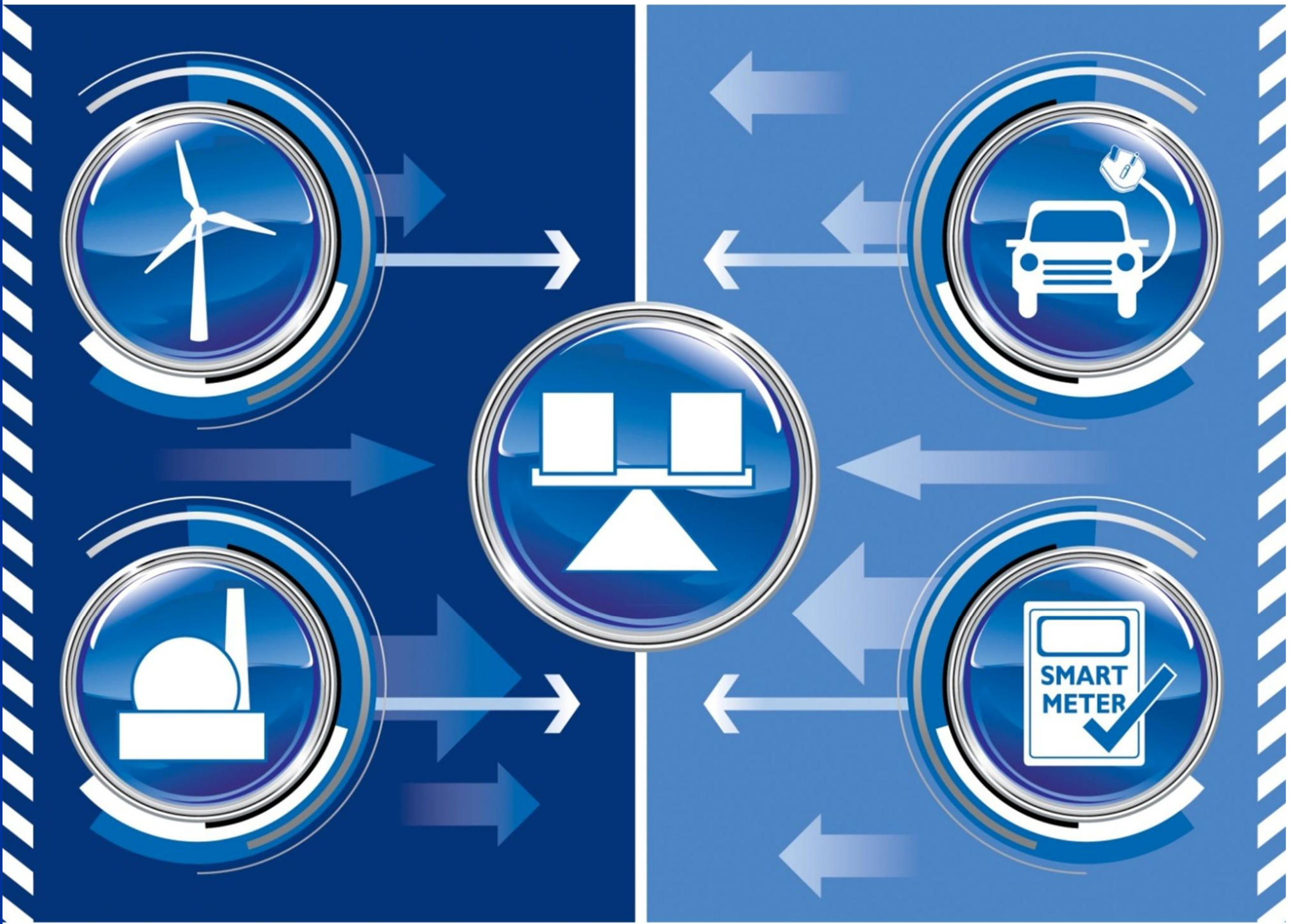
ANALYSING TECHNICAL CONSTRAINTS ON RENEWABLE GENERATION TO 2050

A report to the Committee on Climate Change

March 2011



ANALYSING TECHNICAL CONSTRAINTS ON RENEWABLE GENERATION TO 2050

Contact details

Name	Email	Telephone
Gary Keane	gary.keane@poyry.com	+44 1865 812236
Oliver Pearce	oliver.pearce@poyry.com	+44 1865 812220

Pöyry is Europe's leading management consultancy specialised in the energy sector, providing strategic, commercial, regulatory and policy advice to Europe's energy markets. The team of over 200 energy specialists, located across 14 European offices, offers unparalleled expertise in the rapidly changing energy sector.

Pöyry is a global consulting and engineering firm. Our in-depth expertise extends to the fields of energy, industry, urban & mobility and water & environment, with over 7,000 staff operating from offices in 50 countries.

Important

This document contains confidential and commercially sensitive information. Should any requests for disclosure of information contained in this document be received (whether pursuant to; the Freedom of Information Act 2000, the Freedom of Information Act 2003 (Ireland), the Freedom of Information Act 2000 (Northern Ireland), or otherwise), we request that we be notified in writing of the details of such request and that we be consulted and our comments taken into account before any action is taken.

Disclaimer

While Pöyry Management Consulting (UK) Ltd (“Pöyry”) considers that the information and opinions given in this work are sound, all parties must rely upon their own skill and judgement when making use of it. Pöyry does not make any representation or warranty, expressed or implied, as to the accuracy or completeness of the information contained in this report and assumes no responsibility for the accuracy or completeness of such information. Pöyry will not assume any liability to anyone for any loss or damage arising out of the provision of this report.

The report contains projections that are based on assumptions that are subject to uncertainties and contingencies. Because of the subjective judgements and inherent uncertainties of projections, and because events frequently do not occur as expected, there can be no assurance that the projections contained herein will be realised and actual results may be different from projected results. Hence the projections supplied are not to be regarded as firm predictions of the future, but rather as illustrations of what might happen. Parties are advised to base their actions on an awareness of the range of such projections, and to note that the range necessarily broadens in the latter years of the projections.

TABLE OF CONTENTS

[This page is intentionally blank]

EXECUTIVE SUMMARY

Introduction

The Secretary of State for Energy and Climate Change has asked the Committee on Climate Change (CCC) to provide advice on the ambition for renewable energy after the delivery of the National Renewable Energy Action Plan (NREAP)[1] for the UK in 2020[2]. Consequently, the CCC announced in September 2010[3] that it would undertake a renewable energy review to assess the role for renewables beyond 2020 in meeting the 2050 target to reduce carbon emissions by 80% on 1990 levels.

Increasing renewable penetration will raise challenges in respect of:

- the ability of the system to balance supply and demand, particularly with high levels of **intermittent** renewable generation; and
- the delivery of high levels of renewable generation between now and 2050.

The first of these challenges is largely associated with issues facing wind generation, which is likely to be the dominant source of renewable energy over this timeframe. Figure 1 shows a plausible pattern of wind output in 2050 with renewable electricity providing 60% of total generation. It highlights three aspects of intermittency in wind generation: variability, unpredictability and price-insensitivity.

Wind generation's variable nature can be seen in the large swings in output, often within timescales of less than a day. The lack of any sort of pattern from one day to the next illustrates the difficulty of predicting wind output over long timescales. The fact that wind output is just as likely to be high at times of low demand (e.g. overnight) as at times of high demand indicates its price insensitive nature.

Under the NREAP, renewable electricity generation will grow from 32TWh in 2010 to 117TWh in 2020, which would represent 31% of electricity demand. Given that the 2020 target itself represents a four-fold expansion from current levels, an ambition to expand renewables rapidly post 2020 raises questions about the level of available resource, and the speed at which it can be deployed.

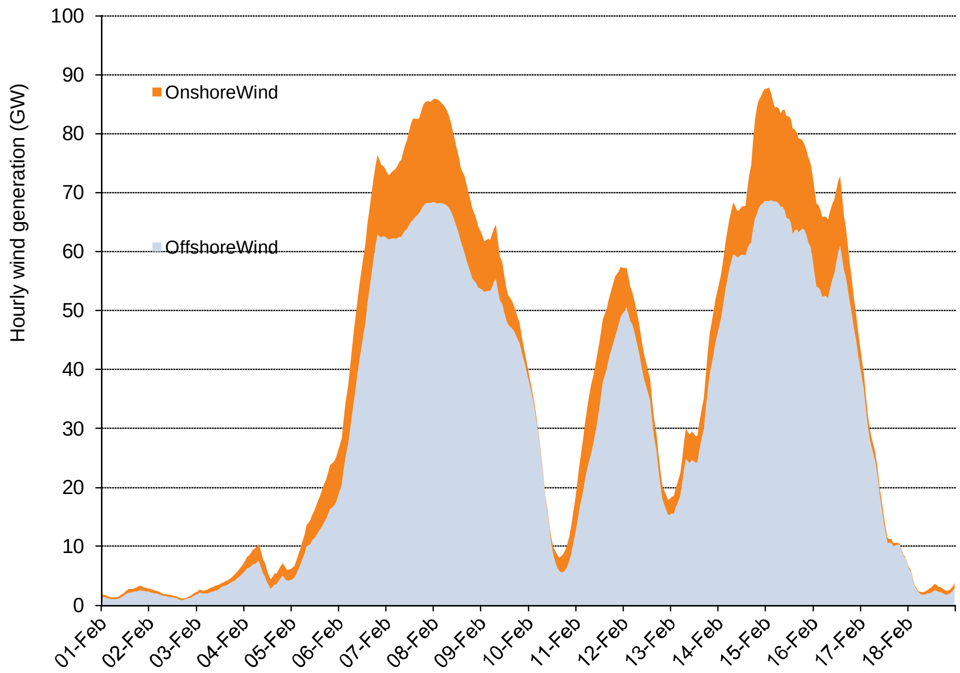
Therefore, the CCC commissioned Pöyry to carry out a detailed quantitative assessment of how the electricity system could both deliver and accommodate higher levels of renewables after 2020.

1 'National Renewable Energy Action Plan for the United Kingdom. Article 4 of the Renewable Energy Directive 2009/28/EC', DECC, July 2010.

2 Letter from Chris Huhne, Secretary of State for Energy and Climate Change, to Lord Turner, Chairman, CCC, July 2010.

3 Letter from Lord Turner, Chairman, CCC to Chris Huhne, Secretary of State for Energy and Climate Change, September 2010.

Figure 1 – Hourly output from wind generation[4] (GW)



Objectives

The key objective of the project was to identify and characterise the technical constraints that could limit the deployment of renewables in the power sector. Therefore, we have carried out a detailed quantitative assessment of:

- the ability of the system to accommodate renewables, both in terms of balancing electricity supply and demand in energy terms, and transporting energy across transmission and distribution networks; and
- the ability to deliver renewables, both in terms of overall resource level and the speed with which the potential can be exploited.

There are a number of non-technical constraints that could also limit the deployment of renewable electricity generation, such as the policy framework, availability of finance and public opinion. However, a detailed evaluation of these constraints was outside the scope of this study.

4 This generation pattern is based on the assumption that the weather of 1-18 February 2006 is exactly repeated with installed capacity of 76GW of offshore wind and 24GW of onshore wind. The level of installed capacity is consistent with our High scenario in 2050.

Approach

We analysed three stretching but feasible scenarios for renewable deployment (as summarised in Table 1) to inform our assessment of the technical constraints on accommodation and delivery of renewables.

Table 1 – Overview of main scenarios

Scenario	Annual demand	Level of renewable penetration	Mix of renewable generation	Deployment of non-renewable generation	Availability of flexibility
High (2030 and 2050)	409TWh in 2030; 551TWh in 2050	60% by 2050	Wind-dominated	Beyond specified minimums, deployment and closure driven by expected returns	High – low carbon generation, active demand, interconnection, bulk storage
Very High (2030 and 2050)	409TWh in 2030; 551TWh in 2050	80% by 2050	Wind-dominated	Beyond specified minimums, deployment and closure driven by expected returns	High – low carbon generation, active demand, interconnection, bulk storage
Max	611TWh	Close to maximum	Wind-dominated	Beyond specified minimums, deployment and closure driven by expected returns. No nuclear or CCS by definition	High – low carbon generation, active demand, interconnection, bulk storage

The construction of these scenarios was influenced by a number of key design considerations:

- **Starting point for renewable generation** – this was defined as the level of renewable deployment in the NREAP.
- **Progress over time** – two scenarios (High and Very High) have snapshot years in 2030 and 2050, whereas the Max scenario[5] is not tied to a particular year.
- **Optimality of renewable generation mix** – scenarios are all assumed to be wind-dominated to test the system's ability to accommodate intermittent renewable generation, and because we expect wind output to account for a major share of renewable generation in this timeframe. The scenarios are not necessarily representative of an ideal range of renewables deployment, although we do investigate the impact of a more diverse renewables mix in two variant scenarios.
- **Limit on average carbon intensity of power generation** – around 80-90gCO_2 per kWh of demand in 2030 and close to zero in 2050.
- **Security of supply** – ceilings on expected energy unserved (EEU) of around 2GWh per annum in 2030 and around 4GWh per annum in 2050 (and in the Max scenario).

[5] The Max scenario attempts to determine the maximum level of renewable penetration that could practically be achieved in Britain by some indeterminate year in the future, based on a wind-dominated generation mix and the assumed level of power system flexibility.

These scenarios were designed to test the impact of going significantly beyond the renewable penetration level of 30% of total generation that was used in the analysis for the CCC's advice on the fourth carbon budget period[6]. Therefore, the scenarios presented in this study do not necessarily reflect an optimal level of renewable penetration.

Conclusions

We developed stretching but feasible scenarios with high levels of renewable generation (reaching up to 94% in the Max scenario). The electricity system was able to accommodate these high levels of renewable generation whilst complying with the specified constraints on emissions and security of supply. However, this was at the cost of shedding low variable cost generation and construction of new peaking capacity; predominantly in the two 2050 scenarios and Max scenario.

These scenarios were also tested against more extreme weather conditions, as defined as increased frequency of low wind periods ('lulls') and greater variability of wind output.

In our (very) high renewable scenarios, we found that there is relatively little difference between the level of security of supply (as measured by the level of EEU)[7] in an average weather year and from the level in one of our extreme weather years.

Shedding increases with more variable wind patterns but does not materially decline if there are a higher number of lulls. This is because shedding is driven by the frequency of high wind periods. These periods happen more frequently with more variable wind but do not necessarily occur less often in months with more lulls.

CO_2.emissions increase in the year with more lulls because fossil fuel plants run at higher load factors to compensate for lower wind output. In contrast, there is a (slightly) higher average annual load factor for wind in the more variable wind year. This leads to lower emissions, particularly in 2030.

Our analysis explored a number of issues that are key to an assessment of **technical** constraints:

- low-carbon flexibility of the power system;
- diversity of renewable mix;
- delivery of required network investment;
- availability of resource; and
- annual build rate.

The following key messages have emerged from our analysis.

---

6 'The Fourth Carbon Budget. Reducing emissions through the 2020s', Committee on Climate Change, December 2010.

7 In our scenarios, we have not altered generation capacity in the extreme weather variants; generation capacity is determined on the basis of a set of historical weather patterns, and the EEU does not increase much in the extreme weather variants.

The closure of unabated gas plants will reduce generation flexibility by 2050

The electricity system is more able to accommodate high levels of renewable penetration (in percentage terms) in 2030 than in 2050. This is illustrated by the fact that, in 2030, there is very little shedding of low variable cost (and low carbon) generation[8] and little need for new peaking capacity build in either the High scenario or Very High scenario, despite renewable penetration levels of 51% and 64% respectively.

However, in 2050, around 40TWh of low variable cost generation is shed in the High and Very High scenarios, with a need for new peaking capacity of 6GW and 10GW respectively[9]. The situation is even worse in the Max scenario in which shedding increases to 120TWh a year, and 21GW of new peaking capacity is required to meet the desired level of security of supply. This is despite an assumed increase in demand-side flexibility and an expansion of interconnection capacity between 2030 and 2050 (and between 2050 and the Max scenario),

This highlights the importance of existing and planned CCGTs in providing considerable flexibility in 2030 – and the problems associated with their absence of most of this CCGT capacity in 2050.

Conversely, the assumed flexibility from low carbon sources (such as demand-side and interconnection) is not sufficient to enable the system to accommodate high levels of renewable generation in 2050 without any shedding and peaking capacity build.

However, low-carbon flexibility does play a valuable role in helping to reduce shedding and peaking capacity build. Reducing demand-side flexibility and delaying the expansion of interconnection until 2050 leads to increased shedding of low variable cost generation and higher peaking capacity build.

Eliminating shedding and peaking capacity build (after the closure of the gas plants) may require the development of longer-term flexibility – e.g. the ability to shift supply and/or demand between months. This is illustrated by the fact that an increase in the duration of hydrogen storage from daily to weekly only leads to a slight improvement in the performance of the system in the Max scenario.

A more diverse renewables mix helps the system to accommodate high renewables

Increasing the deployment of solar and tidal range (and reducing offshore wind deployment) in the High scenario leads to a big fall in the amount of shedding and in required new capacity build in 2050. This suggests that the system is better able to cope with high levels of renewables if the renewable mix is more diverse.

---

8 Defined for the purposes of this study as nuclear and renewables (excluding biomass). Shedding of low variable cost (and low carbon) generation reduces the amount of useful low-carbon generation produced by a given level of installed capacity. This therefore increases the levelised cost of additional low-carbon capacity, particularly if it is high capital cost (e.g. offshore wind and nuclear). This will push up the incremental costs of decarbonisation.

9 Despite the increase in shedding, construction of nuclear capacity is still cost-effective given the assumed set of fuel and carbon prices and generation costs. However, the levelised cost of deploying nuclear and renewables would be reduced if shedding was lower.

Alternatively, interconnectors could be used to provide GB with access to a more diverse renewables mix in Europe, drawing on the analysis in Pöyry's recent study on the impacts of high renewable deployment on electricity markets in North West Europe[10].

However, in this study, increasing solar deployment in Spain in the Very High scenario (in which there is already significant GB solar deployment) only has limited benefits for the GB system in terms of shedding and peak capacity build.

Major network reinforcement is needed to accommodate high renewables

Increasing the level of renewable penetration will require massive expansion of the transmission network, largely due to the geographical remoteness and intermittent output of the wind resource.

Peak demand (on the distribution network) is comparable in the High and Very High scenarios (albeit it has increased significantly by 2050 from the expected 2020 level). It is much higher in the Max scenario as flexible demand helps to balance the greater variability of supply.

In all of the scenarios, at least half of gas demand from power generation comes from abated gas plants running at average load factor below 20%. This means that the electricity system needs the gas transmission (and supply infrastructure) to be able to operate with high peak deliverability but low annual throughput.

There is not a binding technical constraint on the level of resource

Sufficient technical resource appears to be available to deliver very high levels of renewable penetration. However, it is difficult to envisage the UK achieving high levels of renewable generation without substantial deployment of offshore wind (both fixed and floating), which limits the scope for diversifying the renewables mix.

Increasing the reliance on decarbonisation from non-renewable sources leads to a need to identify additional sites for nuclear, with 30GW of new nuclear build by 2050 in the High scenario.

Annual build rates are much more challenging before 2030 than after 2030

The build rates for renewables, particularly offshore wind, are much more stretching between today and 2030 than they appear to be between 2030 and 2050. In particular, there will need to be a significant increase in deployment rates after 2020. Although challenging, these deployment rates are technically feasible.

10 'The challenges of intermittency in North West European power markets (public summary)', Pöyry Management Consulting, March 2011.

Implications for policy makers

The implications for policy makers can be considered against each of the technical constraints discussed above.

Low-carbon flexibility of the power system

The pattern of shedding in both the High and Very High scenarios highlights that challenges for low-carbon flexibility are not just driven by the level of renewable penetration. In 2030, CCGTs play an important role in helping to accommodate high levels of renewables, although they are supported by sources of low-carbon flexibility, such as demand-side flexibility and interconnection.

There remains considerably uncertainty about the operating lifetime of these CCGTs, most of which are expected to close in the decade after 2030. Therefore, policy makers need to ensure that the system will be able to cope with the closure of these CCGTs, even if it is earlier than expected.

The scenarios have significant amounts of within-day and multi-day flexibility, particularly from the demand-side. However, this flexibility is not able to avoid prevent high levels of shedding in 2050 (after the closure of the CCGTs). Therefore, policy makers should investigate options for longer-term flexibility that would allow demand and/or supply to be shifted between months.

Diversity of renewable mix

A more diverse renewables mix helps the system to accommodate high levels of renewables. Therefore, this benefit should be taken into account by policy-makers when considering what priority should be placed on individual renewable technologies, particularly if these technologies are more expensive and/or challenging to deploy.

As increased diversity can reduce the requirement for additional low-carbon flexibility, it offers policy-makers an alternative route to achieving higher levels of renewable deployment. This approach would need to take account of the trade-off of the cost[11], challenges and resource limits of deploying some of the alternative technologies.

In any case, wind is still likely to play an important part in the renewable mix, particularly at high levels of renewable penetration, which means that there will be limits on the contribution that can be made by increased diversity.

Delivery of required network investment

The delivery of the transmission network reinforcement is likely to be a massive challenge, and will require significant further attention. Delivery of required network reinforcement will require significant preparatory effort in the near-term because network assets are long-lived and network development tends to have substantial lead times (often as a result of preconstruction activities, such as planning, rather than technical build rates).

11 A full analysis of deployment costs was outside the scope of this study because the CCC CCC commissioned a separate parallel study on the costs of deploying different renewable technologies. The results of that study, which were not available during our study, could be used to compare the deployment costs of different renewable mixes.

Availability of resource

The scenarios have been designed to be feasible given the estimated technical feasibility of renewable resource. Therefore, the renewable resource should in itself not be a technical constraint, as long as the technology is available to exploit the resource.

If floating wind turbine technology does not prove to be commercially deployable (by say 2030), then it would be more challenging (and maybe impossible) to deliver the high renewable scenarios presented in this study. This means that it may be prudent not to set a renewable target beyond 2030 (when we are still relying largely on current technologies) until it becomes clearer as to the progress of floating turbine technology. However, the decision on setting a long-term target should not be delayed so long as to leave insufficient (lead) time for other low-carbon technologies that might be needed to be developed as alternatives to floating offshore wind.

Annual build rate

The key implications of the required build rates for renewables relate both to what policy-makers have to do to in support, and what happens if those build rates are not delivered.

In all the scenarios, there is a step up from the NREAP levels in the build rate of offshore wind required after 2020. Therefore, this will require continued investment in the supply chain in the run-up to 2020, through clear signals about the expected long-term contribution of offshore wind (compared to for example onshore wind, where the build rate is expected to decline after 2020). Even in the Very High scenario, offshore wind deployment in 2030 does not exceed the capacity of sites that have already been identified for development. Therefore, the emphasis should be on ensuring that those sites can be delivered, and responding to any shortfalls, rather than a massive new expansion of sites for 2030.

The renewable deployment is to a certain extent front-loaded, with build rates before 2030 higher than build rates after 2030. This means that a lower annual build rate to 2030 would not necessarily mean that the 2050 level of renewable deployment could not technically be reached. Rather the issue relates to one of lock-in, whereby slower renewable deployment could lead to non-renewable generation being built by 2030 that could restrict the scope for deploying renewables after 2030.

