCS generation**
(Counterfactual 4, reference case




### 4.2.2 Requirement for flexibility within-year

Looking at duration curves can help us to understand the distribution of values across the whole year, including the extent to which minimum and maximum values are outliers. For the reference case for each counterfactual, this section presents hourly duration curves for demand[35] (Figure 16), wind (Figure 17) and demand net wind (Figure 18).

The relative steepness of the curves in Figure 16 illustrate that electrification makes demand peakier. This is primarily as a result of the electrification of heating demand, which is highest (in the reference case) in winter evenings[36] – the same time as the existing system peak. The effect on peak demand can be seen in the way in which the duration curve for the 2050 cases becomes much steeper on the left hand side of the chart (which contains the hours of peak demand) than on the right hand side.

Figure 17 demonstrates the annual range of hourly wind output increases how the hourly load factor of wind varies between zero (on the right hand side of the curve) and approximately 90% (on the left hand side of the curve). This obviously means that the range of wind output across the year increases with the amount of installed capacity. In the case with highest installed capacity of wind, output can vary from 10GW to 40GW in the middle 50% of hours (i.e. excluding the top and bottom 25% of hours), which shows the extent of wind variability and the consequent challenges for system management.

35 The two 2050 worlds (Counterfactuals 3 and 4) have the same demand assumptions and hence identical duration curves.

36 In contrast, electricity demand from electric vehicles is assumed to be baseload in the reference case which means that it moves the whole curve upwards and does not affect the slop e (or 'peakiness') of the demand duration curve.

**Figure 16 – Annual duration curve of demand** (reference cases, GW)

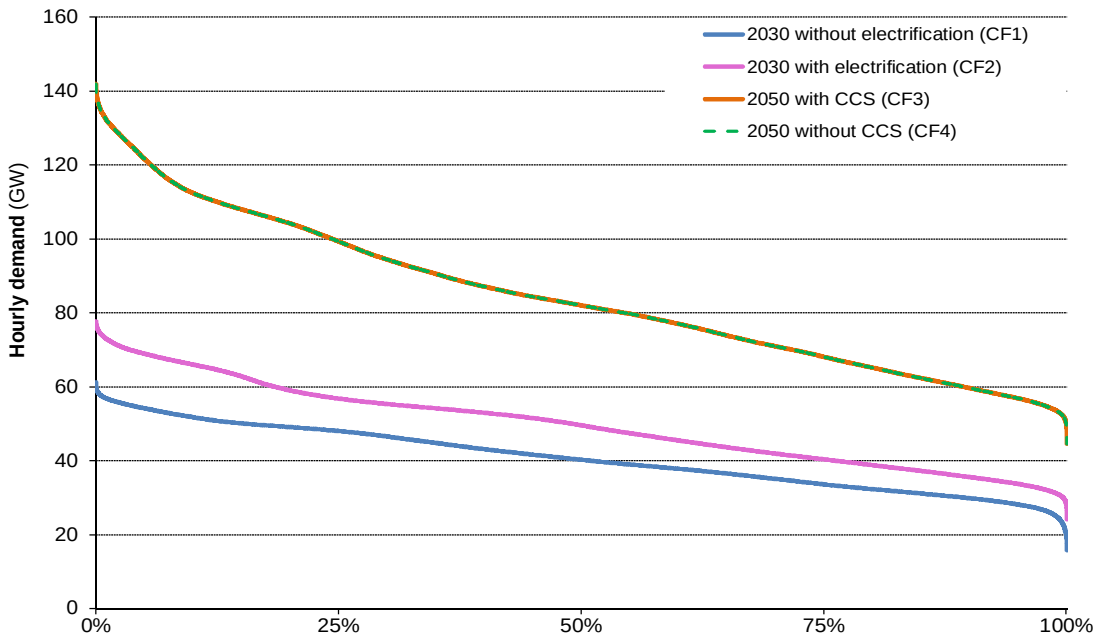
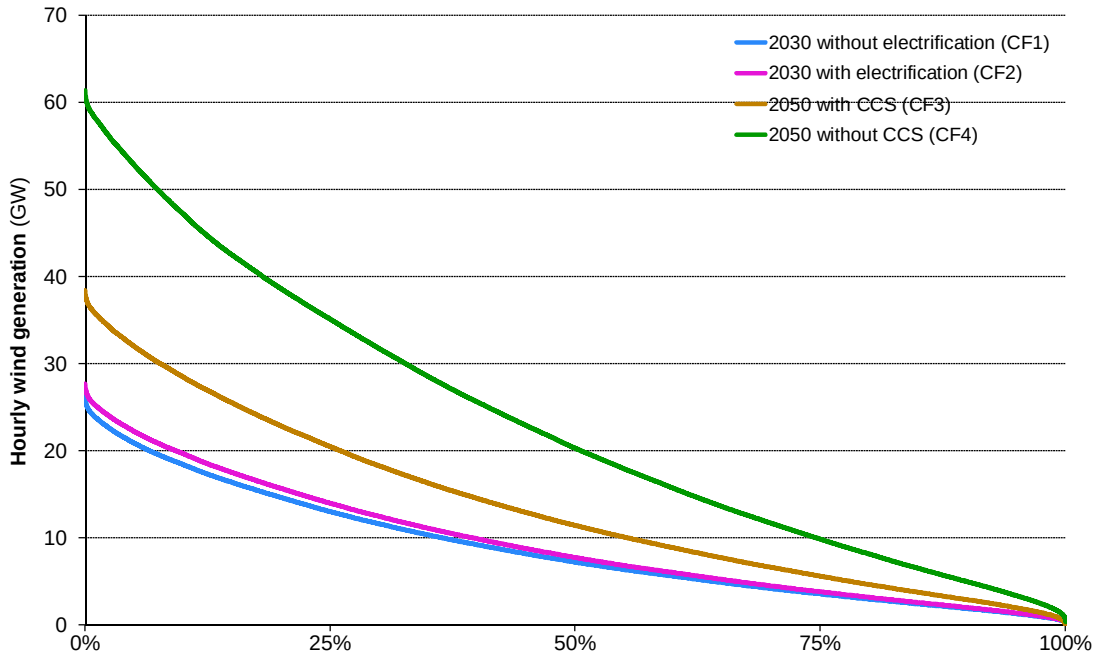



**Figure 17 – Annual duration curve of wind generation** (reference cases, GW)




The demand net wind duration curve shown in Figure 18 is calculated by subtracting total wind output in a particular hour from the demand in that same hour. These resulting values are then ranked to produce the duration curve. Figure 18 cannot be produced by

simply subtracting the duration curve for wind (Figure 17) from the demand duration curve (Figure 16) because the highest demand hour will not coincide with the hour with the highest wind output.

The left hand end of the duration curve shows the peak requirement for non-intermittent generation, whereas the right hand end provides an insight into the baseload requirement. In general, the flatter the duration curve, the higher proportion of non-intermittent generation, such as nuclear, CCS coal and CCS gas, that would be expected to be able to operate at high annual load factors.

However, the distribution of the operating pattern through the year also matters – for example, the annual duration curve does not indicate whether all of the periods of low values for demand net wind happen overnight throughout the year or for extended periods during the summer. *Zephyr* is able to capture these issues in the modelling process.

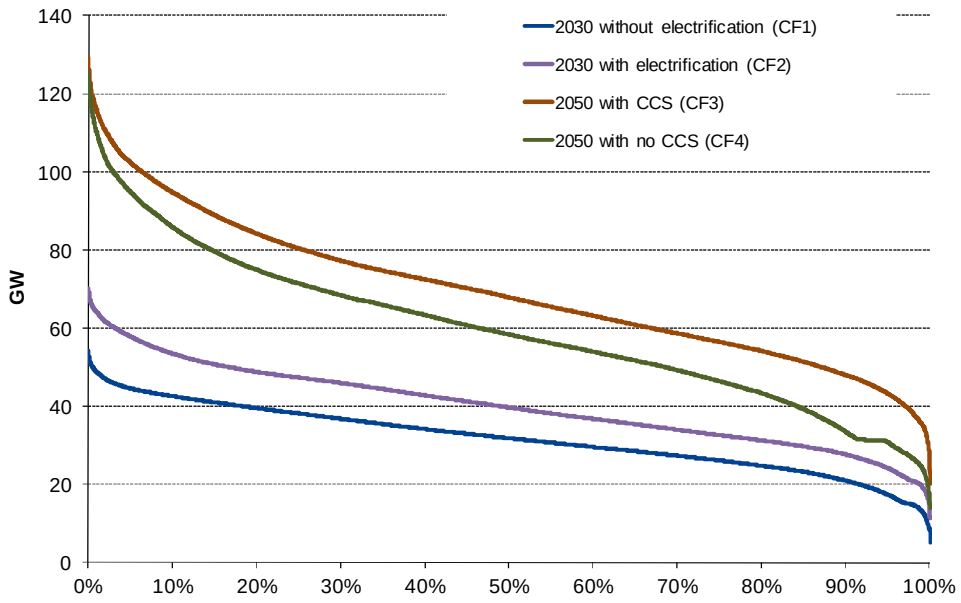
Electrification of heat and transport pushes up the demand net wind duration curve for the 2030 world with electrification (CF 2) compared to the curve for the 2030 world without electification (CF 1). The gap is widest at times of peak demand net wind, which reflects the peakiness of heating demand in Counterfactual 2.

The steeper duration curve illustrates how greater seasonality in demand would reduce average annual load factors for low-carbon generation, such as nuclear, CCS coal and CCS gas. Because the capital costs of this type of generation are high and the variable costs are low, the investment returns are very sensitive to the achieved annual load factor: Lower expected load factors could undermine deployment.

The duration curves for both 2050 worlds (CFs 3 and 4) are much steeper than for 2030, and could mean that at least 50GW of non-intermittent generation could be required to operate at annual load factors below 50%. This is the result of the interaction of much higher levels of demand and installed wind capacity in 2050.

Furthermore, the duration curve for the non-CCS world (CF 4) is much steeper than for Counterfactual 3. This would further depress average annual load factors. The kink in the duration curve in Counterfactual 4 illustrates the challenge of balancing a system largely reliant on nuclear and wind. The kink is caused by the deloading of wind at times when nuclear output is unable to fall below its minimum stable generation.

**Figure 18 – Annual duration curve of demand net wind** (reference cases, GW)




### *4.2.3 Requirement for flexibility from hour to hour*

As well as the range of hourly demand net wind across the whole year, it is important to understand the size of short-term swings, as this would affect the extent to which fast-acting rather than long-lasting flexibility is required.

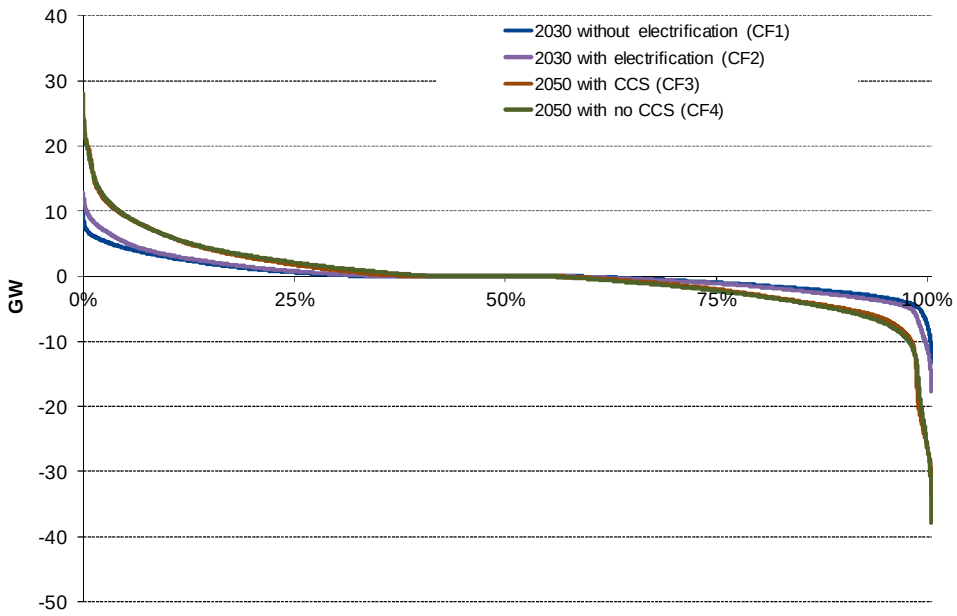
Figure 19 shows the change in the level of demand net wind from one hour to the next. This shows significant hourly swings in demand net wind, with the maximum hourly changes in demand net wind reaching 20GW in 2030 and 40GW in 2050. The impact of this on the system would depend on how predictable these swings are over different time horizons. This is influenced by the extent to which they are driven by the expected within-day demand profile or by fluctuations in wind.

The main difference in the hourly change in demand net wind between Counterfactuals 1 and 2 is at the left hand side of the curve, highlighting the impact of electrification of heating on the demand profile in peak periods in the reference case.

The duration curves for the two 2050 worlds (CF 3 and CF 4) are similar across most of the range. Although this shows a similar frequency distribution of the hourly change in demand net wind, it does not imply not that that the magnitude and direction of the change in demand net wind is similar in the same hour of the year in the two cases. More analysis would also be needed to establish whether the hourly changes were more predictable, and hence easier to manage, in Counterfactual 3 with lower offshore wind than in Counterfactual 4.

Although demand is the biggest driver of the hourly swings in demand net wind, the impact of bigger offshore wind capacity in Counterfactual 4 can be seen at the extremes – the maximum swings are +26GW and -34GW in Counterfactual 3, and are +32GW and -40GW in Counterfactual 4.

**Figure 19 – Hour on hour changes in demand net wind** (reference cases, GW)




Having looked at the variations in non-intermittent generation at either end of the modelling timescale (across the whole year and from hour to hour), we now look in more detail over the range of intermediate periods, starting with day to day, and within-day variations, before examining the dispatch pattern for a selected winter week and a selected summer week.

### *4.2.4 Requirement for flexibility from one day to the next*

Figure 20 shows the change in average hourly demand from one day to the next. The chart actually looks similar to the hour on hour variation shown in Figure 19, with one important difference. There is a much greater difference in the results for the two 2050 worlds in Figure 20 than in Figure 19. This shows that wind is an important driver of day to day variations in average requirement for non-intermittent generation. In contrast, the peakiness of the demand profile means that the level of hourly demand is more stable day to day than hour to hour.

Some of the day to day variation is predictable as it reflects shifts between business days and non-business days. The values for the day to day variation can be grouped into four categories:

- business day to business day (e.g. Tuesday to Wednesday);
- business day to non-business day (e.g. Friday to Saturday);
- non-business day to non-business day (e.g. Saturday to Sunday); and
- non-business day to business day (e.g. Sunday to Monday)

The variations for consecutive business days in Counterfactual 1 have been separated out and are shown in Figure 21. This shows how they are clustered around the middle of the range shown in Figure 20.

The following chart (Figure 22) shows the daily variations for the remaining three categories in the list above – this highlights that as expected, there is a systematic fall in demand between Friday and Saturdays with the points being concentrated on the right hand side of the curve. There is a further fall from Saturday to Sunday, before demand rises again as the working week starts (as shown by the grouping of the orange points on the left hand end of the curve).

This analysis illustrates that the significant variations in average daily demand shown in Figure 20 can be predicted to a reasonable extent, which reduces the challenge that they pose for flexibility.

**Figure 20 – Day on day change in average daily requirement for non-intermittent generation** (reference cases, GW)

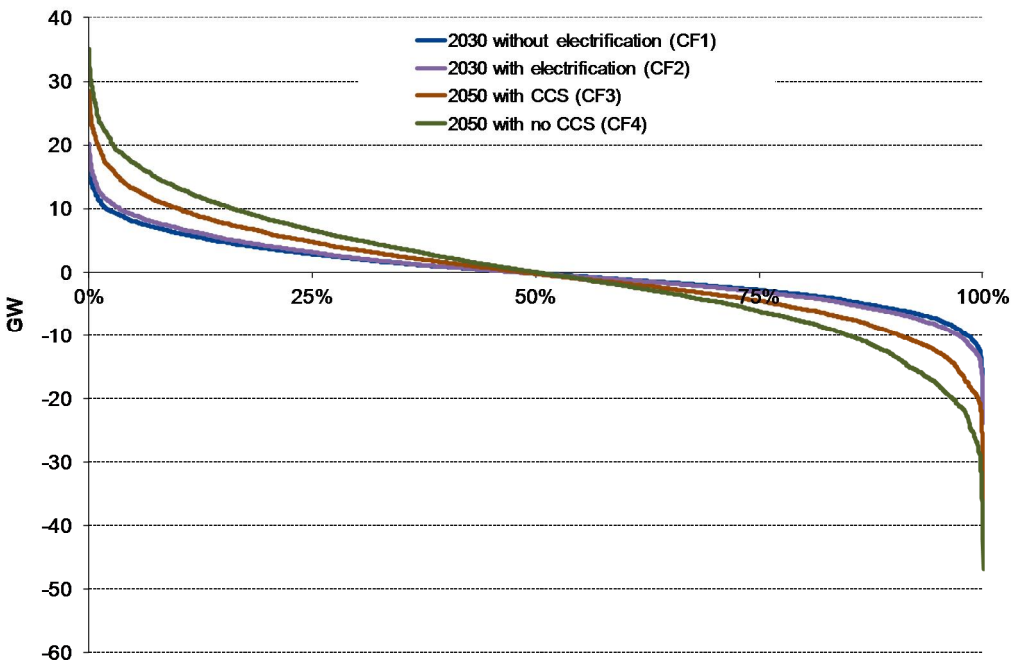


**Figure 21 – Changes between consecutive business days in average requirement for non-intermittent generation** (Counterfactual 1, reference case, GW)

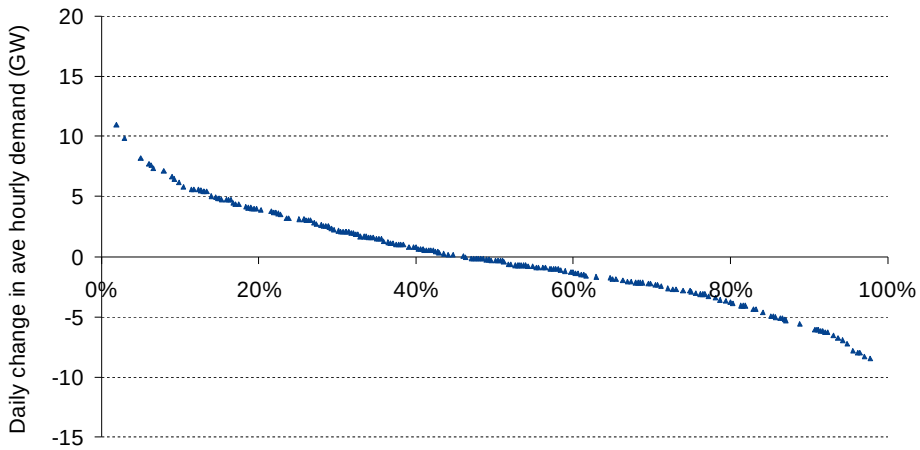
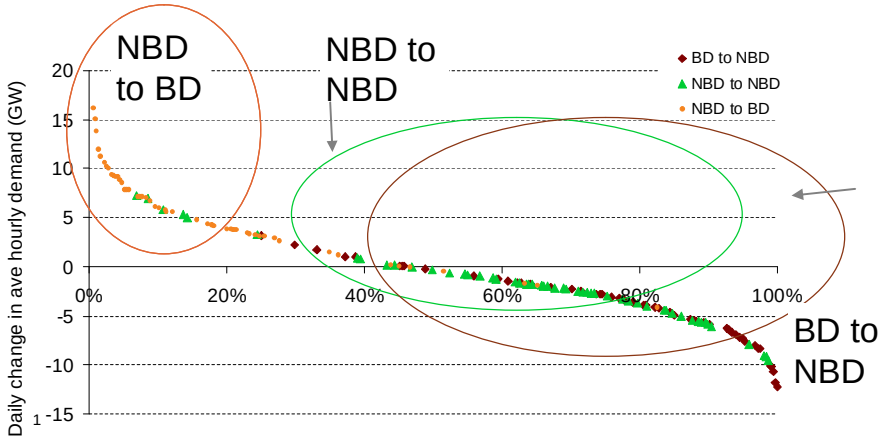



**Figure 22 –Changes in average daily requirement for non-intermittent generation not between consecutive business days**
(Counterfactual 1, reference cases, GW)

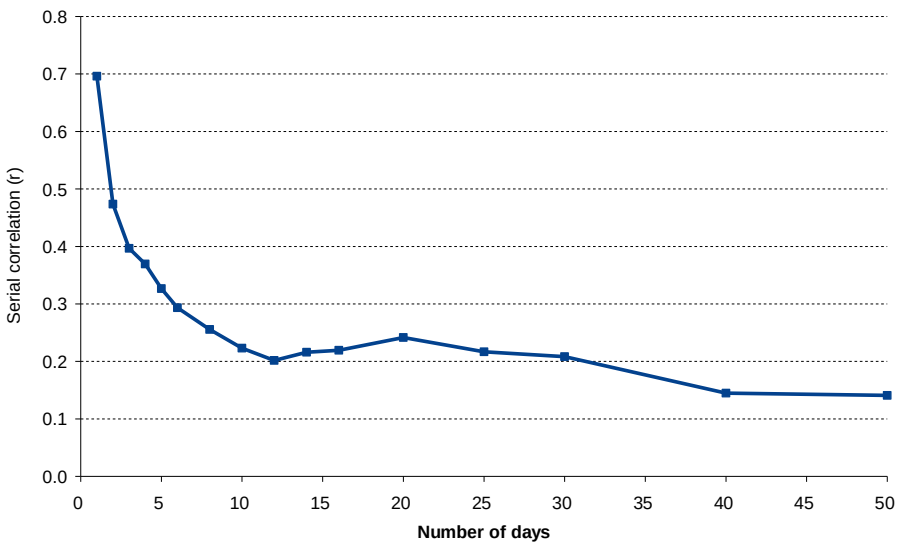



The persistence of wind levels over a number of days is also important in understanding the extent to which day to day variations in non-intermittent generation are predictable.

Figure 23 shows the serial correlation of daily load factors for wind – as expected, this falls off quite quickly after one day, which means that today's wind level is useful in forecasting tomorrow's wind level but quickly becomes increasingly less useful for predicting wind output further ahead.

This chart provides insight into the average persistence in wind output. In order to understand the likelihood of a multi-day period of high (or low) demand net wind, further analysis would be needed to explore whether and how the persistence patterns vary if wind is at particularly high (or low) load factors. The relationship with temperature persistence would also be needed to understand the prevalence of cold, still periods.

**Figure 23 – Serial correlation of average daily wind output**



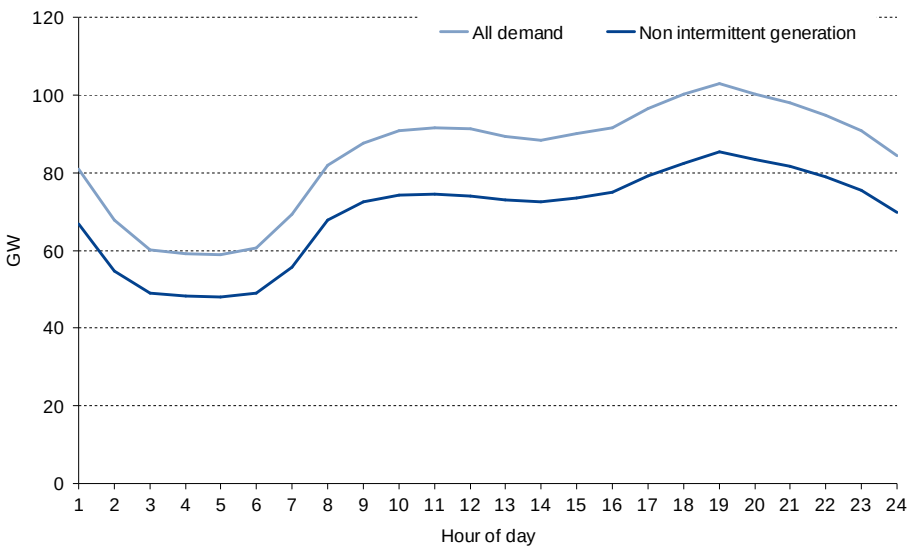

### *4.2.5 Requirement for flexibility across the day*

The within-day shape of demand in the reference cases, where most of the new heating demand comes on at peak times, is a key driver of the large hourly swings in the requirement for non-intermittent generation.

Figure 24 shows the average within-day shape for demand and non-intermittent generation in the reference case for the 2050 low-carbon world with CCS generation (CF 3). This shows the expected pattern of demand peaking at just over 100GW in the evening and then falling to a low of 60GW overnight before rising again at about 6am as we head towards the start of the traditional working day. The pattern for non-intermittent generation largely follows that of demand, although the gap between the lines is largest at the evening peak (with peak demand net wind of just over 80GW), when (onshore) wind generation tends to be higher than at other periods of the day (see Figure 10 for a description of the average within-day pattern of wind generation).

This pattern suggests that moving demand around during the day would make a major impact on smoothing the average within-day shape of the requirement for non-intermittent generation. This would support the use of ex-ante tariffs, appropriately adjusted for variations in the average demand profile (by day of week and time of year). However, it is important to remember that Figure 24 shows the average pattern, from which there can be significant deviations, both in demand and in the requirement for non-intermittent generation.

**Figure 24 – Average demand and non-intermittent generation in each hour across the year** (Counterfactual 3, reference case, GW)




### *4.2.6 Variations in demand and dispatch within selected weeks*

Figure 25 and Figure 26 illustrate how the future interaction between demand and variations in wind output could lead to big changes in dispatch pattern for non-intermittent generation. They show, modelled for 2030, one winter week based on weather of 2000 and one summer week based on weather of 2006

They show the variability in demand, which is higher during the week than at weekends (the last two days shown on each chart), and higher during the day than overnight, particularly during the winter week when heating demand is much more substantial. Demand is also much higher in the winter (peaking at around 70GW) than in the summer, (when it remains below 60GW) driven by increased demand for heating and lighting.