This risk increases with a higher renewable target for 2050 which would allow less scope for non-renewable plants to play an active role in 2050. For example, if renewable build to 2030 was in line with the High scenario, then there would be just under 20GW of nuclear by 2030. Given the high capital cost and long-lived nature of the nuclear capacity, this may restrict the ability of the system to move towards the Very High scenario (in which there is only be just over 10GW of nuclear in 2050).

Renewable deployment may be delayed for a number of (possibly linked) reasons:

- **slower development in power system flexibility** – for example through delayed electrification, the absence of storage alongside heat pumps, inadequate smart infrastructure, or delayed interconnection expansion;
- **delays in network reinforcement** – particularly transmission (although delayed distribution reinforcement could slow the development of demand-side response);
- **slower renewable technology development** – this is less likely to be a constraint for 2030 than for 2050; and
- **failure to deliver required supply chain developments**.

Therefore, policy-makers will need to monitor developments in these areas to identify emerging constraints on renewable deployment.

[This page is intentionally blank]

1. INTRODUCTION

1.1 Introduction

This report sets out the results of a study carried out by Pöyry Management Consulting, the leading European management consultancy specialising in the energy sector, on behalf of the Committee on Climate Change (CCC).

Pöyry led the research, analysis and interpretation of findings in this study. Its project team consisted of staff from the Pöyry Management Consulting (UK) office in Oxford along with Mike Lewis, an expert advisor on nuclear generation from the engineering arm of the Pöyry group.

The CCC participated in regular discussions and a number of working-level meetings throughout the course of the study. The CCC also provided a number of modelling assumptions, most notably in the composition of annual electricity demand for 2030 and 2050 and confirmation of assumed renewable deployment by 2020.

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 the CCC is interested in exploring the issues around delivering and accommodating high levels of renewable electricity generation;
- Chapter 3 explains Pöyry's approach to the modelling of different scenarios of renewable penetration;
- Chapter 4 compares the impact on the electricity system of accommodating different levels of renewable generation;
- Chapter 5 sets out the deployment trajectories towards the level of renewable penetration reached in each scenario;
- Chapter 6 reviews the source and impact of different technical constraints on the ability of the system to accommodate and deploy high levels of renewable generation, particularly in relation to system flexibility, supporting transportation networks, resource availability and build rates; and
- Annex A provides a supporting data table containing non-generation costs for each of the main scenarios.

1.2 Conventions

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

[This page is intentionally blank]

2. OBJECTIVES OF THE STUDY

In this chapter, we present the background, objectives and key aspects of the study.

The objective of this project is to identify and characterise the technical constraints that will limit the deployment of renewables in the power sector to 2030 and beyond. These technical constraints may take the form of:

- limits on the ability of the electricity system to accommodate high levels of renewable generation;
- restrictions on the delivery of the resulting system, in terms of;
  - deployment of renewables;
  - roll-out of non-renewable generation; and
  - non-generation developments needed to help the system accommodate the renewable generation.

2.1 Long-term ambitions for renewable deployment

In May 2010, the coalition Government pledged to 'increase the target for energy from renewable sources subject to the advice of the Climate Change Committee *(CCC)*'. Consequently, the Secretary of State for Energy and Climate Change wrote to the CCC to formally request its advice on:

- the size of the 2020 renewables target (by September 2010); and
- final recommendations on post 2020 ambition (by March 2011).[12]

In September 2010, the CCC published its advice[13] that the 2020 target should remain in line with the National Renewable Action Plan (NREAP) for the UK[14].

At the same time, the CCC stated it would undertake a renewable energy review to assess the role for renewables beyond 2020 in meeting carbon budgets and the 2050 target to reduce carbon emissions by 80% on 1990 levels[15]. The deployment of renewables is expected to play an important role in meeting the long-term carbon targets.

---

12 Letter from Chris Huhne, Secretary of State for Energy and Climate Change, to Lord Turner, Chairman, CCC, July 2010.

13 Letter from to Lord Turner, Chairman, CCC to Chris Huhne, Secretary of State for Energy and Climate Change, September 2010.

14 'National Renewable Energy Action Plan for the United Kingdom. Article 4 of the Renewable Energy Directive 2009/28/EC', DECC, July 2010.

15 It is the responsibility of the CCC to set five-yearly carbon budgets on a path to meet the 2050 target and to advise Government on policy to ensure the budgets are met.

2.2 Renewable energy review

In its September 2010 letter, the CCC described how the renewable energy review would help to address the three issues highlighted by the Secretary of State in relation to future Government policy:

- what priority should be placed on renewables in contributing towards reduced carbon emissions beyond 2020? e.g. through access to support;
- what priority that should be placed on individual renewable technologies? e.g. through the level of support offered; and
- to what extent could changes in policy influence the costs of renewable generation? e.g. through the nature of the support provided.

The CCC commissioned Pöyry to carry out a detailed quantitative assessment to identify and characterise the technical constraints that could limit the deployment of renewable generation after 2020[16].

Our analysis has provided the CCC with evidence for use in its advice to the UK Government on the ambitions for renewables after 2020, particularly in relation to four of the areas highlighted in the September 2010 letter:

- the development of scenarios with range of renewable penetration in 2030 and 2050, highlighting when higher deployment may be appropriate and key decision points;
- the extent to which technologies and infrastructure add to system flexibility;
- the scope for renewable energy uptake; and
- the drawing out of implications from longer-term analysis for actions that are required before 2020.

2.3 Accommodating high levels of renewables

The decarbonisation of electricity generation combined with significant electrification of transport and heat is expected to play a key role in helping the UK to achieve its 2050 target[17]. The generation mix in a decarbonised electricity system is likely to be fundamentally different to the existing system in three main ways:

- **Intermittent[18] (unavailable when needed).** Wind, solar, wave and tidal technologies are all intermittent technologies, and exhibit a reliability when needed that is significantly lower (on average) than conventional plant. With significant volumes of wind and marine generation, there will be much more intermittent generation on the system than today.

16 Starting from the assumed delivery by 2020 of the level of renewables set out in the NREAP.

17 As described in the six low-carbon pathways in ‘2050 Pathways Analysis’, DECC, July 2010.

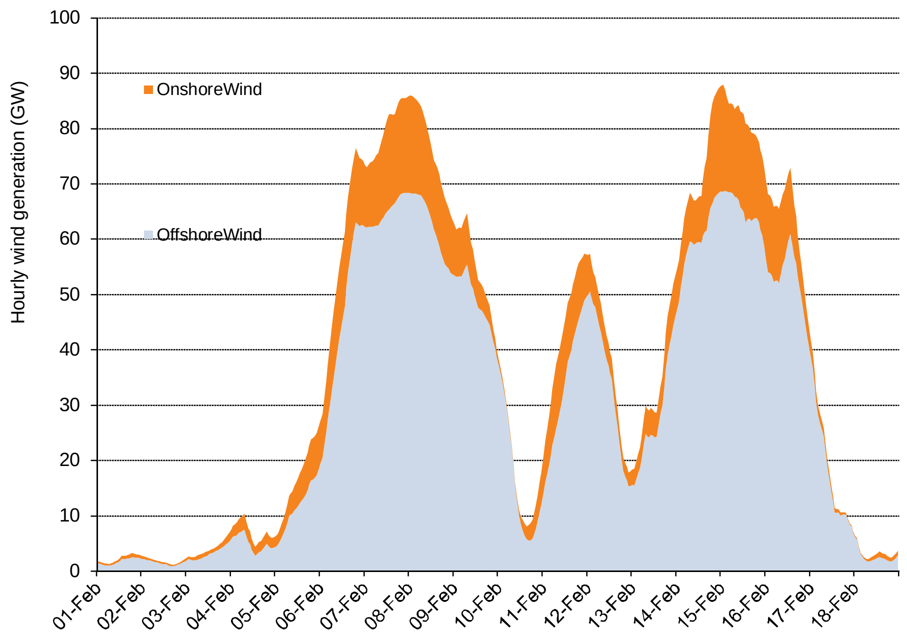
18 The term ‘intermittency’ is regarded by some as a pejorative term – and terms such as ‘variability’ have been proposed as a more accurate description of wind generation patterns. Given that ‘intermittency’ has become the most widely accepted term across the industry, Pöyry has chosen to use this, and regards it as descriptive rather than pejorative. It is also observed that all generation types are not wholly reliable – even the best new technology might achieve availabilities in the low 90%’s and many plant have availabilities at 70%. However the availability of wind generation is significantly lower than this – hence the distinction of intermittent generation.

- **Unpredictable.** Predictability describes the extent to which generation levels can be forecast. Wind and wave generation are both inherently unpredictable – and the error in a forecast of wind generation increases dramatically as the time interval increases, in the same manner as any weather forecast. Tidal generation, on the other hand, is extremely predictable – we know the time of high tides accurately for the next thousand years or so.
- **Price insensitive.** Most new generation planned for a future low carbon world is price insensitive, such as wind, solar, nuclear and CCS[19]. This means that the amount of generation that will vary its generation in response to price and/or varying demand will decrease significantly.

These three issues are all associated with wind generation, as illustrated in Figure 2 which shows a plausible pattern of wind output in 2050 with renewable electricity penetration of 60%.

The intermittent nature is shown by the large swings in output that are likely to occur within timescales of less than a day. The lack of any sort of pattern from one day to the next illustrates the difficulty of predicting wind output over long timescales. And the fact that wind output is just as likely to be high at times of low demand (e.g. overnight) as at times of high demand indicates its price insensitive nature.

Figure 2 – Hourly output from wind generation[20] (GW)



19 Although much of this generation may be technically flexible, including new nuclear plant, it is possible that it may choose not to operate flexibly due to the underlying economics and market design.

20 This generation pattern is based on the assumption that the weather of 1-18 February 2006 is exactly repeated with installed capacity of 76GW of offshore wind and 24GW of onshore wind. The level of installed capacity is consistent with our High scenario in 2050.

At the same time as the decarbonisation of electricity generation, the electrification of heat and transport could 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.

This combination of factors will result in a need for increased power system flexibility in order to match generation and demand. Therefore, in this study, we explored how a system with extensive electrification of heat and transport can accommodate higher levels of intermittent renewable generation, particularly wind, alongside other forms of low-carbon generation, such as nuclear and CCS, that want to run at or close to baseload.

We assessed the performance of the system with reference to the Government's energy policy goal for the delivery of a low-carbon, secure and affordable electricity supply. This will help to inform the level around which it may be sensible to set long-term renewables ambitions, given the expected deployment of and response from sources of system flexibility.

A key aspect of the analysis was assumptions about the level and sources of system flexibility, which can be provided by generation, interconnection, bulk storage and demand. This study builds on previous work by Pöyry for the CCC that explored the impact of decarbonisation on the supply and demand for flexibility in the electricity system[21].

Our analysis showed how system performance changes with the level of renewable penetration. This will help to identify any penetration levels beyond which the system has to work much harder to accommodate the renewable generation. We also looked at the robustness of the performance of the system to variations in the renewable mix and changes in the delivery of flexibility from the demand-side and across interconnectors.

2.4 Delivering systems with high levels of renewables

There are two key aspects to the review of the trajectories for delivering electricity systems with high levels of renewable penetration:

- description of the trajectory to delivering the high-renewable systems, covering;
  - the deployment of renewable generation;
  - the roll-out of non-renewable generation;
  - the development of supporting infrastructure (e.g. networks, interconnection and demand-side measures); and
- discussion of decision points and milestones in the delivery of the required trajectory.

The levels of possible deployment were driven by the magnitude of available resources for the technology and, particularly out to 2030, limits on the annual build rate.

Our analysis started from the 2020 assumptions provided by the CCC, namely the delivery by 2020 of the level of renewables set out in the NREAP, with 117TWh of renewable electricity generation meeting 31% of electricity demand. This compares to renewable generation of 32TWh in 2010, equivalent to 9% of electricity demand.

21 'Options for low-carbon power sector flexibility to 2050. A report to the Committee on Climate Change'. Pöyry, October 2010.

Hence, it is assumed that the supply chain is in place to deliver at least the annual deployment rate set out in the NREAP. If the levels of renewable generation set out under the NREAP targets were not met, there would need to be an additional step change in the rate of renewable generation deployment to meet the stretching 2030 milestones set under our scenarios. Indeed, if the UK falls a long way short of the NREAP targets, then it may not be feasible to increase the supply chain quickly enough from its 2020 position to meet our 2030 milestones.

The temporal aspect to our scenarios is important – the choices made now over the direction of development of the generation mix will set the foundations for that mix well into the future. This study will provide insight into decisions that need to be taken in the short-term as well as a guide for assessing progress of the electricity system towards the features required by 2030 and 2050.

2.5 Constraints on deployment trajectories

Achieving the deployment rates of renewable technologies in our main scenarios will require an ambitious combination of technology development and deployment. Therefore, the study assessed the constraints related to the delivery and accommodation of high renewable deployment trajectories. The constraints are grouped under four broad categories:

- system flexibility constraints;
- supporting transmission and distribution constraints;
- resource availability constraints; and
- build rate constraints; and

We also consider the prospects for being locked into certain trajectories, whereby developments in the near-term narrow the range of options for the future electricity system[22].

In some cases, the assessment is quantitative through the use of additional modelling to test the impact of changing a particular assumption, such as the availability of demand-side response. For other types of constraint, we provide a qualitative assessment.

22 For example construction of large amounts of plant which is inflexible, either for economic or technical reasons may preclude larger deployment of wind at a later stage.

[This page is intentionally blank]

3. MODELLING APPROACH

This chapter sets out the approach used to assess the performance of the system in accommodating high levels of renewable generation.

We used scenario analysis to make a detailed quantitative assessment of how the electricity system can accommodate high levels of renewable penetration. This involved both the analysis of a set of main scenarios but also the analysis of variants designed to test the impact of changes to input assumptions, e.g. reductions in the level of power system flexibility.

This quantitative assessment was primarily carried out using the wholesale electricity model *Zephyr* that Pöyry Management Consulting first developed for use in its GB and Ireland intermittency study in 2009[23].

Therefore, the approach to the assessment can be broken down into the following components:

- developing feasible scenarios and variants;
- modelling platform;
- inputs and assumptions; and
- outputs of the analysis.

3.1 Developing feasible scenarios and variants

The first step in the analysis was the development of scenarios for the deployment of renewables out to 2050. To inform the deployment trajectory analysis, we used an iterative modelling process to produce pairs of consistent scenarios for 2030 and 2050 – i.e. for a particular scenario, the results from 2030 determine the starting point for 2050, and the 2050 results inform the attractiveness of investments in 2030.

There were a number of different factors taken into account in the development of these scenarios:

- assumptions about annual electricity demand;
- target for level of renewable penetration;
- the suggested mix of renewable generation;
- views on possible deployment of non-renewable generation; and
- assumptions about availability of flexibility from different sources.

Putting together each possible combination of all these different factors would produce an unmanageable number of scenarios. As the focus of the study was on characterising the constraints that will limit the deployment of renewables, our main scenarios were differentiated by the level of renewable penetration in 2050. We explored the other factors listed above either through the analysis of variant scenarios (in which we tested the impact of changing particular assumptions).

---

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

We also assessed the impact of variation in weather patterns by using our mini-Monte Carlo approach in Zephyr to allow us to look in detail at the performance of the system during spells of extreme weather. We used our hourly results to create ‘synthetic years’ which combined the historical months with the most extreme results for the desired weather patterns – which were the number of sustained periods of low wind output (or lulls), and the variability of wind output respectively.

Table 2 provides an overview of the key design features of the main scenarios.

Table 2 – Overview of main scenarios

Scenario	Annual demand	Level of renewable penetration	Mix of renewable generation	Deployment of non-renewable generation	Availability of flexibility
High (2030 and 2050)	409TWh in 2030; 551TWh in 2050	60% by 2050	Wind-dominated	Beyond specified minimums, deployment and closure driven by expected returns	High – low carbon generation, active demand, interconnection, bulk storage
Very High (2030 and 2050)	409TWh in 2030; 551TWh in 2050	80% by 2050	Wind-dominated	Beyond specified minimums, deployment and closure driven by expected returns	High – low carbon generation, active demand, interconnection, bulk storage
Max	611TWh	Close to maximum	Wind-dominated	Beyond specified minimums, deployment and closure driven by expected returns. No nuclear or CCS by definition	High – low carbon generation, active demand, interconnection, bulk storage

A number of *Zephyr* modelling runs were used to develop a final capacity mix that ensured that these scenarios met the constraints agreed with the CCC:

- **Limit on average carbon intensity of power generation** – around 80-90gCO_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 (and in the Max scenario), with the difference reflecting the fact that annual electricity demand was about twice as high in 2050 and in the Max scenario) than in 2030.

3.1.1 Annual electricity demand

The CCC provided assumptions for the annual level of electricity demand in 2030 and 2050 from different sources – such as residential customers and electric vehicles. We combined this with our assumptions about the consumption profile and flexibility of different types of end-users to produce an hourly profile of fixed demand for 2030 and 2050. The electricity demand assumptions did not differ between scenarios for the same year.

3.1.2 Renewable penetration

These scenarios were designed to test the impact of going significantly beyond the renewable penetration level of 30% of total generation that was used in the analysis for the CCC's advice on the fourth carbon budget period[24].

Therefore, our scenarios were based around the:

- delivery of 60% renewables by 2050 in the High scenario (with analysis of 2030 and 2050); and
- delivery of 80% renewables by 2050 in the Very High scenario (with analysis of 2030 and 2050).

We also developed a Max scenario[25] to look at the impact of trying to deliver a system with renewable penetration as close to 100% renewables as possible, given our assumptions about system flexibility.

3.1.3 Renewable mix

In all of the scenarios, the renewable generation mix is assumed to be dominated by wind. There are three key drivers for this:

- wind is the renewable resource believed to have the largest practicable potential for the GB system;
- the particular nature of wind in terms of mix of unpredictability and intermittency; and
- the benefits of testing the system impact of a less diverse renewable supply capacity.

We used variants to test the system benefits of a more diverse renewable mix (with a lower reliance on wind).

3.1.4 Non-renewable generation

The deployment of non-renewable generation in the High and Very High scenarios started from the same assumed position for 2020. This took into account existing plants (given expected closure schedule), plant currently under development and minimum requirements for new CCS and nuclear build provided by the CCC. In the Max scenario, there was assumed to be no nuclear or CCS plants.

We then used an iterative modelling process to inform decisions about the construction of additional plant (based on returns received) and the early closure of existing plant (where it was not recovering its fixed costs).

3.1.5 Availability of power system flexibility

As part of the supporting work for the CCC's fourth carbon budget report, Pöyry identified and characterised sources of low-carbon flexibility out to 2050[26].

---

24 'The Fourth Carbon Budget. Reducing emissions through the 2020s', Committee on Climate Change, December 2010.

25 This scenario was not bound to a particular year.

26 'Options for low-carbon power sector flexibility to 2050. A report to the Committee on Climate Change', Pöyry Energy Consulting, October 2010.

A mix of flexibility is needed over a range of timescales, which stretch from the provision of reserve and response over very short periods to matching annual generation and demand. The interaction between renewable generation and fixed demand will determine the mix of flexibility required in each scenario.

One of the core assumptions for the scenarios analysed in this study is that a high level of system flexibility will be developed to support renewable penetration of at least 60% by 2050. We used variant analysis to test the impact of changes in the assumptions about system flexibility, particularly in relation to demand-side response, interconnection and the capacity (and hence duration) of hydrogen storage.

3.2 Modelling platform

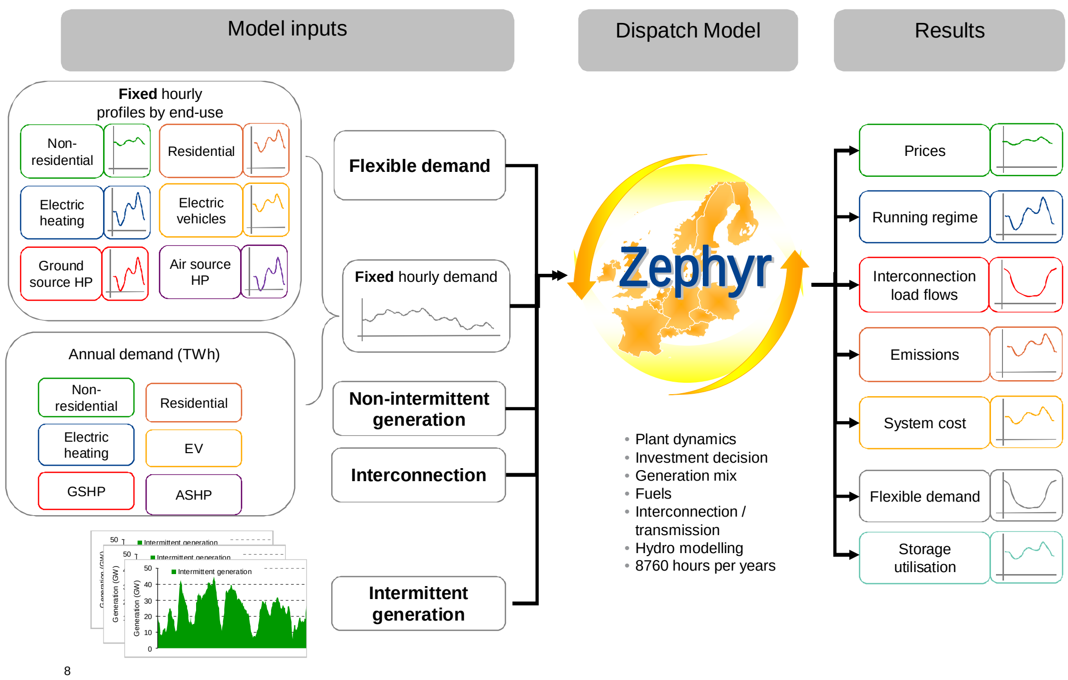
The quantitative assessment is based on the outputs of our wholesale electricity model *Zephyr,* which delivers the least-cost dispatch of flexible sources of supply and demand to meet the gap between inflexible supply and inflexible demand.

The model was initially specifically designed to reflect the impact of intermittency in renewable generation, especially wind, on system operation, costs and prices, and has been subsequently refined through a number of further studies. In particular, we have developed the demand side modelling capability as part of the flexibility study we carried out for the CCC in 2010.

3.2.1 Overview of Zephyr

Figure 3 provides an overview of this unparalleled modelling platform, which is backed by a wealth of historical data on profiles for intermittent generation, availability of non-intermittent generation and demand.