During the January week shown, the output from wind is at close to zero for a couple of days before then increasing to nearly 100% of installed capacity. When low wind coincides with high demand as during the daytime periods between 24 January and 26 January, significant amounts of peaking plant must be run. When high wind output coincides with low demand (summer, weekends and overnight), then some nuclear and CCS coal generation must operate below full output. Indeed nearly the entire CCS coal fleet is forced to shut down for the whole of 29 January in this particular example.

Wind output in the summer week peaks during the middle part of the week at around 20GW (which is a load factor of about 65%) before then falling off to virtually zero as we head into the weekend. The combination of high wind and low demand in the summer leads to shutdown of some nuclear and CCS capacity during the whole of 21 June, a Wednesday in this example. However, during that day, some CCGT is deployed to meet peak demand, and hence is running whilst low-carbon plant is idle – this reflects constraints in the reference case on the ability of the nuclear and CCS coal plant to meet short periods of high demand. The chart also illustrates how despite the apparent predictability of day to day variations in demand, there can be significant swings in the dispatch pattern for nuclear and CCS plant from one business day to the next.

**Figure 25 – Demand and dispatch pattern in January 2030 with electrification**
(Counterfactual 2, reference case, January 2000 weather, GW)

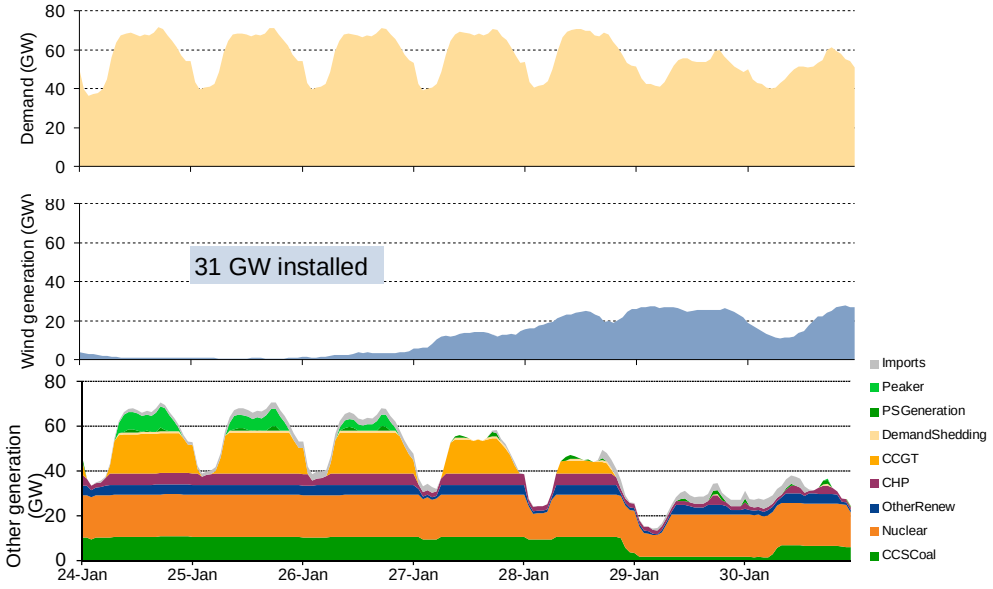
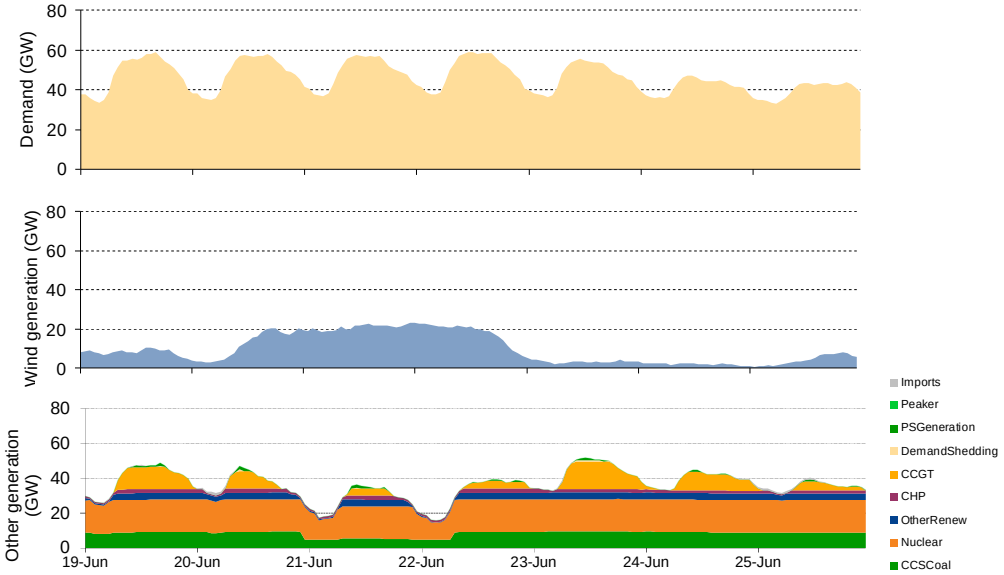



**Figure 26 – Demand and generation pattern in June 2030 with electrification**
(Counterfactual 2 reference case, June 2006 weather, GW)



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# 5. CHARACTERISTICS OF SOURCES OF FLEXIBILITY

Power system flexibility helps to match the profile of generation to demand, either by changing the pattern of generation or varying demand. Alternatively, intermediate measures, such as bulk storage and interconnection[37], could be used to help the system to cope with a mismatch between generation and demand.

In this chapter, we start by exploring the key distinctions between different flexibility options before then looking at the technical and economic characteristics of the options in more details. This begins with electricity generation, then moving on to interconnection and bulk storage, and concluding with an examination of the options for flexibility in electricity demand. Where appropriate, we discuss how the characteristic of the flexibility option differs between its inflexible operation (as typified in the reference cases) and the flexible mode used in the relevant flexibility package.

One of the aims of the assessment of different packages of these measures was to identify potential substitutes for the provision of flexibility from unabated gas-fired generation. However, it is important to focus on the characteristics of the good required (i.e. the provision of flexibility as required in the analysis in Chapter 4) rather than trying to find options with similar technical characteristics to gas-fired plants.

In summary, there could be a significant technical potential for the provision of flexibility from sources other than unabated gas-fired plants even by 2030. All sources of flexibility offer some form of within-day flexibility, which is needed to mitigate the increased variability of demand due to electrification as much as to balance variations in wind. However, the question remains about how much of this flexibility would be available and/or delivered in practice.

It is important to distinguish between economic and technical flexibility – the latter is a requirement for economic flexibility but does not guarantee it. Technical flexibility means that a party can repeatedly change their behaviour on an unscheduled basis but economic flexibility means that they would change their behaviour in response to appropriate incentives. Inflexible operation on safety grounds is an extreme example of lack of responsiveness to economic signals such as price.

In this study, we focus on economic flexibility through centralised dispatch against a ranking of technologies by variable cost. The model is designed to use the sources of flexibility as required to minimise the variable costs (including start-up and no-load costs) of meeting electricity demand in each hour given the characteristics of generation, bulk storage, interconnection and demand[38].

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37 Production of hydrogen through electrolysis is an option for helping to balance electricity supply and demand. It is most attractive in a world where there is substantial hydrogen demand (e.g. from transport) which can be met by using a low-carbon electricity supply. Therefore, we only consider it in a sensitivity on the 2050 cases described in Section 6.4.2, which also outlines the underlying assumptions for this technology.

38 The model is effectively acting as a centralised dispatch market designed to minimise variable costs. We do not make any assumptions about the detailed market design that would be required to produce this result. For example, we assume that there are no contractual restrictions on the use of interconnector capacity.

## 5.1 Characteristics of sources of flexibility

For the purposes of this study, we define flexibility as a change in behaviour over an appropriate timescale that helps to electricity demand to be met at least cost whilst complying with emissions targets.

The options for flexibility differ in a number of key characteristics[39]:

- **quantity**, both annual volumes and maximum hourly contribution;
- **speed**;
- **duration**;
- **availability**, both regular patterns and unexpected outages; and
- **costs**; covering both investment and operational.

These characteristics help to determine the suitability of different options for meeting structural flexibility requirements and/or for responding to unexpected variations in demand and generation.

Structural flexibility can be based on the information and incentives available some time ahead of the actual time period. This would for example include:

- the operation of coal plants in the 1990s in two phase shifting mode;
- the scheduling of maintenance outages for interconnectors[40]; and
- changes in consumption patterns in response to time of use tariffs set at a month-ahead stage, which still requires an 'engaged consumer' to react to by changing behaviour (e.g. through use of heat stores).

These changes in behaviour can help to reduce a mismatch between the structural patterns of generation and demand in a relatively low-tech manner. However, they cannot respond to deviations in supply and demand from the expected profile. This requires more active sources of flexibility, which respond to differences between supply and demand much closer to real-time.

These active sources of flexibility can be used to address unpredictability in supply and demand, as well as structural mismatches. However, active flexibility solutions typically involve the implementation of more technically complex solutions with higher investment costs and infrastructure requirements. For example, more dynamic demand may be possible to offset some of the intermittent effects from wind – demand would increase at times of high wind generation, and fall when there is less wind.

Section 4.2 described a number of different measures of the need for flexibility, which provide insight into the balance between structural and unexpected requirements for

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39 Unless otherwise stated, plant will be assumed to have same economic and technical characteristics in 2050 as in 2030. This is to avoid very arbitrary/speculative assumptions about technological developments between 2030 and 2050. This represents an upside to the scenarios – for example, 'pebble-bed' nuclear reactors that are smaller and more flexible could be starting to be commercially deployed by 2040.

40 In order to allow users to make alternative arrangements during the maintenance period, sufficient notice must be given of the maintenance period. This public commitment makes it (economically) difficult to delay or bring forward the outage at short notice, even if it is technically possible.

flexibility. The relative pace of development of intermittent renewable generation and electrification is one of the key drivers of this balance.

Although intermittent generation, such as wind, displays some average patterns (e.g. lower overnight generation from onshore wind), its key feature is that these regular patterns are not a very good predictor for the observed level. Therefore, at higher levels of wind deployment, active sources of flexibility are likely to be increasing important.

In comparison, the within-day shape of heating demand is relatively predictable, which can increase the benefits of measures (such as ex-ante time of use tariffs) that flatten the expected demand profile. However, the day to day requirement for heating demand can be much more variable, and only as predictable as the British weather.

Characterisation of the different flexibility options was based on a number of different sources, including discussions with our expert advisors on nuclear generation, thermal generation and the demand side. When evaluating the technical and economic potential for flexibility from different sources in 2030 and 2050, there are few if any published studies with an appropriate level of quantitative detail to directly inform the modelling inputs used for *Zephyr*.

## 5.2 Summary of options for flexibility

Table 10 provides an overview of the different options included in the flexibility packages covered by this study, indicating where they could be good at providing flexibility, and reasons why (at times) they may not be able to contribute significantly to meeting the need for flexibility. The flexibility described in Table 10 refers to the capability of the option when it is included in a 'flexibility package' assessment. For the reference cases and all other flexibility packages, the flexibility option is assumed to be relatively inflexible.

This illustrates that different options are suited for providing different types of flexibility, depending on the:

- duration of requirement for flexibility;
- speed of response needed;
- time of year; and
- predictability of the requirement (i.e. the balance between structural and unexpected).

If electrification of heat and transport proceed as planned, then demand could become a key source of within-day flexibility, particularly for heat. Often though, the within-day flexibility is needed to mitigate the impact of electrification on the demand profile as much as to balance variations in wind. Furthermore, the demand side would have limited potential to deliver over longer periods, certainly for 2030 where electrification is focused on heat rather than transport.

Using ex-ante tariffs to flatten the expected demand net wind profile would allow other sources of flexibility to focus on balancing unexpected variations in wind and demand rather than following a more predictable within-day shape. The potential for flatter expected demand profiles is quite large by 2050 given that 40% of electricity demand could be coming from heat and transport, which should offer more opportunity for demand shifting than traditional forms of electricity demand.

Generation, bulk storage and interconnection have a greater potential to provide flexibility over several days. Generation is more suited to sustained periods of provision of flexibility, in the example of shutting down for several days.

In contrast, flexibility from bulk storage is likely to be provided in bursts rather than being sustained throughout the whole period (e.g. focused on providing supply at times of peak daily demand). This reflects constraints on the amount of energy that can be stored compared to hourly generation capacity – the assumed storage volume available in the study would allow five hours of generation from bulk storage at maximum capacity. Therefore, this picture would change if there was a major shift in the balance between energy storage capacity and deliverability.

Over even longer timescales, generation could be a key source of flexibility, with barriers to flexibility becoming primarily economic rather than technical. This is because the levelised costs of high capital cost plants increase rapidly as achieved load factor drops.

For each source of flexibility, delivering the flexibility discussed in Table 4 will require behavioural changes supported by the investment needed to enable behavioural changes. This could include for example, investment in an interconnector with Norway in the 'imported flexibility' package or the building of smart infrastructure in the 'active demand side' package.

There remains uncertainty about the detailed technical performance capability of the low-carbon generation (primarily nuclear and CCS) that will be deployed in 2030 and 2050. This means that some improved flexibility beyond the reference case could be expected in an optimistic view of the future. However, reliance on waiting for a good out-turn will not necessarily be sufficient to deliver the type of flexibility discussed in Table 4, given the importance of the choices that are made in the design and construction phases (as discussed further in Section 5.3.1).

In the 'active demand side' package, we assumed that there was storage available alongside all heat pumps so that we could explore the maximum contribution that could be made by demand. This reflected the fact that the study was designed to explore the impacts of increased low-carbon flexibility (including demand side response) in the GB system. Increasing the number of heat pumps without storage (from zero) in this package would worsen the flexibility challenge by raising peak (winter) demand and reducing the amount of movable demand. However, it was out of the scope of this study to quantify the benefits for flexibility of different levels of storage alongside heat pumps (e.g. estimating the magnitude of flexibility benefits from having storage alongside 75% of heat pumps compared to only having it alongside half of heat pumps).

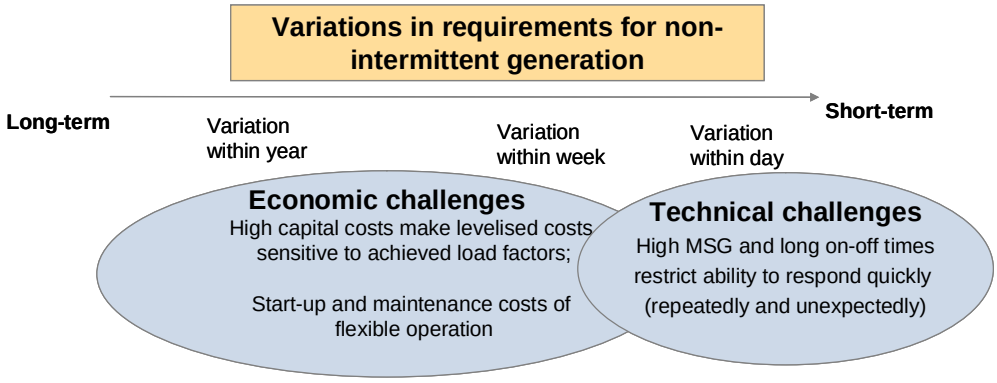
## Table 10 – Overview of strengths and weaknesses of each option for flexibility

| Flexibility source | Strengths (in 'flexible' mode) | Weaknesses (in 'flexible mode') |
|---|---|---|
| **Nuclear** | Reduction in minimum stable generation to 25% provides access to significant flexibility (i.e. can vary output by up to 75% of installed capacity)<br>Maintenance scheduling can be used to match seasonal variations | Economic barriers to provision of long-term flexibility<br>If plant is required to shut-down, it cannot restart for minimum of 48 hours<br>Uncertain how repeated ramping up and down would affect safety cost, operating lifetime and maintenance costs |
| **CCS coal and CCS gas** | Suited to medium-length periods of flexibility (e.g. at least 6 hours) such as turning off overnight or use of storage solutions<br>Maintenance scheduling can be used to match seasonal variations<br>IGCC may be faster source of flexibility | Economic barriers to provision of long-term flexibility by coal plants<br>Uncertain how repeated ramping up and down would affect safety cost, operating lifetime and maintenance costs<br>Uncertainty about technology development<br>Not suited to dealing with large hour to hour oscillations<br>IGCC flexibility restricted to within-day as hydrogen storage capabilities may be limited to 12 hours |
| **District heating CHP** | Can provide within-day flexibility, particularly in winter | Variable potential as linked to heating demand<br>Not assumed to be on the system in 2050<br>Flexibility limited by storage capability |
| **Interconnection with SEM and/or NW Europe** | Flows driven by wind differentials, so help to offset wind conditions in GB, even over extended periods<br>NWE link gives access to large market | Flows not driven by relative levels of demand net wind<br>Flows could exacerbate extreme situations in GB<br>Flexibility from SEM limited by small market size |
| **Interconnection with Norway** | Effectively provides access to storage outside GB, which can help to balance system over periods of several days | Competition from other European markets for access<br>Cannot provide seasonal flexibility |
| **Bulk storage** | Can provide flexibility across a number of days | Provision of multi-day flexibility is periodic rather than constant<br>Needs increase in GWh of storage capacity per GW of output to avoid becoming energy constrained |
| **Hydrogen production through electrolysis** | Absorbs excess supply, particularly over extended periods of low demand in summer<br>Reduces carbon intensity of other energy sectors | Constrained by the level of daily gas demand by 2050 when technology is available<br>Most useful in summer when gas demand is low, which limits magnitude of flexibility available |
| **Ex-ante tariffs** | Effective at flattening within-day demand profile (which is helpful for networks), especially when heating demand is high | Largely limited to within-day smoothing.<br>Unresponsive to 'unexpected' changes in demand and/or wind |
| **Active management of heating load** | Effective at within-day smoothing of requirement for non-intermittent generation, particularly in winter.<br>Storage may be easier to deliver in the non-residential sector | Flexibility potential much lower in summer<br>Flexibility largely limited to within-day because of size limitations and energy losses from storage.<br>Uncertainty about extent to which storage will be deployed alongside heat pumps by 2030<br>Fuel switching only available as transitional option |
| **Active management of EV load** | Potential to shift demand across days, which is enhanced by fuel switching.<br>Flexibility potential more consistent across year | Uncertainty about behaviour and infrastructure<br>Limited deployment by 2030<br>EV to grid not displace thermal plant in practice |
| **Active management of wet appliance load** | Help within-day smoothing of need for non-intermittent generation<br>Potential consistent across year | Limited magnitude and duration of flexibility potential as typically can only shift within-day at most |

## 5.3 Low-carbon generation

Flexibility raises technical (in the short-term) and economic issues (in the longer term) for low-carbon generation, as summarised in Figure 27. Technical issues are related to the ability to change output quickly and repeatedly whereas economic challenges result from the rapid increase in levelised costs of high capital cost plants as the achieved load factor drops (as illustrated in Figure 28).

**Figure 27 – Flexibility of low-carbon generation over different timescales**




### *5.3.1 Summary of current outlook for flexible generation*

The study considers the options for increased flexibility from three forms of low-carbon generation – nuclear plant, CCS technologies (coal and gas[41]) and district heating CHP[42]. There is considerable debate at present about the (current and future) flexibility of these different technologies.

#### *5.3.1.1 Nuclear generation*

Traditionally in the UK (and many other countries) nuclear generation has provided baseload electrical generation capacity and there is therefore little, if any, empirical evidence of the flexibility of nuclear generation in the UK market.

The nuclear plants expected to be on the system in 2030 and 2050 are expected to be new designs, with limited track record of performance at the moment. The designs for future nuclear plants currently undergoing the UK Generic Design Assessment (GDA) are:

- Areva's European Pressurised Water Reactor (EPR); and
- Westhinghouse-Toshiba's Advanced PWR (AP1000).

41 The CCC constrained the use of biomass options in the study because of concerns about the non-zero lifecycle emissions. However, the use of CCS for biomass generation would raise some interesting issues around negative life cycle emissions.

42 We also investigated the flexibility of different technologies for micro-CHP. However, this was not a generation technology that featured significantly in the counterfactuals for the provision of heat prepared by the CCC.

These designs are used as the basis of the nuclear fleet operating in 2030 and in 2050 in the study[43].

#### *5.3.1.2 CCS generation*

As CCS generation technology has yet to be deployed on a commercial basis, there remains considerable uncertainty about how the plants would perform under baseload operation, let alone in flexible modes. As well as by fuel source (i.e. coal, gas or even biomass), CCS plants can be differentiated by whether they are pre- or post-combustion technologies. After discussions with CCC, it was agreed that all CCS capacity modelled in this study would be assumed to be post-combustion.

Post-combustion technologies involve placing the capture equipment at the end of the generation process for a standard unabated fossil fuel plant. This reduces net generating efficiency because of the power required to operate the capture equipment. It also means that the flexibility of the whole process is constrained by the flexibility of both the capture equipment and the network for transporting the carbon dioxide to the final storage site.

The capture equipment is effectively based around a chemical process that is best suited to baseload operation and hence reduces the scope for flexibility in standard operation, although the extent of the restriction is not well understood at present.

One source of generation flexibility is to turn off the capture equipment, which would increase the net capacity of the CCS plant because it no longer has to provide power to the capture equipment. This could therefore provide an alternative to building peaking generation just to meet periods of very high demand net wind. However, the incremental emissions of turning off the capture equipment could be as high as 2500g/kWh[44], which would not make it a viable option for more than a handful of hours given the overall carbon targets, and would lead to the operator incurring significant carbon costs [45].

The flexibility of the transport network is primarily an economic rather than technical issue as the supporting infrastructure (including pipes) can be oversized to support peak flows (at the cost of a lower utilisation and hence higher cost per tonne of carbon dioxide transported).

The second form of CCS technology is pre-combustion, which for coal requires gasification through an IGCC. This may offer more scope for flexibility as the capture process can run separately from the generation plant – this is done by storing hydrogen (the output of pre-combustion capture process) which is then fed into the generation plant as required. Current indications suggest that hydrogen storage capabilities would limit the

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43 A third proposed design is GE-Hitachi's Economic Simplified Boiling Water Reactor (ESBWR) but this is not expected to complete GDA before 2015, with adoption by a UK utility company unlikely for some years afterwards (until the plant has been proven elsewhere, e.g. in home market). We were able to explore the key issues around nuclear flexibility with the two designs described above, and hence the ESBWR was not considered in this study.

44 Incremental emissions are defined as additional emissions per additional kWh of output. The figure of 2500g/kWh is based on the extra emissions incurred by increasing total output by 400MW by effectively replacing a 1200MW CCS coal plant with emissions intensity of around 100gCO2/kWh with a 1600MW unabated coal plant with emissions intensity of around 700gCO2/kWh of generation.

45 The incremental carbon cost alone would be £175/MWh in 2030 and £500/MWh in 2050.

flexibility to no longer than 12 hours, so it would be suitable for shifting generation during a day.

We did not include CCS IGCCs in the flexibility packages because in general, we wanted to look at flexibility options available in more than one counterfactual. IGCCs did not appear in either of the 2030 counterfactuals provided by the CCC, which were based on the 'EFC' and '3-EP' cases from the September 2009 report from Redpoint[46]. Counterfactual 4 is a world without CCS.

If CCS IGCCs had been modelled in place of post-combustion CCS coal plants, they would have increased the flexibility of low-carbon generation to respond to unexpected within-day variations in demand net wind (given the impact of ex-ante tariffs on smoothing expected demand), rather than over longer timescales.

#### *5.3.1.3 District heating CHP*

Electricity output from CHP units typically follows a heat load, which means that they are normally seen as being inflexible. However, the ability to store heat[47] means that the heat load can be adjusted temporarily, with obvious implications for the electricity output from the CHP plant.

The magnitude and duration of this adjustment would depend on the nature of the heat load, rather than any operating characteristics of the CHP plant itself. This illustrates the importance of distinguishing between economic and technical flexibility.

The low-carbon energy worlds provided by the CCC had only limited capacity of CHP in 2030 and none at all in 2050. Therefore, this source of flexibility could only make a contribution in the 2030 worlds (CFs 1 and 2).

### *5.3.2 Quantity of flexibility*

There are two aspects to the quantity of flexibility provided by a generation plant. The first is the annual volume of flexibility, and the second is the peak amount of flexibility that can be provided.

The peak amount of flexibility is generally related to the installed capacity of the plant (with the subtlety as described above for post-combustion CCS plant that can increase capacity by turning off the capture equipment). The speed and duration of flexibility would determine how the extent to which the peak capacity for flexibility is used in practice.

The potential volume of flexibility can differ significantly from the amount actually used in one of the modelled years, either because of the profile of flexibility required and/or other sources being better placed to provide the flexibility.

When not operating flexibly, as in the reference cases in 2030, nuclear achieves an annual load factor of close to 90% and CCS coal achieves around 85%, close to their assumed annual availability. This means that the provision of flexibility in these situations would result in a reduction in annual generation, and hence load factor (as the plant reduces generation in some periods but cannot increase generation in other periods as it was already operating at maximum).

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46 'Decarbonising the GB power sector: evaluating investment pathways, generation patterns and emissions through to 2030', September 2009, Redpoint Energy.