Figure 3 – Overview of Zephyr



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

- **Hourly demand profiles** – based on combination of historical demand patterns and historical weather pattens that would affect new sources of demand (e.g. from heat pumps). This means that the hourly fixed demand profile varies by historical year, with peaks and troughs in demand occuring at different times in each year.
- **Hourly intermittent generation profiles** – based on available historical data on weather (including solar irradiation) and on predictable future aspects such as timing of the tides.
- **Hourly plant availability profiles and dynamics** – plant availability profiles are based on historical profiles (by plant type) for several individual years[27]. This includes scaling for different properties (maximum output, minimum on and off time, minimum stable generation etc) estimated from historical MEL data.
- **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 to these variable costs to create the hourly wholesale price. The value of capacity 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 change our assumptions about new build and/or value of capacity through an iterative modelling process to produce a set of wholesale prices that are consistent with the new entry decision for thermal plant.
- **Active demand units** – the model includes different categories of active demand units, covering heating, electric vehicles and residential washing appliances.

3.2.2 Dispatch within Zephyr

Based on a mixed integer linear programming platform, *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[28].

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. This optimisation takes into account the sum of variable costs (including fuel and carbon), the costs of starting plant and the costs of part-loading.

---

27 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.

28 For this study, Zephyr has been run 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, as are the mentioned plant dynamics constraints. We have also restricted the model runs to Great Britain only to reflect the scope of this study.

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 are not completely 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) [29], for example to avoid shutting down a nuclear plant and incur the cost of restarting it later; and
- failing to meet demand, which is measured as the amount of expected energy unserved (EEU).

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.

3.2.3 Modelled data set

For each future year that is modelled in this study (i.e. 2030, 2050 and the Max scenario), we carried out four iterations based on historical data. This means that for any given future year, there is a total of 35,040 hours modelled (8,760 x 4), giving a comprehensive representation of possible interactions between weather, availability and demand.

We selected the four historical years[30] from our data set of 10 historical years based on the features most useful for testing the ability of the system to accommodate high levels of renewable generation, with wind dominating the renewable mix:

- highest annual output from wind generation;
- most number of days with temperature below 5 degrees Celsius;
- highest wind variability from one period to another; and
- highest number of lulls (with a lull defined as period of at least 72 hours with wind output below 15% installed capacity).

Using weather, availability and demand profiles for four rather than 10 historical years more than halved the run time for the model, allowing us to deliver the number of model runs required within the project timetable.

In addition, we constructed two ‘synthetic years’, which combined the historical months with the most extreme results for the desired weather patterns – which were number of lulls, and the variability of wind output respectively.

---

29 It is not possible to increase output from intermittent generation.

30 These years were 2006, 2007, 2008 and 2009.

3.3 Inputs and assumptions

There are four broad categories of input and assumption into the Zephyr modelling process:

- **fuel and carbon prices** – based on assumptions published by DECC;
- **electricity demand** – annual electricity demand (TWh) for each sector were provided by the CCC, with hourly demand profiles for each sector being based on Pöyry analysis;
- **generation capacity and plant characteristics** – technical and economic plant assumptions based on a mixture of DECC and Pöyry assumptions; and
- **non-generation sources of flexibility** – amount and flexibility of interconnection, bulk storage and movable demand.

3.3.1 Fuel and carbon prices

The following assumptions for fuel prices were taken from Scenario 2 (Timely Investment, Moderate Demand) in DECC's January 2010 update of fossil fuel prices[31]:

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

These were converted into sterling using an exchange rate of $1.60:£1, in line with assumptions made in DECC's published guidance on fuel prices. As the DECC update only provided assumptions out to 2030, we held the 2050 price constant at the 2030 level.

Our assumed carbon prices were £70/tCO_2 in 2030 and £200/tCO_2 in 2050[32].

3.3.2 Electricity demand

There are four components to the modelling of electricity demand within Zephyr:

- annual electricity demand by sector (TWh);
- ex-ante (fixed) demand profiles for each sector;
- allocation of annual demand for each sector between fixed profiles and active demand units. ('movable demand'); and
- the characterisation of active demand units (with an accompanying set of flexibility constraints and characteristics).

Figure 4 shows the assumptions for final electricity demand in GB provided by the CCC[33]. It illustrates 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 continues after 2030, which together with use of electrolysis to produce hydrogen for

---

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

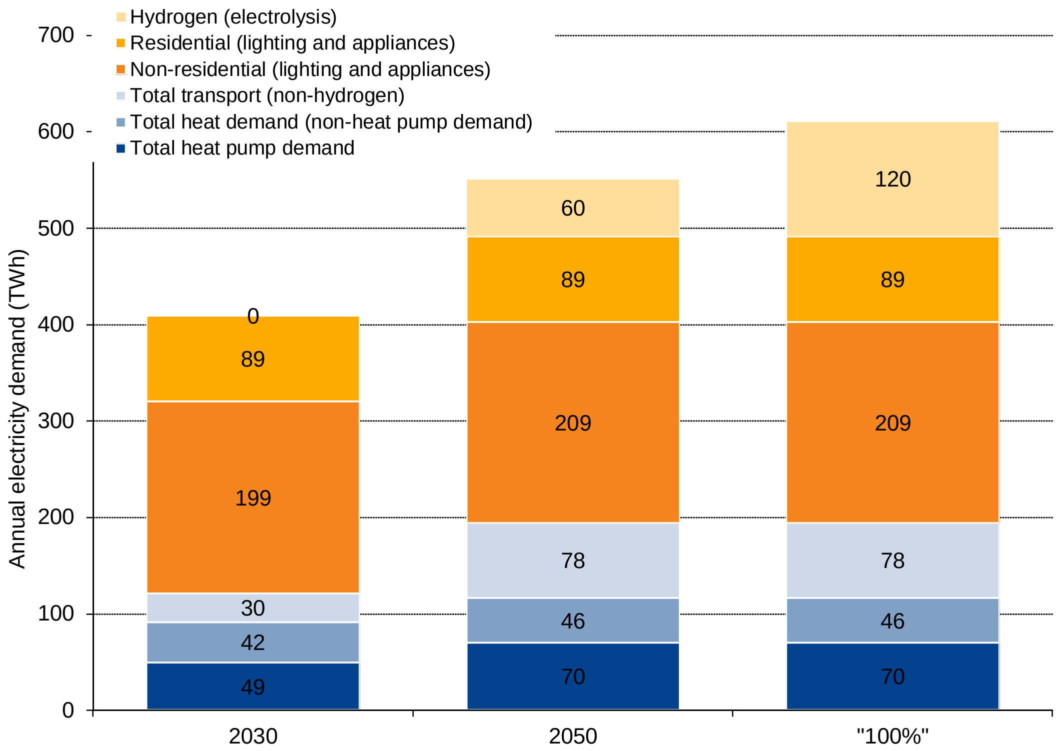
32 'Carbon Valuation in UK Policy Appraisal: A Revised Approach', Climate Change Economics, DECC, July 2009.

33 *Zephyr* uplifts electricity demand to take account of network losses when calculating the requirement for generation and imports.

transport. Consequently, electricity demand reaches about 550TWh in 2050 from 409TWh in 2030 (compared to around 350TWh at present). As well as increasing the level of electricity demand, these developments change the pattern and variability of electricity demand compared to the current system.

In the Max scenario, demand is based on the 2050 assumptions with additional electricity demand coming from electrolysis. This is doubled from the 2050 level because the assumed absence of CCS in the Max scenario means that electrolysis produces the hydrogen coming from IGCC units in 2050 in the other scenarios.

Figure 4 – Annual final electricity demand (TWh)



Source: Committee on Climate Change

The fixed demand profiles were based on the profiles used in our flexibility study for the CCC[34], with the exception of the fixed profile for (inflexible) EV demand. This was assumed to peak around the start and the end of the working day.

Section 5.4.2 describes the amount of movable demand in each scenario and Section 3.3.4.3 summarises the approach to the modelling of the active demand units.

34 'Options for low-carbon power sector flexibility to 2050. A report to the Committee on Climate Change', Pöyry Energy Consulting, October 2010.

3.3.3 Generation capacity and characteristics

The input assumptions for installed renewable capacity reflect Pöyry's expert analysis of the scope for renewable deployment to meet the renewable generation requirements for each scenario. Chapter 5 provides more details on the deployment trajectories for renewable capacity after 2020.

Deployment of non-renewable generation in the High and Very High scenarios started from the same assumed position for 2020. This took into account existing plants (given expected closure schedule), plant currently under development[35] and minimum requirements for new CCS and nuclear build provided by the CCC.

An iterative modelling process is used to inform decisions about the construction of additional plant (based on returns received against a benchmark requirement of 10%) and the early closure of existing plant (where it was not recovering its fixed costs).

Chapter 5 provides more details on the deployment trajectories after 2020 for nuclear and CCS. In the Max scenario, there was assumed to be no nuclear or CCS plants.

We used DECC assumptions[36] 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[37], including our flexibility study for the CCC[38].

3.3.4 Non-generation sources of flexibility

There are three main sources of non-generation flexibility: interconnection, bulk storage and demand-side response. Estimates of the costs of these sources of flexibility are set out in Annex A.

3.3.4.1 Interconnection

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 scope of the assumptions provided by the CCC. Therefore, we had to make border assumptions for input into *Zephyr* with respect to interconnections with:

- the Single Electricity Market in Ireland (**SEM**), which includes Northern Ireland;
- electricity markets in North West Europe, namely France, Netherlands and Belgium **(NW Europe**); and
- Norway.

---

35 Of the 7GW of CCGT plant under development; 1.6GW was undergoing commissioning, 3.3GW was under construction, with the remaining 2.1GW having received planning permission (and being expected to proceed to commissioning).

36 Based on data sourced from a study undertaken for DECC by Mott MacDonald.

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

38 'Options for low-carbon power sector flexibility to 2050. A report to the Committee on Climate Change', Pöyry Energy Consulting, October 2010.

There are three key components to the modelling of interconnectors in *Zephyr* – available capacity (discussed in Section 5.4.1), flexibility of operation (on an hourly basis), and determinants of flow (in terms of both direction and magnitude).

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

Explicitly modelling other European countries was outside the scope of this study. Therefore, the input assumptions for interconnector flows have been determined by analysis outside the GB *Zephyr* model. However, *Zephyr* is able to reduce (but not increase) the level of flows based on the balance of supply and demand in GB.

The hourly flows across the interconnectors with the SEM are assumed to be driven by differences in the hourly wind load factor between GB and the SEM. This reflects the fact that although the precise capacity mix in Ireland 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 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 SEM, then the interconnector would flow into GB worsening a potential excess supply situation. Additional capacity only helps if the flows are in the right direction to balance the wind. In addition, the small size of the Irish market means that it can offer a limited source of flexibility to the GB market. Therefore, the interconnection capacity between GB and the SEM has been increased to only 2GW in all scenarios.

Net flows across the interconnector between GB and the SEM were assumed to be zero [39] – i.e. annual imports equal annual exports on average across the four historical years. Flows across the other interconnectors (with NWE and with Norway) are based on the analysis in Pöyry's intermittency study for NWE[40]. The magnitude of the flows are scaled with changes in the level of the interconnector capacity.

Consequently, the input net flows are not assumed to be zero. In practice, the input net flows in the High and Very High scenarios happen to be close to zero across the interconnectors with NWE. The Norwegian interconnector is assumed to provide annual net imports to GB of 7.5TWh in 2030 and 2050.

In the Max scenario, the net imports from NWE and Norway are around 12TWh because of the assumed increase in interconnection capacity.

The output flows from *Zephyr* may differ from the input flows because the model will reduce the flows in the following circumstances (but can never increase flows):

- it will reduce imports before deloading intermittent renewables; and
- it will reduce exports during any periods of load loss in GB.

---

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

40 'The challenges of intermittency in North West European power markets (public summary)', Pöyry Management Consulting, March 2011.

3.3.4.2 Bulk storage

There are three main aspects to the quantity of flexibility provided by bulk storage – generation capacity (or ‘peak deliverability’), input capacity (the rate at which the storage capacity can be filled) and storage capacity.

In all scenarios, bulk storage is assumed to have generation capacity of 4GW compared to a figure of 2.8GW today. This storage is assumed to have the (operating and cost) characteristics of Dinorwig[41], by far the largest pumped storage facility currently operating in GB. Consequently, bulk storage can generate for 5 hours at maximum capacity[42], with the facility then taking at least 7 hours to completely refill[43]. Therefore, bulk storage can at most complete two cycles (of filling and withdrawal) a day.

From hour to hour, the bulk storage facilities are assumed to be fully flexible. However, *Zephyr* is required to balance the flows in and out of the bulk storage over a week to avoid excessive optimisation of the model. This means that the bulk storage cannot provide flexibility over a longer period than a week.

The limits on storage capacity are the only restrictions on the availability of the bulk storage facility across the year – i.e. it cannot be used to increase demand net wind by pumping into storage if the reservoir is already full.

3.3.4.3 Demand-side response

There were three sources of demand-side response in this study – movable demand from active demand-side units, the production of hydrogen through electrolysis, and demand destruction.

Section 5.4.2 provides details of the allocation of annual electricity demand to active demand-side units. *Zephyr* optimises the use of this movable demand based on the characteristics and constraints of each active demand-side unit, based on:

- end-use (e.g. washing appliances, heating, or electric vehicles);
- sector (e.g. residential or non-residential); and
- technology (e.g. EV or hybrid, air source or ground source hear pump).

---

41 This reflects the limited data available on costs and operation of bulk storage. The assumed increase in bulk storage could come from new pumped storage schemes, such as the two 600MW projects (Coire Glas and Balmacaan) identified by SSE. Alternatively, new storage technologies could be deployed such as adiabatic compressed air storage plant (A-CAES) plus battery technology.

42 With an effective storage capacity of 20TWh.

43 With an effective input capacity of 2.9GW.

These characteristics and constraints include:

- **the energy demand profile**[44], (i.e. demand for heating, as opposed to the demand for electricity for heating) with the general restriction that the energy demand requirements must be met for each unit;
- **changes in efficiency of the demand-side unit over the year,** e.g. the coefficient of performance for air source heat pumps (which falls in winter, increasing the amount of electricity demand required to provide a particular level of heating demand);
- **(dis)charging rate**;
- **availability of storage capacity**[45];
- **rate of energy loss in (heat) storage**; and
- **options for fuel switching**, e.g. through use of petrol in hybrid vehicles in response to high electricity prices.

For this study, the CCC provided an assumption that the electricity sector in 2050 was required to produce a total of 100TWh of hydrogen from two sources – electrolysis (direct form of electricity demand) and the diversion of hydrogen produced by CCS IGCCs (thereby restricting its availability to generate electricity) [46].

In the High and Very High scenarios, hydrogen production was assumed to be split equally between these two sources. In the Max scenario, all of the hydrogen demand was met from electrolysis as there was assumed to be no CCS plants.

For both production methods, hydrogen flexibility is effectively limited to being within day – an assumption that was relaxed in one of the variant scenarios.

We assumed that in all scenarios, there was approximately 1 GW of voluntary demand reduction (or destruction) in response to high electricity prices. This was consistent with the assumption made in previous CCC studies. The demand reduction took place in the following combinations of quantities and prices[47]:

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

---

44 For heating and transport, the underlying energy demand profile is used to reduce the amount of electricity in storage over time, creating the need to refill storage.

45 Storage is separately managed for each demand-side unit – e.g. electricity in storage for residential ASHPs cannot be used to meet electricity demand from residential GSHPs or from non-residential ASHPs.

46 All assumptions in relation to hydrogen were provided by the CCC and hence the development of these assumptions is not described in this report.

47 Figures are based on 'Estimation of Industrial Buyers' Potential Demand Response to Short Periods of High Gas and Electricity Prices. A report to the DTI and Ofgem', Global Insight, 2005.

3.4 Outputs

Zephyr produces a detailed set of physical (e.g. generation by plant) and financial (e.g wholesale electricity price) outputs, which we used to make a quantitative assessment of each scenario. The hourly resolution of these outputs means that they describe in detail how the system copes during periods of stress, when renewable generation is high, low and/or variable.

In this report, we show the following annual physical outputs based directly on results from *Zephyr:*

- generation by technology;
- load factor by technology;
- unused production from low variable cost generation, defined as renewables (excluding biomass) and nuclear;
- CO_2 emissions by source;
- CO_2 emissions intensity of the generation sector;
- net interconnector flows; and
- the annual level of expected energy unserved (EEU), which is a measure of the level of security of supply.

The unused production from low variable cost generation is the calculated as the difference between available and actual generation from renewables (excluding biomass) and nuclear. This illustrates the extent to which this high capital cost generation capacity is not being fully utilised.

Outputs from *Zephyr* are used to calculate the requirements for network reinforcement, with the resulting network costs for each scenario included in Annex A. Distribution network reinforcement is based on the level of peak demand (including losses).

The projected power flows across key GB transmission network boundaries (in *Zephyr)* are used to determine the amount of transmission network investment, based on the trade-off between investment costs and constraint costs.

[This page is intentionally blank]

4. ACCOMODATING HIGH RENEWABLES

This chapter summarises the results of our detailed quantitative analysis of the different scenarios (High, Very High and Max) for the level of renewable generation in GB described in Section 3.1

We set out the key results for the generation sector in terms of installed capacity, annual output and annual load factors. This illustrates the impact of changes in renewable penetration on the build and operation of nuclear and CCS plants.

The next section then looks at how the system uses different sources of flexibility (generation, interconnection, bulk storage and demand-side response) to balance supply and demand, first during a snapshot period of one month and then over the whole year.

Finally, we assess the scenarios on their performance against three measures:

- **Security of supply** – the amount of peaking capacity required to meet the constraint on the level of expected energy unserved (EEU)[48] increases with renewable penetration (in the same year)[49].
- **Utilisation of available low variable cost generation**[50] – the shedding of low variable cost generation is much greater in 2050 than in 2030, with the level of renewable penetration only seeming to make a marked difference when moving beyond 80% in the Max scenario.
- **Delivery of low-carbon system** – all scenarios satisfy the constraints on annual CO2 emissions[51], although the assumed absence of nuclear and CCS in the Max scenario means that emissions are higher in the Max scenario than in the other two scenarios in 2050 (despite higher renewable penetration).

4.1 Results for the generation sector

This section sets out the following results by generation technology – installed capacity, annual generation and annual load factors.

4.1.1 Installed capacity

Figure 5 shows total capacity (and mix) in each scenario while Figure 6 enables a comparison of installed capacity of each generation type in the High and Very High scenarios. In Figure 6, moving from the charts on the left hand side to those on the right highlights changes over time, whereas moving from the top charts to the bottom charts illustrates the impact of moving from the High scenario to the Very High scenario (with an increase in the level of the renewable penetration in the same year).

---

48 The EEU constraint is around 2GWh of in 2030 and around 4GWh in 2050 and the Max scenario, with the difference reflecting the fact that annual electricity demand was about twice as high in 2050 (and in the Max scenario) than in 2030.

49 A comparison between 2030 and 2050 for the same scenario is complicated by changes in the level, composition and flexibility of demand.

50 Low variable cost generation is defined as nuclear and renewables excluding biomass. Shedding increases the levelised cost of additional low-carbon capacity, particularly if it is high capital cost (e.g. offshore wind and nuclear). This will push up the incremental costs of decarbonisation.

51 Around 80-90gCO_2/kWh of demand in 2030 and close to zero in 2050.

Figure 5 – Installed capacity by scenario (GW)

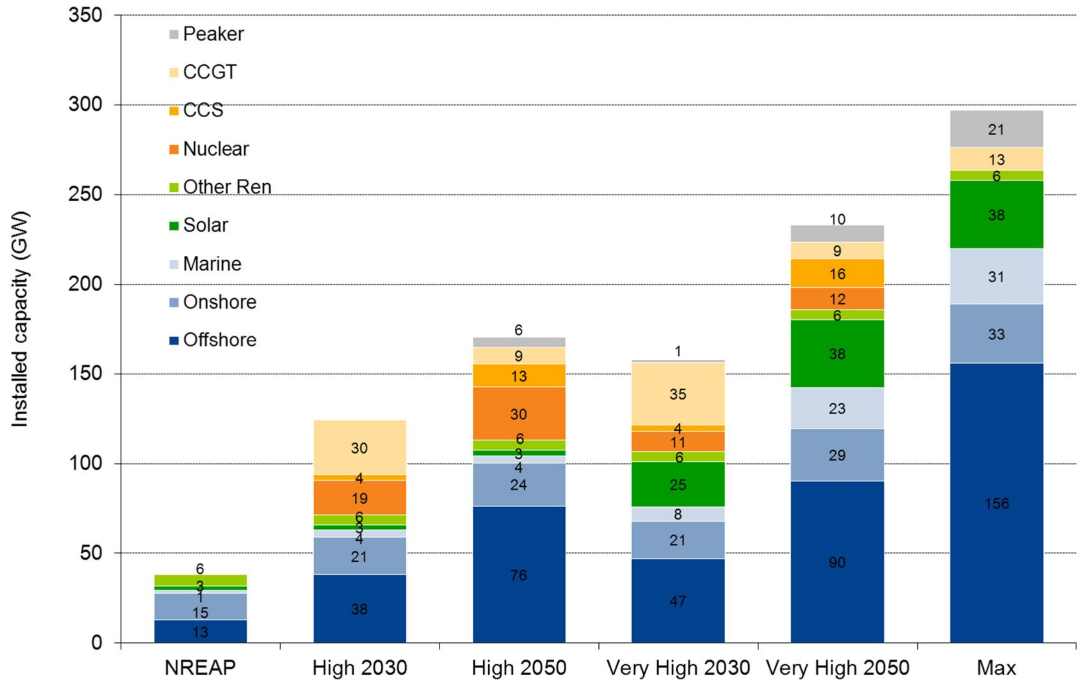
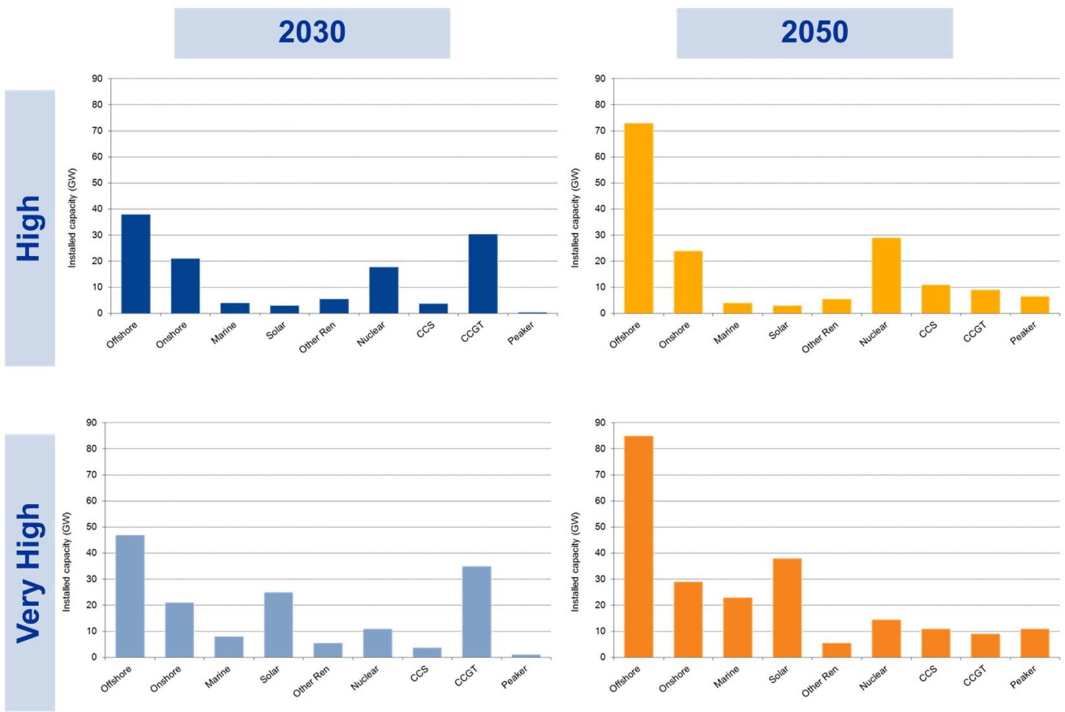


Figure 6 – Installed capacity in 2030 and 2050 by scenario (GW)



The two charts illustrate the following key messages:

- **Total installed capacity increases with the level of renewable penetration,** as shown by the fact that total capacity in 2030 and 2050 is higher for the Very High scenario than for the High scenario[52].
- **Renewable generation is dominated by wind, primarily offshore wind.** Although it is possible to use alternative renewables, such as biomass marine and solar, to help meet part of the renewable generation target; given the level of UK wind resource, our scenarios have focused on the development of offshore wind.
- **In 2030, the increase in renewable penetration between scenarios is primarily achieved through greater deployment of solar and additional offshore wind**. This can be seen by comparing the capacities in the Very High scenario to those in High 2030 scenario, with solar capacity rising to 25GW (compared to 4GW) and offshore wind capacity increasing by 9GW.
- **Increased renewable penetration in 2050 is delivered through greater deployment of a mixture of technologies, including solar, offshore wind, marine and onshore wind.** Between the Very High scenario in 2050 and the High scenario in 2050, there is an increase in capacity of 35GW for solar, 12GW for offshore wind, 6GW for marine and 5GW for onshore wind.
- **Raising renewable penetration in 2050 more than halves the level of nuclear deployment but slightly increases CCS capacity.** Higher CCS capacity in 2050 in the Very High scenario compared to the High scenario is the result of the flexibility of CCS gas.
- **In all of the scenarios, there is no new construction of CCGTs beyond plant currently under development.** Installed CCGT capacity is lower in 2030in the High scenario compared to the Very High scenario. This reflects the early closure of an additional 5GW of CCGT in the High scenario because it fails to recover its fixed costs (rather than the construction of new CCGT in the Very High scenario).
- **Construction of peaking plant is not required until after 2030 in either the Very High or the High scenario.**

Chapter 5 describes in detail the deployment trajectories for delivering the levels of renewable, nuclear and CCS capacity shown in Figure 5 and Figure 6.

4.1.2 Annual generation

We present two charts showing the annual output by generation type (as we did for the installed capacity). Figure 7 compares the total generation mix by scenario, whilst Figure 8 facilitates a comparison of generation over time (by moving left to right between charts) and between the High and Very High scenarios (moving between the top and bottom charts). Figure 8 also shows the impact of the synthetic years described in Section 3.2.

---

52 A comparison between 2030 and 2050 for the same scenario is complicated by changes in the level, composition and flexibility of demand.

Figure 7 – Annual generation by scenario (TWh)

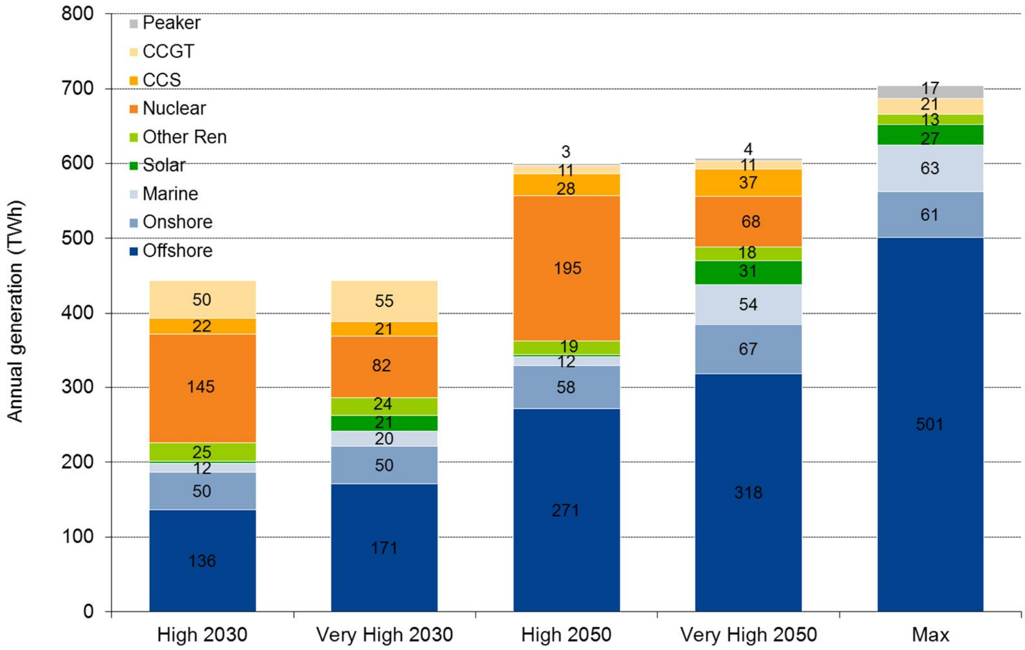
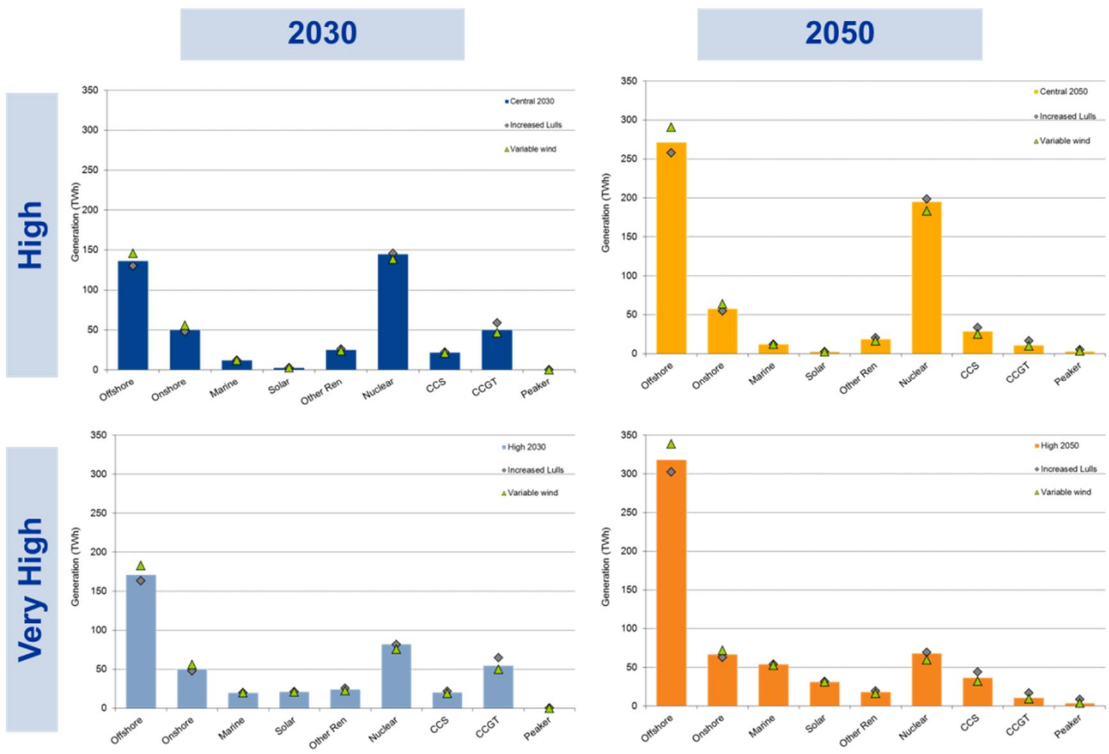


Figure 8 – Annual generation in 2030 and 2050 by scenario (TWh)



These two charts illustrate the following key messages:

- **the generation mix is dominated by wind, particularly offshore, and nuclear**, although the relative contribution of nuclear falls as renewable penetration increases;
- **solar accounts for only a small share of the generation mix in the Very High scenario despite high levels of installed capacity**;
- **CCGT and peakers represent a much smaller share of the generation mix than the capacity mix;** and
- **generation from CCGT and peakers is higher in the Max scenario than in the other two scenarios in 2050**, because the higher renewable generation does not entirely compensate for the increase in demand and assumed absence of nuclear and CCS generation.

Figure 8 shows that in the synthetic year with a high number of lulls, total output from wind generation is a little lower than the average of the historical years. However, the fall is perhaps not as much as expected, illustrating that the monthly load factor may not be particularly low even if there are a number of extended periods of low wind in the month. The lower wind output results in higher non-intermittent generation, with the increase spread across the different technologies.

In the synthetic year with greater wind variability, the annual load factor of wind is actually higher than the figure for the historical years, with the result that wind output is more variable around a higher average. This leads to lower output from non-intermittent generation, particularly nuclear.

4.1.3 Annual load factors

Figure 9 combines the results for capacity and generation[53] to compare the annual load factor by technology in the High and Very High scenarios, with the load factors for the Max scenario shown separately in Figure 10[54].

---

53 The results for the synthetic years mirror the pattern seen in the generation charts because the capacity is same in the synthetic years as in the historical years.

54 Section 4.3.2 looks in more detail at the utilisation of low variable cost generation, which is defined as nuclear and renewables excluding biomass.

Figure 9 – Annual load factors in 2030 and 2050 by scenario (%)

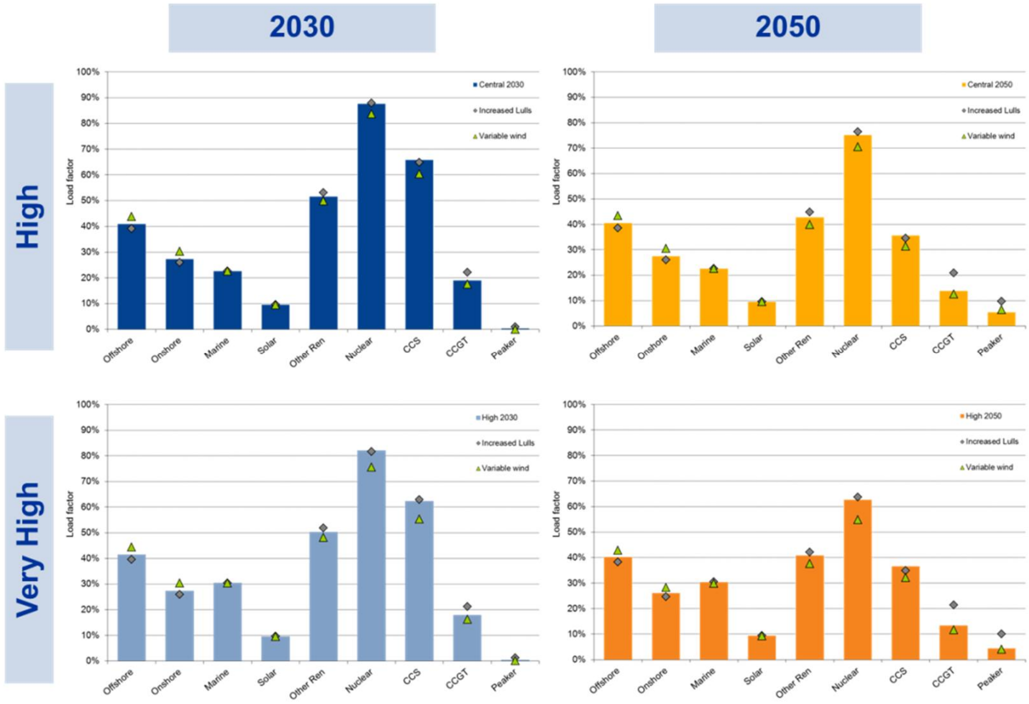
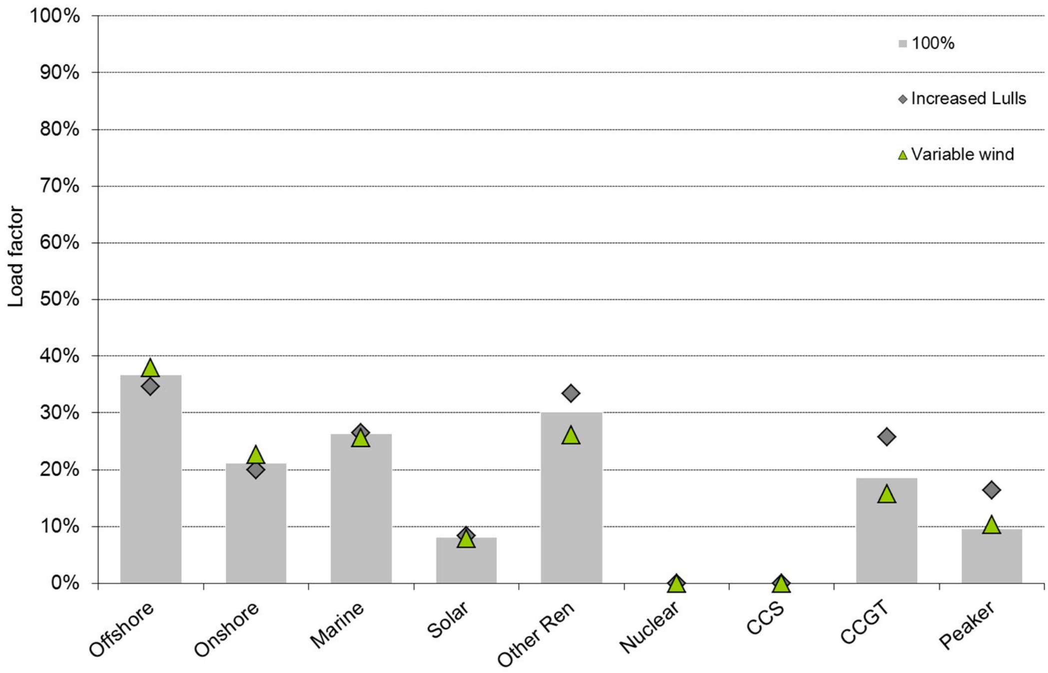


Figure 10 – Annual load factors in Max scenario (%)



The key messages from these charts are:

- **The low variable cost (and controllability) of nuclear plant means that it is the only technology running close to baseload in 2030, but cannot prevent its achieved load factor dropping to 60% in 2050 in the Very High scenario**. This is because it is increasingly displaced by intermittent generation as renewable penetration increases.
- **When offshore wind capacity is at its highest (in the Max scenario), its achieved annual load factor falls below 40%**. This is the result of high levels of shedding of offshore wind output in this scenario.
- **Solar has a very low annual load factor (around 10%), compared to around 40% for offshore wind.** In the absence of shedding, 4GW of solar would be required to replace the annual generation of 1GW of offshore wind. However, this rule of thumb does not apply when high levels of offshore wind capacity, with relatively highly correlated output patterns, leads to increased shedding and hence a decrease in the achieved load factor of incremental offshore wind capacity.
- **The load factor of the non-intermittent ('other') renewables (biomass and hydro) falls from 50% in 2030 in the High scenario to 30% in the Max scenario.** This is because it is displaced by intermittent renewable generation.
- **Achieved load factors are very low for CCGTs and particularly for peaking plants.**

4.2 Use of flexibility to cope with high levels of renewables

In this section, we look at how the system uses the various sources of flexibility to balance total supply and demand in response to the differences between inflexible demand and intermittent generation.

We start by looking in detail at the pattern of dispatch for a snapshot period, before looking in turn in the use over the year of flexibility from generation, interconnection and demand-side response.

4.2.1 Use of flexibility in snapshot period

Figure 11 shows for the High scenario in 2050, the pattern of supply and demand over the period between 1 and 18 February, as if the weather conditions of 2006 were exactly repeated. We have chosen to show this period because the variable pattern of intermittent renewable generation will particularly test the system during winter when demand is higher than at other times of the year.

The **top chart** captures the interaction between 'inflexible' demand and intermittent generation. It illustrates the within-day pattern of inflexible demand with evening peaks and overnight troughs. The fall in demand on 4/5 February and 11/12 February shows how inflexible demand is lower at weekends compared to working days. The inflexible demand profile is quite regular over the period, particularly compared to the pattern of intermittent generation.

Intermittent generation is dominated by wind, primarily offshore, with total installed wind capacity of 100GW[55]. In the first half of the period, there is an extended lull (in which

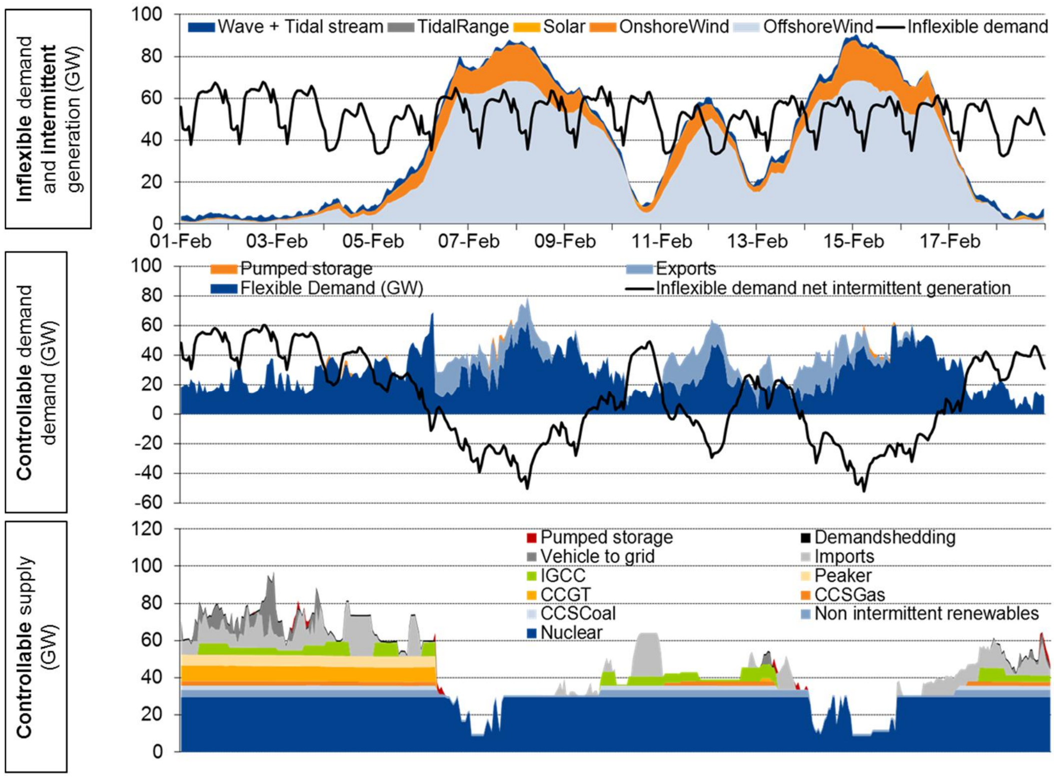
55 76GW of offshore wind, and 24GW of onshore wind.

output remains below 8GW between 1 and 4 February). This followed by a period of persistently high wind output, which remains over 60GW for three days (6-8 February).

In the second half of the period (starting from 9 February), the wind pattern is much more variable. Output start to decline, reaching a low about 10GW by the evening of 10 February, which coincides with the daily peak in inflexible demand. Wind generation then increases to a peak of 60GW overnight (11/12 February) and stays there over the weekend when inflexible demand is relatively low.

After another dip in wind output (although it remains above the levels seen at the start of the month), there is then a three day period in which wind output stays above 60GW and sometimes exceeds 80GW (14-16 February). Finally, the level of wind drops back below 20GW on the last day of the period.

Figure 11 – Demand and supply in the High scenario in 2050[56] (GW)



Differences between inflexible demand and the level of intermittent generation is shown by the solid line in the **middle chart.** This illustrates the challenge faced by the system in having to deal with extended periods in which there is too little (line above the x-axis) or too much intermittent generation (line below the x-axis) compared to inflexible demand. In general, the shape of the line closely follows (albeit inversely) the pattern of wind generation, although the impact of low overnight and weekend demand can also be seen.

The middle chart shows how sources of flexibility (such as demand-side response, exports, and demand from bulk storage) help to address the imbalance between inflexible demand and intermittent generation.

56 Using historical weather patterns of February 2006.

In general, demand from these flexibility sources is higher in periods in which there is a relative excess of intermittent generation. However, they are not able to completely shift their demand away from extended periods of low wind, e.g. because of the constraints imposed by storage capacity and the need to meet the underlying energy demand. For example, electricity demand from electrolysis can only be shifted within a single day.

The pattern of exports shows the value to the system of interconnection. In general, the system exports at times when there is more intermittent generation than fixed demand. However, it does not export at all such times, and the level of exports does not necessarily increase as the gap grows between intermittent generation and fixed demand. This reflects the fact that the interconnector flows will be influenced by the pattern of generation and demand in other countries, which constrain the ability to flows to respond exactly to the needs of the system in GB.

The interaction between flexible demand and interconnector flows is highlighted in the middle chart. Wind output increases rapidly during 5 February and continues to rise into 6 February. As the system is not exporting, there is a big increase in flexible demand to help absorb the additional wind generation. However, storage constraints mean that the flexible demand drops off with the result that nuclear plant is turned down on 7 February, even though the system has started exporting.

The **bottom chart** shows changes in supply from the various sources of flexibility, such as generation, imports, generation from bulk storage, vehicle to grid flows, and demand shedding. The total supply equals the level of total demand minus intermittent generation.

The baseload requirement for demand net intermittent generation is around 60GW during the sustained lull between 1 and 6 February. Therefore, most thermal plant including peakers and CCGT's are running. The CCS IGCC's reduce electricity output at times because they need to produce hydrogen to meet demand from transport. The system is also utilising imports to help meet demand and vehicles are also exporting energy to the grid, taking advantage of high prices.

The rise in wind generation (6 February) is followed by the interconnector swinging from importing to exporting and the shutting down of peakers, CCGTs and CCS plant, and ultimately nuclear plants reducing output to minimum stable generation levels. The peakers and CCGTs do not restart production during the rest of this period shown in Figure 11.

Increased flexible demand leads to the nuclear plant ramping up again by 8 February, although all other generation remain shut down until 10 February. After this, CCS and non-intermittent renewable plant restart production and remain on until 13 February, despite a rise in wind generation (which is accommodated by increased exports).

Exports and increased flexible demand are not able to stop the ramping down of nuclear and the shutdown of all other plants as a result of wind output rising above 60GW on 14 February. Although nuclear output ramps up again on 15 February, other generation does not come back on until 17 February, by which time wind output has falling significantly.