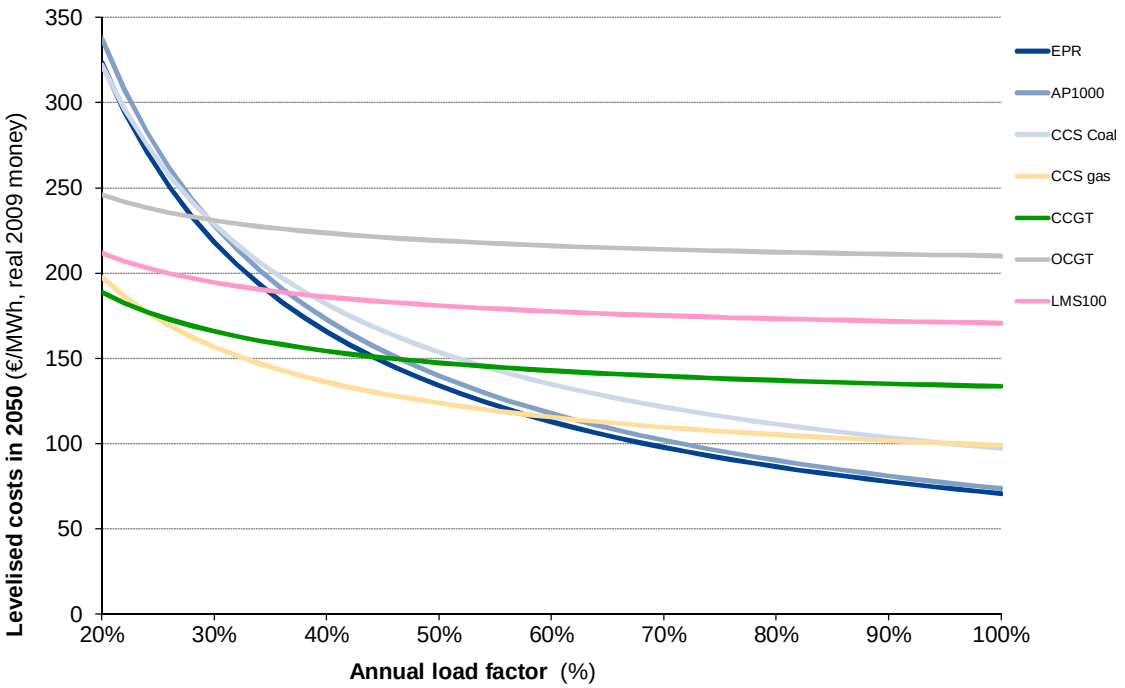
47 Heat storage is likely to be an integral feature of most CHP systems, not just district heating CHP systems.

The situation is different for the 2050 reference cases, with nuclear operating at around 80%, CCS coal at 70% and CCS gas at just under 50%. The provision of flexibility would not necessarily reduce the annual load factor as there are some periods in which the plant could increase generation above those levels achieved in the reference case. A similar situation exists for CHP whose annual generation is largely determined by the heat load that it must provide.

High capital costs of low-carbon generation means that the investment case is typically quite sensitive to the achieved annual load factor. Therefore, a fall in expected lower load factors could undermine investment in low-carbon generation. As a result, a comparison of levelised new entry costs against different load factors give an indication of the maximum potential reduction in load factor that could be achieved without undermining the investment case for low-carbon generation.

Figure 28 shows how the load factor affects the levelised new entry costs for different generation technologies in 2050[48]. This suggests that nuclear has lower levelised costs than CCS gas down to an annual load factor of 60%, which is then cheaper than CCGTs down to a load factor of around 30%.

**Figure 28 – Levelised new entry costs by technology in 2050**
(€/MWh, real 2009 money)




Source: Pöyry analysis of cost assumptions by Mott MacDonald for 'UK Electricity Costs Update'

This suggests that in theory, the high carbon price in 2050 (£200/t$CO_2$) means that nuclear plants could operate at a much lower load factor and still remain the cheapest options for new build generation. However, levelised cost comparisons are useful for

48 The levelised cost for an IGCC plant is not shown as no installed IGCC capacity was assumed in the study. Our analysis suggests that it could be potentially competitive at load factors of around 45%.

illustrating the impact of different annual load factors on plant economics but do not capture the dynamic aspects of flexibility, such as start-up speed and minimum on or off times. Technical limits on flexibility mean that the nuclear plant could not necessarily operate flexibly enough to capture the most profitable hours – therefore, we have used the rate of return achieved by each technology from the model as a guide to the investment decision.

The flattening of demand by ex-ante tariffs in the 'flexible generation' package means that load factors actually increase for nuclear and CCS coal plant compared to the reference case. This makes it difficult to establish a baseline to isolate the difference in operating pattern caused solely by a change in the flexibility assumptions for the nuclear and CCS coal plants.

Compared to the 'imported flexibility' package (which also has ex-ante tariffs), the fall in achieved load factors for the nuclear and CCS plants in the 'flexible generation package' is generally quite small. Total production[49] from CCS and nuclear falls by:

- 3TWh in Counterfactual 1, with 0.3% fall in nuclear load factor and 4% fall in CCS coal load factor;
- 2TWh in Counterfactual 2, with 0.3% fall in nuclear load factor and 2% fall in CCS coal load factor;
- 3TWh in Counterfactual 3, with no change in nuclear load factor, and a 1% fall in the load factor for CCS coal and CCS gas; and
- 17TWh in Counterfactual 4, with 3% fall in nuclear load factor.

### *5.3.3 Speed of flexibility*

The speed of generation flexibility has two dimensions – how quickly can a plant reduce or increase generation (without shutting down or starting up) and how long it takes to shut down or start up.

Typically, the most flexible mode of operation for a low-carbon plant is to fluctuate between its minimum stable generation (MSG)[50] and its maximum generation capacity. However, to access the peak flexibility (represented by total installed capacity), a plant will need to shut down (or start up), which is a slower process. Also, repeated operation at or close to the MSG could significantly reduce the load factor of the plant, hence significantly depressing the achieved return.

For the key (non-renewable) generation technologies covered in this study, Table 11 lists the MSG, and the minimum off and on times. This highlights the changes for each generation technology between operating in standard mode and in flexible mode.

The flexible nuclear plant has a lower MSG but still has long on and off times, meaning that the output can vary between 25% and 100% of capacity within-day. The reduction in the MSG in the 2050 world with CCS (CF 4), equates to an additional 16GW of flexibility[51]

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49 In order to remove impact of changes in installed capacity level, the benchmark production for the inflexible operation was calculated by applying the load factors from the 'imported flexibility' package to the installed capacity in the 'flexible generation' package.

50 The lowest level of output that can be sustained by a plant.

51 Indeed the absence of CCS and CHP from the capacity mix in Counterfactual 4 means that nuclear is the only source of flexible generation in this case.

which helps to reduce the amount of wind deloading[52]. However, the nuclear plants would not be able to shut down overnight if they are needed to meet demand during the day – there is the possibility though that they can shut down over the weekend, which is typically a time of lower demand.

For the CCS plants, the big change is a fall in the minimum on and off times, although there is also some reduction in the MSG. This makes the CCS plant able to shut down and start up within day, behaving more like (but not exactly the same as) an unabated plant.

The flexibility of CHP operation is increased by the use of heat storage rather than by changing the characteristics of the generating plant. This reflects the fact the generating characteristics are reasonably well understood for this mature technology, which is much more established than CCS and the new nuclear designs.

**Table 11 – Characterisation of generation flexibility**

| Technology | Minimum stable generation (% of installed capacity) | Minimum on time (hours) | Minimum off time (hours) |
|---|---|---|---|
| Standard nuclear 1 | 50% | 48 | 48 |
| Standard nuclear 2 | one period of 2-10 hours at 50% allowed per 24 hours; otherwise 90% | 48 | 48 |
| Flexible nuclear | 25% | 48 | 48 |
| Standard CCS coal | 90% | 24 | 24 |
| Flexible CCS coal | 70% | 6 | 6 |
| Standard CCS gas | 90% | 24 | 24 |
| Flexible CCS gas | 75% | 5 | 5 |
| Standard CHP | 40% | 24 | 24 |
| Flexible CHP | 40% | 24 | 24 |
| CCGT | 55% | 3 | 3 |
| Peaking plant | 35% | <1 | <1 |

### *5.3.4 Duration*

For nuclear and CCS plants, the main limit on the duration of flexibility is economic as being shut down for long periods would depress the load factor, and hence the investment case. In fact, for these technologies, there is a minimum constraint for the duration of flexibility (based on the minimum and maximum off times shown in Table 11).

52 Given the length of the time horizon until 2030 and then to 2050, wind and wave are assumed to bid in at zero in these years.

There are two generation technologies (CHP, and CCS IGCC), which use storage to provide flexibility and hence have restrictions on the duration of flexibility. In both cases, the storage is assumed to be limit the flexibility to being within-day.

In flexible operation, district heating CHP is assumed to have enough access to heat storage so that it can change its operating pattern within-day. However, it must still meet the daily demand for heating.

Although not modelled in the study, we also considered the flexibility of an CCS IGCC. Assumptions provided by the CC on the costs of hydrogen storage suggests that 12 hours of hydrogen production could be stored, which leads to electricity production (using this hydrogen) being flexible within-day only. This makes it less useful when demand side response has already smoothed the expected demand profile within-day.

### 5.3.5 Availability of flexibility

Maintenance schedules, unexpected outages and the pattern of demand are the main drivers of the availability profile for flexibility from (non-CHP) generation.

Maintenance scheduling is the main driver of structural patterns of availability. This is a low cost option for helping to mitigate expected seasonal variations in requirements for non-intermittent generation. This is often done on a more coordinated basis in other European electricity markets, for example the maintenance of nuclear plants in France. Policymakers would need to consider how effectively this could be done within the framework of the wholesale electricity market in Great Britain.

Furthermore, if greater space cooling boosts summer demand and reduces the seasonality of demand, spring and autumn could be left as periods of low electricity demand. The possibility for a hot or cold spell in these months would limit the degree to which scheduled generation maintenance can be shifted to these periods, given that the maintenance period could stretch from 20 days (for a simple refuel) to 60 days.

The pattern of demand and hence the requirement for non-intermittent generation would determine the extent to which the plant is operating, and hence whether the potential for flexibility is upwards (through increased output) or downwards (if it is already operating at full load).

In the summer, when the heat load is much lower, the CHP would be operating at a lower level than in the winter. This means that the CHP plant may be able to increase output by operating in electricity only mode but would not be able to provide downward flexibility by turning down from its normal mode of operation to help accommodate a high wind spell.

### 5.3.6 Cost of flexibility

The main costs of flexibility from the different types of generation are the costs of starting up (fuel and maintenance) and running part-loaded (which reduces efficiency). These tend to be a relatively small part of overall generation cost.

Beyond these costs, plants are not assumed in this study to bear additional costs in flexible operation compared to standard operation. This reflects the fact that for new nuclear plants and the CCS plants, differences in flexibility are driven primarily by uncertainty about technology developments, which will be influenced by the incentives for delivering flexibility.

For the CHP plant, we have not evaluated the cost of heat storage (which may already be in place and hence not require additional investment).

There is a much better understanding of the issues around cost of delivering flexibility from nuclear plants than from CCS plants. This is because we can draw on lessons from the commercial and technical operation of existing nuclear plants and results of the Design Assessment Process – evidence that is not available for CCS plants which are yet to be commercially deployed.

Indeed for nuclear plant, it is understood that the design basis of the EPR already includes enhanced features representing industry best practice (e.g. from France, Germany) supporting load following and flexible operation. The question remains about how these would be exploited in practice in the GB context.

The uncertainty about the flexibility of nuclear generation has been highlighted by the ongoing debate in Germany about the flexibility of its current nuclear generation fleet. This has been driven by a number of negative price periods being recorded in the German wholesale electricity market as a result of high wind output combined with a significant amount of inflexible generation. RWE have said that nuclear can be ramped down at 15MW per minute and EnBW has said that ramping rates can reach up to 400MW/hour[53]. In contrast, E.ON (UK) has reported that nuclear is not a flexible generation technology[53].

The flexible operation of nuclear plants involves additional operation (compared to baseload operation) of a number of components, which may then require more frequent maintenance, refurbishment or replacement. For example:

- Reactor control rod assemblies may show additional wear and require more frequent replacement. These can only be changed during a shutdown period and may add to the duration of, for example, a simple refuel outage.
- Daily or weekly power cycling may be in part achieved by chemical means, giving rise to additional usage and (radioactive) waste arisings. For the EPR and AP1000 it is believed that chemical recovery plants will be installed, significantly reducing this factor for new plants.

It would seem therefore that any costs associated with replacement items, consumables and maintenance resulting from flexible operation would be small compared to the standard capital and operating costs. This is particularly the case if repair and replacement can be done as part of an outage scheduled for other reasons (e.g. refuelling). However, costs associated with lost output could be large if a specific outage is required to address issues resulting from flexible operation.

These costs can be further minimised if the need for flexibility is factored in at the investment stage, most notably in power chemical recovery processes, and in enhanced control and instrumentation in the Control Room and on ancillary plant.

Operation of a nuclear reactor results in the consumption of the nuclear fue, such that eventually the plant must be shut down and some of the fuel replaced. The design of the fuel (in terms of enrichment, and associated cost) is strongly influenced by the desired fuel cycle pattern. Clearly, given potentially fixed points for refuel (periods of low demand), utilities would not wish to underburn/ underuse their fuel. Intermittency of operation of nuclear plant would add significant uncertainty to fuel costs, if the actual operating output is significantly different to that assumed at the design of the fuel cycle. Thus it is present practice to accept restrictions in plant flexibility late in a given fuel cycle and utilise inherent characteristics of PWR to accommodate 'stretch operation' for periods of a few months in cases of excess usage.

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53 'CCS will reduce flexibility prized by German utilities', 8 March 2010, Platts Power in Europe.

## 5.4 Interconnection

Table 12 lists the possibilities for increased interconnection that were considered as part of this study. We were relatively conservative in our assumptions about the scope for increased interconnection. This reflected concerns that a large expansion of interconnection capacity could effectively assume the problem away without detailed modelling of the relevant markets to see if they could provide a high level of flexibility (which was outside the scope of this study).

Section 3.5.4 describes the modelling of the interconnectors. Flows across the links with North West Europe and with the Irish market (SEM) are driven by relative wind levels in GB and the relevant market (with the assumption that import and export flows are required to balance over a year). Greater flexibility is provided by increased capacity of the interconnectors rather than by a change in the technical or economical parameters of the interconnector.

Increased flexibility is also provided by the deployment of a Norwegian interconnector across which the flows are determined by prices in the GB market (subject to the assumed constraint that imports and exports are balanced over a month).

**Table 12 – Possible interconnections for the GB market by 2030**

| **Region** | **Current capacity** (GW) | **Capacity in reference cases** (GW) | **Other proposals** | **Capacity when interconnection is flexible** (GW) |
|---|---|---|---|---|
| SEM | 0.4 | 0.9 | Imera: 0.5GW<br>Imera 2: 0.5GW (post 2020) | 1.9 |
| NW Europe | 2 | 3.3 | Nemo (Belgium): 0.7GW<br>Additional IFA? (1GW)<br>Second Dutch? (1) | 6 |
| Norway | 0 | 0 | 1.2GW plus | 2.5 |
| North Sea supergrid | 0 | 0 | Under discussions | 0 |
| Iceland | 0 | 0 | 1 GW (post 2020) | 0 |
| Mediterranean | 0 | 0 | Link to Spain proposed for post-2020 | 0 |

In increasing interconnector flexibility, we did not assume:

- the North Sea SuperGrid because the flexibility provided would be a mixture of the flexibility of the Norwegian and NWE links, which we preferred to look at separately;
- a link to Iceland because this is expected to be backed by geothermal generation operating at baseload which would not improve the flexibility position; and
- a link to the Mediterranean because it is uncertain what flexibility this would provide.

### 5.4.1 Quantity of flexibility

There are two aspects to the quantity of flexibility provided by the interconnectors – gross annual flows and total peak flow. The total peak flow is determined by the capacity of the interconnection, as set out in Table 12.

We had to make an assumption about annual net flows across each interconnector because we were not explicitly modelling other European countries in this study. The net flows across each interconnector were assumed to be zero – i.e. annual imports equal annual exports on average across the nine Monte Carlo years. This has the effect on requiring generation in GB to completely meet electricity demand in GB (including network losses). Setting net flows to zero used to allow the study to focus on the role of the interconnectors in providing flexibility rather than allowing them to reduce annual carbon emissions by simply displacing annual generation in GB[54].

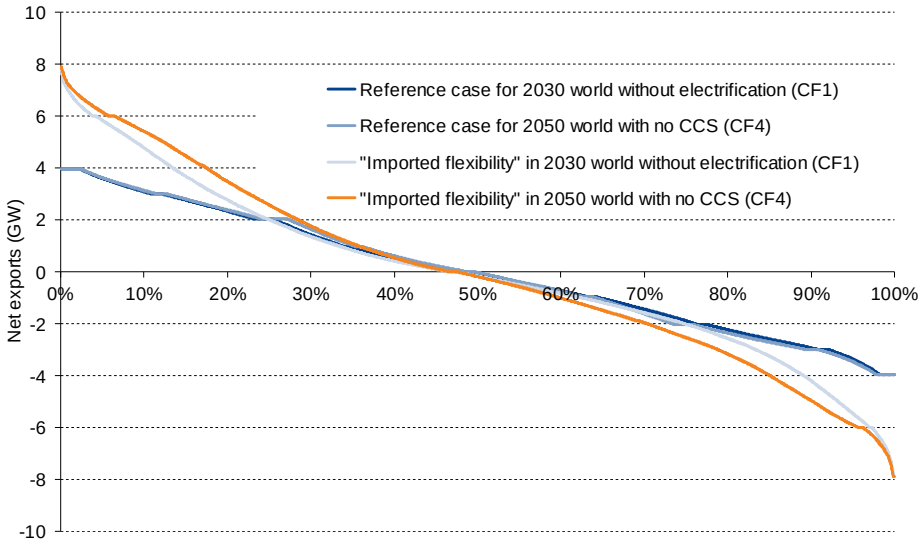
Consequently, that the maximum potential flows in one direction are equivalent to the interconnector running at full capacity in one direction for half of the year (4380 hours). This produces the following maximum flows (in one direction) across each interconnector:

- SEM – 8TWh;
- North West Europe – 26TWh; and
- Norway – 11TWh.

Figure 29 shows the annual distribution of combined flows across the interconnectors with the SEM and with North West Europe, firstly in the reference cases and then for the case with increased capacity in the 'imported flexibility' package. It shows for around 60% of hours, the flows in the reference cases are the same as with flexible interconnection. It is only at the extremes that the flows diverge, with capacity utilisation for the expanded interconnectors only above 50% (4GW) in 40% of hours.

54 It also reflects that there is no certainty (or existing contractual arrangements) in relation to the annual level of net flows across these interconnectors.

**Figure 29 – Annual duration curve of flows across NWE and SEM interconnectors (GW)**




### 5.4.2 Speed of flexibility

There are no restrictions on technical flexibility (based on hourly granularity) for any of the modelled interconnectors. Therefore, they can change direction from full export to full import (or vice versa) from hour to hour.

### 5.4.3 Duration of flexibility

The requirement to have a balance between import and export flows over a specified period is the only restriction on the duration of flexibility from the interconnectors (beyond the timescale of one hour).

Although the Norwegian interconnector is effectively providing access to pumped storage, we do not model any limits on the size of the storage capacity, given the relatively small size of the link compared to the expected capacity available in Norway. To avoid the model treating Norway as a very large sink for the GB system (and as a result, possibly over-optimising), we assumed that there is a zero net flow across the Norwegian interconnector over a month[55] (i.e. to prevent the GB system importing from Norway continuously for two months which would require very large storage capacity in Norway). This means that the Norwegian link cannot provide flexibility between months.

For the other interconnectors (SEM and NWE), we assumed that there was (on average) a net flow of zero across each interconnector (as discussed in Section 5.4.1). This means that each interconnector cannot flow continuously in one direction for the whole year.

55 This is consistent with the assumption that there are zero net flows over the year, and reflects the absence of any certainty about the seasonal pattern of flows across the Norwegian interconnector.

### 5.4.4 Availability of flexibility

The interconnectors are technically available to provide flexibility all year. However, the flows across the SEM and NWE interconnectors are driven by relative wind levels, and therefore are not directly responsive to market conditions in GB.

Flows across the Norwegian interconnector are driven by differences between the hourly wholesale electricity price in GB and the monthly average price in GB. There is only one constraint on its availability to respond to the position of demand net wind in GB – namely, that flows across the Norwegian link are constrained by wind differences between GB and NWE. If Great Britain is exporting to North West Europe, then there are limits on the imports from Norway (and vice versa). Therefore, the Norwegian link would have limited impact on the situation of low wind in Great Britain but even lower wind in North West Europe.

The Norwegian interconnector is included in the 'imported flexibility' package. The flexibility provided by this link varies by counterfactual, as illustrated by a comparison of Figure 30 and Figure 31, which show the average within-day profile of flows for business days and non-business days in one 2030 world (CF 1) and one 2050 world (CF 4).

In both charts, exports are higher on non-business days than business days (within the same season), which shows how the interconnector is being used to smoothing demand net wind between working days and weekends. Similarly, it would also be used to smooth demand net wind between windy and still days.

There is a characteristic within-day shape in the flows in the 2030 world without electrification (CF 1) in Figure 30, whereby exports to Norway are high at night, with imports to GB seen during the day. In the 2050 world with no CCS (CF 4) shown in Figure 31, the electrification of heating and transport means that the ex-ante tariffs are much more effective at flattening the expected demand profile across the day. As a result, the **average** within-day shape in the flows across the Norwegian interconnector is much flatter, with flows being much more responsive to unexpected within-day changes in wind, availability and demand. The residual shape of imports overnight and exports during the day shows the time of use tariffs are not completely successful in levelling out the within-day profile of demand net wind (even on average) – however, average flows are well below the installed capacity of 2.5GW.

**Figure 30 – Flows across Norwegian interconnection in 2030 world without electrification** (Counterfactual 1, 'imported flexibility', GW)

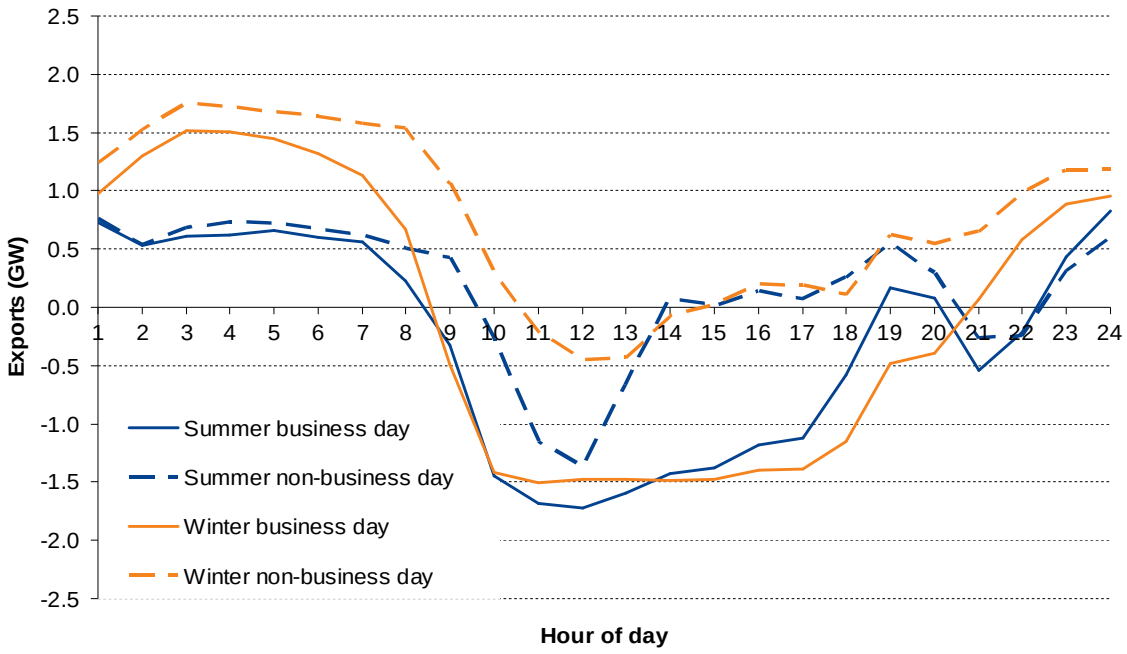
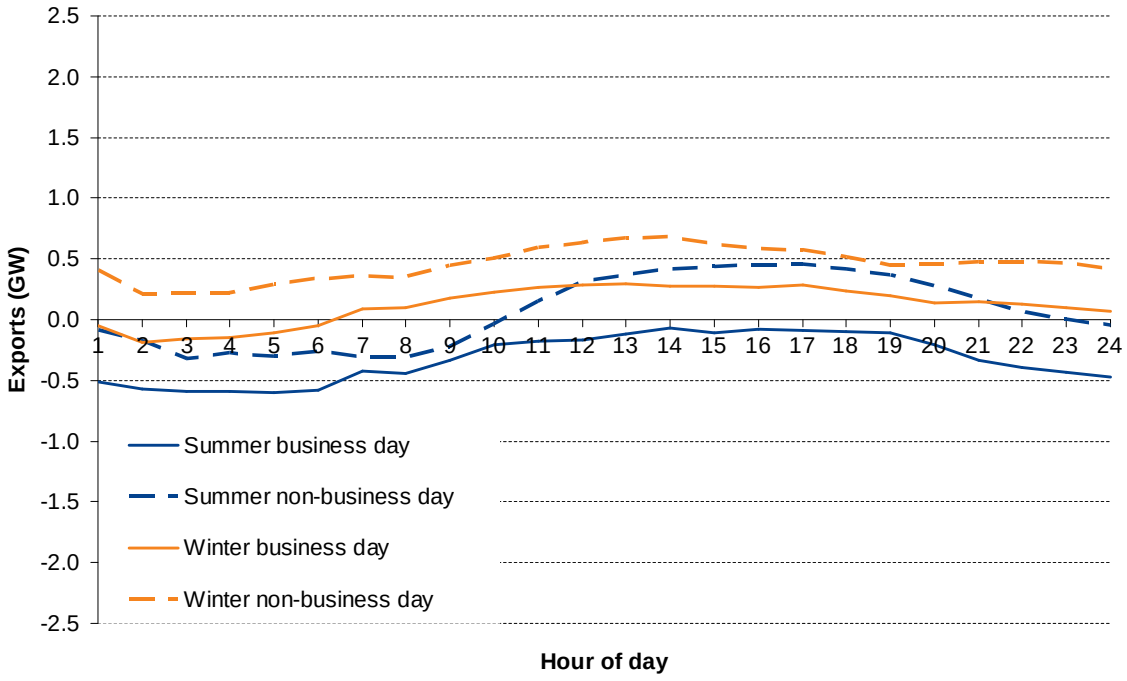



**Figure 31 – Flows across Norwegian interconnection in 2050 world with no CCS** (Counterfactual 4, 'imported flexibility', GW)



### 5.4.5 Cost of flexibility

The costs of the interconnectors are primarily driven by investment costs, with operating costs being only a small part of the overall cost. Capex costs are driven by distance and capacity of the interconnection – we assume €100m/GW for the SEM interconnector, €300m/GW for the NWE interconnector, and €900m/GW for the Norwegian interconnector.