In summary, we conclude that:

- **inflexible demand follows a reasonably regular pattern over the period with demand falling overnight and at weekends;**
- **hourly generation from the 100GW of wind capacity is highly variable over the period,** with there being extended periods of low and high output, and periods of large day to day swings;
- **movable demand shifts to periods of high wind but is constrained by limits on duration of flexibility (mainly within-day);**
- **during some periods of high wind, even nuclear has to reduce output** (and is assumed to be able to do this with high level of flexibility, with the National Nuclear Laboratory noting that although the new reactors will technically be able to load follow, delivery of this flexibility in practice will require appropriate economic signals[57]);
- **the CCS IGCC operating pattern is constrained by maximum daily load factor of 50%** (to meet requirements for hydrogen for transport);
- **interconnector flows are generally helpful in balancing supply and demand in GB but their contribution to system flexibility is constrained by foreign supply and demand conditions;** and
- **vehicle to grid can only offer flexibility for limited duration (early part of lull in wind) because of storage constraints.**

4.2.2 Generation flexibility

This section explores two aspects of generation flexibility (on a monthly basis):

- shedding of low variable cost generation; and
- the use of unabated fossil generation.

Figure 12 shows the monthly pattern of shedding of low variable cost generation (defined as nuclear and renewables excluding biomass). The key messages from this chart are:

- the level of shedding is very low in 2030 in the High and Very High scenarios;
- shedding is largely limited to the winter months in 2050 in the High and Very High scenarios; and
- shedding occurs across the year in the Max scenario but is concentrated in the winter months.

It may seem a little surprising that shedding is higher in the winter months, when total (and moveable) electricity demand is higher (as shown in Figure 16). However, it is the result of the highly seasonal profile of offshore wind generation, with output about twice as high as winter in summer (as illustrated in Figure 11 of our flexibility study for the CCC[58]).

---

[57] UK Nuclear Horizons. An independent assessment by the UK National Nuclear Laboratory', National Nuclear Laboratory, March 2011.

[58] 'Options for low-carbon power sector flexibility to 2050. A report to the Committee on Climate Change', Pöyry Energy Consulting, October 2010.

Figure 12 – Monthly shedding of low variable cost generation (TWh)

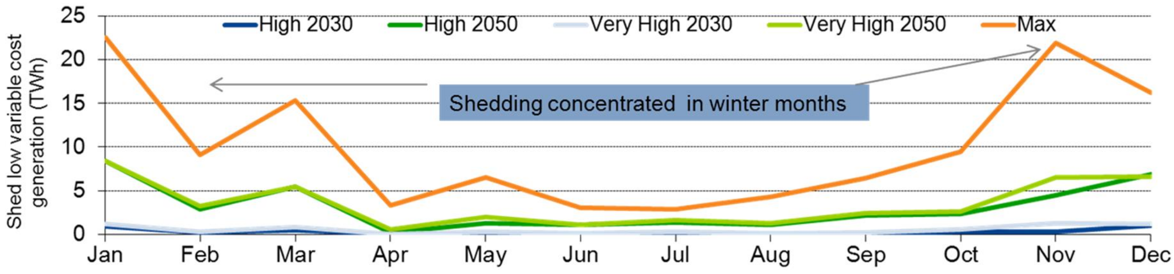
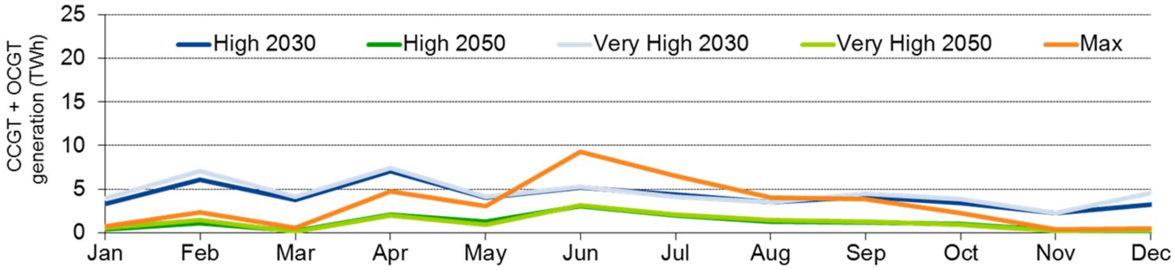


Figure 13 shows how the generation from CCGTs and peakers changes across the years. It highlights that in the High and Very High scenarios, the level of unabated generation in 2030 is relatively stable across the year, and is consistently higher than in 2050 when the CCGTs and peakers are primarily operating in the summer months. The strongest seasonal pattern is in the Max scenario, with the output from CCGTs and peakers in the summer exceeding the levels seen in the other two scenarios in 2030.

Figure 13 – Monthly pattern of unabated fossil fuel generation (TWh)



Viewed together, Figure 12 and Figure 13 illustrate that in some months, the system is not using all available low variable cost generation but in other months, it is having to use high-carbon generation to meet demand. If the system could use the low variable cost generation to displace the high-carbon generation, then this would help to reduce CO_2 emissions.

One way of helping the system to do this is to have much bigger storage capacity that would allow shifting of electricity supply (and demand) over long periods. This could be achieved by using the shed electricity in electrolysis to produce hydrogen, which would then be stored for use as the input fuel into the CCGTs and peaking plant (in a similar manner to the operation of pre-combustion CCS)[59]. This would require hydrogen storage of much longer duration than assumed in our main scenarios, in which hydrogen storage is restricted to a single day.

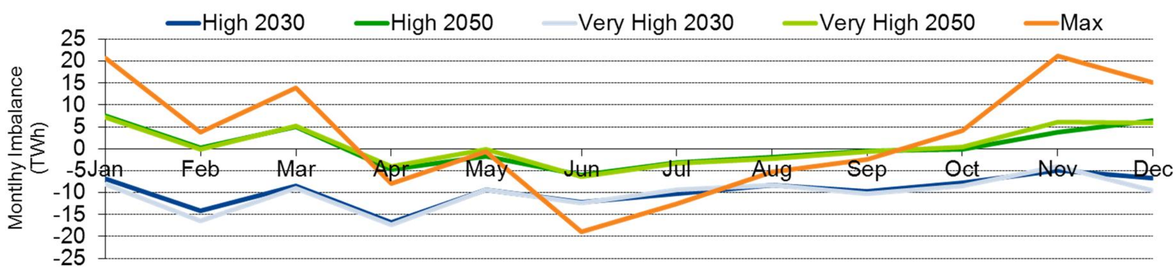
59 In January 2011, Scotland's First Minister Alex Salmond opened a new state-of-the-art energy research facility, the 'Hydrogen Office', at an energy park in Fife. The £4.7mn facility houses a hydrogen production system that keeps surplus energy generated by a 750kW wind turbine. The facility stores the energy as hydrogen when the wind is not blowing and then uses a hydrogen fuel cell to generate electricity as required.

There would also be a number of sources of inefficiency in the conversion process, including:

- electricity network losses during the transportation of the electricity to the site for electrolysis;
- energy losses during the electrolysis process (in terms of hydrogen produced per kWh of electricity demand); and
- efficiency of CCGTs and peakers in turning hydrogen back into electricity.

We used the monthly patterns of shed generation and unabated generation (in Figure 12 and Figure 13 respectively) to carry out an initial assessment of whether the development of within-month hydrogen storage would allow the shed generation to meet the fuel requirements of the CCGTs and peakers. Figure 14 shows the difference between the amount of generation shed in each month and the electricity required to produce hydrogen to power the CCGTs and peakers[60].

Figure 14 – Imbalance between shed electricity and electricity required to produce hydrogen for CCGT and peakers (TWh)



In summary:

- **the development of within-month hydrogen storage will be of little benefit by 2030** (for this purpose) as there is very little shed low variable cost energy to store;
- **longer-term hydrogen storage (i.e. multi-month) would be needed in the 2050 scenarios** as there is too much shed generation available in the winter and too little in the summer; and
- **in the Max scenario, longer-term hydrogen storage would be needed to shift the shed generation into the summer months,** however, peakers and CCGTs alone cannot absorb all of the shed generation.

4.2.3 Interconnector flows

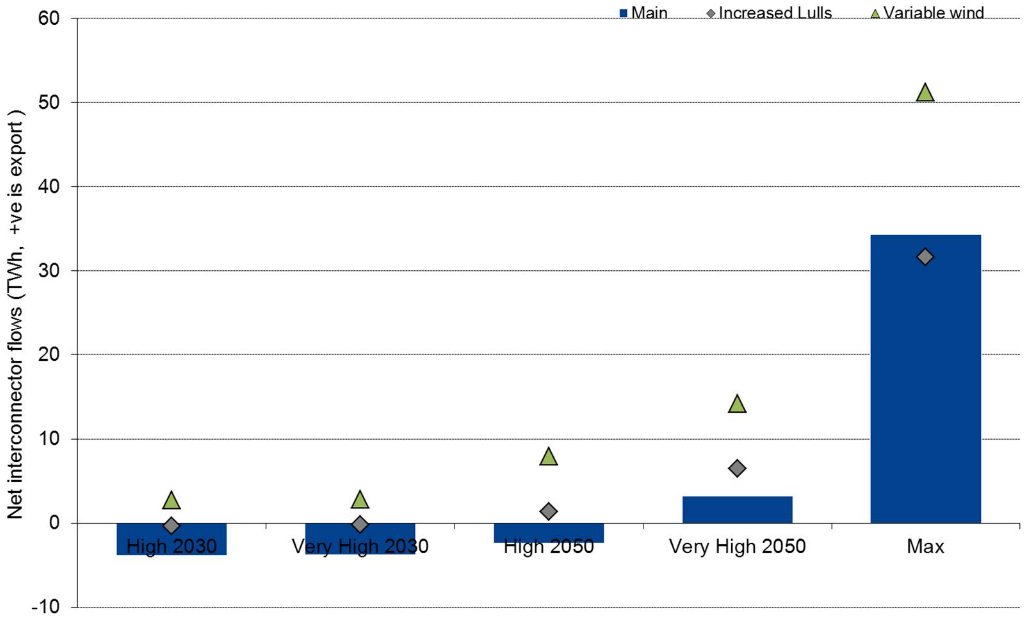
Figure 15 shows the balance of interconnector flows across the year[61]. The chart illustrates that as the level of renewable penetration increases, GB shifts away from being a net importer (because there are more periods in which *Zephyr* reduces imports than in

60 This calculation is based on the assumption that 1.18kWh of electricity is required to produce 1kWh of hydrogen through electrolysis, and that the CCGTs and peakers have an average efficiency of 50%.

61 This represents the output flows from the modelling process, which can differ from the input flows because *Zephyr* can reduce imports before shedding intermittent renewable generation, or reduce exports if they would lead to loss of load in GB. In the input flow assumptions, GB is a net importer of about 5-10TWh (varying across scenarios).

which it turns down exports). Although GB has become a small net exporter in 2050 in the Very High scenario, the most dramatic shift occurs as the system moves beyond 80% renewables in the Max scenario. If demand and supply conditions in Europe mean that it is unable to absorb the high level of net exports from GB in the 'Max' scenario, then this will further increase the amount of shedding of low variable cost generation.

Figure 15 – Annual net export flows (TWh)



In the synthetic year with more variable wind, net exports in all scenarios are higher than on average for the historical years. The rise in net exports in the synthetic year increases with the level of interconnection capacity (which rises from 2030 to 2050 and from 2050 to the Max scenario). This outcome is not just the result of variable wind patterns in GB, as it will also be influenced by the correlation between wind in GB and wind in Europe (which affects the input flows derived from the NW intermittency study).

4.2.4 Demand-side response

Figure 16 shows average daily movable demand[62] for the High 2030 scenario, the High and Very High 2050 scenarios and the Max scenario respectively[63]. It illustrates two key messages:

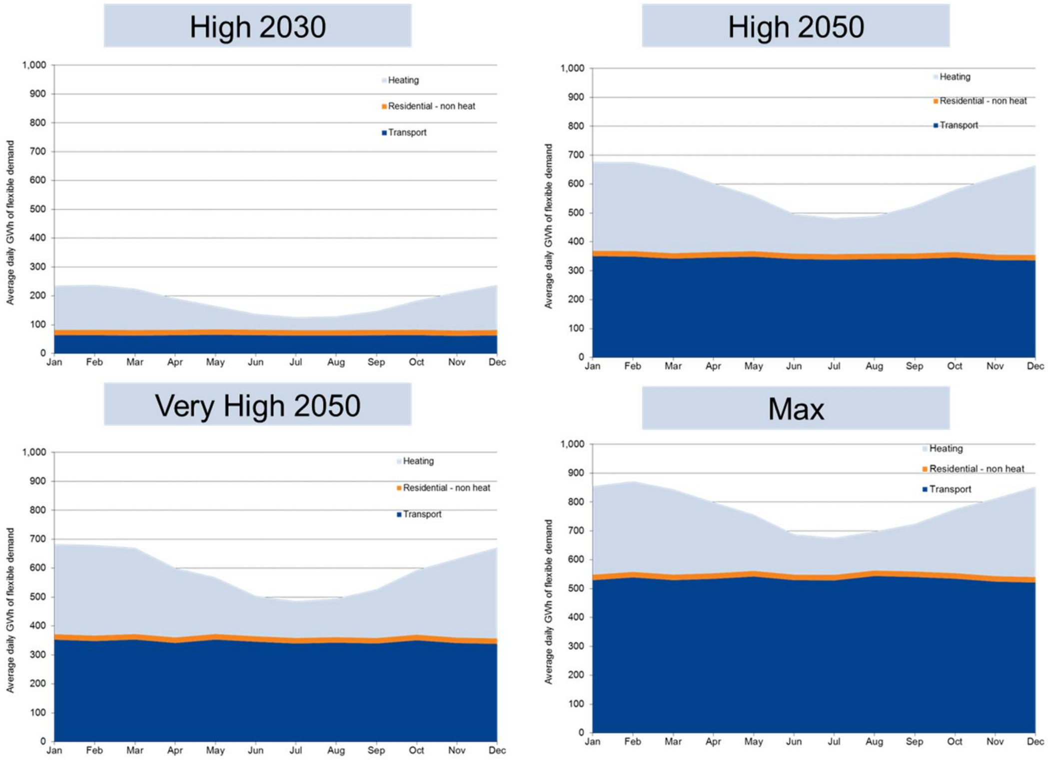
- the amount of movable demand increases from 2030 to 2050, and from 2050 to Max scenario; and
- movable demand follows a seasonal profile and is much higher in winter than summer.

---

62 This is the sum of demand from active demand-side units and from electrolysis (which is included in transport demand).

63 We have not shown the Very High 2030 scenario in Figure 16 as the level and profile of available movable demand is the same as the High 2030 scenario.

Figure 16 – Annual profile of movable demand (GWh)



Movable demand electricity from transport (including electrolysis) increases from 2030 to 2050 in line with the expected increase in demand from electric vehicles and the use of electrolysis to produce hydrogen. In the Max scenario we assume there is no IGCC CCS plant to provide hydrogen. Instead the hydrogen is provided by electrolysis which increases the level of movable transport demand. Flexible heating demand increases from 2030 to 2050, while residential flexible demand stays about the same.

There is more movable demand in winter than in summer. However, this is primarily driven by seasonal variations in heating demand, which is not very flexible across days. Daily (total) electricity demand for transport demand is assumed to be flat across the year. However, there is some limited variation between months in the level of daily flexible transport demand because flexible electricity from transport can be shifted between days (at the end of one month and the start of the next). Tre seeing demand shift across month boundaries which slightly affects the daily average reported for a given month.

4.3 Assessment of system performance

We have used three metrics to assess how well the system copes with high levels of intermittent renewable generation:

- **security of supply,** as measured by the amount of additional peaking capacity required to meet the constraint on expected energy unserved (EEU);
- **utilisation of available low variable cost generation**[64]**,** as measured by the amount of available low variable cost generation not used (or shed) by the system; and
- **delivery of low-carbon system** – as measured by the annual level of CO_2 emissions.

With our assumed high level of flexibility[65], the system seems to cope quite well with the levels of renewable penetration reached in 2030 in the High (51%) and Very High (64%) scenarios. Both of these scenarios perform comparably to the 2030 scenario with 30% renewables penetration presented in the CCC's advice on the fourth carbon budget[66].

By 2050, the High and Very High scenarios both deliver a generation sector with carbon intensity of close to zero. However, compared to 2030, there is a greater need for peaking capacity and more shedding of low variable cost generation. Indeed, peaking capacity build and shedding in 2050 in the High scenario are markedly higher than in the 2030 Very High despite a lower level of renewable penetration (60% rather than 64%). This comparison highlights the importance of existing and planned CCGTs in providing considerable flexibility in 2030. The increase in both interconnection capacity and movable demand cannot fully compensate for the absence of most of this CCGT capacity and the higher absolute levels of renewable generation[67].

Peaking capacity build in 2050 is higher in the Very High scenario than in the High scenario, whereas the shedding of low variable cost generation is at about the same level in the two scenarios. Despite the increase in shedding compared to 2030, construction of nuclear capacity is still cost-effective given the assumed set of fuel and carbon prices and generation costs. However, the levelised cost of deploying nuclear and renewables would be reduced if shedding was lower.

The results from the Max scenario highlight the size of the challenge for the system in moving beyond 80% renewable penetration, even with our assumption of high system flexibility. Peaking capacity build more than doubles to 21GW, while the shedding of low variable cost generation more than triples to 120TWh a year (equivalent to about 15-20% of the total generation requirement). At the same time, carbon emissions are more than double those seen in 2050 in the Very High scenario, albeit still very low. This is because in the Max scenario, all non-renewable generation has to be met by unabated gas fired

64 Low variable cost generation is defined as nuclear and renewables excluding biomass. The shedding of nuclear generation is included in the metric as this captures when intermittent renewables generation displaces nuclear plant (with no benefit in terms of CO_2 reductions).

65 The analysis presented in Chapter 6 quantitatively assesses how the system performance changes with revised assumptions about the flexibility of demand and/or interconnection capacities.

66 'The Fourth Carbon Budget. Reducing emissions through the 2020s', Committee on Climate Change, December 2010.

67 The absolute level of renewable generation (TWh) is greater in the 2050 High scenario than the 2030 Very High scenario, because of the increase in electricity demand between 2030 and 2050.

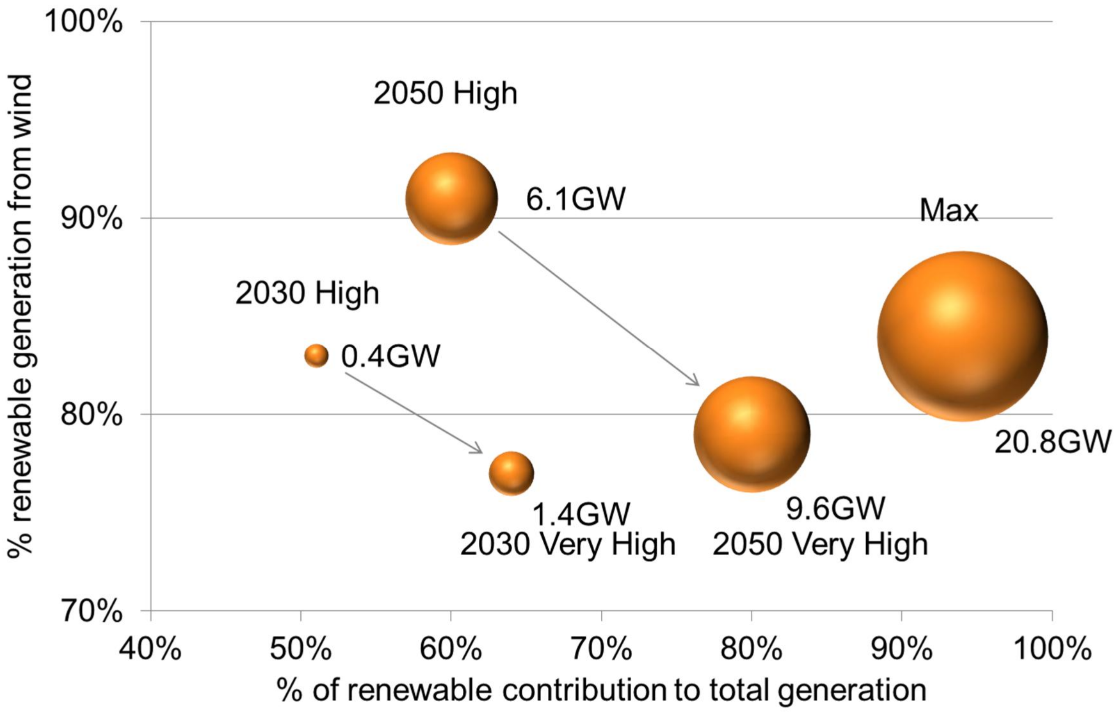
generation (as renewables are assumed to be the only available form of low-carbon generation).

4.3.1 Security of supply – build of peaking capacity

Figure 17 shows the amount of peaking capacity required to meet the security of supply constraint, which was set at around 2GWh in 2030 and around 4GWh in 2050 and the Max scenario. The difference reflects the fact that annual electricity demand was about twice as high in 2050 (and in the Max scenario) than in 2030.

The horizontal axis in Figure 17 shows renewable penetration as a percentage of total electricity generation. The vertical axis shows the proportion of renewable generation that comes from wind. The area of the circles represents the amount of peaking capacity built in each scenario.

Figure 17 – Peaking capacity build in each scenario (GW)



In 2030, only around 1GW of additional peaking capacity build is required to maintain security of supply in both the High and Very High scenarios. This is comparable to the peaking capacity build of 0.7GW in the 30% renewable scenario for 2030 presented in the CCC's report on the carbon budget report[68].

Nearly 10GW of peaking capacity is built in the Very High scenario in 2050 compared to 6GW in the High scenario in 2050. Interestingly, the High 2050 scenario requires much

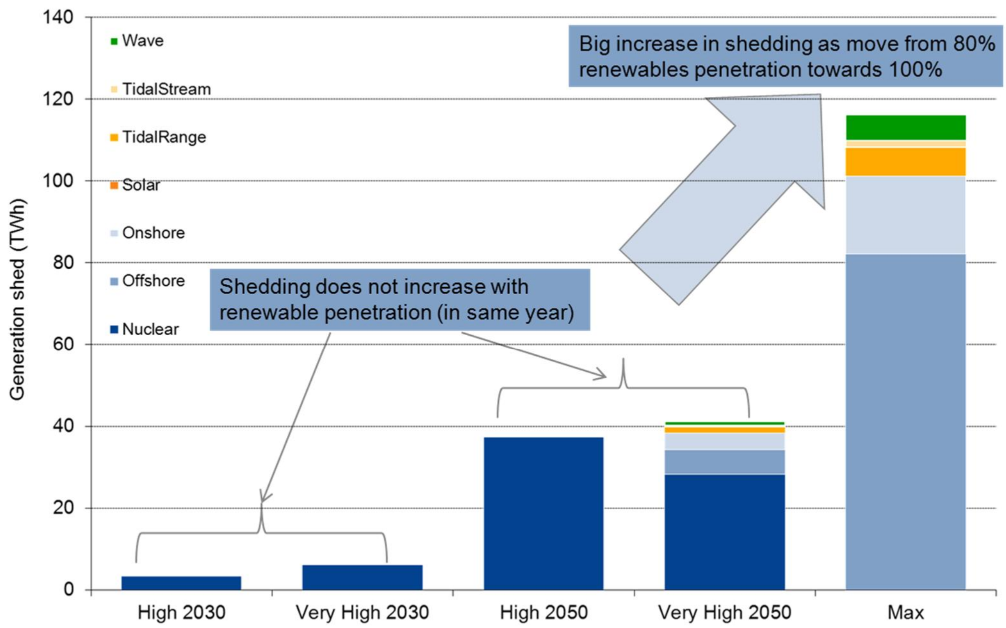
68 In this scenario, wind provided 80% of renewable generation. However, a direct comparison with the 30% renewable scenario is complicated by differences in flexibility assumptions between this study and that scenario, which had less interconnection and bulk storage/

more peaking capacity than the Very High 2030 scenario despite it having a lower level of renewable penetration (60% rather than 64%). This highlights the importance of flexibility from the CCGTs operating in 2030 that are closed by 2050, the impact of which outweighs the benefits of greater levels of movable demand and interconnection by 2050.