Interconnection costs are a small part of the overall cost – the bigger questions are delivering the capacity (including in the supporting network) and the uncertainty about what flexibility would be provided in practice.

## 5.5 Bulk storage

Increased flexibility from bulk storage is driven by investment in storage facilities which are assumed to be comparable in operating characteristics to existing pumped storage facilities. These operating characteristics also include round trip efficiency, rate of energy losses and the ratio between generation capacity and reservoir volumes.

The economics of dedicated storage provide a challenge for the widespread deployment of such technology. Dedicated storage collects its revenues from arbitrage between prices at different times. If it is successful and widely deployed, then it would reduce the price differentials and hence depresses its own revenue streams.

### 5.5.1 Quantity of flexibility

There are three aspects to the quantity of flexibility provided by the interconnectors – gross annual flows into and out of storage, generation capacity (or 'peak deliverability') and input capacity (the rate at which the storage capacity can be filled).

In the reference case, bulk storage is assumed to have generation capacity of 1.8GW (as some of the existing storage is not available to the wholesale market) and input capacity of 1.3GW. The storage can at most complete two cycles (of filling and withdrawal a day), which means that the theoretical maximum potential gross flows in (and out of) storage is just under 2TWh a year.

In the flexibility option for bulk storage, the output capacity and input capacity are increased to 6.8GW and 6.3GW respectively. This is comparable to the Level 3 for bulk storage set out in the July 2010 pathways analysis published by DECC, and would raise the theoretical ceiling for gross flows to 30TWh a year. The bulk storage is unlikely to deliver anything like this level of gross flows in practice, particularly when the model takes into account the round trip efficiency factor, which means that each cycle creates additional electricity demand that must be met from the generation sector.

### 5.5.2 Speed of flexibility

From hour to hour, the bulk storage facilities are assumed to be fully flexible.

### 5.5.3 Duration of flexibility

The duration of flexibility from storage is determined by the relationship between output (and input) capacity and the size of the storage reservoir. Currently, the reservoir volume of 9TWh can allow the facility to generate for 5 hours at maximum capacity, with the facility then taking at least 7 hours to completely refill. In the 'imported flexibility' package, we assume an increase in the reservoir capacity to 34TWh so that the facility can generate at its maximum output level of 6.8GW for five hours.

The flows in and out of the bulk storage must be balanced over a week (to avoid excessive optimisation of the model) so that the bulk storage cannot provide flexibility over a longer period than a week.

### 5.5.4 Availability of flexibility

There are no structural restrictions on the availability of the bulk storage facility across the year beyond the limits imposed by its storage capacity – i.e. it cannot be used to increase demand net wind by pumping into storage if the reservoir is already full.

### 5.5.5 Cost of flexibility

The key costs for bulk storage are:

- capital investment costs of £1200/kW;
- fixed annual operating costs of £12/kW per year; and
- round trip efficiency of 73% (i.e. the electricity generated is 73% of the electricity used to fill storage).

As with interconnection, the costs of bulk storage represent a small part of the overall costs of the low-carbon energy future, and therefore, the comparison of system cost is not sensitive to these cost assumptions. A much more important issue for bulk storage is the physical deliverability of the assumed expansion in capacity whether through pumped storage or through alternative storage technologies.

## 5.6 Demand

Electrification of heat and transport provides access to new sources of flexible demand, particularly over relatively short timescales of up to a day or so, as summarised in Table 13. In our modelling, we have explored the impact of the delivery of most of the potential flexible demand in order to understand the upper limits on the magnitude of potential benefits for the electricity system.

Large questions remain about the extent to which demand will be flexible in practice, given the importance of end-user behaviour and access to large amounts of heat storage in delivering the flexibility.

Table 13 highlights four sources of flexibility electricity demand:

- rescheduling energy demand, which requires significant behavioural change;
- fuel switching, which changes the level of electricity demand without varying the underlying level of energy demand[56] – examples include immersion heaters, back-up gas boilers and plug-in hybrid cars;
- decoupling of electricity demand and energy demand through the use of storage; and
- the provision of electricity back to the grid from demand units.

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56 The destruction of electricity demand through fuel switching is different to the shedding of energy demand, for example if factories shut down production. The latter option is not included in Table 13 as it was not seen as an option for providing increased flexibility to be considered in this study.

Shifting energy demand can be hard as it requires significant consumer engagement and willingness to change behaviour. The main potential source of rescheduling energy demand is from 'wet appliances', primarily in the residential sector. This covers washing machines, tumble-dryers and dishwashers.

Much of the potential flexibility in the current system only arises from increasing[57] or decreasing[58] electricity demand, rather than shifting it. The modelling takes into account the possibilities for fuel switching in transport and in heating – however, this is an option primarily limited to Counterfactual 2 as there are no PHEVs in 2050 and gas demand is much lower in 2050.

The fuel switching is done on the basis of a comparison of variable costs of energy from electricity and from an alternative source, which is petrol or diesel for transport, and gas for heating[59]. This cost comparison assumes that by 2030, carbon costs are reflected in consumer prices for gas and petrol/diesel, just as they are included in electricity prices to consumers.

The electrification of heat and transport offers much greater potential access to storage that allows the shifting of electricity demand between time periods without changing the underlying energy demand. In the current system, this type of flexibility is provided by electrical storage heaters.

Electric cars are assumed to be the only potential source of electricity for the grid from the demand side. Questions remain about the impact of this on battery lifetime and performance, with batteries being one of the biggest cost components for an electric vehicle.

57 E.g. through back-up immersion heaters. The electrification of heating may reduce the extent to which electricity (through immersion heaters) is a secondary rather than primary heat source, and there are issues related to the link between gas and electricity prices, the level of storage available and the impact on the gas network particularly in summer.

58 E.g. through switching to alternative fuels or *energy* demand destruction.

59 This is a legacy benefit of heat pumps being installed before gas boilers are due for replacement. It is a temporary feature as the gas boiler is assumed not to be replaced when it reaches the end of its operating lifetime if it is only used as a back-up system.

**Table 13 – Options for flexibility from different types of demand**

| | Shift end-use energy demand | Switch input fuel | Decouple electricity and energy demand | Provide electricity back to grid |
|---|---|---|---|---|
| Electric vehicles | No | Hybrids | Batteries | Batteries |
| Space cooling | No | No | Inertia/store | No |
| Space heating | No | Gas (legacy) | Heat store | No |
| Water heating | No | Gas (legacy) | Heat store | No |
| Washing | Time-delays | No | No | No |
| Refrigeration | No | No | Inertia | No |
| Cooking/catering | No | Gas | No | No |
| Lighting | No | No (?) | No | No |
| Motive power | No | No (?) | No | No |
| Computing | No | No | No | No |
| Entertainment | No | No | No | No |
| Processes | No | No (?) | No | No |

In the modelling process, demand is split into three types:

- **inflexible** – shape and level of electricity demand is unresponsive to any price signals;
- **responsive to ex-ante tariffs** – these are designed to shift movable demand to fill in troughs in the **expected** demand profile, and avoid double peaks that would result from the application of current E7 profile; and
- **active demand** – optimised within the model to meet energy demand profile subject to constraints on flexibility (including storage capacity, availability etc).

Section 3.5.5 provides further details of the modelling approach for each of these categories. In the flexibility packages, the total (underlying) electricity demand is the same as in the reference cases but the mix of demand between these three categories changes.

### *5.6.1 Quantity of flexibility*

Whether demand is responding to either ex-ante tariffs or active demand signals, there are two dimensions to the quantity of demand flexibility – annual volumes of movable demand and the peak amount that can be shifted. Table 14 shows the annual amount of movable demand in each category, both in TWh and as a percentage of annual demand in that category.

Table 14 highlights the importance of electrification for demand side response as at least 90% of moveable demand comes from heating and transport[60].

In theory, the annual flexibility from fuel switching options is the total demand from units that can fuel switch either through a back-up gas boiler in heating[61] or using a hybrid vehicle in transport. In practice, the amount of fuel switching that can be done is constrained by the emissions target as the resulting emissions from gas and petrol are included in our reported electricity emissions for the generation sector.

**Table 14 – Annual amount of movable demand** (TWh)

| **Type of demand** | **2030 world without electrification** (CF 1) | **2030 world with electrification** (CF 2) | **2050** (CF 3 and CF 4) |
|---|---|---|---|
| Movable demand from wet appliances[62] | Up to 4 TWh (48%) | Up to 5TWh (64%) | Up to 10TWh (74%) |
| Movable demand from heating[63] | 34 TWh (100%) | 90TWh (100%) | 182TWh (100%) |
| *Heating demand with fuel switching options* | *0 TWh* | *30TWh (33%)* | *2TWh (1%)* |
| Movable demand from transport | Up to 3TWh (75%) | Up to 12TWh (75%) | Up to 96TWh (75%) |
| *PHEV demand (fuel switching option)* | *2 TWh (50%)* | *8 TWh (50%)* | *0 TWh* |

The amount of movable demand available each day will vary according to the profile of the underlying energy demand. For example, the daily level of movable heat demand will be much higher in the winter than in the summer.

The maximum possible figures for movable demand in a hour (Table 15) look very large, particularly for 2050 – this is driven by the fact that there are many millions of heating units and electric vehicles rather than by optimistic assumptions about the charging rate of individual units. We assume an average charging capacity of about 5kW for a car battery and 5kW (heat) for domestic heating, which equates to an electricity demand of about

60 This is consistent with Ofgem's statement in its recent paper on demand-side response (page 2) that the 'proportion of current demand that can be shifted is relatively small'. 'Demand Side Response. A Discussion Paper', 15 July 2010, Ofgem.

61 This is assumed to result from boilers not being scrapped prematurely as a result of an accelerated roll-out of heat pumps.

62 Wet appliances are assumed to account for about 15% of residential electricity demand (excluding heat and electric vehicles).

63 This assumes that storage is installed alongside all electric heating systems. Section 7.1.2 discusses the significant difficulties of delivering this level of storage in practice, particularly at high levels of penetration of electric heating.

1.5kWe for heat pumps. In addition, wet appliances are assumed to require a minimum of two hours to complete their cycle, which means that the maximum demand is only equal to half the movable demand within a particular period.

As the following sections explain, there are a number of restrictions on demand flexibility which then determine the magnitude of the response actually delivered at different times.

**Table 15 – Potential maximum limit for hourly movable demand** (GW)

| **Type of demand** | **2030 world without electrification** (CF 1) | **2030 world with electrification** (CF 2) | **2050** (CF 3 and CF 4) |
|---|---|---|---|
| Movable demand from wet appliances | 6 | 6 | 9 |
| Movable demand from heating | 27 | 73 | 168 |
| Movable demand from electric vehicles | 3 | 15 | 99 |

Table 16 illustrates how increased flexibility changes the level of demand in the peak periods in the reference case in the 2030 world with electrification (CF 2).

In the reference case, the peak final demand (i.e. excluding network losses) is around 76GW in the reference case, with about half of the demand coming from lighting and processes in the non-residential sector. Around a third of demand is for heating (residential and non-residential), with the remainder (around 15%) primarily being from lighting and appliances in the residential sector.

Ex-ante tariffs reduce demand by about 15GW (to 61GW) for the same hours in the 'flexible generation' and 'imported flexibility' packages. The main reduction is in heating demand which falls from about 23GW to 9GW. There is also a small shift in electric vehicle demand, which is low in 2030. The fall in residential demand is driven by shifting in demand from wet appliances, which account for about 15% of residential demand.

In the 'active demand side' package, there is a further fall in demand to 51GW primarily in response to the low wind output in these periods (about 2.5GW out of installed capacity of 31GW), which means that more demand has to shift away from the peak than on an average day. This is helped by increased flexibility of electric vehicle and wet appliance demand in this package.

The delivery of this level of response in practice would be very challenging, because of both the consumer engagement required and the economic and practical aspects of delivering storage alongside heat pumps.

**Table 16 – Demand at peak periods (in reference case) in 2030 world with electrification[64]** (Counterfactual 2, GW)

| Type of demand | Reference case | Ex-ante tariffs | Active demand side |
|---|---|---|---|
| ASHP | 14.4 | 4.4 | 0.7 |
| GSHP | 5.9 | 1.8 | 0.3 |
| Non-heat pump heat | 3.2 | 2.7 | 0 |
| Electric vehicles | 1.9 | 1.6 | 0.5 |
| Residential (lighting and appliances) | 13.1 | 12.5 | 11.8 |
| Non-residential (lighting and processes) | 37.3 | 37.5 | 37.4 |
| **Peak final demand** | **75.9** | **60.6** | **50.6** |

### *5.6.2 Speed of flexibility*

The ex-ante tariffs are assumed to fix the expected demand shape at say the month-ahead stage, meaning that there is no flexibility to changes in the pattern of wind or in response to unexpected variations in demand.

Apart from the minimum on time of two hours for wet appliances, the active demand side response is fully flexible from hour to hour (subject to being able to meet underlying energy demand profile).

Refrigeration is likely to be a demand side option that offers the fastest response, making it suited to the provision of ancillary services, such as reserve and response, within the wholesale market. However, there are questions over the duration of this response (in terms of stretching beyond one hour), which would affect the ability of refrigeration to capture value in a model of an hourly electricity market.

### *5.6.3 Duration of flexibility*

#### *5.6.3.1 Active demand side*

For wet appliances, the duration of flexibility is limited by the length of time over which consumers are willing to shift the underlying energy demand. We assume that consumers would be happy to shift demand within a window of twelve hours (either 7pm to 7am, or 7am to 7pm).

64 All demand figures shown in Table 16 illustrate the level of demand in the hours that peak demand occurs in the reference case. These hours may not be the hours in which peak demand occurs in the flexibility packages.

For heating and transport, the duration of flexibility is determined by the interaction between the underlying energy demand profile and the size of storage. Storage is separately managed for different users (e.g. electricity in storage for residential ASHPs cannot be used to meet electricity demand from residential GSHPs or from non-residential ASHPs).

We assume that for both the residential and industrial sectors, heat storage is large enough to store just over a day's worth of average heating demand[65] for that sector, which equates to a total storage capability of about:

- 105GWh in 2030 world without electrification;
- 281GWh in 2030 world with electrification; and
- 661GWh in both 2050 worlds;

This means that its effective storage capability in terms of hours of consumption is much lower in the winter when space heating demand is high, and much larger in the summer when space heating demand is low. A further constraint on storage is that we assume energy losses in heat storage at 1% per hour[66].

We assumed the battery size of EVs allows for 4 days of average usage (96km or 19kWh) in 2030 and 3 days of average usage (116km or 23kWh) in 2050 to reflect an expected decline in the importance of 'range anxiety'.

The assumed battery size was smaller for PHEVs (which are only in 2030) at 12kWh (60km). This is equal to 3.5 days of average electricity usage by these vehicles, which can provide additional flexibility through fuel switching.

A further restriction imposed on storage in a vehicle battery was that there needed to be 1.5 days of average usage (which varied by user) in the battery needed to be at the end of the daily period in which the battery is available for charging. For a high user, this level represented 70% of the capacity of the battery in 2030, and 90% in 2050.

#### *5.6.3.2 Ex-ante tariffs*

We assume the following:

- demand from residential wet appliances is shifted overnight;
- heating demand can only be shifted within-day (given the restrictions on storage and the unpredictability of day to day variations when setting tariffs); and
- EV demand can be shifted by at most one day (from Friday and Monday into the weekend) [67].

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65 As discussed earlier, we are exploring the potential for the demand side to provide flexibility. There is significant uncertainty about the extent to which heat storage would be delivered in practice, particularly alongside heat pumps.

66 This factor is based on the energy efficiency of a heat storage facility. As information improves on the operational performance of heat pumps, you would also need to take into account the dynamic impact on the coefficient of performance of heat pumps of having to heat water to a higher temperature for storage over longer periods.

67 Ex-ante tariffs are assumed to differentiate between three types of days – working days, Saturdays and Sundays, Therefore, they cannot shift demand between working days.

### 5.6.4 Availability of flexibility

There are two key determinants of the availability of flexibility – the energy demand profile and behavioural restrictions.

For wet appliances, the energy demand profile follows the existing residential electricity demand profile, meaning that it is a little higher in winter than in summer, and at weekends than in week. We assumed that customers were willing to shift their usage only within a twelve hour period, which was overnight (7pm to 7am) for all 'flexible' customers in 2030. By 2050 in the 'active demand side' flexibility package, some customers were also willing to shift demand during the daytime (7am to 7pm).

It was agreed with the CCC that demand from electric vehicles would be flat across the week and the year. This means that the availability of flexibility from electric vehicles was broadly constant across the year. For the active demand side package, the within-day shape of energy demand from electric vehicles was based on data on the current driving profile.

The mobile nature of a car means that it has to have an energy store, but also means that energy store might not always be 'plugged in'. Although cars are stationary for approximately 90% of the time, they may not always be parked in a place where charging is possible (depending on the nature of the charging infrastructure that is in place).

Consequently for the 'active demand side' package, we allocated the cars into three groups depending on when they were available for charging:

- available all day (assumed to 25% of vehicles with movable demand);
- overnight chargers (7pm to 7am – 37.5% of vehicles with movable demand); and
- daytime chargers (7am to 7pm – 37.5% of vehicles with movable demand).

At all other times, the cars were assumed not to be available for charging (or discharging back onto the grid).

Unlike cars, heating systems are always 'plugged in' and hence available for charging. However, the flexibility that they can provide as active demand units is restricted by the energy demand profile. When demand is high (as in the winter), then there is more movable demand but it can shifted over shorter periods (because of storage limits). During the summer, the amount of movable demand is low but it can be shifted over longer periods, subject to the impact of energy losses on the cost of shifting.

For ex-ante tariffs, heating demand could only be shifted within-day meaning that the daily heating demand determined the amount of movable heating demand each day.

Gas prices are typically lower in the summer which increases the relative attractiveness of fuel switching than compared to the winter (when the electricity system may be more stressed and hence fuel switching might be more useful).

### 5.6.5 Cost of flexibility

A number of investment costs are associated with the provision of demand side flexibility:

- smart demand infrastructure (smart meters, smart grids etc);
- smartening of appliances;
- distribution network reinforcement;
- storage costs; and
- charging infrastructure.

The first three categories are covered in our estimate of system cost discussed in Section 6.2.4. The costs of delivering smart infrastructure are assumed to be greater for the 'active demand side' package than for the other flexibility packages that use ex-ante tariffs, which provide a less dynamic response.

Costs of storage and of the charging infrastructure are assumed to be inherent costs of electrification, rather than flexibility, and hence have not been included in our assessment of system cost for this study.

The key operational costs of flexibility taken into account in this study are the cost of fuel switching (based on cost of alternative fuel) and energy losses, primarily from heat storage and from the round trip efficiency of vehicle batteries used to provide electricity back to the grid (assumed to be 75% for EVs and 60% for PHEVs).

Two other costs were considered in the study – inconvenience costs and impact on vehicle battery lifetime of different charging patterns.

Inconvenience costs are driven by customers having to change their behaviour and hence particularly apply to changes in energy demand (e.g. for wet appliances). In this case, we assumed that demand is only shifted within a twelve hour period by some 'flexible' customers, which would limit any inconvenience costs.

For electric vehicles, there may be some costs of not having the battery fully charged at all times but it is difficult to robustly assess the magnitude of these costs given current availability of data on use of electric vehicles.

The biggest impact of battery cycling (i.e. charging and discharging) is on low users as more of the capacity is available for cycling. Our understanding is that it is not clear at the moment the extent to which current restrictions on the duration of battery lifetime (defined in number of years) would generally drive replacement before the impact of greater cycling is felt.

# 6. ASSESSMENT OF FLEXIBILITY PACKAGES

We used our wholesale electricity model *Zephyr* to carry out a detailed quantitative assessment of the different flexibility packages shown in Table 17[68]. This chapter first looks at the flexibility packages in more detail before summarising their performance against the four key performance criteria – carbon dioxide emissions, security of supply, generation costs, and total system cost.

We then review selected findings of interest, looking at issues such as the change in the variability of non-intermittent generation, the conflict between use of demand side response for generation and network purposes, and reserve and response.

Finally, we conclude by reporting the results of some additional sensitivities related to space cooling demand and use of hydrogen production from electrolysis to take advantage of periods of low electricity prices.

**Table 17 – Flexibility packages[69]**

| Flexibility packages | Generation | Demand | Interconnection and storage |
|---|---|---|---|
| Flexible generation | More flexible nuclear and CCS | Ex-ante ToU tariffs smooth demand | As in reference case |
| Imported flexibility | More flexible district heating CHP | Ex-ante ToU tariffs smooth demand | More interconnection More storage |
| Active demand side | As in reference case | 'Real-time' response from demand | As in reference case |

In summary, all three flexibility packages deliver a wholesale market with lower generation costs, lower carbon intensity and at least the same level of security of supply as the reference cases. Further analysis of wider energy system cost and implementation risks would help to more strongly differentiate the flexibility packages.

In practice, the optimal solution is likely to be a mixture of the three packages. As well as helping to deal with uncertainty about the exact flexibility mix required, diversity in supply can help to mitigate the impact of lower delivery from one source, and higher costs and challenges as we move further up the supply curve for a particular flexibility option.

The fall in wholesale cost does not necessarily translate into lower time weighted average (TWA) wholesale prices. This is because the TWA wholesale electricity price is driven by the long run marginal costs (LRMC) of new entrant low-carbon generation, such as nuclear, CCS coal and CCS gas. The level of TWA wholesale prices would also be affected by assumptions about the level of non-market revenue available to nuclear and CCS plants.

68 Green boxes denote a strong contribution, amber boxes identify a weak contribution and red boxes show where there was no contribution at all.

69 In all three packages, it was possible to deload wind (and wave) generation if required to balance supply and demand.

Increased flexibility would change the shape of wholesale electricity prices within the day and across the year. This could undermine the case for investments in technologies such as storage and interconnections that obtain their funding from arbitraging between periods with different price levels.

## 6.1 Flexibility packages

The three alternative flexibility packages were based on the following themes:

- **Flexible generation** – ex-ante time of use tariffs were used to smooth the expected demand profile with 'real-time' flexibility being provided by (new) nuclear and CCS capacity that can operate more flexibly than in the reference case (as described in Table 11);
- **Imported flexibility** – ex-ante time of use tariffs were used to smooth the expected demand profile with 'real-time' flexibility being provided by expansion in the capacity of interconnection and bulk storage (as described in Table 12) and by district heating CHP (as described in in Table 11); and
- **Active demand side** – active management of demand within the modelling process, primarily from heating and transport, provided greater system flexibility (as described in Section 5.6).

In all three packages, it was possible to deload wind (and wave) generation if required to balance supply and demand.

Annual electricity demand input into the model was the same level as in the reference cases for all of the flexibility packages. However, the installed (non-renewable) generation capacity was adjusted in response to changes in operating patterns of different plant types in a more flexible system.

The flexibility characteristics of the different categories of movable demand are relatively stable across counterfactuals. However, there is significant difference between the counterfactuals in the amount of movable demand available:

- **Demand from wet appliances** is around 15% of residential electricity demand (non-heat and non-transport). This is relatively most important in the 2030 world without electrification (CF 1), where there is little demand from heat and transport.
- **Demand for heating** is biggest in absolute terms in 2050, but as a share of overall electricity demand, it is most important in the 2030 world with electrification (CF 2).
- **Electric vehicle demand** grows from 16TWh in 2030 world with electrification (CF 2) to 128TWh in both 2050 worlds (including demand for electricity to produce hydrogen for the transport sector).

### *6.1.1 Variant package for active demand side management*

We modelled an additional flexibility package as a variant on the 'active demand side' package, in which more constraints were placed on the use of storage. This was intended to explore the difference between smart grids, allowing coordinated use of storage as in the main load management scenario, and smart meters, with uncoordinated use of storage.

There was very little impact on the performance of the flexibility package with respect to emissions, security of supply or costs in the wholesale market. This reflects the fact that the only change in wholesale modelling assumption was a simple constraint on the coordination of use of storage. It is hard to gain insight from wholesale market modelling

as this cannot capture many of the possible practical advantages for a smart grid compared to smart meters. These benefits could include local distribution network benefits, faster response within-hour, and reduced risk of herding in a price driven response.

## 6.2 Performance against assessment criteria

These packages were assessed with respect to four detailed quantitative criteria – carbon intensity, security of supply, generation cost and total cost. A benchmark was provided by the reference cases (one for each counterfactual) in which flexibility in both supply and demand is limited to the flexibility of generation and customers that we observe today.

The results are summarised below and then explored in more detail in the following sections:

- **Carbon intensity of the power generation sector** – generally lower than in the reference cases for all combinations of counterfactuals and flexibility packages (with only one exception).
- **Security of electricity supply** – investments in generation capacity were adjusted to ensure that the flexibility packages delivered security of supply broadly in line with reference cases.
- **Total generation cost** (covering investment and operating costs) – this was lower than the reference cases for all combinations of counterfactuals and flexibility packages. The fall in wholesale costs was broadly similar across the three flexibility packages, and was around 5-10% in 2030, and 10-15% in 2050.
- **Total system cost** – the impact on total cost is inconclusive. This is because of the uncertainty about non-generation cost, relating to both the level of this cost and the extent to which it should be attributed to the provision of flexibility (such as smart metering).

The generation and system cost estimates should not be used to compare the desirability of the different low-carbon worlds as they differ to the extent to which final energy demand (e.g. useful heat, mobility) that is met by electricity. A comparison of the counterfactuals would require an assessment of the total cost of meeting all final energy demand (by a combination of electricity and alternative fuels).

Annex A contains further detailed results for each reference case and flexibility package for each counterfactual:

- capacity, output and load factor by generation technology;
- costs and carbon dioxide emissions by generation technology; and
- costs by category.

### *6.2.1 Carbon emissions*

Table 18 compares the carbon intensity (per kWh of final demand) of the electricity generation sector in the reference cases with the levels achieved in the flexibility packages. The improvements seen in virtually all cases with greater flexibility are typically the result of an increase in load factor and installed capacity for low-carbon plant, primarily nuclear, at the expense of gas-fired generation.

'Imported flexibility' was the flexibility package with the best performance in the two counterfactuals for 2030. There was a constraint on interconnector flows to balance

across the whole year which means that the reduction in emissions was not due to a reduction in annual generation in the GB system.