4.3.2 Shedding of low variable cost generation

Figure 18 shows the volume and type of low variable cost of generation that is shed in each scenario. For reference, the level of renewable penetration in each scenario is shown at the bottom of the chart.

Figure 18 – Shedding of low variable cost generation (TWh)



Renewable penetration	51%	64%	60%	80%	94%

In 2030, there is little shedding of low variable cost generation (and no shedding of renewable generation), suggesting that the system has enough flexibility available to mitigate the impact of intermittent generation. To put the performance of the system into context, the amount of shedding in both scenarios represents about 1% of total electricity demand.

Shedding of low variable cost generation is much higher in 2050 than in 2030 at around 7% of total electricity demand in both scenarios. Although the level of shedding is similar in the two scenarios, the mix is different. The shedding is entirely of nuclear generation in the High scenario, whereas there is some shedding of renewables in the Very High scenario which has higher renewable generation (although nuclear is still the main source of shedding).

Despite the increase in shedding, construction of nuclear capacity is still cost-effective out to 2050 given the assumed set of fuel and carbon prices and generation costs. However, the levelised cost of deploying nuclear and renewables would be reduced if shedding was lower.

There is nearly double the amount of shedding in the Very High 2030 scenario than the High 2030 scenario – 6.2TWh against 3.3TWh. This is predominantly a result of higher levels of wind generation – an additional 40TWh in the Very High 2030 scenario. This highlights that the greater levels of movable demand and interconnection by 2050 are not sufficient to help the system accommodate higher levels of low-carbon generation in 2050 than in 2030.

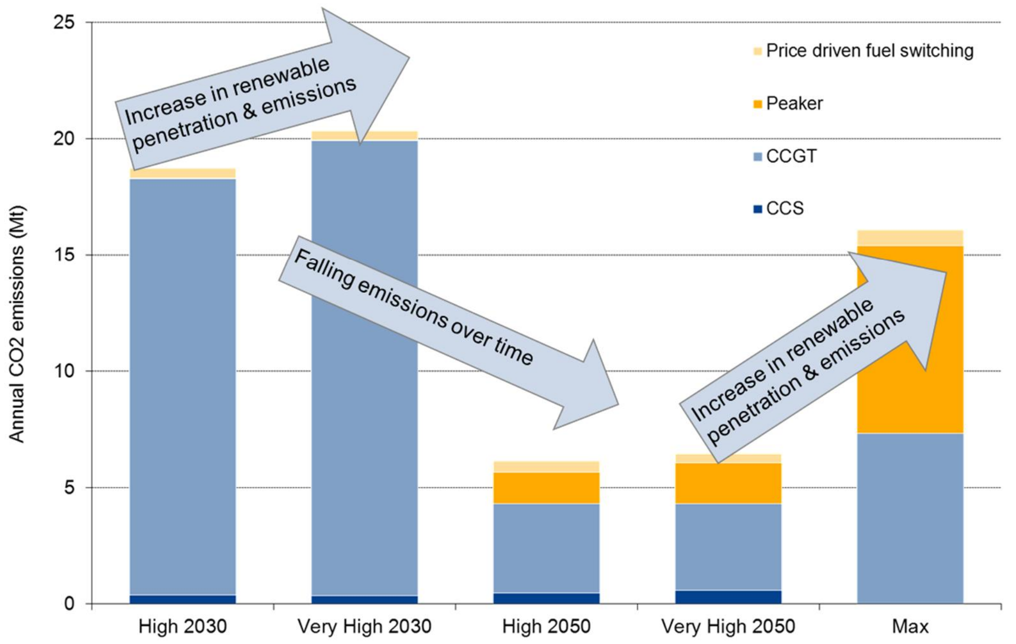
In the Max scenario, the level of shedding increases to about 120TWh (or 20% of demand); with the majority of shed generation (80TWh) attributable to offshore wind. The clear implication is that given our assumptions about flexibility and the renewable mix, the system struggles to accommodate renewable penetration above 80%.

4.3.3 Decarbonisation

Figure 19 shows the total CO_2 emissions in each scenario split by source (CCS, CCGT, peaking plant or price driven fuel switching in hybrid electric vehicles[69]).

Figure 19 – CO_2 emissions in each scenario ($MtCO_2$)

S



	High 2030	Very High 2030	High 2050	Very High 2050	Max
Emissions intensity (g/KWh of demand))	47	51	13	14	26
Renewable penetration	51%	64%	60%	80%	94%

In 2030, the carbon intensity of the generation sector is around 45-50g CO_2/kWh of demand, well below the constraint of around 80-90g CO_2/kWh. The 2050 scenarios

69 Price driven fuel switching occurs when hybrids are powered by liquid fuel rather than by electricity as a result of high electricity prices, rather than range limitations (range-driven fuel switching). In practice, emissions from price-driven fuel switching are a fairly small part of overall emissions.

deliver a generation sector with carbon intensity of below 15gCO2/kWh, which is deemed to meet the constraint of having a carbon intensity of close to zero.

While load factors of CCGT and peaker plants do not change much between 2030 and 2050, there is much less installed capacity and hence lower emissions by 2050.

A comparison of emissions between scenarios in the same year suggests that increasing renewable penetration alone may not necessarily reduce emissions. This is because emissions level is dependent on the penetration and mix of low-carbon (rather than just renewable) generation. Therefore, moving from the High scenario to the Very High scenario (in 2030 and 2050), emissions increase because higher levels of wind displace nuclear capacity, driving slight increases in the load-factors of peaking plant.

The Max scenario has higher emissions than the High and Very High scenarios in 2050 because CCGT and peaking plant are used to balance the system in the assumed absence of CCS and nuclear plant in this scenario.

[This page is intentionally blank]

5. DEPLOYMENT TRAJECTORIES

This chapter describes a feasible deployment trajectory, including key decision points and milestones, for each of the following inputs into each scenario (High, Very High and Max) analysed in Chapter 4:

- capacity of renewable generation (Section 5.2);
- capacity of non-renewable low-carbon generation, i.e. nuclear and CCS (Section 5.3); and
- amount of interconnection and flexible demand (Section 5.4).

In developing a feasible deployment trajectory, we considered two types of technical constraint on the amount that can be delivered for each technology[70] – estimated potential resource available (which is influenced by the maturity of the technology), and the ability of supply chain to deliver annual required build rates.

This chapter covers the input assumptions developed specifically as part of this study. Therefore, it does not discuss inputs directly provided by the CCC, such as fuel and carbon prices, electricity demand and requirements for hydrogen production. It also does not include the outputs of the modelling process, such as the expansion of electricity networks. These outputs are discussed in Chapter 6, which looks at the constraints on delivering higher levels of renewables.

5.1 Context for deployment trajectories

We analysed three main scenarios in this study:

- High – with renewable penetration of 51% in 2030 and 60% in 2050;
- Very High – with renewable penetration of 64% in 2030 and 80% in 2050; and
- Max – with renewable penetration of 94%.

Section 3.1 describes these scenarios in more detail. In this section, we discuss the context for the deployment trajectories underpinning these scenarios, in relation to the starting point for the trajectories, mix between different types of generation, and annual build rates.

5.1.1 Starting point for renewable deployment trajectories

Our trajectories for renewable deployment in all three scenarios start from the assumption provided by the CCC that, by 2020, renewable electricity generation has reached the levels set out in the National Renewable Action Plan (NREAP)[71]. Hence, it is assumed that the supply chain is in place to deliver at least the annual deployment rate needed to reach the level of renewable generation NREAP (117TWh) compared to a level of 32TWh in 2010. Failure to meet the NREAP targets would have a knock on effect on the rate of deployment required to 2030 in particular.

---

70 As opposed to the amount of generation that could be accommodated by the system, which was the focus of the analysis described in Chapter 4.

71 'National Renewable Energy Action Plan for the United Kingdom. Article 4 of the Renewable Energy Directive 2009/28/EC', DECC, July 2010.

5.1.2 Balance between renewable and non-renewable generation

The scenarios had to meet constraints on the level of security of supply and CO_2 emissions. The latter constraint required more generation to come from non-renewable low-carbon generation (i.e. CCS and nuclear) in the High scenario than in the Very High scenario. We used the Max scenario to explore the issues around pushing the level of renewable deployment as high as possible. In this scenario, it was assumed that there was no CCS or nuclear generation.

A key objective of this study was to test the impact of going significantly beyond the renewable penetration level of 30% of total generation that was used in the analysis for the CCC's advice on the fourth carbon budget period[72]. Therefore, even in the High scenario, the deployment trajectories are designed to be stretching for renewable generation. As a result, the scenarios may not be as challenging for the deployment of non-renewable generation, which primarily plays a supporting role to renewable generation in this study.

Reducing the target for renewable penetration below the level of the High scenario would make the renewable deployment requirements less challenging. However, this would need to be traded off against the challenges of delivering the amount of non-renewable generation needed to meet the carbon emissions target. This trade-off would need to be informed by analysis of low-carbon trajectories that was more focused on exploring the technical constraints on the deployment of non-renewable low-carbon generation (as opposed to renewable generation).

5.1.3 Optimality of renewable generation mix

The objective of this study was to identify and characterise the technical constraints that will limit the deployment of renewables in the power sector to 2030 and beyond. The trajectories are assumed to be wind dominated as this increases the challenge for the system to accommodate high levels of renewable generation[73]. Therefore, the study has not sought to determine the optimal renewable generation mix for high levels of renewable generation.

A wind-dominated renewable mix would be challenging for the system because:

- wind is unpredictable (over long timescales) as well as intermittent; and
- a lower level of diversity in the intermittent generation mix is associated with a higher degree of variability in the overall output.

Compared to other sources of renewable generation, wind has perhaps the most unpredictable nature (over long time scales) in terms of deviations from an average production profile. This will increase the challenge for the system in accommodating renewable generation. For example, solar generation can be unpredictable but its generation profile is dominated by a regular profile based on time of day and time of year. Output from tidal range is intermittent but highly predictable, which should place fewer demands on system flexibility.

---

72 This scenario was not bound to a particular year.

73 Although all the scenarios are wind-dominated, wind has a greater share of the renewable generation mix in the High scenario than the Very High scenario. However, the absolute level of wind generation is greater in the Very High scenario (as a result of the higher overall renewable penetration).

Pöyry's intermittency study for GB and Ireland[74] showed that correlation of output between wind farms can raise challenges for system performance. This is because when it is windy in one location, it is also likely to be windy at another location; the opposite is also true. We found that prolonged cold spells are often accompanied by an anticyclone which causes wind output at a national level to fall to low levels. Reducing the capacity of wind on the system reduces this effect as other renewables are not correlated with the wind generation profile.

Section 6.1.2 discusses the impact of a more diverse renewables mix (with higher levels of non-wind generation) on the ability of the system to accommodate high levels of renewables.

Other renewables may present less of a problem in being accommodated by the system because they are more controllable (e.g. bio-energy[75]) and/or predictable (e.g. tidal range, solar). However, there may be implications in terms of delivery costs and challenges with an increased reliance on non-wind renewables – for example, deployment of solar PV will be done on a decentralised basis which may increase the difficulty of a co-ordinated and efficient rollout.

In addition, focusing on a dominant technology will bring 'learning by doing' benefits that will help to reduce costs further and improve technology efficiency and reliability. There may also be supply chain competition (e.g. ports) between offshore wind and other technologies (e.g. wave and tidal stream), which would split the cost of the supply chain between more parties.

5.1.4 Assumed annual build rates

The High and Very High scenarios were time-bound with snapshots at 2030 and 2050. This means that the 2050 position was constrained by developments up to 2030, which itself was constrained by the assumed starting position for the scenario (such as the delivery of renewable generation by 2020 in line with the NREAP).

The Max scenario was not tied to a particular year, which means that resource availability was the only relevant technical constraint for the deployment trajectory (as build rate only matters in a time-bound scenario).

Table 3 presents the average annual (net) build rates for the different technologies deployed in the High and Very High scenarios.

---

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

75 By agreement with the CCC, installed capacity of bio-energy, hydro and geothermal was limited to the NREAP level. If these technologies could be deployed at a higher level, the system would be expected to be able to accommodate high levels of renewables.

Table 3 – Average (net) build rates for different generation technologies (GW/year)

GW/year	2020 – 2030		2030 – 2050	
	High	**Very High**	**High**	**Very High**
Onshore wind	0.6	0.6	0.2	0.4
Offshore wind	2.5	3.4	1.9	2.2
Solar PV	0.0	2.2	0.0	0.7
Tidal range	0.0	0.4	0.0	0.5
Wave	0.1	0.1	0.0	0.3
Tidal stream	0.1	0.1	0.0	0.0
Nuclear	1.5	0.7	0.5	0.0
CCS[76]	0.0	0.0	0.5	0.6

5.1.5 Defining the maximum limit on long-term annual build rates

Predicting the upper bound to potential growth rates of renewable technologies is complex. A robust derivation of these upper limits would require significant additional work in terms of identifying technical constraints on build rates that are consistent with the philosophy and assumptions underlying high renewables scenarios.

The following paragraphs explain the issue by discussing some of the interlinked economic and technical constraints that can limit the rate of deployment of renewable generation (as opposed to resource potential, which can limit the total level of deployment).

Economic constraints influence the growth rate of renewable technologies by either incentivising or dis-incentivising investment. In order to achieve the high levels of renewable generation assumed in these scenarios, we implicitly assume that adequate levels of government support drives investment and regulatory frameworks to relieve potential economic constraints (i.e. long term transparent revenue streams at levels sufficient for investment). The result is a sustainable demand for renewables technologies. The ability to deliver the RES technologies in response to this demand is dependent on technical constraints.

76 There is an increase of 1.8GW in CCS capacity between 2020 and 2030 in the High and Very High scenarios. However, this is a result of the assumed retrofitting of CCS coal demonstration projects, rather than new build.

Technical constraints limit the growth rate of the technology through constraints in the renewable development supply chain be it through production of required inputs, availability of capital and labour for installation, and/or availability of viable locations for the technology (which is linked to resource potential).

It is relatively easy to identify technical constraints in the short term e.g. supply chain capacity over the next 2 years because there is a time-lag involved (e.g. it takes 2 years to build a new factory and we may find there is a lack of global manufacturing capacity that will not allow imports to fill the gap).

Unless we assume the status quo remains in place, it is much more difficult to identify technical constraints on build rates in the longer term (>10years). This is because technical constraints are often seen as soft constraints over longer timescales i.e. given sufficient incentives and timescales technical constraints can be assumed away. For example, prolonged demand for a technology at a sufficient price will incentivise investment in the supply chain resulting in capacity expansion (either domestically or through imports or both). A similar case can be made for constraints on installation rates.

The only way to identify truly hard technical constraints on build rates (i.e. those you cannot assume away through sufficient and timely investment signals) would be a detailed bottom up model of the supply chain, covering developments in other countries (to assess the ability of the UK to capture a share of the global supply chain). This analysis was outside the scope of this study.

5.2 Renewable deployment

In this section, we describe the deployment trajectories for each renewable generation technology in each scenario. The levels of renewable capacity in the High, Very High and Max scenarios are summarised in Figure 20, Figure 21 and Figure 22 respectively.

These charts highlight the importance of wind in all three scenarios, which all need

- **the development of floating turbine technology** so that it can be commercially deployable from 2030 (benefitting from the supply chain built up to deliver fixed offshore wind before 2030); and
- **delivery of additional onshore wind capacity beyond 2020**, although the required build rate is less than the average build rate required after 2010 to meet the NREAP.

In the High scenario shown in Figure 20, there is very limited deployment of non-wind renewables (solar, tidal range and wave). Moving to the renewable penetration levels in the Very High scenario (Figure 21) involves a significant increase in these non-wind renewables, as well as some increase in wind generation.

Figure 20 – Renewable deployment in the High scenario (GW)

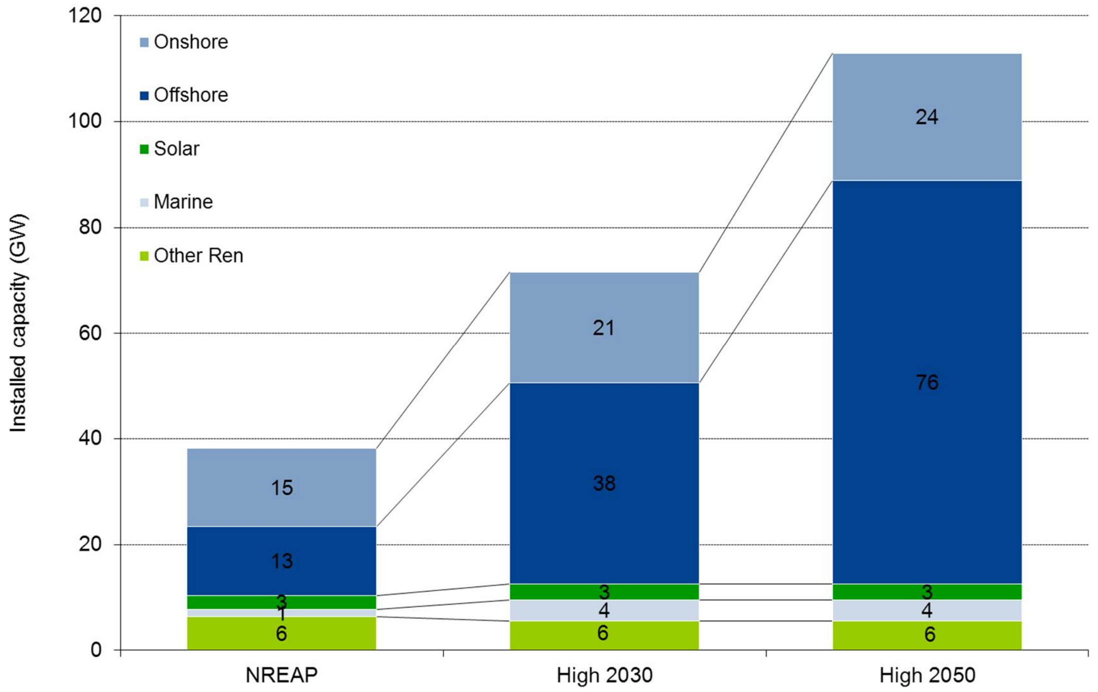


Figure 21 – Renewable deployment in the Very High scenario (GW)

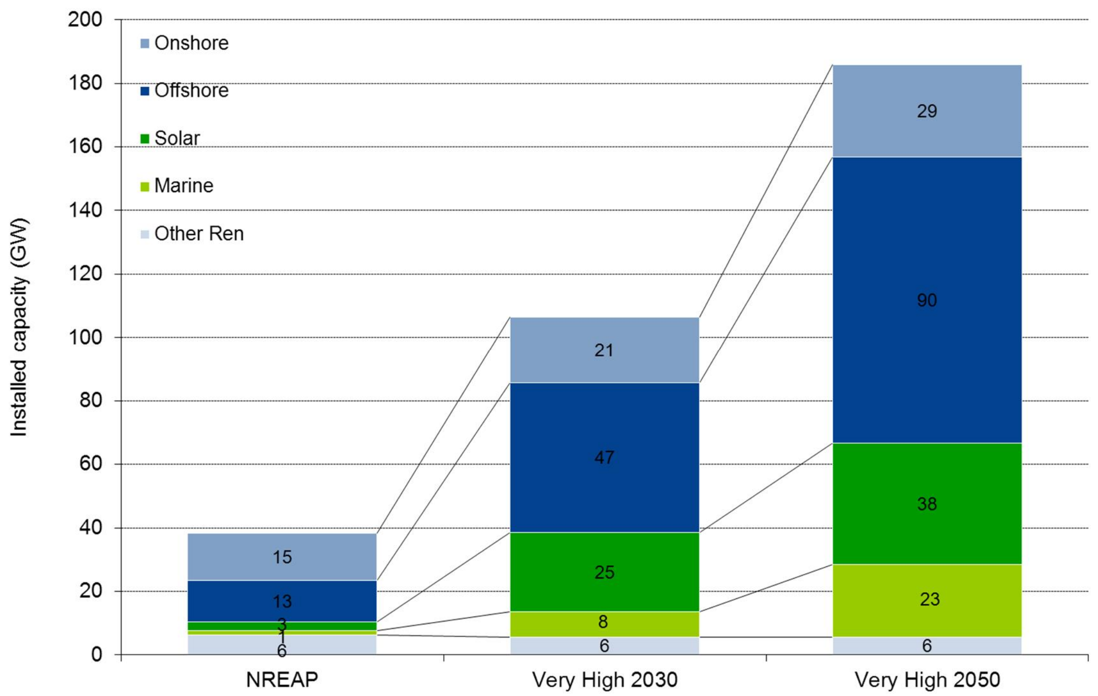
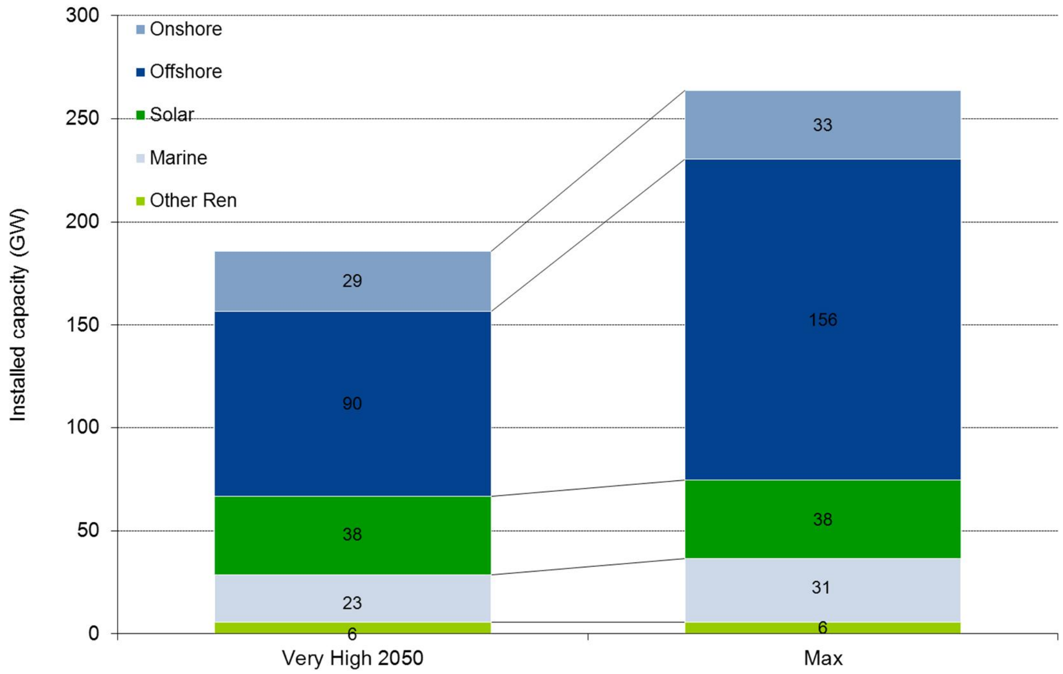


Figure 22 illustrates how moving from the Very High scenario to the Max scenario is based around a massive expansion of offshore wind. This would require the ability to deploy a significant proportion of the estimated resource potential, of which there is much uncertainty.