In the 2050 counterfactual with CCS (CF 3), there is relatively little difference in the performance of the different flexibility packages. In the 2050 world in which there is no CCS (CF 4), emissions are lower in the reference case than for CF 3. This is because there is more zero-carbon generation because it is dominated by wind and nuclear. CCS coal and CCS gas is low-carbon generation because only 90% of emissions are captured. As the capture process reduces the net generating efficiency of the plant, this means that emissions from CCS plants are more than 10% of the emissions from an unabated plant.

In the 'flexible generation' package, the replacement of low-carbon generation with zero-carbon generation does not significantly reduce carbon intensity in CF 4 compared to CF 3. In contrast, the 'imported flexibility' and 'active demand side' packages respond to a 'technology risk' (failure to deploy CCS commercially) by significantly reducing the carbon intensity of the generation sector in CF 4 compared to CF 3.

Shifting demand from peak to off peak is likely to be a good thing for high capital cost (generally low CO2) generation. However, the 'active demand side' package in the 2030 world with electrification (CF 2) actually increases the carbon intensity of the generation sector compared to the reference case .

The demand side response is so effective at lowering peak demand net wind that it reduces the space for CCS coal build. As a result, some of the generation from CCS coal in the reference case is replaced by nuclear but about a third is replaced by production from existing CCGTs which pushes up emissions. This is primarily a transitional issue as the effect is not seen in 2050, and also suggests that in this case, (anticipated) under-delivery of demand side response could actually help to lower carbon intensity of generation.

The other two flexibility packages perform much more strongly in the 2030 world with electrification (CF 2) than in the case without electrification (CF 1). This is helped by use in these packages of ex-ante tariffs to smooth the expected within-day profile of demand. In the 2030 world with electrification, these tariffs are more effective as the deployment of heat pumps means that there is initially a more variable within-day demand shape and a greater amount of flexible demand that can be moved.

**Table 18 – Carbon intensity of electricity generation sector** (gCO2/kWh of demand)

| Flexibility package | 2030 world without electrification (CF1 ) | 2030 world with electrification (CF 2) | 2050 world with CCS (CF 3) | 2050 world with no CCS (CF 4) |
|---|---|---|---|---|
| Reference case | 101 | 89 | 42 | 32 |
| Flexible generation | 91 | 71 | 20 | 18 |
| Imported flexibility | 76 | 64 | 22 | 14 |
| Active demand side | 84 | 97 | 19 | 11 |

### 6.2.2 Security of supply

The capacity mix in each scenario was adjusted to deliver a level of security of supply broadly in line with that achieved in reference case for each counterfactual. This means that the benchmark figures for total expected energy unserved were around 2GWh in 2030 and approximately 4GWh in 2050 based on a much higher level of electricity demand. These figures take account only of occasions in which generation is insufficient to meet demand, and therefore exclude the impact of network failures.

Table 19 shows this constraint was broadly met by each flexibility package. It was not possible to exactly meet the constraint in every case because the flattening of the expected profile of demand net wind makes the level of expected energy unserved increasingly sensitive to the installed mix. This means that the observed differences ine expected energy unserved are not material enough to be used to differentiate between the flexibility packages.

**Table 19 – Expected energy unserved** (GWh/a)

| Flexibility package | 2030 world without electrification (CF 1) | 2030 world with electrification (CF 2) | 2050 world with CCS (CF 3) | 2050 world with no CCS (CF 4) |
|---|---|---|---|---|
| Reference case | 2 | 2 | 3 | 5 |
| Flexible generation | 2 | 2 | 3 | 4 |
| Imported flexibility | 1 | 1 | 5 | 3 |
| Active demand side | 1 | - | - | 5 |

### 6.2.3 Total generation cost

For each case, Figure 32 shows the time weighted average (TWA) annual wholesale electricity alongside the (annualised) generation cost, which consists of:

- capital investment costs (capex);
- fuel costs;
- fixed annual costs (FOWC – Fixed Other Works Costs);
- (strictly) variable operating costs (VOWC – Variable Other Works Costs);
- fuel and maintenance costs from starting plant and from running plant part-loaded, which reduces efficiency (SUNL – Start-Up and No-Load); and
- carbon costs, which represents the cost of carbon emissions evaluated at the assumed price for carbon of £70/t$CO_2$ in 2030 and £200/t$CO_2$ in 2050[70].

[70] 'Carbon Valuation in UK Policy Appraisal: A Revised Approach', July 2009, Climate Change Economics, Department of Energy and Climate Change.

It highlights the importance of capital investment, which is by far the largest cost component in all cases. These investment costs are driven by high capital costs of low-carbon generation, rather than by investment in peaking generation (or even CCGTs) which has relatively low capital costs. This means that total capital expenditure may not be reduced by the provision of increased flexibility if it results in the construction of more low-carbon generation capacity[71].

Consequently, any benefits from the flexibility packages might primarily be seen in the change in operating patterns which affects only a relatively small proportion of the bill. Although improved utilisation may reduce start-up and no-load costs, this is a very small part of the overall bill.

This is illustrated by the cost breakdown in the reference case for the 2050 world without CCS, which is heavily reliant on nuclear and wind. Compared to the reference for Counterfactual 3 (which has CCS generation), capital costs are much higher. However, fuel costs are well below the level seen in 2030 although electricity demand is much higher by 2050.

Overall savings in the generation cost from the flexibility packages are limited in the 2030 world without electrification (CF 1). As expected, the savings are smallest in the flexibility package relying on active demand side management because the scope for this is much more limited in the absence of electrification.

In contrast, the 'active demand side' flexibility package achieves the largest savings of the three flexibility packages in the 2030 world with electrification (CF 2). However, this reinforces the point made earlier about high capital costs of low-carbon generation. In this package, there is lower CCS coal build than in the reference case, with some of the generation from CCS coal in the reference case being replaced by production from existing CCGTs. This reduces capital costs but means that fuel and carbon costs with the demand side flexibility package are actually slightly higher than in the reference case.

The savings from increased flexibility are much greater in the two 2050 worlds (CF 3 and CF 4). This is helped by the high level of peaking capacity in the reference cases – 28GW in the world with CCS (CF 3) and 35 GW in the world without CCS (CF 4). Consequently, shaving peak demand net wind leads to capex savings from avoided investment in peak generation, supported by lower fuel and carbon costs.

The performance of the flexibility packages is broadly similar in Counterfactual 3. However, the reliance on nuclear flexibility in Counterfactual 4 (owing to the absence of CCS coal, and CHP) means that the 'flexible generation' package makes the smallest savings in this world, particularly compared to the 'active demand side' package.

71 In addition, peaking plant may still be needed to provide reserve even if it is not required for peak energy capacity. If so, this will push up the cost of reserve and negate the capital investment cost savings from avoided investment in the wholesale electricity market.

**Figure 32 – Total generation cost and wholesale electricity prices** (real 2009 money)

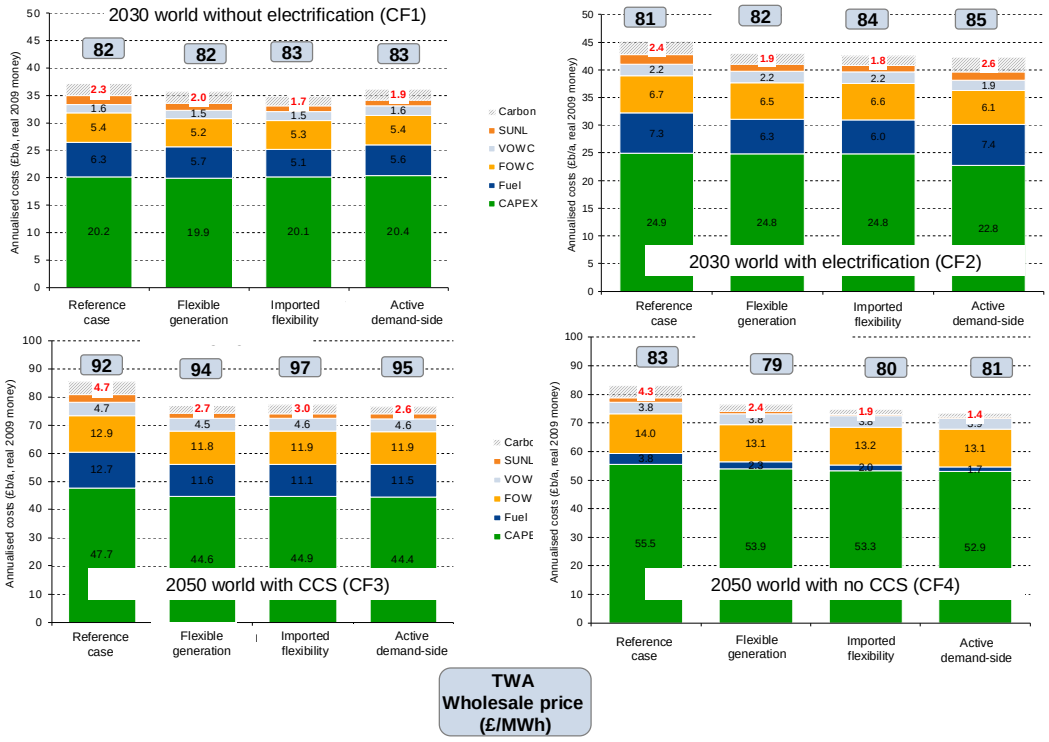



Figure 32 illustrates that the fall in generation costs only translates into lower time weighted average (TWA) wholesale prices in one of the four counterfactuals (2050 world without CCS). In fact, the TWA wholesale electricity price increases in the flexibility packages in the three other counterfactuals.

This is because, the TWA wholesale electricity price is assumed to be driven by the long run marginal costs (LRMC) of new entrant low-carbon generation, such as nuclear, CCS coal and CCS gas. The level of TWA wholesale prices would also be affected by assumptions about the level of non-market revenue available to nuclear and CCS plants.

As part of the modelling process, we compare the achieved IRR (internal rate of return) of the plant (based on its modelled revenues) with its target IRR. If a technology achieves an IRR above its target, it suggests that it would be profitable for more plants of that technology to be built. Such an event encourages more plant into the market, which then decreases the IRR (and load factors) back towards the target level.

However, it was not possible to ensure that the IRRs of the nuclear and the CCS plants reached an exact equilibrium of 10% in each combination of counterfactual and flexibility package.

The IRR is quite sensitive to capacity assumptions and hence it is not possible to reach exactly the equilibrium level in each case. This was the main reason for the pattern of the TWA prices within each counterfactual – the range may have been narrowed by repeated iteration but this is definitely subject to the law of diminishing returns.

For nuclear plants, the IRRs were consistently higher than that of the CCS plants. If we were building scenarios from scratch, then we would have reduced the CCS capacity and increased the nuclear capacity. However, we generally took the capacity assumptions

given to us for the reference case as a floor for the capacity for the nuclear and CCS plants.

In Counterfactuals 1, 2 and 4, nuclear achieved IRRs of 10-11% across the reference case and scenarios. However, in order to maintain the large CCS capacity in Counterfactual 3, we took a portfolio approach whereby we built a mix of nuclear and CCS and looked at the IRR of this new build mix. This pushed nuclear IRR to 12-13% because CCS IRRs were below 10%.

If it was assumed that the CCS plants received additional support from outside the wholesale market, then the IRR of nuclear in Counterfactual 3, and hence the TWA wholesale electricity price could have been comparable to those in Counterfactuals 1, 2 and 4. This would not have affected the generation cost but would have affected the level of average annual wholesale electricity prices.

The within-year shape of prices is sensitive to assumptions about whether an explicit capacity payment is made (which we have assumed that it is in order to support the construction of peaking plant) and the formula for spreading that payment over the year.

### *6.2.4 Total system cost*

Estimates of the overall (annualised) system cost are shown in Figure 33, and have been converted into figures for the average cost per MWh of electricity demand to help compare the system cost between counterfactuals.

The chart illustrates that the generation cost represents the majority of the system cost evaluated in this study. Of the non-generation cost, electricity distribution network costs vary the most between flexibility packages and between the counterfactuals.

Distribution costs are driven by a combination of peak demand and locational issues. For this study, we have derived distribution costs by scaling the existing annual distribution cost by the change in peak electricity demand for residential, heating and transport (i.e. excluding demand in the non-residential sector for uses other than heating and transport). These demand categories are likely to be found at the lower levels of the distribution network, and are likely to be a stronger driver of distribution costs than overall peak demand.

This means that distribution costs increase with electrification of heating and transport by more than the proportionate increase in overall electricity demand. This can be seen by comparing the distribution costs for each reference case shown in Figure 33.

All three flexibility packages use some form of demand smoothing, whether it is based on ex-ante tariffs or on some form of active demand response. This involves shifting demand for heating, electric vehicles and residential washing, which can actually cause increase the peak demand for these demand groups.

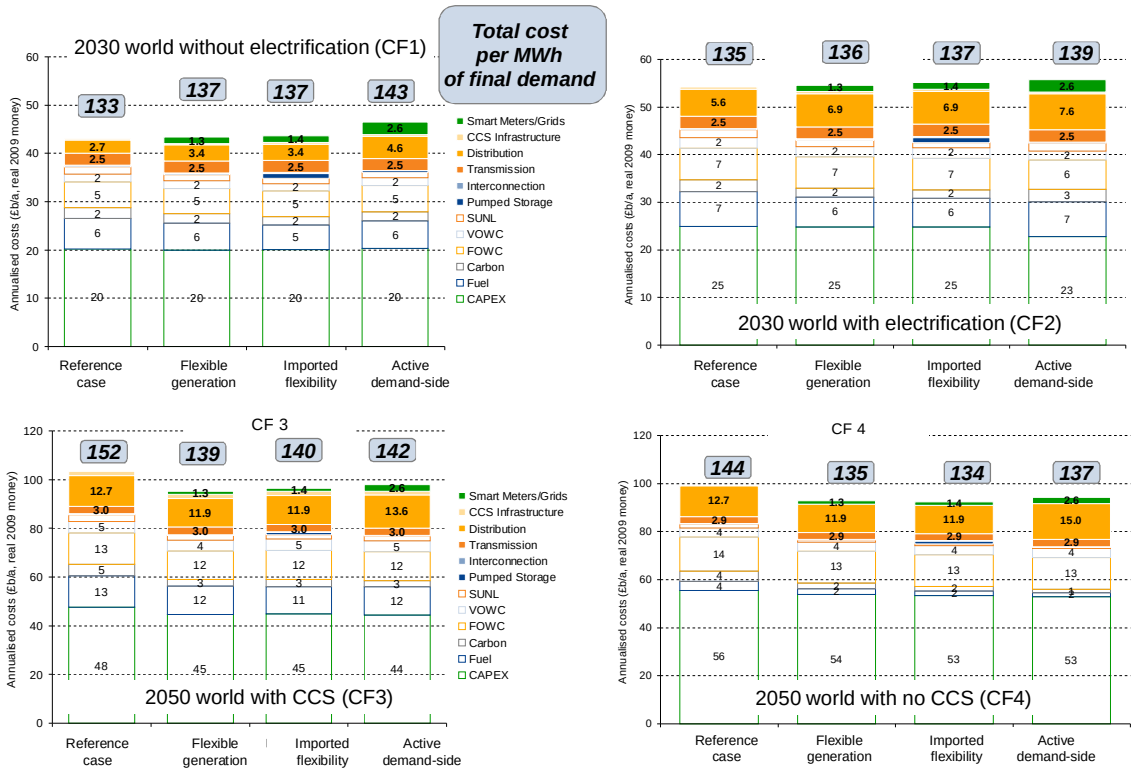
In the ‘imported flexibility’ and ‘flexible generation’ packages, the ex-ante tariffs shift heating and transport (and some residential) demand in order to flatten the overall demand profile. In the 2030 worlds, flexible demand is a relatively smaller proportion of overall demand, which means that more of the heating and transport demand is shifted, and hence distribution costs go up in these flexibility packages.

By 2050, heating and transport are a much bigger share of overall demand. Therefore, flattening the demand profile actually results in a reduction in peak heating, residential and transport demand, as well as a reduction in overall demand.

In the 'active demand side' flexibility package, the flexible demand is shifted to flatten demand net wind rather than demand. This means that there are times when demand is increased in response to high wind, rather to flatten the demand profile. As a result, this means that in each counterfactual, distribution costs in the 'active demand side' flexibility package are higher than in the reference case and than in the other two flexibility packages.

There could also be particular locational issues for networks if response is concentrated amongst clusters of customers with electric heating and electric vehicles. Section 6.3.2 explores further the possible trade-off between smoothing peak demand for generation and smoothing peak demand on distribution networks.

**Figure 33 – Estimated system cost** (real 2009 money)




The other non-generation cost component that varies significantly is the cost of the infrastructure for enabling response, as proxied by the costs of smart meters and grids.

We have assumed that ex-ante time of use tariffs require smart meters so that hourly consumption data can be calculated and tariffs can be updated remotely (on say a monthly basis). The figure of around £1.4m (annualised) is almost entirely comprised of the costs of the preferred options for smart metering in domestic and non-domestic sectors set out in the Government's impact assessment on the deployment of smart metering.

For the 'active demand side' flexibility package, there are additional costs driven by:

- network investment to ensure the communications required to underpin 'real-time' tariffs (estimated at around £500m per year based on the Phase I of the smart grid strategy presented by the ENSG); and
- further requirements for 'smartening' appliances in the home (annualised at around £600m per year).

In this study, we have allocated all of the costs of the smart infrastructure to the provision of system flexibility, whereas in practice, the smart infrastructure also provides a number of other benefits including:

- smart meters[72];
  - better billing;
  - remote reading of meters;
  - improved customer information for energy efficiency;
- smart grids[73];
  - enhanced network management;
  - facilitation of generation connection;
  - improved system operation; and
  - (possibly) mitigating risk of customer herding.

It is uncertain how the costs of the smart infrastructure should be allocated between the provision of flexibility and other benefits listed above. This means that in an evaluation of the costs and benefits of system flexibility, the smart infrastructure costs allocated to wholesale market flexibility can range from zero (i.e. the infrastructure would be built anyway) to 100% (as we have done).

On the other hand, we have not included the costs of investments in storage for heating and transport. At the time of modelling, it was uncertain to extent to the delivery of storage would be an integral part of the electrification process. As further details emerge of the prospects for electrification, particularly with respect to heat storage, then an analysis of the costs and benefits of flexibility would need to consider the extent to which investment in storage is specifically driven by flexibility needs.

For example, in a study for the CCC on low-carbon heat scenarios (issued after the completion of the analysis for this study)[74], the assumed differential between peak and off-peak electricity prices (in the central case) means that storage would be economic for about half of non-residential heat pump demand and virtually no heat pump demand in the residential sector.

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72 Time of Use tariffs are only of seven options for smart meters being trialled in the Energy Demand Reduction Programme being overseen by Ofgem.

73 Although there is no standard global definition, the European Technology Platform for Smart Grids (http://www.smartgrids.eu/) defines Smart Grids as electricity networks that can intelligently integrate the behaviour and actions of all users connected to it – generators, consumers and those that do both – in order to efficiently deliver sustainable, economic and secure electricity supplies.

74 'Decarbonising Heat: Low-Carbon Heat Scenarios for the 2020s. Report for the Committee on Climate Change', June 2010, NERA and AEA.

Figure 33 shows that the other cost components are a relatively small part of the overall total. This means that where there is uncertainty about costs in these areas, this is unlikely to have a material impact on the picture for overall system cost. However, in all of these areas, the ability to physically deliver the investment required is likely to be a much bigger barrier than cost, and have a bigger impact on system flexibility. For example, transmission costs are largely driven by the locational pattern of generation (rather than by its operating pattern or by demand) and are a relatively small part of the overall costs. However, the delivery of adequate transmission capacity is a vital part of ensuring delivery of a low-carbon energy future.

In summary, the differences in system cost between the flexibility packages are not definitive given the uncertainty about:

- the extent to which these costs should be attributed to flexibility measures (e.g. smart meters or smart grids, which could have much wider benefits than considered in this study); and
- the level of some of these costs (given the scope of this study), particularly distribution network costs.

## 6.3 Selected results

We used our wholesale electricity model *Zephyr* to capture the interaction between supply and demand based on wind, availability and demand profiles for 9 years (2000 – 2008 inclusive). This provides a far richer set of results than can be covered in a high level summary of annual performance against the agreed assessment criteria, as described in Section 6.2.

Therefore, this section explores some selected results in more details, looking at areas such as:

- impacts of flexibility on dispatch patterns within a week;
- trade-off between smoothing network flows and smoothing non-intermittent generation; and
- reserve and response.

### *6.3.1 Impacts on dispatch patterns*

One of the benefits of flexibility is to reduce the impact of interaction between the patterns of demand and wind output on the dispatch pattern for non-intermittent generation. Section 4.2.6 described how in the reference case for the 2030 world with electrification, this dispatch pattern varies across one winter week based on weather of 2000 and one summer week based on weather of 2006.

Figure 34 and Figure 35 show how the different flexibility packages affect the dispatch pattern in these two weeks. When comparing the impact of different flexibility packages, it is important to remember that ‘imported flexibility’ and ‘active demand side’ are designed to smooth the requirement for non-intermittent generation. However, in the ‘flexible generation package’, low-carbon generation can run more flexibly and hence you might expect to see greater variation in their operating pattern.

The demand smoothing that takes place in all three flexibility packages allows CCGTs to run in a more stable pattern over the first few days of the January week, and virtually eliminates the need for peaking generation (compared to the reference case).

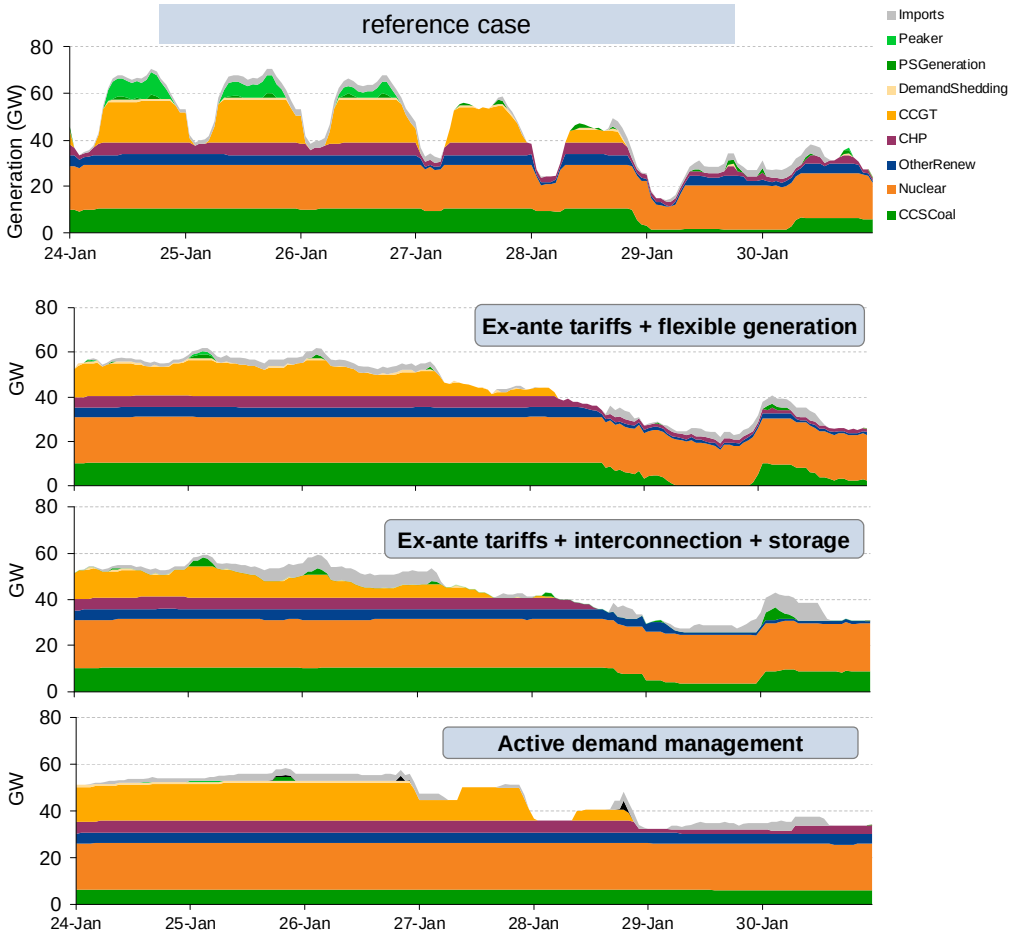
The 'flexible generation' package can't stop CCS coal plant closing down as a result of the falloff in demand on (Saturday) 29 January. However, it does reduce the 'blockiness' of the generation pattern for the CCS coal plants.

Similarly, some CCS coal plant still shuts down on 29 January in the 'imported flexibility' case, although unlike in the reference case, some CCS plant is able to keep operating over the whole weekend. The closed plant is also able to come back onto the system more quickly (by early Sunday morning) than in the reference case.

The 'active demand side' package is most effective at smoothing the operation of nuclear and CCS coal plant over the whole week, with none of it being shut down at the weekend. The dispatch of CCGTs in the first three days of the week is also much smoother than under the other two packages.

There is less CCS generation in the case with active demand management because there is less CCS installed. As explained in Section 6.2.1, demand side response reduces the amount of new generation build required, and hence there is lower CCS build in this package than in the reference case and in other two flexibility packages.

**Figure 34 – Dispatch in January 2030 under the different flexibility packages[75]**



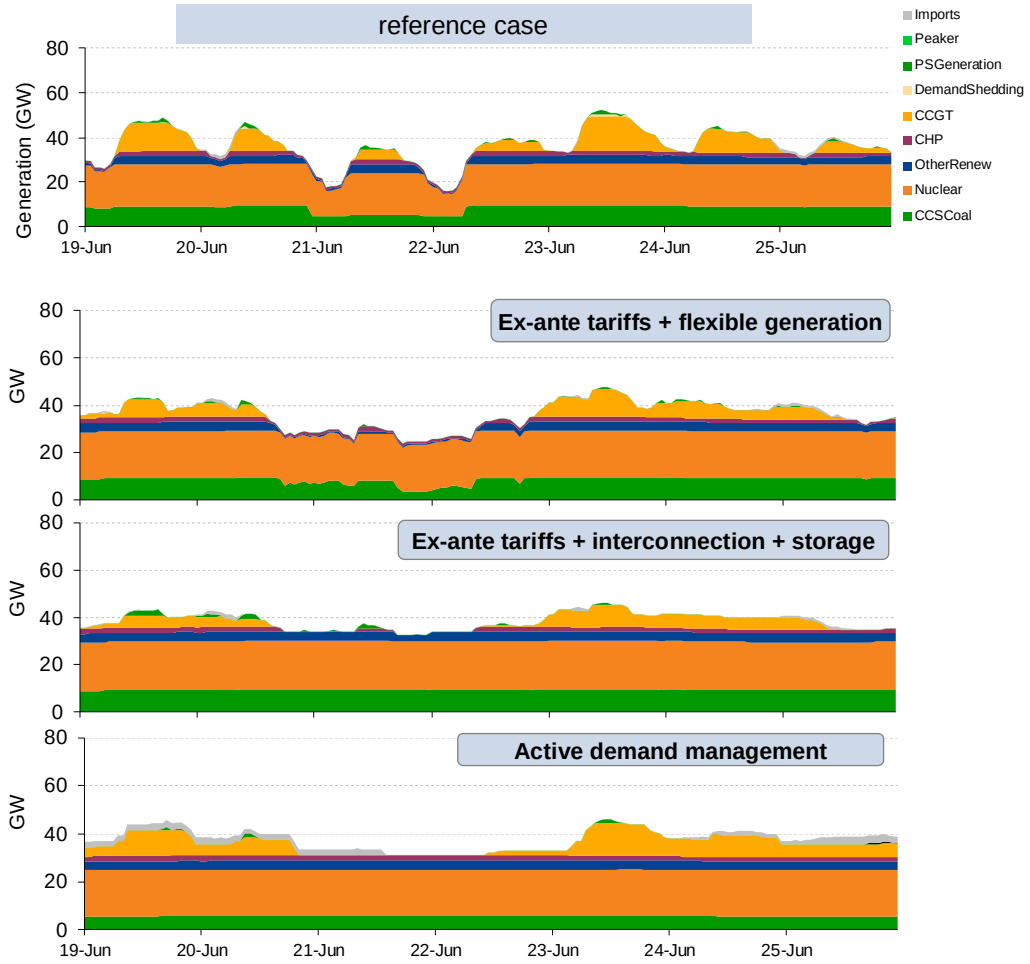

75 2030 case with electrification, Jan 2000 weather

The difference between the flexibility packages is much less clear in the dispatch patterns for the summer week (Figure 35). This reflects the fact that the heating demand is limited to hot water and hence there is much less flexible demand available.

Both the 'imported flexibility' and 'active demand side' packages manage to keep the CCS coal and nuclear plant on consistently throughout the week, even during the dip in demand seen on Wednesday 21 June. They also reduce the diurnal variations in CCGT dispatch.

In the other package (second chart), the generation can be seen to be operating more flexibly compared to the blocky pattern seen in the reference cases, with again the demand smoothing reducing the within-day swings in CCGT dispatch.

**Figure 35 – Dispatch in June 2030 under the different flexibility packages[76]**




### 6.3.2 *Trade-off between smoothing network flows and smoothing non-intermittent generation*

Demand side response is one instrument that may be used to meet two policy objectives – balancing variable generation, primarily wind, and flattening load. At times, these policy

76 2030 case with electrification, June 2006 weather

objectives would be complementary, for example when wind is low and demand is high. However, at other times, they would conflict such as when wind is high and demand is high. This tension may be particularly acute at lower levels of the distribution system, where the flexible demand sources for heating and transport are likely to be found.

Figure 36 illustrates this tension for a week in January, based on the 2030 world with electrification (and the weather pattern of 2000).

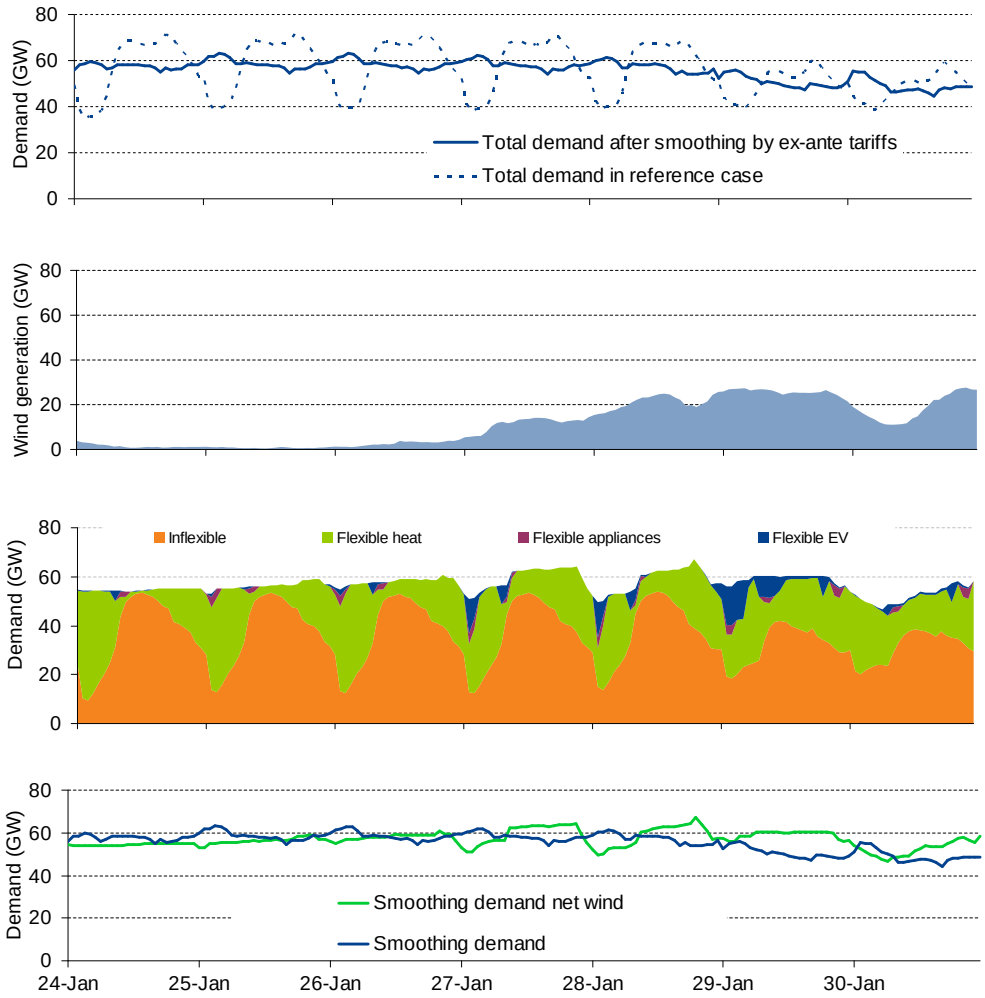
The top chart shows how the load curve seen in the reference case can be flattened through demand smoothing based on ex-ante tariffs (as used in two of the flexibility packages – 'flexible generation' and 'imported flexibility').

The variations in the pattern of wind generation during a single week are shown in the second chart. Based on an installed wind capacity of 31GW, output rises from an extended period of being at virtually zero to reach a load factor of nearly 100% in the latter half of the week.

The third chart shows how in the 'active demand side' flexibility package, different types of demand can be shifted in response to the change in wind generation.

The load flattening approach (top chart) and the dynamic demand side response (third chart) are then compared in the bottom chart. It shows that the two approaches produce similar results when the wind is low in the early part of the week. However, a 10GW difference in demand emerges between the two approaches in 29 January when wind output is at its peak.

**Figure 36 – Demand patterns from load flattening and generation balancing** (2030 with January 2000 weather, GW)




### 6.3.3 Reserve and response

Response and reserve requirements provide 'insurance' against unexpected changes in generation availability and (within-hour) fluctuations in demand. Keeping plant, such as CCGTs, warm or partloaded, would produce carbon dioxide emissions. Therefore, if a more flexible system can reduce the need for part-loading, then there should be emissions (and costs) benefits.

The hourly requirement for low frequency response (over timescales of up to 30 minutes) reduces as demand increases. Similarly, the need for tertiary reserve (between 30 minutes and 4 hours) falls at higher levels of demand but increases with the volume of wind and the wind forecast error. Improvements in wind forecasting would reduce reserve requirement, particularly in the 2050 world with no CCS where there is the biggest installed capacity of wind generation.

This means that increased level and flexibility of demand would reduce the hourly requirement for reserve and response to be met from thermal generation. This can include nuclear plants which can provide up to 10% of the capacity for response purposes even in the reference cases.

Higher electricity demand as a result of widespread electrification means that the residual requirement for low frequency response is reduced to 200MW at peak demand in 2050 reference cases. However, the flattening of the demand profiles that occurs in the flexibility packages means that the requirement increases again. At the same time, the increased flexibility reduces the build of peaking generation, which can be a key source of reserve and response without needing to be kept warm (and hence its emissions are driven by when reserve is called rather than by the 'insurance requirement'[77]).

The flexibility packages offer some alternative sources for meeting the reserve and response requirements, such as unused bulk storage capacity. This can be very important in the 'imported flexibility' package which has a 5GW increase in deliverability from bulk storage.

In the 'active demand side' package, the (technical) potential low frequency response from fridges could be up to 700MW, in addition to the scope for reducing charging of or increasing discharging from electric cars. Over the short timescales for frequency response, direct control may be a better solution for delivering demand flexibility than short-term price signals which may risk the creation of a stampede response amongst millions of customers.

This means that the biggest challenge for avoiding part-loading for low frequency response may be in the 'flexible generation' package, particularly at times where nuclear and CCS plant are operating close to capacity, and pumped storage is also generating already.

## 6.4 Additional sensitivities

There were two additional sensitivities carried out to explore flexibility options that did not fit into the main flexibility packages:

- higher demand for space cooling; and
- use of electrolysis to absorb excess electricity production

These sensitivities were only carried out against a subset of the counterfactuals and/or flexibility packages as they were focused on addressing the particular flexibility challenges raised by that combination(s) of counterfactual and flexibility package.

### *6.4.1 Space cooling*

Increasing seasonality of demand was one of the challenges for flexibility raised by the reference cases in the worlds with electrification of heat (CFs 2-4). Heat pumps lend themselves to providing space cooling in the summer months, which would reduce the seasonality of demand.

The impact of increased space cooling was explored by sensitivities on the 'flexible generation' package in Counterfactuals 2 and 4. The figures for annual cooling demand were 11TWh in 2030 (CF 2) and 26 TWh in 2050 (CF 4)[78]. Although annual electricity

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77 The lower generation efficiency of peaking plant compared to CCGTs means that the emissions would be higher when the plant was actually called, which would need to be set against the saving in 'warming' emissions.

78 Based on a 2006 Metroeconomica study for Defra., which set out estimates of annual cooling demand by sector for a number of economic and climate scenarios. The figures are contained in chapter 8 of the report.

demand was higher, it could reduce emissions if it increased the space for low-carbon generation to run at high enough load factors to be an attractive investment case.

The use of space cooling in Counterfactual 2 helped to reduce emissions and generation cost per MWh because it allowed additional investment in nuclear capacity which then displaced some CCGTs from the generation mix.

Total carbon dioxide emissions fell from 28Mt$CO_2$ to 26Mt$CO_2$. The increase in demand meant that the fall in carbon intensity (per kWh of demand) was proportionately larger – from 71g$CO_2$/kWh to 64g$CO_2$/kWh. Increased investment in nuclear capacity increased overall capex and annual fixed costs – however, the generation cost per MWh of demand fell from £107/MWh to £106/MWh.

The sensitivity on Counterfactual 4 actually led to an increase in emissions because the space cooling demand led to increased generation from CCGTs, as well as more investment in nuclear. This was because the demand pattern is less seasonal in 2050, as heating is a smaller part of the mix because of the high penetration of electric vehicles after 2030.

The higher level of CCGT generation in Counterfactual 4 pushes up both total emissions (from 12Mt$CO_2$ to 14Mt$CO_2$) and carbon intensity (from 18g$CO_2$/kWh to 20g$CO_2$/kWh). Despite the increase in total costs, there is a very small decrease in the generation cost per MWh of demand from £112/MWh to £111/MWh.

### *6.4.2 Electrolysis*

Electrolysis uses electricity to produce hydrogen and effectively provides an option for ‘mopping up’ excess low-carbon electricity to reduce the overall carbon intensity of the energy sector.

In this sensitivity, we assumed that the hydrogen would be used for injection into the gas grid, hence reducing the carbon intensity of the gas system. We could also have modelled other uses, such as use of hydrogen for transport, which are reliant on developments in the transport sector outside the scope of this study.

As electrolysis in this sensitivity relies on the flexibility of the gas system, it was tested as an additional option for the ‘imported flexibility’ package. Electrolysis only seems to be commercially viable, and in fact extremely profitable, in the 2050 world without CCS generation (CF 4).

In summary, the production of hydrogen through electrolysis appears to offer an attractive long-term option for allowing more low-carbon generation (to actually decarbonise the gas sector rather than the electricity sector). However, it is constrained by the level of daily (and annual) gas demand – if the pattern of daily gas demand across the year was more flexible (e.g. through increased storage), then this could allow more electrolysis to occur. For example, in the ‘imported flexibility’ scenario in Counterfactual 4, 2GW of electrolysis allows 6TWh more of nuclear generation (with low additional generation cost) with the resulting hydrogen reducing the carbon intensity of gas sector.

The high carbon and gas prices in 2050 means that the hydrogen produced is worth approximately £61/MWh. Based on a levelised cost of £45/kW/a, and the quoted efficiency figures, this means the electricity prices needs to be below £52/MWh (2050) for electrolysis to be commercially viable. This means that it is only of value when the marginal source of generation is nuclear or wind.

The combination of high wind and high nuclear in Counterfactual 4 means that the operating profit for a small test unit would be about £170/kW/a. There are questions however about the extent to which this level of profitability would be sustained if the electrolysis process would be scaled up, potentially cannibalising the expected revenue stream.

There is a daily limit of displacing no more than 15% of the non-power gas demand (80TWh in 2050) because of higher concentrations of hydrogen on the gas network and the absence of options for long-term storage of hydrogen. This limit can be strongly binding on the level of electrolysis, particularly if the demand net wind profile is quite smooth within-day and there is significant seasonal variation in electricity demand. This would means that most of the periods of excess low-carbon electricity would occur in summer when gas demand is at its lowest, and hence the constraint is most binding.

# 7. POLICY IMPLICATIONS

The findings of this study raise a number of important issues for consideration for policymakers trying to design and implement a robust framework to help the UK meet its long-term targets for reduction in emissions of carbon dioxide. We have collected the various issues into the following groupings:

- role of policy, regulatory and commercial framework in incentivising the delivery of flexibility, including the role of price signals;
- interaction between electrification and deployment of low-carbon generation;
- relationship between electricity system and other parts of the energy system;
- timings of decisions; and
- areas for further research and analysis.

## 7.1 Framework for incentivising flexibility

The low-carbon electricity system envisaged by the UK Government would have high penetration of electricity in the heat and transport sectors, with the resulting electricity demand supplied by a mix of low-carbon generation including renewables, CCS plants and nuclear power stations. Compared to today, such a system would have:

- much more variable levels of electricity demand across the year;
- greater reliance on intermittent forms of generation, such as wind, and
- significant amount of generation, such as nuclear or CCS plant, wanting to run at or close to baseload (because of high capital costs).

This raises the risk that the drive for decarbonisation undermines the Government's other energy goals of affordability and security of supply. To mitigate this risk, policy, market and regulatory arrangements must support the delivery of an appropriate mix of flexibility to meet the needs of a low-carbon future.

There are a number of different aspects to the flexibility required, which vary across the year and between the four low-carbon futures (or counterfactuals). The system must be able to deliver flexibility over a range of timescales, making duration of flexibility an important consideration, as well as speed of response.

This means that in practice, one source of low-carbon flexibility is unlikely to be able to be able to meet all of the needs for the system. For example, as discussed in Section 5.2, demand side response, particularly for heating demand, may be very useful in smoothing the requirement for non-intermittent generation. However, constraints on storage means that it would only be able to provide the system with limited assistance over an extended period of low wind generation.

Diversity in supply of flexibility can also help to mitigate the impact of inadequate delivery from one source (e.g. there is less flexibility than expected in foreign electricity systems to which GB is linked) and reduce the exposure to exponential increases in costs and challenges from moving further up the supply curve for a particular flexibility option.

Therefore, the policy, regulatory and commercial framework must take into account the investment and operational incentives for, and barriers to, different potential sources of flexibility, including generation, demand, interconnection and bulk storage.

### 7.1.1 Role of price signals

Price signals are expected to play an important role in incentivising the delivery of flexibility, over both investment and operational timescales. This raises questions about the:

- ability of market players to respond to price signals
- balance between ex-ante and 'real-time' price signals; and
- sharpness of price signals for shifting demand and supply over time.

As far as possible, different market players should be able to respond to price signals. For example, commercial arrangements must encourage the responsiveness of interconnectors to dynamically changing levels of demand net wind, rather than determining flows on the basis of pre-determined price expectations.

This is consistent with ongoing EU initiatives, such as the draft Framework Guidelines for capacity allocation and congestion management published by the European regulators in September 2010[79]. The proposed arrangements aim to ensure that interconnector flows more closely reflect real-time market fundamentals, with this expected to support the integration of intermittent generation.

Ex-ante tariffs could potentially be very effective in smoothing the within-day demand profile, assuming that there is sufficient storage available to shift heating demand to overnight periods. However, such tariffs can facilitate only limited flexibility over periods longer than a day and, unlike dynamic 'real-time' tariffs, would not encourage shifting in response to 'unexpected' variations in wind.

These variations in wind are an important driver of the requirement for flexibility as the wind capacity ramps up towards projected levels for 2050. However, the ability of suppliers to deliver dynamic tariffs will depend on the capability of smart infrastructure, which is not necessarily in their control. This increases the importance of coordinated developments in smart infrastructure in order to maximise system benefits.

The sharpness of price signals for shifting generation and/supply between periods is very important for sources of flexibility that are based on price arbitrage between different periods, including demand side storage, bulk storage, and the (Norwegian) interconnector.

Periods of very high prices typically reflect the fact that low load factor plant are trying to recover their capital investment and fixed operating costs in a small number of hours. Very strong price signals may be dampened by policymakers in response to concerns about price spikes. If more revenue streams are developed to support investment (e.g. in peaking plant) that allow fixed cost recovery (e.g. capacity mechanism) outside the hourly wholesale market, then this may reduce the sharpness of wholesale price signals between hours.

Furthermore, if the power system is very flexible, then this could result in the flattening of price signals between periods, which would undermine the benefits of, and hence investment in, flexibility sources that rely on arbitraging between periods.

This situation, even just the risk of it happening, could result in too little investment in these types of flexibility sources compared to the social optimum level (given that the

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79 'Draft Framework Guidelines on Capacity Allocation and Congestion Management for Electricity (Ref: E10-ENM-20-03)', 8 September 2010, issued by ERGEG in place of ACER.

flexibility source does not capture the external benefit to other customers of flattening peak prices)[80]. In contrast, flatter price profiles may be better for low-carbon generation with high capital costs, such as nuclear and CCS coal, and/or variable output, such as wind.

### 7.1.2 Delivery risks

Even if adequate incentives are in place and sufficient finance is available, difficulties in implementation and practical delivery will still make exploiting the flexibility potential very challenging. This means that delivery costs should not be the sole determinant of the favoured pathways for reaching a flexible and low-carbon energy system.

Risk must also be an important part of the analysis carried out by policymakers. These risks include:

- the scale of physical investment required;
- the speed of technology improvements needed;
- the delivery of behavioural responses; and
- becoming locked into undesirable pathways.

The scale of physical investment required is a key issue for the delivery of flexible demand[81]. Firstly, the distribution networks must be able to handle the changing demand patterns – even where the costs of network expansion are relatively small, delivery over the required timescales may be limited by the challenges (and lead times) of upgrading the network, particularly for the low-voltage network where underground cabling is prevalent, and there are millions of individual customer connections.

Secondly, being able to shift daily heating demand to the overnight period would require significant amounts of storage to be installed alongside heat pumps, which is likely to be much more challenging in the domestic sector than for industrial and commercial customers.

If the storage is in the form of hot water tanks, then there would be large space requirements, which may not be compatible with the direction of housing design (for example, with the move towards higher density housing, and the shift towards combination systems without a hot water tank).

A study for the CCC on low-carbon heat scenarios (issued after the completion of the analysis for this study)[82] suggests that storage alongside heat pumps is possible in most cases. However, the assumed differential between peak and off-peak electricity prices (in the central case) means that storage would be economic for about half of non-residential heat pump demand and virtually no heat pump demand in the residential sector. This will raise questions for policy-makers as the extent to which heat pump storage has social benefits (by reducing electricity prices for all customers) and therefore should be incentivised or even mandated.

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80 This could also be extended to operators of peaking plant, who may have an incentive to maintain high price periods as their revenue is determined by a relatively small number of hours.

81 This excludes the requirement for the delivery of renewable generation assets and supporting infrastructure, primarily electricity transmission networks.

82 'Decarbonising Heat: Low-Carbon Heat Scenarios for the 2020s. Report for the Committee on Climate Change', June 2010, NERA and AEA.

A number of the sources of flexibility rely on a rapid improvement in technology to be fully effective by 2030. For example, CCS generation is not yet proven on a commercial scale, even at a baseload operating pattern. Deployment delays would then reduce the scope for trial of different designs for flexible operation. Similarly, it is uncertain how quickly electric vehicle battery technology will develop to facilitate the discharge of electricity back onto the grid.

Consumer engagement is vital in delivering demand side response, even if the engagement is indirect insofar as consumers place the actual load management decision with other parties, such as a supplier or a network operator. In this study, we have assumed an effective response from customers with movable demand – there remains a large question mark over the extent to which this would be delivered in practice, particularly if it is expected to be solely in response to price differentials.

For example, the electrification of vehicles is expected to significantly reduce running costs compared to today, given the relative prices of electricity and petrol. Given this cost saving, consumers may then need very strong price signals to be flexible in their charging behaviour. This may then raise questions about social acceptability given the fact that some consumers would not be able to be flexible in their electricity demand patterns and are then exposed to very high price periods.

The timescale of a single year is too short a time to allow changes in installed capital to deliver the required response. However, all factors of production, including capital, are fully flexible in the long-term and responsive to changes in market arrangements and support schemes.

However, many of the assets affecting the results of this study have long lifetimes, including boilers, generation plants, electricity network wires and the housing stock (which has a very low turnover rate). This increases the risk of effectively being locked into inappropriate pathways as a result of decisions in the near future.

Furthermore, the lead time required for research and investment into capital needed to mitigate technical restrictions in particular places importance on ensuring that clear and consistent policy signals are provided at a sufficiently early stage.

Sending clear signals now would help to influence the investment, and R&D, decisions for generation technology that could reduce the cost of providing flexibility in the future. These signals may be price and non-price, such as the specification of technical requirements at the start of regulatory approval process for new plant design.

For example, the European Utilities Requirements (Document) (the 'EURD') specifies flexibility performance for new build plant, drawing upon experience in France and Germany, and reflecting that non-baseload operation of nuclear plant may needed in future European generation mix. However, the EURD is not mandatory and countries may choose to omit the flexibility clause in their procurement guidelines.

If these signals are not provided early enough, then flexibility would be underweighted in the investment decision, increasing the cost of providing it from that plant in the future. This must be balanced against the benefits of flexible policy pathways that may not lead to the most efficient endpoint when viewed with the benefit of hindsight, but allow response to unforeseen events.

Also, market players are sensitive to price signals that may be subject to time inconsistency problems. For example, expectations of a high carbon price could support investment in low-carbon generation with high capital costs, such as nuclear or CCS coal. However, once the capacity has been built, the carbon price only needs to be high to

make CCS plants competitive with unabated plants on a variable cost basis – this price would be lower than the price required to support investment.

## 7.2 Interaction between electrification and renewable deployment

As typified in Counterfactuals 2, 3 and 4, the pathway to the low-carbon future often sees the decarbonisation of generation in the 2020s as being followed by the electrification of heat and transport to absorb the low-carbon generation with its low marginal costs of production. Electrification of heat and transport will provide opportunities and challenges for the provision of flexibility.

The reference cases show that electrification of heat and transport could make electricity demand much more peaky in the absence of demand side response. In these circumstances, policymakers would need to balance the needs of system flexibility against decarbonisation.

For example, electricity demand from heat pumps may be particularly peaky because of the combination of the heat demand profile and the fall in the electrical efficiency of heat pumps in the winter. However, heat pumps using low-carbon electricity are a lot more carbon-efficient than many other forms of heating. Waiting until the system is deemed to be flexible enough to accommodate the heat pumps could risk customers becoming locked into other heating systems.

The failure to deliver demand side response will have the double effect of removing one of the key options for flexibility and at the same time, making demand net wind more variable. Therefore, there are strong reasons for policy-makers working to deliver effective demand side response.

### *7.2.1 Variability of demand*

Greater deployment of electric heating would link electricity demand more strongly to temperature and to wind. Where demand increases with wind, this would help to offset the variability of wind generation. However, the gap between electricity demand and wind output would be widened on cold and still days. This impact is exacerbated by heat pumps because their coefficient of performance is also inversely linked to the difference between internal and external temperatures.

### *7.2.2 Flexibility of demand*

As discussed in Section 5.6, the vast majority of the increase in movable demand is expected to come from the electrification of heat and transport because storage will allow the electricity demand to be shifted without changing the underlying energy demand. Because there is no requirement for people to change their **energy consumption behaviour** (i.e. their heating or driving patterns), consumer engagement, and hence the flexibility of electricity demand, may be higher. This means that electrification will be a key enabler of greater demand side response in the future.

The delivery of flexible demand depends upon:

- electrification of heat and transport;
- adequate storage;
- smarter demand infrastructure;
- appropriate market arrangements; and
- behavioural response.

If insufficient flexibility is available from generation and supporting infrastructure to meet the requirements of intermittent generation, then (some) earlier electrification may be needed to support rather than follow high levels of decarbonisation. In these circumstances, the demand side response will probably need to be based on dynamic response from active demand units. This is because ex-ante tariffs respond to expected patterns of demand and generation that become increasingly less relevant at higher levels of intermittent generation.