Figure 22 – Renewable deployment in the Max scenario (GW)



5.2.1 Onshore wind

In all three scenarios, additional onshore wind capacity is required beyond the NREAP level of 15GW, which is assumed to be reached in 2020. However, Table 3 shows that in the time-bound scenarios (High and Very High), the annual build rate is considerably below the average annual build rate needed to meet NREAP (1.1GW/a between 2010 and 2020).

5.2.1.1 High scenario

Between 2020 and 2030, we project an increase in onshore wind capacity of 6GW to 21GW. This is consistent with DECC's level two pathway[77] and requires an average deployment rate of 0.6GW/year.

Some of the additional capacity in 2030 could come from adding additional turbines to existing sites and re-powering existing turbines at a higher capacity. For example if 4GW of existing capacity was repowered so that the average rating increased by 25%, overall capacity would increase by 1GW.

77 '2050 Pathways Analysis', DECC, July 2010.

There is a further increase of 3GW in onshore wind capacity by 2050. This reflects limited improvements in technology and/or repowering at higher capacities at sites developed between 2010 and 2020.

The High scenario also assumes 1GW of micro wind[78] by 2030, which is well within DECC's level two pathway. If the average installation size were 3kW this would equate to over 300,000 installations. It is expected that the majority of micro wind turbines would situated in rural locations consistent with the conclusions of the Energy Saving Trust field trials of micro onshore wind turbines[79].

In summary, the relatively small increase in installed capacity for onshore wind (compared to offshore wind) after 2020 in this scenario is the result of:

- the maturity of onshore wind technology, which means that it is expected to have already undergone its rapid growth stage by 2020 (reflected in it being the renewable technology with highest installed capacity in the NREAP); and
- the extent to which the public is willing to accept additional onshore wind farms.

5.2.1.2 Very High scenario

The installed capacity of onshore wind in the Very High scenario is assumed to be the same as the High scenario to 2030. By 2050, the Very High scenario has an additional 5GW of capacity. This is consistent with the upper limit of the study on onshore wind potentials conducted by the Energy Technology Support Unit (ETSU)[80] which is below DECC's level three pathway of 32GW in 2050. The level of micro wind installed is assumed to be 1GW as in the High scenario.

Most of the additional capacity in this scenario is expected to come through re-powering existing sites (with larger turbines), with some new sites being developed subject to gaining sufficient public support.

5.2.1.3 Max scenario

The Max scenario assumes that onshore wind capacity reaches 33GW. This is consistent with DECC's level three pathway for onshore wind in 2050 (32GW) and would require a more than doubling onshore capacity projected in the NREAP. This would require both repowering and development of new sites, with the need to ensure public acceptability of such an expansion.

It is assumed that micro wind reaches 2GW in this scenario. This is within the potential identified by the Energy Saving Trust in its report on field trials of domestic scale wind. It is also well within DECC's level three pathway for micro onshore wind generation.

---

78 This is expected to have an average annual load factor of about only 10%.

79 'Location, location, location, domestic small-scale wind field trial report', Energy Saving Trust, July 2009.

80 'The Costs of Supplying Renewable Energy (R-99 as reported by Enviros Consulting Limited)', Energy Technology Support Unit (ETSU), 2005.

5.2.1.4 Decision points and key milestones

There appears to be sufficient technical resource for the level of onshore wind seen in all three scenarios, and the required build rate actually falls after 2020. This means that meeting decision points and key milestones are expected to be much more important in delivering the NREAP level than for achieving the deployment trajectory for these scenarios.

In practice, the main barriers to achieving the level of onshore wind capacity are likely to be non-technical, relating primarily to public acceptance and the effectiveness of any support mechanism for onshore wind.

Public support for onshore wind has been mixed, with large numbers of projects struggling to gain planning permission. Some of the difficulties in obtaining planning permission could be attributed to the planning process itself. However, the ability to gain planning permission is also dependent on public acceptance irrespective of the process.

As the build rate is below the NREAP level, the planning process itself is not expected to be a constraint as effective processes are assumed to be in place by 2020. However, gaining public acceptance could become increasingly difficult as the overall capacity of onshore wind increases.

Reaching 21GW of onshore wind capacity by 2030 (in the High and Very High scenarios) would require the addition of capacity comparable to the level of onshore wind commissioned to date. To reach this level of capacity by 2030, developers would need to be confident of gaining planning permission for additional sites and/or increasing capacity at existing sites by around 2022/23[81].

5.2.2 Offshore wind

The high estimated potential for offshore wind generation in the UK means that it is expected to be the key technology for reaching a high renewable penetration level in 2030 and beyond. This is illustrated by the required build rates for offshore wind shown in Table 3, which are very aggressive, particularly out to 2030.

Much of the potential offshore wind generation is in deep water and could only be captured using floating (i.e. anchored) offshore wind turbines. As a result we have split our assumptions into fixed and floating capacity.

We have characterised the growth in offshore wind to 2030 as being centred on fixed offshore turbines, and the growth beyond 2030 primarily being the deployment of floating offshore turbines. This dynamic is highlighted in Figure 23, which shows the split between offshore fixed and floating turbines for the scenarios under investigation.

Figure 23 reflects that floating offshore wind is an immature technology which is currently undergoing development (there is no dominant floating turbine concept design). To date two separate turbines have been commissioned for testing[82] and there are plans to test full scale offshore wind parks in the next couple of years e.g. a 92MW wind park in Tricase, Italy. The ability of floating turbines to deal with rough seas and, hence the durability of the technology, is still largely unknown.

---

81 This is based on the assumption it takes around 3 years to develop an onshore wind project from conception to the point of full commissioning.

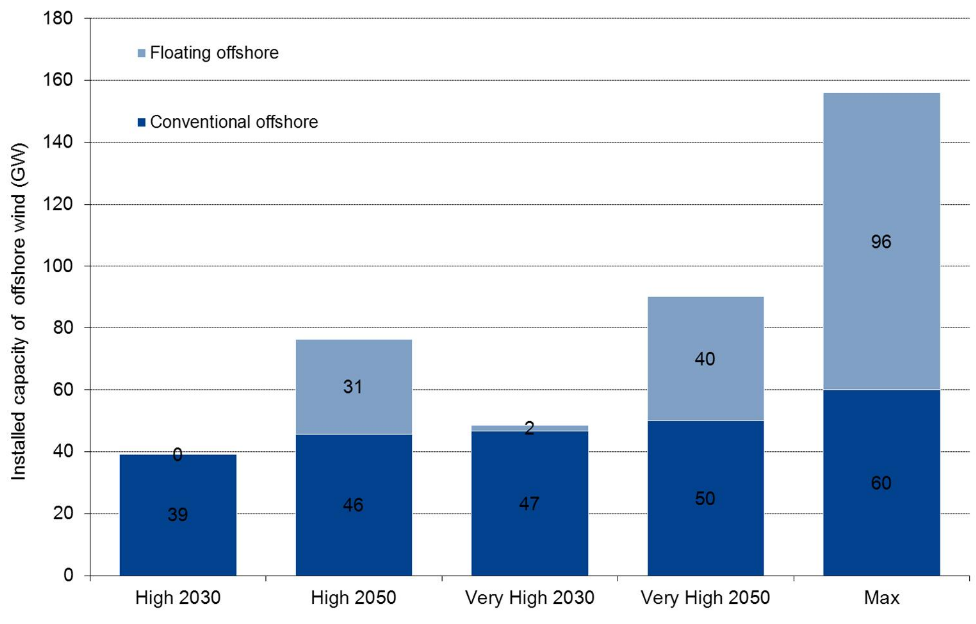
82 Hywind near Stavanger, Norway, and Blue H off the coast of Puglia, Italy

In practice, there may be significant overlap and competition between the two technologies, particularly for sites not in deep water – the key trade-off in any decision between the two will be whether the saving from avoiding sinking a monopole (for a fixed turbine) is greater than the cost of a floating structure.

This overlap also means that if floating offshore wind turbines are not commercially deployable by 2030, some of the estimated resource could still be exploited by increased deployment of fixed offshore wind turbines in sites in shallow water. In addition, the resource for fixed turbines is unlikely to have been exhausted by the time floating turbine technology becomes available. However, there is a limit on the extent to which the deployment of additional fixed turbines can compensate for a lack of a viable floating offshore technology.

As a result, the split shown in Figure 23 between offshore fixed and floating turbines could be subject to change in light of future technology developments.

Figure 23 – Split between conventional and floating offshore wind (GW)



5.2.2.1 High scenario

In this scenario we have assumed that between 2020 and 2030, the installed capacity of fixed offshore wind turbines increases from 13GW (NREAP) to 38GW.

To put this level into context, projects already allocated under the Crown Estate's leasing Rounds 1, 2 and 3, along with the allocated Scottish leases, have a maximum combined capacity of 47GW. Ofgem have estimated that connecting projects covered by Rounds 1,2 and 3 will cost £15billion[83] while RenewableUK has estimated that 7,500km of cables will be required by 2020 to connect offshore wind sites to the onshore electricity network[84].

83 http://www.ofgem.gov.uk/Networks/offtrans/oriot/Pages/oriot.aspx

84 'Rebirth of UK Manufacturing. An Opportunity for a World Class Industry', RenewableUK, March 2010.

The deployment trajectory to 2030 in this scenario has an average required build rate of 2.5GW/a. This compares to:

- 1.8GW/a expected by 2020 under NREAP;
- 2.3GW/a by 2020 in Pöyry's High Feasible timeline[85] ; and
- 3GW/a from 2020 in Level two of DECC Pathways[86].

After 2030, floating offshore wind takes over from fixed offshore wind, with a significant amount of the supply chain built up to deliver fixed offshore assumed to adapt to deploy floating offshore wind. However, the increased length of cables required may reduce the annual build rate, although this may be mitigated by the development of offshore wind hubs. The assumed annual build rate for floating offshore wind is only 1.5GW/annum from 2030 onwards to deliver 31GW by 2050.

Beyond 2030 we have assumed an increase in installed capacity of fixed offshore wind from 38GW to 46GW by 2050. It is expected most of this would be developed in the 2030s (at a much lower annual build rate than before 2030) with additional fixed offshore capacity being minimal from 2040 onwards.

By 2050, the total offshore wind capacity is 76GW, which is between level 2 (60GW) and level 3 (100GW) of the DECC Pathways.

5.2.2.2 Very High scenario

Fixed offshore wind capacity is assumed to increase even more rapidly after 2020 in this scenario, reaching 47GW by 2030. This is equivalent to the maximum capacity of currently allocated sites but there is the potential for fixed offshore wind to be developed at new sites.

This requires a deployment trajectory build rate of 3.4GW/year between 2020 and 2030. Although some back-loading is assumed, the annual build rate of 4GW/a after 2025 is lower than the build rate of 5GW/a assumed from 2025 in Level 3 of DECC Pathways.

Again, floating offshore wind is assumed to dominate growth in offshore wind from 2030, with 35GW of floating turbines assumed to be installed by 2050. This increase of 33GW in 20 years is comparable to the 40GW of fixed offshore wind assumed to be deployed between 2010 and 2030 in this scenario.

There is only a small increase in fixed offshore wind from 47GW in 2030 to 50GW by 2050. This is expected to come from expanding capacity at sites developed before 2030, with through repowering at larger capacities and/or adding further turbines. For example, the 13GW commissioned by 2020 will pass 20 years of operation in 2040 and so improvements in technology are likely to provide opportunities for raising their capacity. If the capacity of these sites were to increase by a third this would provide an additional 4GW.

---

85 'Timeline for wind generation to 2020 and a set of progress indicators', Pöyry Energy Consulting, July 2009

86 '2050 Pathways Analysis', DECC, July 2010.

5.2.2.3 Max scenario

Fixed offshore wind capacity reaches 60GW in this scenario, which is consistent with DECC's level 2 pathway for offshore wind. For fixed offshore wind this represents 13GW over the maximum capacity available under the sites already allocated. Therefore, new sites would need to be identified. However, the total fixed offshore wind capacity is well below the Offshore Valuation Group's estimate of 116GW for the total capacity of fixed offshore renewable resource[87].

In this scenario, floating offshore wind is assumed to reach 96GW, meaning that the total offshore wind capacity is156GW.

5.2.2.4 Decision points and key milestones

All of the deployment trajectories are reliant on an increase in the annual deployment rate of fixed offshore wind after 2020. The average timescale from conception to commissioning for offshore wind generation has been estimated to be 8 years[88]. Therefore, to keep momentum going beyond 2020, projects need to be entering development from 2013 onwards.

In the High scenario, the supply chain will need to expand after 2020 to allow the annual build rate to grow from 1.8GW/year by 2020 to 2.5GW/year by 2023. This equates to an additional four vessels being available in this period, assuming each vessel is capable of installing 175MW/year in line with our wind timelines report to the CCC88.

The installation rate of 2.5GW/year will require an estimate average labour force of 25,000 and 1.5million tonnes of steel per year (based on the methodology presented in the Offshore Valuation report[89]). The transition to the lower average installation rate of 1.9GW/year between 2030 and 2050 indicates a slight contraction to 19,000 jobs and steel requirements of 1.1 million tonnes per year.

To reach 4GW/year by 2025 in the Very High scenario, twelve additional vessels capable of installing 175MW/year are assumed to become available. Beyond this date, the level of available vessels falls slightly as older vessels go out of service or are deployed elsewhere. Existing vessels are then increasingly used for repowering existing turbines. The rate of installation between 2020 and 2030 could require an estimated workforce of 34,000 and 2 million tonnes of steel per year. The lower installation rate between 2030 and 2050 translates to 22,000 jobs and 1.3 million tonnes of steel per year.

The deployment trajectories assume that before 203,0 floating turbine technology is not deployed on a commercial scale but that it has been demonstrated to work on a commercial scale. The deployment trajectory for the Very High scenario assumes a more aggressive demonstration phase leading to 2GW of floating offshore wind capacity installed by 2030.

As floating offshore wind takes over from fixed offshore wind, it is likely that a significant proportion of the supply chain (e.g. vessels) built up to deliver fixed offshore will adapt to

---

87 'The offshore valuation: a valuation of the UK's offshore renewable energy resource', The Offshore Valuation Group, May 2010.

88 'Timeline for wind generation to 2020 and a set of progress indicators', Pöyry Energy Consulting, July 2009.

89 'The offshore valuation: a valuation of the UK's offshore renewable energy resource', The Offshore Valuation Group, May 2010.

accommodate floating offshore wind. This could help to support investment in the supply chain for fixed offshore wind after 2020, as there is scope for continued operation after 2030. However, there will also need to be additional elements (e.g. platforms) developed to allow the floating offshore wind supply chain to be in placed by 2030.

There remains significant uncertainty about the amount of practical offshore wind potential, particularly in relation to floating offshore wind. The Offshore Valuation Group[90] estimates potential of about 190GW-350GW, depending on whether sites over 100 nautical miles are utilised. This compares to the figure of 235GW (929TWh) for offshore wind (made up of 120GW fixed and 116GW floating) in Level 4 of the revised DECC Pathways (March 2011)[91] Therefore, the expected deployment trajectories for offshore wind would need to be reviewed as further analysis narrows the range of estimated potential.

5.2.3 Solar PV

By 2050 in the High scenario, solar PV is assumed to have grown only slightly beyond NREAP levels (as demonstrated in Table 3). At the same time, the installed capacity in the Max scenario is assumed to be the same as in 2050 in the Very High renewables scenario. Therefore, this section only looks at the deployment trajectory of solar PV in the Very High scenario.

5.2.3.1 Deployment trajectory

At present, the UK has 26.5MW of installed solar capacity, with 4MW of capacity installed during 2009[92]. As we assume NREAP targets for solar are met in our baseline, the UK is expected to have 2.7GW of installed solar capacity by 2020 (i.e. around 100 times the size of the current level).

To make the step change required to reach the NREAP level, the UK will need to have developed a robust supply chain that allows an average annual rate of installation of 270MW/year between 2010 and 2020. Recent developments; such as the investment in a 500MW/year PV assembly plant by Sharp, suggest that the UK will have sufficient domestic manufacturing capacity to meet 2020 targets.

Estimates for current installation times for PV panels are around 1-3 days for most residential systems of around 3kWp. Based on an average installation period of 2 days, approximately 180,000 man days per year (or approximately 900 trained installers) would be required to meet the NREAP target.

This supply chain would need to support nearly a tenfold increase in annual build rate between 2020 and 2030 (compared to 2010-2020) – with an workforce of approximately 7,500 trained installers required to provide the 1,500,000 man-days needed per year .

The level of capacity reached by 2050 is 38GW, which lies between Level 1 and 2 in 2050 in DECC's Pathways analysis. This means that even more than with offshore wind, the solar PV deployment trajectory for the Very High scenario is front loaded (as demonstrated by Table 3) as the annual build rate falls off sharply after 2030.

---

90 Ibid

91 '2050 Pathways Analysis. Response to the Call for Evidence. Part 2', DECC, March 2011.

92 http://www.decc.gov.uk/en/content/cms/statistics/source/renewables/renewables.aspx

5.2.3.2 Decision points and milestones

The deployment trajectory requires a build rate of 2GW/year for the 2020s which is nearly a tenfold increase on the build rate required to meet the NREAP targets. Assuming that current global manufacturing capacity is 15GW[93], it seems reasonable that the UK can assemble and import a sufficient number of PV components or assembled panels at a rate of 2.2GW/year. This annual build rate is comparable to or below the rate at which other countries have deployed PV capacity. For example, the German NREAP sets a target installation rate of around 3GW/year to reach 50GW by 2020 – 7GW was installed in 2010.

5.2.4 Tidal range

Tidal range is only deployed after 2020 in the Very High and Max scenarios. As the installed capacity in the Max scenario is the same as the Very High scenario in 2050, this section describes only the deployment trajectory of tidal range in the Very High scenario (and hence in the Max scenario).

5.2.4.1 Deployment trajectory

Under the Very High scenario we project 4GW of installed capacity by 2030 and a further 9GW by 2050. This is equivalent to a number of small barrages in service by 2030 (such as a Mersey barrage) followed by a larger Severn barrage (in the Cardiff-Weston configuration) by 2050.

5.2.4.2 Decision points and milestones

The majority of tidal range technologies are similar to those required for hydro projects and are therefore well understood, albeit with some of the components requiring further testing[94]. Therefore the key will be building up the supply chain to ensure that expertise and capacity are in place in order to deliver 4GW by 2030 and an additional 9GW by 2050.

Barrages are, typically, large projects that require significant civil engineering works. Estimates suggest that a typical tidal range project requires a total lead time of 8 years[95]. This can broadly be split into 3-4 years to complete planning, regulatory, design, tender, and contract processes, and a further 3-4 years to undertake civil works, construct and commission the project.

This means that the supply chain must be set up to support the delivery of a small number of complex large-scale civil engineering projects, rather than continuous deployment of smaller projects (as with wind and solar for example). This should help the second phase of deploying tidal range to build on experience gathered in the first phase.

The 9GW barrage is likely to require government support and additional incentives could be required to ensure that building materials, manufacturing facilities, construction yards, skilled labour and managers, vessels are all available. We also assume that tidal range is able to gain public acceptance given the environmental objections raised during discussions of a potential Severn Barrage.

---

93 ‘Solar generation 6. Solar photovoltaic electricity empowering the world’, EPIA, February 2011.

94 ‘The Marine Energy Action Plan’, DECC, March 2010.

95 Ibid

5.2.5 Wave and tidal stream

Generation from wave and tidal stream makes virtually no contribution to renewable penetration in the High scenario in 2030 and 2050. There is some growth in wave capacity after 2030 in the Very High scenario but tidal stream capacity remains very low. Even in the Max scenario, wave and tidal stream provides only a small share of renewable generation, although installed capacity is around double the 2050 levels in the other two scenarios.

5.2.5.1 Deployment trajectory

In our High scenario, installed wave capacity reaches 2GW in 2030 and remains at that level to 2050. This compares to 1.1GW in 2030 for level 3 in the DECC Pathways analysis and 3.6GW in 2030 for level 4.

Wave capacity also reaches 2GW in 2030 in the Very High scenario. However, we then see a further 6GW between 2030 and 2050, leaving a total of 8GW installed capacity in 2050. This is a similar level to Level 2 of the DECC pathways analysis – approximately 9.6GW.

Tidal stream capacity is assumed to grow to 2GW by 2030 in both the High and Very High scenarios. After 2030, there is assumed to be no growth in tidal stream capacity in either scenario.

In the Max scenario 14GW of wave capacity and 4GW of tidal stream is deployed – an additional 6GW and 2GW respectively compared to the 2050 levels in the Very High scenario. These values lie between level 2 and level 3 in the DECC Pathways analysis.

5.2.5.2 Decision points and milestones

The supply chain required to reach the installed capacity levels in our scenarios is likely to be fairly modest. Aside from manufacturing capacity, it is likely that wave and tidal stream technology could share some of the facilities set up to help deliver offshore wind (e.g. ports and possibly vessels).

Estimates for tidal stream indicate that 3-4 days will be required to install a tidal stream device of 1.2MW. Vessels are assumed to have an installation capacity of 60MW/year[96]. Therefore to meet the average deployment trajectory of 140MW/year between 2020 and 2030, 3 vessels will be required. This is unlikely to be a constraint for wave energy as reports suggest any general purpose vessel can be used for installation[97].

However, the relatively immature nature of wave and tidal stream technology means that there are a number of areas in which progress needs to be made before 2020 in order to reach 2GW of deployment by 2030. These can be summarised as successful technology demonstration and successful commercial deployment.

There are multiple test configurations and projects underway. Examples for wave generation include the Wave Dragon deployed in 2009 and the Pelamis device deployed in Portugal. Tidal stream examples include the 1.2MW Seagen device, operating since

96 'Quantification of Constraints on the Growth of UK Renewable Generating Capacity', SKM, June 2008.

97 Ibid.

2008 and the OpenHydro turbines deployed as part of a demonstration programme at the EMEC.