For the electrification of transport, the key issues relate to behaviour and supporting infrastructure. In general, the potential for flexibility would be maximised by ensuring that vehicles are connected to the grid for as often and as long as possible, and by using the storage capacity of the battery to the fullest extent, which may have impacts on battery lifetime and hence cost.

## 7.3 Impacts on wider energy system

This study has focused on the demand for and supply of flexibility in the electricity sector. Provision of power system flexibility would in many instances increase the requirements for flexibility in other parts of the whole energy system, particularly for transportation networks for electricity, CCS and/or gas. Examples include:

- demand side response designed to balance the wholesale market can increase the level of peak flows across distribution (and transmission) networks;
- fuel switching requires flexibility in the supply chain for the alternative fuel, be that the gas distribution (and transmission) networks, or from petrol stations (for hybrid vehicles);
- flexibility from gas-fired generation has knock-on effects on gas transportation networks and on gas infrastructure requirements, as analysed by Pöyry in its recent study on the impact of intermittency on the gas network[83];
- flexible operation of post-combustion CCS plant would require flexibility in the CCS network, which could include the oversizing of pipes and compressors;
- interconnectors require adequate flexibility to be available in other European electricity systems, which are likely to be undergoing similar changes in demand and supply in moves towards low-carbon energy worlds[84]; and
- the use of electrolysis to produce hydrogen for injection into the gas grid must be restricted by safety limits on the concentration on hydrogen in the gas system[85].

Therefore, it is important that improved power system flexibility does not create undue problems in other parts of the energy system.

For example, demand side response is one instrument that may be used to meet two policy objectives – balancing variable generation, primarily wind, and flattening network load. At times, these policy objectives are complementary, for example both would drive a

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83 'How wind generation could transform gas markets in Great Britain and Ireland. A multi-client study. Public summary', June 2010, Pöyry Energy Consulting.

84 Even where other European electricity systems are believed to a high level of flexibility (such as Norway), this flexibility will be in demand from other European countries and so cannot necessarily assumed to be solely available to the GB system.

85 Similarly, if the hydrogen was being used in transport, the level of hydrogen demand from transport would affect the scope for electrolysis to provide flexibility to the electricity system.

reduction in demand when wind is low and demand is high. However, at other times, they would conflict such as when high wind drives an increase in demand to help match generation and demand.

If demand side response is largely limited to clusters of customers with electric heating and transport, this tension may be particularly acute at lower levels of the distribution system, where the flexible demand sources for heating and transport are likely to be found.

## 7.4 Decision points

In this section, we discuss the timing of decisions needed to support flexibility from the main flexibility options evaluated in this study, highlighting in particular where decisions are needed in the short-term.

In general, sending clear signals in the near term would help to encourage the investment and R&D decisions for technology that could reduce the cost of future flexibility. These signals could take a number of forms.

One example would be a commitment to a market design that actively encouraged flexibility, for example through supporting sharp price signals for shifting demand and generation over time. However, this could have negative impacts on final electricity bills for those customers that can't or won't move demand, which raises welfare questions.

Alternatively, a separate revenue stream for provision of flexibility in addition to electricity could be introduced. This would need to be available to as a wide a range of participants as possible (and not just limited to generation).

Where price signals are not expected to be enough to deliver the required flexibility, an alternative approach is through mandated standard, such as the process of approval of new designs for nuclear power stations.

### *7.4.1 Low-carbon generation*

There is around 15-20GW of nuclear generation on the system in our 2030 low-carbon worlds. Virtually all of this will be built over the next twenty years and will still be operating in 2050. Most, if not all, of this capacity will be based on the two main designs currently undergoing the UK Generic Design Assessment (GDA) – Areva's European Pressurised Water Reactor (EPR); and Westhinghouse-Toshiba's Advanced PWR (AP1000).

Given the expected speed of the new build programme, any encouragement for flexibility would need to be clearly set out as part of the current design process if it has to have any impact on the plants constructed by 2030. If this is not possible and greater flexibility is needed from the nuclear fleet in 2030, one option would be to make a conscious decision to 'sacrifice' a limited number of plants that operate flexibility at a cost of higher maintenance costs and shorter operational lifetimes. The other plants would then keep to baseload operation. However, it is unclear how this could be done effectively in the absence of a coordinated fleet management programme, given the interests of commercial players to reduce operational risk as far as possible.

There may be a later opportunity to influence the flexibility of a second tranche of nuclear fleet to be deployed between 2030 and 2050. By that stage, the importance of nuclear flexibility should be more clearly understood given developments in intermittent generation and demand in particular. The expected size of the nuclear fleet in 2050, and hence the importance of its flexibility, should be more certain than now as it will be influenced by the commercial viability of CCS technology.

In the 2030 energy worlds, there is about 10GW of CCS installed by 2030, of which around a third is expected to be built as part of commercial trials. In the short-term, the focus will be on delivering plants that can operate reliably and on a commercial basis. Therefore, there is likely to be limited scope in the short-term to actively encourage flexibility.

However, the pathway to 2050 (assuming CCS is commercially deployed) suggests that there could be another 30-40GW of CCS built after 2030. At that stage, it will be important to ensure that the appropriate signals to encourage flexibility given the relative flexibility characteristics of different CCS options.

For example, levelised costs suggest that CCS gas could be cost-effective at annual load factors of between 30% and 60%, making it suited to deal with large variations across the year in non-intermittent generation.

Alternatively, the production of hydrogen in the IGCC process could help provide greater flexibility through storage (allowing the generation plant to operate more like an unabated gas-fired plant) and/or the diversion of hydrogen for other uses (e.g. transport or injection into gas grid). The benefits of these different types of flexibility will become clearer as we get a better understanding of the delivery of demand side response, which could be a key source of within-day flexibility.

### 7.4.2 Interconnection and bulk storage

The level and type of interconnection assumed in the study should be able to be delivered within ten years. Therefore, no decision is needed in the near-term for it to be delivered by 2030. If a much more ambitious interconnection programme was envisaged, this would need a longer lead time. If this is part of the development of a European 'super-grid', it is likely to involve the construction of links that do not directly involve GB, over which British policy-makers would have limited influence.

In the short-term, the encouragement of price-driven flows across interconnectors should continue as it has benefits even without electrification and intermittent generation.

In the 'imported flexibility' package, there is a significant expansion in bulk storage by 2030. Over these timescales, this would probably need to be in the form of pumped storage, or possibly compressed-air electricity storage (CAES), rather than other technologies, such as batteries, which may be available by 2050.

One of the key findings of the study was that the provision of flexibility over longer time periods will need an increase in storage capacity relative to generating capacity. This is particularly the case if demand side response provides effective within-day flexibility.

Therefore, this expansion in bulk storage (and in particular in relative size of storage capacity) will represent a significant infrastructure development that will probably need to overcome a number of planning issues, around environmental impact and public acceptability, even after technically suitable sites are identified. After this, the construction phase is likely take a number of years. Therefore, if bulk storage is seen as a key solution for 2030, significant impetus will be needed in the short-term.

### 7.4.3 Demand side response

As discussed in Section 7.2.2, there are a number of conditions that need to be fulfilled to deliver effect demand side response – the electrification pathway is outside the scope of this study but the others are all relevant from a timing perspective.

In planning the roll-out of heat pumps, policy-makers will need to assess the extent to which investment in heat storage is desirable for system management purposes even if it is not seen as economically attractive by the end-user. There may also be a strong consumer preference to use the space taken up by storage for other purposes.

If the decision is taken to encourage storage alongside heat pumps, policy-makers would need to take a more active role in the heat pump deployment process through the provision of incentives and/or standards. These decisions need to be made in the initial stages of the design of any heat pump roll-out so that installation of storage can be part of an integrated process to minimise consumer disruption.

On the other hand, if storage alongside heat pumps is seen to be desirable but not practical given the commercial incentives and consumer preferences, then policymakers would need to consider whether the power system was flexible enough to accommodate the planned deployment of heat pumps, at the same time as a growth in intermittent generation. However, this must be balanced against greater carbon efficiency of heat pumps (from low-carbon electricity) compared to other forms of heating, and the decarbonisation benefits of avoiding customers becoming locked into other heating systems.

There will need to be significant development in infrastructure to support demand side response, both in terms of upgraded distribution networks and the delivery of a smart infrastructure.

The electrification of heating and transport is likely to require major investment in the distribution networks in order to accommodate the additional flows at lower voltages. This requires a significant lead time and will results in long-lived assets. For example, the distribution assets put in place in the next 10 years will generally be expected to still be in place in 2050.

As far as possible, the distribution networks must be capable of accommodating future levels and patterns of demand side response – this is hindered by the uncertainty about the timing and location of electrification, and the detailed requirements for flexibility from the demand side (as opposed to other sources). Therefore, there may need to be spare capacity and functionality on the system (with the possibility of stranded assets in the long-term), which may increase delivery costs in the short-term.

To help guide the required investment, policy makers should set out a clear view of what type of response is expected from demand – smoothing network flows or balancing intermittent generation – and what happens when the two responses conflict. Pöyry has completed a study for DECC on this area, with the results to be published in the coming months.

Delivery of a smart infrastructure will require changes both on the networks and in consumer premises. The scale of these changes will depend on the extent to which the demand side response is required to be dynamic. In the initial stages of electrification, using ex-ante tariffs to mitigate variability of demand may be effective (and may be helpful to help acclimatise consumers to demand side response). However, as intermittent generation develops, a more dynamic response may be needed even by 2030.

It would seem sensible to plan in the capability for more active demand side response given the lifetime of many of the assets. For example, the smart meters installed as part of the government's mandatory rollout may still be in place by 2030. Otherwise, there is the risk that deployment of intermittent generation will be delayed until time-consuming infrastructure updates are completed.

As electrification and intermittent generation deployment moves forward, a system of traffic lights can be used to highlight risks in the pathway to the development of a low-carbon energy system. For example, the interaction between electrification, intermittency and system flexibility could be developed into a relationship between the amount of electrification and demand side response consistent with different levels of wind penetration. This would not be a trivial task given the complexities of the links between different demand mixes, different generation patterns and different levels of flexibility from non-demand sources.

## 7.5 Areas for further work

This study has provided a detailed quantitative assessment of the performance of different options for the sources of power system flexibility in 2030 and 2050. This has highlighted a number of areas (outside the scope of this study) in which further research and analysis would be of benefit in helping to formulate an appropriate policy, regulatory and commercial framework.

### *7.5.1 Requirements for flexibility*

Section 4.1 sets out the three key drivers of flexibility within the power system:

- compatibility of structural (i.e. typical) patterns of demand and generation;
- random deviations from structural profile of demand and generation; and
- degree of foresight of deviations from expected profile.

This study has identified two areas in which further analysis would be helpful in developing an even deeper understanding of the requirements for flexibility. These are the seasonality of the future energy demand profile for heating and for electric vehicles, and improvements in forecast accuracy for wind and temperature.

#### *7.5.1.1 Changes in seasonal energy demand profiles*

Analysis of changes in the underlying profile of energy demand was outside the scope of this study. However, it would affect the requirement and potential for flexibility from the power system. For example, energy efficiency improvements may shorten the heating season from its current length. This would make increase the relative importance of water heating, which is more constant across the year than space heating.

The seasonality of electricity demand for passenger vehicles is determined by the mileage profile across the year and the distance achieved per kWh of charge. As discussed in Section 4.1.1, further detailed quantitative work would be beneficial for exploring the relationship between outside temperature and electricity demand from vehicles, and between sunshine and electricity demand from vehicles. This will also depend on the technical specifications of typical electric vehicles by 2030 and 2050.

The production of hydrogen through electrolysis appears to offer an attractive long-term option for allowing more low-carbon generation (to actually decarbonise the gas sector rather than the electricity sector) but is constrained by the level of daily gas demand in 2050. Therefore, establishing the scope for electrolysis to provide this type of flexibility needs further work on the shape and level of gas demand in the low-carbon energy futures for 2050. This could be in a similar vein to the work carried out by Pöyry in its

study of the impact of intermittent generation on gas networks[86]. Similarly if hydrogen is used in transport, then seasonality of the hydrogen demand for transport will affect the flexibility offered by electrolysis.

#### *7.5.1.2 Forecasting of wind and temperature*

Wind generation reduces the range of average wind net demand (compared to raw demand) figures for season and hour of day but increases the deviation from 'average' figures. In order to further understand the predictability of the shifts in non-intermittent generation over different time periods, further analysis is needed on the relative importance and predictability of demand and wind.

For two cases for one Monte Carlo year, we examined the serial correlation of 'unexpected' variations in changes in requirements for non-intermittent generation. This shows there is a richness of information that is not easy to pull out without some more detailed analysis of the serial correlation of forecasting accuracy. Furthermore, to really understand the predictability, more analysis would be needed on the extent to which it is changes in wind or demand that are driving the changes in requirement for non-intermittent generation.

This would need to be supported by more detail on expected improvements in wind forecasting ability and the predictability of demand – for example, we would generally assume that at the day-ahead stage, demand would be more predictable than wind but further analysis would be needed to confirm this hypothesis.

If storage-based options are going to be used to provide multi-day flexibility, then this places greater importance on the forecast accuracy of wind over that time period. This is because the operator needs to know that the low wind is coming in order to fill up the storage in anticipation.

### *7.5.2 Options for flexibility*

This study has characterised options for flexibility in 2030 and 2050 covering generation, interconnection, bulk storage and demand. In a study of this scope, it is not possible to address all the detailed questions that arise about these options. Therefore, the study has highlighted the following areas in which more detailed analysis and research would help to further improve the comparison of options for flexibility:

- the impact of flexible operation on performance of low-carbon generation options;
- flexibility offered by developments in Europe (and beyond) in terms of greater renewables, changing demand patterns and expanded interconnection; and
- constraints on the delivery of demand side response.

The CCC has overseen a number of relevant studies in parallel to this project, for example on the operation of CCS gas plants and on the roll-out of renewable heat,with a consideration of the economics and feasibility of storage being put in place alongside heat pumps. It is important that the findings of these studies are integrated into future analysis of the requirement for flexibility.

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86 'How wind generation could transform gas markets in Great Britain and Ireland. A multi-client study. Public summary', June 2010, Pöyry Energy Consulting.

#### *7.5.2.1 Impact of flexible operation on generation plant*

In general, low-carbon generation options appear to have the technical flexibility required. However, the associated economic costs are uncertain because there is a lack of empirical evidence on how sustained flexible operation of low-carbon plants will impact on generation maintenance costs and expected operational lifetimes[87].

Low-carbon generation is typically high capital cost which means that the investment case can be sensitive to expectations about the achieved annual availability, and length of operational lifetime. For example, analysis of the performance of European PWRs (nuclear) suggests that loss of availability due to load following could be as much as 2%.

The issue is also clouded by a feedback loop in that there is (at the moment) sufficient lead time for flexible operation to be designed in to some extent if there are strong enough market signals. This would therefore mitigate the impact of the flexible operation of the plant on maintenance costs and operational lifetime.

For example, PWRs are the most widespread reactor design in the world and are inherently able to load follow. Additional design features improve transient performance and the choice of these devices/ features determine the rate at which a plant can load follow. Thus design decisions made before construction would influence the load follow characteristics of the plant when built, as would intended fuel cycle durations.

Significant work has been done in this area for conventional plant. For example, Pöyry has undertaken work for DECC to provide accurate data on gas and coal power station efficiencies for use in the DECC Energy Model. This looked at:

- how efficiencies of the generating technologies vary as a function of load factor; whether the efficiencies of plants change if they are being used to follow load;
- if there a significant seasonal component to efficiencies; and
- how efficiencies are expected to change in the future.

#### *7.5.2.2 Flexibility available in European electricity systems*

The focus of this study was primarily on assessing the options for flexibility in the GB electricity system. As a result, we made relatively conservative assumptions on the capacity and flexibility of interconnections. In order to justify an assumption of greater flexibility potential, then more detailed modelling and analysis will be required of developments in Europe that would be consistent with the scenarios developed for GB. This addresses the risk that the challenges for power system flexibility in GB are met by making assumptions about developments in other power systems over which GB policy makers have relatively little influence.

We would need to understand the implications for the flexibility of European power systems from higher penetration of renewables, changing demand patterns and increases in interconnection between Continental systems.

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87 For example, the safety case for Sizewell B (the one existing nuclear plant on the system in 2030) suggests that one year of automatic frequency response operation (AFRO) might reduce the design life by as much as 10 years depending on the number of load follow cycles involved. This has not been tested empirically as the plant has run baseload since its commissioning.

For example, a link with Norway appears to be very promising for system flexibility. However, to evaluate the flexibility offered by interconnection capacity greater than the relatively modest one used in this study, we need to understand how the drivers of supply and demand for flexibility in Norway. If all of the electricity systems in North West Europe are hoping to use Norway as a key source of flexibility, then the supply of flexibility from Norway may become constrained, particularly by 2050.

Pöyry is looking at these issues as part of its multi-client study on the impact of intermittency on electricity markets in North West Europe. This is being modelled by applying the *Zephyr* modelling principles to a single model covering Germany, France, Benelux, GB, Switzerland, Austria, Poland and the Nordic region.

#### *7.5.2.3 Constraints on the delivery of demand side response*

Two key conditions for the delivery of large amounts of flexible demand are the installation of heat storage alongside electrical heating and appropriate behavioural response from residential and non-residential customers.

The cost of heat storage has not been included in the cost estimates because at the time of modelling, it was uncertain the extent to which heat storage would be an integral part of the deployment of heat pumps. Future analysis in this area should integrate the findings from the parallel study for the CCC on low-carbon heat scenarios[88] on the prospects for storage alongside heat pumps.

The development of alternative (and more energy dense) storage technologies would obviously be helpful for flexibility. Other possible mitigation strategies are the use of community heating systems (which may have greater opportunities for storage) or the deployment of small CHP units. If the CHP units follow the heating load, then they would be generating electricity at times of peak heating demand which may alleviate the demand requirement from heat pumps. However, the CHP units are expected to have a top-up boiler to meet peak heating demand which would reduce the strength of this effect.

The roll-out of different heating solutions was an exogenous input for this study and was provided by the CCC. Therefore, we did not compare the costs and benefits of different heating solutions.

In the scenarios, we have assumed a high technical potential for shifting demand for heat, transport and wet appliances (residential). This is either in response to ex-ante tariffs in two flexibility packages ('imported flexibility' and 'flexible generation') and 'real-time' prices in the 'active demand side' package.

However, we have not explored how to ensure that consumer engagement is sufficient to deliver this potential in practice. This would also need to consider how to manage the possibility of herding in the consumer response (whereby too many consumers respond). Such aspects create a wide range of uncertainty about what demand side response would be delivered in practice.

The challenge of data gathering in this area is illustrated by the results of a Pöyry review of literature on the impact of international electricity demand side response initiatives. This was completed as part of our work for the Irish regulators on defining a 2020 vision for

88 'Decarbonising Heat: Low-Carbon Heat Scenarios for the 2020s. Report for the Committee on Climate Change', June 2010, NERA and AEA.

demand side response for the Single Electricity Market[89]. Although we were able to draw some broad conclusions, the literature review confirmed that detailed quantitative evidence is lacking in this area at the moment:

- some schemes (even major ones) are implemented without a control or a baseline, making change impossible to measure;
- as the objectives of demand side response programmes vary, so do the type of results reported;
- it is difficult to correct for selection bias in the case studies that are publicly available;
- there is uncertainty about the persistence of the effect of some initiatives; and
- research is limited on the potential of some emerging technologies.

If it proves challenging to deliver storage alongside heat pumps, then this places increased emphasis on the provision of flexibility from electric vehicles. Therefore, research into consumer behaviour should also consider the management of storage in vehicle batteries, particularly in relation to 'range anxiety'.

Vehicle to grid charging (V2G) is seen as one option for helping the system to meet (short) periods of peak demand for non-intermittent generation. However, the scope for it will be affected by behavioural and technical characteristics. For example, if consumers place a high value on convenience, then they may want the battery fully charged as possible and will be unwilling to allow V2G.

Further work is also need on how V2G would affect the lifetime, cost and performance of vehicle batteries. Car manufacturers are unlikely to prioritise the ability for V2G in battery design (at the expense of other features such as cost and performance) unless there is a clear demand from consumers. This is particularly the case given that the large upfront cost of the battery is already seen as a disincentive for consumers to buy electric vehicles.

### *7.5.3 Impact of flexibility*

In general, the packages with increased flexibility in our study led to an electricity system with lower carbon intensity and lower generation costs whilst maintaining the level of security of supply (as detailed in Section 6.2). However, the differences in overall system cost between the flexibility packages are not definitive given the uncertainty about:

- the extent to which costs should be attributed to improvements in flexibility (e.g. smart meters or smart grids, which could have much wider benefits than considered in this study,); and
- the level of some costs, particularly distribution network costs.

Clearly then more detailed analysis in these areas would help to further improve the analysis of the impacts of power system flexibility on overall costs.

Within the scope of this study, the impact of changes in demand patterns on network investments and operation has necessarily been looked at a high-level. In conjunction with the University of Bath, Pöyry has recently completed a study for DECC looking in more detail at the network impacts of different patterns of demand side response. When

89 The source covered in this review included IEA DSM reports, studies prepared for national governments and research project reports.

the report from this study is published in the coming months, it will provide valuable insight into how demand side response can be used to minimise system costs.

We assessed the performance of different flexibility options using data on intermittent generation, demand and plant availability for nine separate years. These years capture a range of weather patterns including a number of cold spells and extended periods of low wind. However, they do not include a particularly cold winter (such as 2009/2010 or 1985/86), which could have implications for electricity demand (heating) and supply (gas availability for power stations). The importance of demand shocks not seen in the data currently available should also be explored, for example looking into the impact of Christmas on the driving (and hence charging) pattern for electric vehicles.

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# ANNEX A – DATA TABLES

This section contains a detailed summary of data from the study including:

- key common input assumptions for each counterfactual (Table 20)
- installed capacity by generation technology (Table 21);
- annual output by generation technology (Table 22);
- annual load factor (Table 23);
- emissions by technology (Table 24);
- annualised costs by generation technology (Table 25); and
- annualised costs by category (Table 26).

In these tables, the low energy worlds are referred to as:

- CF 1 – 2030 world without electrification;
- CF 2 – 2030 world with electrification;
- CF 3 – 2050 world with CCS; and
- CF 4 – 2050 world with no CCS.

**Table 20 – Key common input assumptions for each counterfactual**

| Category | Assumption | CF 1 | CF 2 | CF 3 | CF 4 | Source |
|---|---|---|---|---|---|---|
| Annual electricity demand (TWh) | Residential (lighting and appliances) | 57 | 57 | 90 | 90 | CCC |
| | Non-residential (lighting and appliances) | 233 | 236 | 280 | 280 | CCC |
| | Electric vehicles | 4 | 16 | 128 | 128 | CCC |
| | Space and water heating (non-heat pump) | 34 | 33 | 115 | 115 | CCC |
| | Space and water heating (heat pump) | 0 | 57 | 67 | 67 | CCC |
| Renewable capacity (GW) | Onshore wind | 19 | 19 | 19 | 19 | CCC |
| | Offshore wind | 10 | 11 | 22 | 45 | CCC |
| | Biomass | 4 | 5 | 5 | 5 | CCC |
| | Wave | 0 | 0 | 4 | 4 | CCC |
| | Tidal | 0 | 0 | 0 | 0 | CCC |
| | Other | 2 | 2 | 2 | 2 | CCC |
| Fuel and carbon prices (real 2008 money) | Oil (Brent, $/barrel) | 90 | 90 | 90 | 90 | DECC |
| | Coal (ARA, $/tonne) | 80 | 80 | 80 | 80 | DECC |
| | Gas (NBP, p/therm) | 74 | 74 | 74 | 74 | DECC |
| | Carbon (£/tCO2) | 70 | 70 | 200 | 200 | DECC |
| Exchange rates | $:£ | $1.56:£1 | $1.56:£1 | $1.56:£1 | $1.56:£1 | CCC |

## Table 21 – Installed capacity by generation technology (GW)

| | Nuclear | CCS Coal | Coal | Biomass | CHP | CCS gas | CCGT | Onshore Wind | Offshore Wind | Wave | Tidal | Other Renewable | Demand Shedding | Peakers | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **CF 1 - Reference case** | **14** | **7** | **0** | **4** | **5** | **0** | **19** | **19** | **10** | **0** | **0** | **2** | **1** | **9** | **91** |
| **CF 1 - Flexible generation** | **15** | **7** | **0** | **4** | **5** | **0** | **19** | **19** | **10** | **0** | **0** | **2** | **1** | **9** | **91** |
| **CF 1 - Imported flexibility** | **16** | **7** | **0** | **4** | **5** | **0** | **19** | **19** | **10** | **0** | **0** | **2** | **1** | **3** | **87** |
| **CF 1 - Active demand-side** | **15** | **7** | **0** | **4** | **5** | **0** | **18** | **19** | **10** | **0** | **0** | **2** | **1** | **4** | **87** |
| CF 1 (Sensitivity) - Constrained demand-side | 15 | 7 | 0 | 4 | 5 | 0 | 18 | 19 | 10 | 0 | 0 | 2 | 1 | 4 | 87 |
| | | | | | | | | | | | | | | | |
| **CF 2 - Reference case** | **20** | **11** | **0** | **5** | **5** | **0** | **21** | **19** | **11** | **0** | **0** | **2** | **1** | **15** | **109** |
| **CF 2 - Flexible generation** | **21** | **11** | **0** | **5** | **5** | **0** | **18** | **19** | **11** | **0** | **0** | **2** | **1** | **5** | **99** |
| CF 2 (Sensitivity) - Flexible generation - space cooling | 23 | 11 | 0 | 5 | 5 | 0 | 18 | 19 | 11 | 0 | 0 | 2 | 1 | 5 | 100 |
| **CF 2 - Imported flexibility** | **22** | **11** | **0** | **5** | **5** | **0** | **18** | **19** | **11** | **0** | **0** | **2** | **1** | **2** | **96** |
| **CF 2 - Active demand-side** | **21** | **6** | **0** | **5** | **5** | **0** | **18** | **19** | **11** | **0** | **0** | **2** | **1** | **1** | **89** |
| CF 2 (Sensitivity) - Constrained demand-side | 21 | 6 | 0 | 5 | 5 | 0 | 18 | 19 | 11 | 0 | 0 | 2 | 1 | 1 | 89 |
| | | | | | | | | | | | | | | | |
| **CF 3 - Reference case** | **41** | **18** | **0** | **5** | **0** | **28** | **16** | **19** | **22** | **4** | **0** | **2** | **1** | **28** | **185** |
| **CF 3 - Flexible generation** | **41** | **16** | **0** | **5** | **0** | **30** | **4** | **19** | **22** | **4** | **0** | **2** | **1** | **13** | **157** |
| **CF 3 - Imported flexibility** | **39** | **21** | **0** | **5** | **0** | **23** | **3** | **19** | **22** | **4** | **0** | **2** | **1** | **15** | **154** |
| **CF 3 - Active demand-side** | **40** | **17** | **0** | **5** | **0** | **27** | **0** | **19** | **22** | **4** | **0** | **2** | **1** | **12** | **151** |
| CF 3 (Sensitivity) - Constrained demand-side | 40 | 17 | 0 | 5 | 0 | 27 | 0 | 19 | 22 | 4 | 0 | 2 | 1 | 12 | 151 |
| | | | | | | | | | | | | | | | |
| **CF 4 - Reference case** | **63** | **0** | **0** | **5** | **0** | **0** | **26** | **19** | **45** | **4** | **0** | **2** | **1** | **35** | **200** |
| **CF 4 - Flexible generation** | **65** | **0** | **0** | **5** | **0** | **0** | **15** | **19** | **45** | **4** | **0** | **2** | **1** | **18** | **174** |
| CF 4 (Sensitivity) - Flexible generation - space cooling | 67 | 0 | 0 | 5 | 0 | 0 | 16 | 19 | 45 | 4 | 0 | 2 | 1 | 18 | 177 |
| **CF 4 - Imported flexibility** | **64** | **0** | **0** | **5** | **0** | **0** | **12** | **19** | **45** | **4** | **0** | **2** | **1** | **15** | **167** |
| CF 4 (Sensitivity) - Imported flexibility - electrolysis | 64 | 0 | 0 | 5 | 0 | 0 | 12 | 19 | 45 | 4 | 0 | 2 | 1 | 15 | 167 |
| **CF 4 - Active demand-side** | **64** | **0** | **0** | **5** | **0** | **0** | **9** | **19** | **45** | **4** | **0** | **2** | **1** | **14** | **162** |
| CF 4 (Sensitivity) - Constrained demand-side | 64 | 0 | 0 | 5 | 0 | 0 | 9 | 19 | 45 | 4 | 0 | 2 | 1 | 14 | 162 |

## Table 22 – Annual production by generation technology (TWh)

| | Nuclear | CCS Coal | Coal | Biomass | CHP | CCS gas | CCGT | Onshore Wind | Offshore Wind | Wave | Tidal | Other Renewable | Demand Shedding | Peakers | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **CF 1 - Reference case** | **108** | **53** | **0** | **23** | **25** | **0** | **60** | **40** | **37** | **0** | **0** | **7** | **2** | **3** | **357** |
| **CF 1 - Flexible generation** | **115** | **54** | **0** | **23** | **25** | **0** | **52** | **40** | **37** | **0** | **0** | **7** | **1** | **2** | **356** |
| **CF 1 - Imported flexibility** | **128** | **50** | **0** | **25** | **24** | **0** | **43** | **40** | **37** | **0** | **0** | **7** | **1** | **0** | **356** |
| **CF 1 - Active demand-side** | **122** | **54** | **0** | **24** | **26** | **0** | **47** | **40** | **37** | **0** | **0** | **7** | **1** | **1** | **359** |
| CF 1 (Sensitivity) - Constrained demand-side | 122 | 54 | 0 | 24 | 26 | 0 | 48 | 40 | 37 | 0 | 0 | 7 | 1 | 1 | 359 |
| | | | | | | | | | | | | | | | |
| **CF 2 - Reference case** | **151** | **80** | **0** | **24** | **25** | **0** | **62** | **40** | **42** | **0** | **0** | **7** | **2** | **3** | **436** |
| **CF 2 - Flexible generation** | **168** | **80** | **0** | **25** | **26** | **0** | **46** | **40** | **42** | **0** | **0** | **7** | **1** | **0** | **435** |
| CF 2 (Sensitivity) - Flexible generation - space cooling | 185 | 79 | 0 | 24 | 25 | 0 | 41 | 40 | 42 | 0 | 0 | 7 | 1 | 0 | 444 |
| **CF 2 - Imported flexibility** | **171** | **82** | **0** | **27** | **26** | **0** | **39** | **40** | **42** | **0** | **0** | **7** | **1** | **0** | **435** |
| **CF 2 - Active demand-side** | **163** | **51** | **0** | **28** | **29** | **0** | **76** | **40** | **42** | **0** | **0** | **7** | **1** | **0** | **436** |
| CF 2 (Sensitivity) - Constrained demand-side | 163 | 51 | 0 | 28 | 29 | 0 | 76 | 40 | 42 | 0 | 0 | 7 | 1 | 0 | 436 |
| | | | | | | | | | | | | | | | |
| **CF 3 - Reference case** | **280** | **113** | **0** | **20** | **0** | **145** | **36** | **40** | **80** | **10** | **0** | **7** | **5** | **6** | **741** |
| **CF 3 - Flexible generation** | **325** | **120** | **0** | **27** | **0** | **122** | **3** | **40** | **82** | **10** | **0** | **7** | **2** | **2** | **740** |
| **CF 3 - Imported flexibility** | **308** | **164** | **0** | **27** | **0** | **94** | **3** | **40** | **82** | **10** | **0** | **7** | **2** | **3** | **741** |
| **CF 3 - Active demand-side** | **320** | **135** | **0** | **28** | **0** | **116** | **0** | **40** | **82** | **10** | **0** | **7** | **2** | **2** | **742** |
| CF 3 (Sensitivity) - Constrained demand-side | 320 | 135 | 0 | 28 | 0 | 116 | 0 | 40 | 82 | 10 | 0 | 7 | 2 | 2 | 742 |
| | | | | | | | | | | | | | | | |
| **CF 4 - Reference case** | **443** | **0** | **0** | **15** | **0** | **0** | **51** | **39** | **165** | **10** | **0** | **6** | **4** | **7** | **741** |
| **CF 4 - Flexible generation** | **462** | **0** | **0** | **14** | **0** | **0** | **29** | **40** | **170** | **10** | **0** | **7** | **4** | **4** | **740** |
| CF 4 (Sensitivity) - Flexible generation - space cooling | 481 | 0 | 0 | 14 | 0 | 0 | 34 | 40 | 170 | 10 | 0 | 7 | 4 | 4 | 764 |
| **CF 4 - Imported flexibility** | **471** | **0** | **0** | **14** | **0** | **0** | **22** | **40** | **170** | **10** | **0** | **7** | **4** | **4** | **741** |
| CF 4 (Sensitivity) - Imported flexibility - electrolysis | 477 | 0 | 0 | 17 | 0 | 0 | 21 | 40 | 170 | 10 | 0 | 7 | 3 | 4 | 748 |
| **CF 4 - Active demand-side** | **483** | **0** | **0** | **16** | **0** | **0** | **15** | **40** | **170** | **10** | **0** | **7** | **3** | **4** | **748** |
| CF 4 (Sensitivity) - Constrained demand-side | 483 | 0 | 0 | 16 | 0 | 0 | 15 | 40 | 170 | 10 | 0 | 7 | 3 | 4 | 748 |

## Table 23 – Annual load factor by generation technology (%)

| | Nuclear | CCS Coal | Coal | Biomass | CHP | CCS gas | CCGT | Onshore Wind | Offshore Wind | Wave | Tidal | Other Renewable | Demand Shedding | Peakers | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **CF 1 - Reference case** | **88%** | **85%** | **-** | **60%** | **53%** | **-** | **35%** | **24%** | **42%** | **-** | **-** | **50%** | **19%** | **3%** | **45%** |
| **CF 1 - Flexible generation** | **90%** | **83%** | **-** | **59%** | **52%** | **-** | **31%** | **24%** | **42%** | **-** | **-** | **52%** | **16%** | **3%** | **45%** |
| **CF 1 - Imported flexibility** | **90%** | **87%** | **-** | **65%** | **51%** | **-** | **26%** | **24%** | **42%** | **-** | **-** | **52%** | **11%** | **0%** | **47%** |
| **CF 1 - Active demand-side** | **90%** | **87%** | **-** | **62%** | **55%** | **-** | **30%** | **24%** | **42%** | **-** | **-** | **52%** | **14%** | **2%** | **47%** |
| CF 1 (Sensitivity) - Constrained demand-side | 90% | 86% | - | 62% | 54% | - | 30% | 24% | 42% | - | - | 52% | 15% | 2% | 47% |
| | | | | | | | | | | | | | | | |
| **CF 2 - Reference case** | **88%** | **86%** | **-** | **58%** | **53%** | **-** | **35%** | **24%** | **42%** | **-** | **-** | **51%** | **17%** | **3%** | **46%** |
| **CF 2 - Flexible generation** | **90%** | **87%** | **-** | **61%** | **55%** | **-** | **29%** | **24%** | **42%** | **-** | **-** | **52%** | **10%** | **1%** | **50%** |
| CF 2 (Sensitivity) - Flexible generation - space cooling | 90% | 86% | - | 59% | 53% | - | 26% | 24% | 42% | - | - | 52% | 9% | 1% | 51% |
| **CF 2 - Imported flexibility** | **90%** | **89%** | **-** | **66%** | **56%** | **-** | **24%** | **24%** | **42%** | **-** | **-** | **52%** | **7%** | **0%** | **52%** |
| **CF 2 - Active demand-side** | **90%** | **89%** | **-** | **68%** | **61%** | **-** | **48%** | **24%** | **42%** | **-** | **-** | **52%** | **11%** | **3%** | **56%** |
| CF 2 (Sensitivity) - Constrained demand-side | **90%** | 89% | - | 68% | 61% | - | 48% | 24% | 42% | - | - | 52% | 11% | 3% | 56% |
| | | | | | | | | | | | | | | | |
| **CF 3 - Reference case** | **78%** | **70%** | **-** | **50%** | **-** | **59%** | **25%** | **23%** | **41%** | **25%** | **-** | **48%** | **43%** | **3%** | **46%** |
| **CF 3 - Flexible generation** | **90%** | **88%** | **-** | **68%** | **-** | **47%** | **9%** | **24%** | **42%** | **26%** | **-** | **52%** | **17%** | **2%** | **54%** |
| **CF 3 - Imported flexibility** | **90%** | **88%** | **-** | **68%** | **-** | **47%** | **12%** | **24%** | **42%** | **26%** | **-** | **52%** | **20%** | **2%** | **55%** |
| **CF 3 - Active demand-side** | **90%** | **89%** | **-** | **68%** | **-** | **48%** | **8%** | **24%** | **42%** | **26%** | **-** | **52%** | **19%** | **2%** | **56%** |
| CF 3 (Sensitivity) - Constrained demand-side | 90% | 89% | - | 68% | - | 48% | 9% | 24% | 42% | 26% | - | 52% | 19% | 2% | 56% |
| | | | | | | | | | | | | | | | |
| **CF 4 - Reference case** | **80%** | **-** | **-** | **36%** | **-** | **-** | **23%** | **23%** | **42%** | **25%** | **-** | **47%** | **38%** | **2%** | **42%** |
| **CF 4 - Flexible generation** | **81%** | **-** | **-** | **34%** | **-** | **-** | **22%** | **24%** | **43%** | **26%** | **-** | **52%** | **36%** | **3%** | **49%** |
| CF 4 (Sensitivity) - Flexible generation - space cooling | 82% | - | - | 35% | - | - | 23% | 24% | 43% | 26% | - | 52% | 37% | 3% | 49% |
| **CF 4 - Imported flexibility** | **85%** | **-** | **-** | **35%** | **-** | **-** | **20%** | **24%** | **43%** | **26%** | **-** | **52%** | **33%** | **3%** | **51%** |
| CF 4 (Sensitivity) - Imported flexibility - electrolysis | 85% | - | - | 41% | - | - | 19% | 24% | 43% | 26% | - | 52% | 32% | 3% | 51% |
| **CF 4 - Active demand-side** | **87%** | **-** | **-** | **38%** | **-** | **-** | **19%** | **24%** | **43%** | **26%** | **-** | **52%** | **31%** | **3%** | **53%** |
| CF 4 (Sensitivity) - Constrained demand-side | 87% | - | - | 38% | - | - | 19% | 24% | 43% | 26% | - | 52% | 31% | 3% | 53% |

## Table 24 – Annual emissions of carbon dioxide by generation technology ($mtCO_2$ per annum)

| | CCS Coal | CHP | CCS gas | CCGT | Peaking | Fuel switching | Total | CO2 intensity (gCO2/kWh of demand) | CO2 intensity (gCO2/kWh of generation) |
|---|---|---|---|---|---|---|---|---|---|
| **CF 1 - Reference case** | **3** | **7** | **0** | **22** | **1** | **-** | **33** | **101** | **92** |
| **CF 1 - Flexible generation** | **3** | **7** | **0** | **19** | **1** | **-** | **30** | **91** | **84** |
| **CF 1 - Imported flexibility** | **3** | **7** | **0** | **16** | **0** | **-** | **25** | **76** | **70** |
| **CF 1 - Active demand-side** | **3** | **7** | **0** | **17** | **0** | **0** | **28** | **84** | **77** |
| CF 1 (Sensitivity) - Constrained demand-side | 3 | 7 | 0 | 17 | 0 | 0 | 28 | 85 | 77 |
| | | | | | | | | | |
| **CF 2 - Reference case** | **4** | **7** | **0** | **23** | **2** | **-** | **36** | **89** | **82** |
| **CF 2 - Flexible generation** | **4** | **7** | **0** | **16** | **0** | **-** | **28** | **71** | **65** |
| CF 2 (Sensitivity) - Flexible generation - space cooling | 4 | 7 | 0 | 15 | 0 | - | 26 | 64 | 59 |
| **CF 2 - Imported flexibility** | **4** | **7** | **0** | **14** | **0** | **-** | **25** | **64** | **58** |
| **CF 2 - Active demand-side** | **3** | **8** | **0** | **27** | **0** | **1** | **39** | **97** | **89** |
| CF 2 (Sensitivity) - Constrained demand-side | 3 | 8 | 0 | 27 | 0 | 1 | 39 | 97 | 89 |
| | | | | | | | | | |
| **CF 3 - Reference case** | **6** | **0** | **6** | **13** | **3** | **-** | **28** | **42** | **38** |
| **CF 3 - Flexible generation** | **6** | **0** | **5** | **1** | **2** | **-** | **14** | **20** | **19** |
| **CF 3 - Imported flexibility** | **9** | **0** | **4** | **1** | **2** | **-** | **15** | **22** | **20** |
| **CF 3 - Active demand-side** | **7** | **0** | **5** | **0** | **1** | **0** | **13** | **19** | **18** |
| CF 3 (Sensitivity) - Constrained demand-side | 7 | 0 | 5 | 0 | 1 | 0 | 13 | 19 | 18 |
| | | | | | | | | | |
| **CF 4 - Reference case** | **0** | **0** | **0** | **18** | **4** | **-** | **22** | **32** | **30** |
| **CF 4 - Flexible generation** | **0** | **0** | **0** | **10** | **2** | **-** | **12** | **18** | **17** |
| CF 4 (Sensitivity) - Flexible generation - space cooling | 0 | 0 | 0 | 12 | 2 | - | 14 | 20 | 18 |
| **CF 4 - Imported flexibility** | **0** | **0** | **0** | **8** | **2** | **-** | **10** | **14** | **13** |
| CF 4 (Sensitivity) - Imported flexibility - electrolysis | 0 | 0 | 0 | 7 | 2 | | 9 | 13 | 12 |
| **CF 4 - Active demand-side** | **0** | **0** | **0** | **5** | **2** | **0** | **7** | **11** | **10** |
| CF 4 (Sensitivity) - Constrained demand-side | 0 | 0 | 0 | 5 | 2 | 0 | 7 | 11 | 10 |

## Table 25 – Annualised costs by generation technology (£b/a, real 2009 money)

| | Nuclear | CCS Coal | Coal | Biomass | CHP | CCS gas | CCGT | Onshore Wind | Offshore Wind | Wave | Tidal | Other Renewable | Demand Shedding | Peakers | Total | TWA price (£/MWh) | Average cost (£/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **CF 1 - Reference case** | **8** | **6** | **-** | **2** | **2** | **-** | **8** | **5** | **4** | **-** | **-** | **0** | **0** | **1** | **37** | **82** | **104** |
| **CF 1 - Flexible generation** | **8** | **6** | **-** | **2** | **2** | **-** | **7** | **5** | **4** | **-** | **-** | **0** | **0** | **1** | **37** | **82** | **103** |
| **CF 1 - Imported flexibility** | **10** | **5** | **-** | **2** | **2** | **-** | **6** | **5** | **4** | **-** | **-** | **0** | **0** | **0** | **36** | **83** | **100** |
| **CF 1 - Active demand-side** | **9** | **6** | **-** | **2** | **2** | **-** | **6** | **5** | **4** | **-** | **-** | **0** | **0** | **0** | **36** | **83** | **101** |
| CF 1 (Sensitivity) - Constrained demand-side | 9 | 6 | - | 2 | 2 | - | 6 | 5 | 4 | - | - | 0 | 0 | 0 | 36 | 83 | 101 |
| | | | | | | | | | | | | | | | | | |
| **CF 2 - Reference case** | **12** | **8** | **-** | **2** | **2** | **-** | **8** | **5** | **5** | **-** | **-** | **0** | **0** | **2** | **45** | **81** | **104** |
| **CF 2 - Flexible generation** | **12** | **8** | **-** | **3** | **3** | **-** | **6** | **5** | **5** | **-** | **-** | **0** | **0** | **0** | **43** | **82** | **99** |
| CF 2 (Sensitivity) - Flexible generation - space cooling | 14 | 8 | - | 2 | 2 | - | 6 | 5 | 5 | - | - | 0 | 0 | 0 | 44 | 80 | 98 |
| **CF 2 - Imported flexibility** | **13** | **8** | **-** | **3** | **3** | **-** | **6** | **5** | **5** | **-** | **-** | **0** | **0** | **0** | **43** | **84** | **98** |
| **CF 2 - Active demand-side** | **12** | **5** | **-** | **3** | **3** | **-** | **9** | **5** | **5** | **-** | **-** | **0** | **0** | **0** | **42** | **85** | **97** |
| CF 2 (Sensitivity) - Constrained demand-side | 12 | 5 | - | 3 | 3 | - | 9 | 5 | 5 | - | - | 0 | 0 | 0 | 42 | 85 | 97 |
| | | | | | | | | | | | | | | | | | |
| **CF 3 - Reference case** | **26** | **16** | **-** | **2** | **-** | **16** | **6** | **5** | **9** | **2** | **-** | **0** | **1** | **4** | **87** | **92** | **117** |
| **CF 3 - Flexible generation** | **25** | **13** | **-** | **3** | **-** | **17** | **1** | **5** | **9** | **2** | **-** | **0** | **0** | **2** | **77** | **94** | **104** |
| **CF 3 - Imported flexibility** | **24** | **18** | **-** | **3** | **-** | **13** | **1** | **5** | **9** | **2** | **-** | **0** | **0** | **2** | **77** | **97** | **104** |
| **CF 3 - Active demand-side** | **25** | **15** | **-** | **3** | **-** | **16** | **0** | **5** | **9** | **2** | **-** | **0** | **0** | **1** | **77** | **95** | **103** |
| CF 3 (Sensitivity) - Constrained demand-side | 25 | 15 | - | 3 | - | 16 | 0 | 5 | 9 | 2 | - | 0 | 0 | 1 | 77 | 95 | 103 |
| | | | | | | | | | | | | | | | | | |
| **CF 4 - Reference case** | **39** | **-** | **-** | **2** | **-** | **-** | **11** | **5** | **19** | **2** | **-** | **0** | **0** | **4** | **83** | **83** | **112** |
| **CF 4 - Flexible generation** | **39** | **-** | **-** | **2** | **-** | **-** | **6** | **5** | **19** | **2** | **-** | **0** | **0** | **2** | **76** | **79** | **103** |
| CF 4 (Sensitivity) - Flexible generation - space cooling | 41 | - | - | 2 | - | - | 7 | 5 | 19 | 2 | - | 0 | 0 | 2 | 79 | 81 | 103 |
| **CF 4 - Imported flexibility** | **39** | **-** | **-** | **2** | **-** | **-** | **5** | **5** | **19** | **2** | **-** | **0** | **0** | **2** | **75** | **80** | **101** |
| CF 4 (Sensitivity) - Imported flexibility - electrolysis | 40 | - | - | 2 | 0 | - | 5 | 5 | 19 | 2 | - | 0 | 0 | 2 | 75 | 83 | 100 |
| **CF 4 - Active demand-side** | **40** | **-** | **-** | **2** | **-** | **-** | **3** | **5** | **19** | **2** | **-** | **0** | **0** | **2** | **73** | **81** | **98** |
| CF 4 (Sensitivity) - Constrained demand-side | 40 | - | - | 2 | - | - | 3 | 5 | 19 | 2 | - | 0 | 0 | 2 | 73 | 81 | 98 |

## Table 26 – Annualised system cost by category (£b/a, real 2009 money)[90]

| | Fuel | Carbon | FOWC (fixed costs) | VOWC (variable costs) | SUNL (start and no load) | CAPEX | Smart Meters & Grids | Inter-connection | Bulk Storage | Trans-mission | Distribution | CCS network | Total | £ per MWh of final demand | *Alternative distribution cost* |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **CF 1 - Reference case** | **6** | **2** | **5** | **2** | **1** | **20** | **0** | **0** | **0** | **2** | **3** | **0** | **43** | **133** | ***3*** |
| **CF 1 - Flexible generation** | **6** | **2** | **5** | **2** | **1** | **20** | **1** | **0** | **0** | **2** | **3** | **0** | **44** | **137** | ***3*** |
| **CF 1 - Imported flexibility** | **5** | **2** | **5** | **2** | **1** | **21** | **1** | **0** | **1** | **2** | **3** | **0** | **45** | **137** | ***3*** |
| **CF 1 - Active demand-side** | **6** | **2** | **5** | **2** | **1** | **20** | **3** | **0** | **0** | **2** | **5** | **0** | **46** | **143** | ***3*** |
| CF 1 (Sensitivity) - Constrained demand-side | 6 | 2 | 5 | 2 | 1 | 20 | 2 | 0 | 0 | 2 | 4 | 0 | 46 | 141 | *3* |
| | | | | | | | | | | | | | | | |
| **CF 2 - Reference case** | **7** | **2** | **7** | **2** | **2** | **25** | **0** | **0** | **0** | **3** | **6** | **0** | **54** | **135** | ***4*** |
| **CF 2 - Flexible generation** | **6** | **2** | **7** | **2** | **1** | **25** | **1** | **0** | **0** | **3** | **7** | **0** | **55** | **136** | ***4*** |
| CF 2 (Sensitivity) - Flexible generation - space cooling | 6 | 2 | 7 | 2 | 1 | 26 | 1 | 0 | 0 | 3 | 7 | 0 | 55 | 134 | *4* |
| **CF 2 - Imported flexibility** | **6** | **2** | **7** | **2** | **1** | **25** | **1** | **0** | **1** | **3** | **7** | **0** | **55** | **137** | ***4*** |
| **CF 2 - Active demand-side** | **7** | **3** | **6** | **2** | **2** | **23** | **3** | **0** | **0** | **3** | **8** | **0** | **56** | **139** | ***4*** |
| CF 2 (Sensitivity) - Constrained demand-side | 7 | 3 | 6 | 2 | 2 | 23 | 2 | 0 | 0 | 3 | 8 | 0 | 56 | 138 | *4* |
| | | | | | | | | | | | | | | | |
| **CF 3 - Reference case** | **13** | **6** | **13** | **5** | **3** | **48** | **0** | **0** | **0** | **3** | **13** | **2** | **104** | **152** | ***8*** |
| **CF 3 - Flexible generation** | **12** | **3** | **12** | **4** | **2** | **45** | **1** | **0** | **0** | **3** | **12** | **2** | **95** | **139** | ***7*** |
| **CF 3 - Imported flexibility** | **11** | **3** | **12** | **5** | **2** | **45** | **1** | **0** | **1** | **3** | **12** | **2** | **97** | **140** | ***7*** |
| **CF 3 - Active demand-side** | **12** | **3** | **12** | **5** | **2** | **44** | **3** | **0** | **0** | **3** | **14** | **2** | **98** | **142** | ***8*** |
| CF 3 (Sensitivity) - Constrained demand-side | 12 | 3 | 12 | 5 | 2 | 44 | 2 | 0 | 0 | 3 | 14 | 2 | 98 | 142 | *7* |
| | | | | | | | | | | | | | | | |
| **CF 4 - Reference case** | **4** | **4** | **14** | **4** | **2** | **56** | **0** | **0** | **0** | **3** | **13** | **0** | **99** | **144** | ***8*** |
| **CF 4 - Flexible generation** | **2** | **2** | **13** | **4** | **1** | **54** | **1** | **0** | **0** | **3** | **12** | **0** | **93** | **135** | ***7*** |
| CF 4 (Sensitivity) - Flexible generation - space cooling | 3 | 3 | 13 | 4 | 1 | 55 | 1 | 0 | 0 | 3 | 12 | 0 | 95 | 133 | *7* |
| **CF 4 - Imported flexibility** | **2** | **2** | **13** | **4** | **1** | **53** | **1** | **0** | **1** | **3** | **12** | **0** | **92** | **134** | ***7*** |
| CF 4 (Sensitivity) - Imported flexibility - electrolysis | 2 | 2 | 13 | 4 | 1 | 53 | 1 | 0 | 1 | 3 | 12 | 0 | 92 | 134 | *7* |
| **CF 4 - Active demand-side** | **2** | **1** | **13** | **4** | **0** | **53** | **3** | **0** | **0** | **3** | **15** | **0** | **94** | **137** | ***8*** |
| CF 4 (Sensitivity) - Constrained demand-side | 2 | 1 | 13 | 4 | 0 | 53 | 2 | 0 | 0 | 3 | 15 | 0 | 94 | 137 | *8* |

90 The system costs for the electrolysis sensitivity include a reduction of £0.4bn, which represents the saving in gas costs net of the cost of the electrolysis equipment.

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