Successful technology demonstration is defined as showing that the technologies are capable of providing reliable operations with acceptable levels of maintenance and reliability, and hence have potential to be viable commercial choices. Moreover, even once the technology is demonstrated, it is likely that significant incentives will be required in order for generators to adopt tidal stream and wave technology. This means that there is a need for prolonged government support for technology demonstration and deployment.

Technology research and demonstration require direct support, which usually comes from public organisations. Some current examples are the Marine deployment fund (a total of £50million) and the ETI marine programme. A prolonged period of clear support for RD&D into tidal stream and wave would, hopefully, drive innovation and hence reduce the technology cost[98].

The Marine Energy Action Plan envisages commercial second and third generation wave and tidal stream systems being deployed from 2020 onwards, with the assistance of long-term market support[99]. These later generation technologies are required to move from near shore to offshore sites, where the majority of wave resource potential resource lies.

5.3 Deployment trajectories for nuclear and CCS technologies

Figure 24, Figure 25 and Figure 26 show the installed capacity for different types of non-renewable generation in each scenario. We do not build any new CCGT plants (beyond those currently under development) in any scenario. Although we do build new peaking capacity, particularly in the Max scenario, there are not expected to be any technical constraints on the delivery of the projected levels of peaking capacity. Therefore, in this section, we describe the deployment trajectories for the non-renewable low-carbon generation technologies (i.e. CCS and nuclear) in each scenario.

Figure 24 illustrates that the delivery of nuclear capacity is the main challenge for new non-renewable build in the High scenario. Even here, the capacity in 2030 is in line with current plans for deployment by 2025, although additional sites would be needed by 2050.

The closure of large amounts of CCGT capacity after 2030 can clearly be seen in both Figure 24 and Figure 25. In addition, there is early closure by 2030 of 8GW of CCGTs in the High scenario and 4GW in the Very High scenario. These plants are closed before their scheduled retirement date because they are unable to cover their fixed costs.

---

98 The recent indication by DECC that it will prioritise applications for NER300 funding falling into the ocean category. (http://www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/energy_mix/renewable/ored/ored.aspx)

99 ‘Marine Energy Action Plan’, DECC, March 2010.

Figure 24 – Deployment of non-renewable generation in the High scenario (GW)

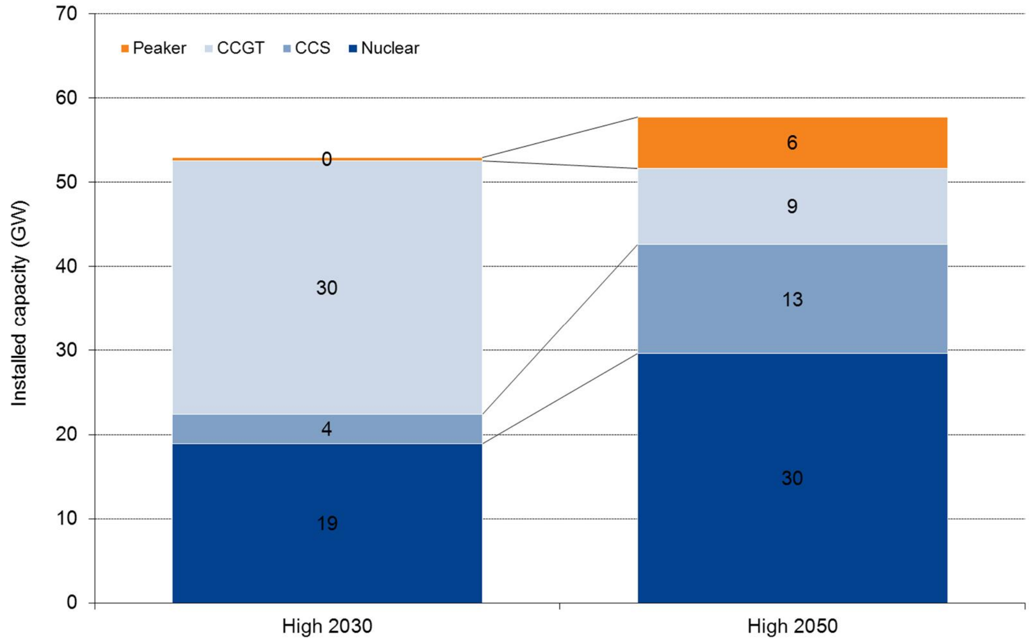


Figure 25 – Deployment of non-renewable deployment in the Very High scenario (GW)

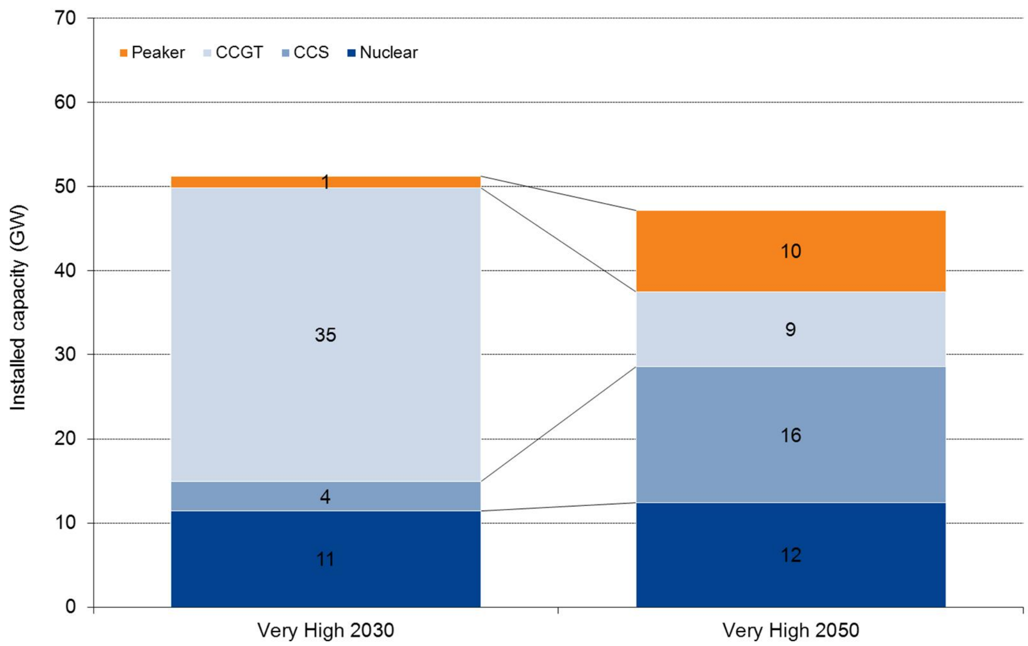
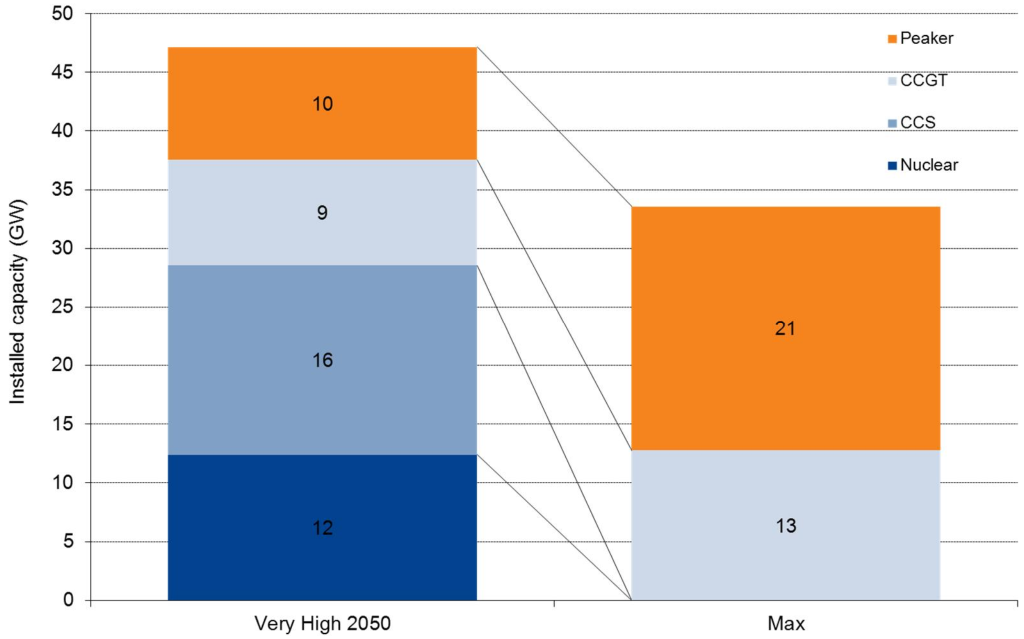


Figure 26 – Deployment of non-renewable deployment in the Max scenario (GW)



5.3.1 Nuclear

There is significant nuclear new build after 2020 in installed nuclear capacity in both of the High and Very High scenario. After 2030, new build continues in the High scenario but is very limited in the Very High scenario. We assume there is no installed nuclear capacity in the Max scenario.

5.3.1.1 High scenario

Nuclear generation is the dominant form of low carbon thermal generation deployed in our High scenario, with 19GW installed in 2030, and an increase of 11GW by 2050.

By 2030, we assume that generation of electricity from the remaining Magnox reactors and next generation Advanced Gas Reactors will have ceased (in line with the existing closure schedule). Thus, the only existing plant still in operation will be Sizewell B. Therefore significant levels of new build nuclear capacity are required to meet our assumed level of 19GW.

Three companies have indicated their intent to invest in, and operate, new nuclear generating capacity in the UK:

- **NNB Genco** (a consortium of EdF S.A., France and Centrica);
- **Horizon Nuclear Power** (an E.ON A.G. and RWE A.G. JV company); and
- **NuGeneration** (a consortium of GdF-Suez, Iberdrola and SSE).

Table 4 shows the timeline for proposed developments of new nuclear plants at sites stated as having Grid Agreements[100] in the National Policy Statement (NPS) on nuclear in 2010[101]. The planned profile of plant deployment is important in terms of logistics, both for the project developer and for the associated supply chain (UK and internationally for large components).

Table 4 – Timings of proposed new nuclear plants (MW)

Company	Site	Reactor type[102]	Capacity (MW)	Scheduled operation dates
NNB Genco	Hinkley Point C	2x EPR	3200	2018, 2019
	Sizewell C	2x EPR	3200	2022
	Bradwell	*1x EPR*	1600	*2024*
	Heysham	*1x EPR*	1600	*2025*
Horizon Nuclear Power	Wylfa	*3x AP1000*	3300	*2020, 2022, 2024*
	Oldbury	*1x EPR*	1600	*2023*
NuGeneration	Sellafield	*2x EPR*	3200	*2023, 2025*

These projects imply an annual build rate of about 2.5GW between the first plant commissioning in 2018 and the last plant commissioning in 2025[103]. This is higher than all of the annual build rates shown for nuclear in Table 3 (where the highest build rate is 1.5GW in the High scenario between 2020 and 2030).

Indeed, there is 17.7GW of new capacity scheduled to be operational by 2025, which would be sufficient to provide the level of new nuclear build required out to 2030 in the High scenario. Therefore, the nuclear build in the High scenario could still be met even with a five year delay on the plans set out in the 2010 NPS.

Under the deployment profile shown in Table 4, the peak of construction activity occurs around 2020, when up to 10 reactors at 6 sites could be under construction. In practice, some will be near the end of construction or in commissioning, while others will be in the early (civil works) phase, and others in the installation (of mechanical and electrical services) phase. Thus the demand upon specific industrial trades will be for a few stations, serviced by peripatetic and local suppliers. It is noted that the peak construction period is after the 2012 London Olympics.

100 The capacity shown in Table 4 is based on the type and number of reactors assumed to be built at each site, and therefore may be slightly lower than the capacity quoted in the relevant Grid Agreement.

101 'Revised Draft National Policy Statement for Nuclear Power Generation (EN-6)', DECC, October 2010

102 Two reactor types are undergoing Regulatory 'Generic Design Assessment' and were (at the time of writing) expected to receive Design Certification for UK development in June 2011. Items shown in italics are Pöyry' sanalysis for the purpose of this study; choice of technology has yet to be confirmed by the respective developers.

103 Although not reflecting the annual deployment rate over the whole build cycle (e.g. from the start of the development process for the first plant), this build rate is calculated on a comparable basis to the deployment rates shown in Table 3.

The companies proposing to develop new nuclear plants are all subsidiaries of large, international organisations, undertaking large energy infrastructure projects as part of their core business. They are also expected to have access to project finance to support development activities. Thus the undertaking of construction of a number of plants concurrently is not seen to be a major risk – staged development is spread across 3 individual organisations, thereby limiting investment exposure at a given time to a modest number proportionate to the turnover of the parent companies. In the scenarios, the UK is assumed to be seen as an attractive market for nuclear development/ deployment by these organisations. In practice, the UK may be competing for liquidity against ambitions in other countries (for example, there will be a limit on how many simultaneous reactor construction projects would/ can these organisations support in a European context).

The remaining stakeholders in achieving this deployment profile are:

- the Nuclear Vendors (Areva and Westinghouse-Toshiba) who may be building several plants elsewhere in the world;
- the national approving authorities; and
- the local approving authorities.

The UK has been judged capable of providing the necessary support to Vendor teams[104]. National regulators will have 'approved (in principle)' the potential reactor designs in advance of the major construction period, and have several years to staff the future requirement/ demand profile. The funding of regulatory activities is recovered from the developer/ operator. Local approving authorities will work with the developers prior to and during construction; since the sites are dispersed around England and Wales, local demands will be limited to single projects.

Further evidence of the ability to construct several plants simultaneously is provided by examination of the AGR construction programme, when 2 or 3 sites were under construction at a time in the mid 1980's. The example of France is often cited as an example of what is technically possible in terms of nuclear deployment rates. Between the early 1970s and the late 1990s, France built a total of 58 reactors (at a rate of about two per year). This included an average annual build rate of 4.5GW between 1979 and 1988 (inclusive)[105].

Beyond the current planned plants, the scale of nuclear new build (at around 2.5GW/a) could continue, either with the existing players and plants, or with new entrants. However in the High scenario, the requirement for a second wave of new nuclear is lower than the level set out in the 2010 NPS. This is because the deficit of base load large capacity generation caused by closure of 'end of life' nuclear and aging coal plants will have passed. At the same time, the High scenario is moving towards renewable penetration of 51% in 2030 and 60% in 2050, limiting the requirement for other forms of low-carbon generation.

Table 5 summarises the potential annual build rate for each developer, with the build rate being more than sufficient to deliver an increase of 11GW in capacity between 2030 and 2050.

---

104 See for example, the assessment of nuclear capacity by the Nuclear Industry Association.

105 World Nuclear Association Reactor Database (http://www.world-nuclear.org/rd/).

These rates are based on expert assessment of the prospects for annual build after the completion of the sites included in the NPS. This considers the investment programme by the nuclear operating companies from the viewpoint of:

- how much build should be invested into one country/ market (policy and regulatory risk) with competing demands in other countries; and
- whether the UK will produce required returns given penetration of other generation capacities.

After 2030, we postulate that each developer organisation can commission one new reactor every 3 years (implying 2 reactors under construction at any one time). Long-term consistent Government policy is key to supporting continued development at these rates.

Table 5 – Projections for average annual build rate for nuclear plant

Company	Build rate
NNB Genco	1.6GW every 3 years
Horizon Nuclear Power	1.1GW every 3 years
NuGeneration	1.1GW every 3 years
Average	**1.3GW/a**

The National Nuclear Laboratory has stated[106] that a total installed capacity of 23GW would be 'marginally viable' with the existing eight sites in the NPS[107]. This means that an important technical constraint on reaching 30GW of nuclear capacity by 2050 will be the availability of additional sites for the new reactors.

In addition to those sites listed in the 2010 NPS, developers identified 3 further sites (Dungeness, Kirksanton and Braystones) which were rejected for 2025. The government's consultants for the NPS also identified 3 further (un-named) sites for consideration, but these were subsequently excluded from the NPS for reasons not given.

In 2006, BERR commissioned a nuclear siting study[108] which recommended that the priority of development should be on existing sites. The BERR siting paper notes certain issues surrounding the development of the non-British Energy sites already sold by the Nuclear Decomissioning Authority[109], notably:

- supply of cooling water;
- connection of transmission lines; and
- future suitability of the site given other development in the interim.

---

106 'UK Nuclear Horizons. An independent assessment by the UK National Nuclear Laboratory', National Nuclear Laboratory, March 2011.

107 Table 4 does not include Hartlepool as there was no Grid Agreement for that site noted in the NPS.

108 'Siting New Nuclear Power Stations: Availability and Options for Government, Consultation Paper for DTi Expert Group', Jackson Consulting, 26 April 2006.

109 In 2008, the NDA sold land at Bradwell, Oldbury, Wylfa and Sellafield to prospective developers.

It might be possible to develop one or more 'brownfield'[110] sites in England and Wales for post 2025 generation. It is interesting to note that as long ago as 1981[111], the shortage of new 'greenfield' sites for nuclear generation development was an issue, and it is doubtful that criteria today would be less stringent.

5.3.1.2 Very High scenario

In our Very High scenario, nuclear plant plays a less substantial role largely because greater levels of renewable are deployed leaving less space for other forms of generation. The projected capacity of 11GW in 2030 and 12GW in 2050 could easily be met by the plans for nuclear plant development under the NPS (under which 18GW of new nuclear build is scheduled to be completed by 2025), without a requirement for additional sites.

5.3.1.3 Decision points and milestones

The timescale to understand and determine the suitability of a new site for new nuclear build, including permissions and any transmission development are significant. Under the new Planning Act 2008, a period of 3 -5 years does not seem unreasonable. If this is coupled with 7 years for pre-engineering and construction activities, then action is needed by 2020 to establish additional sites suitable for new nuclear deployment beyond those set out in the 2010 NPS. For example, a new nuclear NPS looking beyond 2030 should be available by 2020 to enable developers to prepare for the period after 2030[112].

There are a number of other milestones that need to be passed in order to ensure that there are no unexpected technical constraints on the development of new nuclear – these relate to public acceptance and supply chain competition.

Public acceptance of new nuclear is important, as is the need to develop waste storage. The UK currently has no national repository for intermediate and high level waste. Government plans are to have one in place by 2040 until which time plants will store waste on site. The site will be part funded by plant operators paying into the Nuclear Waste Liabilities Fund.

We assume that the UK will successfully compete for supply chain capacity against other countries that are building nuclear plant. Although there has been some publicity around the availability of new reactor pressure vessels (currently there is global reliance on Japan Steel Works), there are at least two other plants under construction (one in France and on in the USA) which will ease this bottleneck. Also, while theoretically possible, in reality not all advertised construction around the world will happen, either on the timescales indicated or perhaps not at all. However, supply of critical components and their lead time for procurement remains an issue for construction rates.

Finally, the assumed build rates are dependent on nuclear getting the investment green light (although this would not be defined as a technical constraint within the scope of this study). The build of unsupported nuclear plant in liberalised markets has been a difficult

---

110 Brownfield in this context is a site not currently used for nuclear generation activities. It can include sites of previous nuclear activity (e.g. Harwell, Winfrith) or other industrial sites (e.g. old conventional power stations).

111 See, for example, 'Can Britain find room for nuclear power?', New Scientist, 19 February 1981.

112 Under these circumstances, there would effectively be a five year gap (2025-2030) as the current NPS looks out to 2025. However, this is not an issue for the scenarios in this study as these only require the NPS capacity to be delivered by 2030 (not 2025).

proposition for developers. The combination of high front end costs coupled with project and regulatory uncertainty and the long construction phase (meaning that costs cannot be recovered quickly) have made new nuclear plant a challenging commercial investment.

5.3.2 CCS

In the High scenario, the installed CCS capacity in 2050 is only very slightly higher than the minimum capacity requirement specified by the CCC in relation to demonstration projects, and the CCS IGCC capacity (8GW) required to produce hydrogen for transport. Although renewable penetration is greater in the Very High scenario, there is some additional CCS gas capacity built after 2030. There is not assumed to be any CCS capacity in the Max scenario.

The limited additional new build of CCS in the High and Very High scenarios reflects the high penetration of renewables in these scenarios, with nuclear appearing to be the most cost-effective non-renewable low carbon option (based on DECC's technology cost assumptions[113]).

5.3.2.1 Deployment trajectory

In the High and Very High scenario, CCS deployment in 2030 is limited to the demonstration projects assumed to be in place by 2020. In these demonstration projects, the CCS capacity is 1.7GW in 2020, with retrofitting (of the unabated parts of the demonstration plants) leading to a further 1.8GW of CCS coal by 2030.

The growth in CCS capacity after 2030 in the High scenario is almost entirely the result of the assumed construction of 8GW of IGCC capacity, of which half is effectively reserved for the production of hydrogen for transport. In the Very High scenario, an additional 4GW of CCS gas is constructed after 2030 despite renewable penetration of 80% (compared to 60% in the High scenario).

5.3.2.2 Decision points and milestones

The levels of installed capacity in the High and Very High in either 2030 or 2050 are not expected to be challenging in terms of build rates (as illustrated in Table 3). However, there are a number of other possible sources of technical constraints including:

- demonstration of viability of CCS technology;
- identification of storage sites; and
- planning consents and location.

There is as yet no fully integrated, commercial scale, power generation scheme with CCS operating anywhere in the world. The required elements of the value chain do though exist at differing levels of technical and commercial maturity. For CCS to become a viable technology the near-term objective needs to be support and development of 'demonstration' projects. Through these projects, opportunities for cost reductions can be identified and operational experience gained. This approach is currently being followed by the UK government which has committed up to £1billion of support for Longannet's

113 Based on data sourced from a study undertaken for DECC by Mott MacDonald.

300MW post-combustion demonstration project and has announced its intention to support a further three projects[114].

Earlier work by Pöyry for the CCC[115] suggested that it is likely that there will need to be two tranches of demonstration projects before power generation with CCS can be deployed on a commercial basis. The first tranche will demonstrate that CCS projects can technically operate at scale.

The second set of demonstration projects will build on the design, construction and operational experience gained in the initial stage to:

- improve performance;
- resolve outstanding regulatory issues; and
- provide the basis for commercial guarantees expected of equipment suppliers and the first reference plant designs.

Our expectation is that due to the length of time required to develop and operate these demonstration projects, the earliest possible date that CCS will become commercial is 2024. It is essential that the demonstration initiatives that have been established by the UK, other governments (US, Canada and Australia) and the EU are continued throughout this period. This will be required in order for CCS to become commercially viable, and to reach even the relatively low levels of CCS in 2050 in the scenarios in this study.

Figure 27 shows a comparison of the CO_2 storage requirements across the different scenarios with the potential UK sites available for the storage (split by geography). It also shows the storage requirements from the analysis of the 'No DSR' variant (presented in Section 6.1.3) in which installed CCS capacity is higher than in the main scenarios.

It can be seen from Figure 27 that in all cases that the amount of potential storage capacity is far greater than required by the amount of installed CCS capacity.

The most desirable sites for the storage of CO_2 are depleted gas fields, as they have previously retained hydrocarbon gas for millions of years. However in the 'no DSR' variant, there is a requirement either for the use of depleted oil fields or saline aquifers because additional gas CCS capacity is deployed (an additional 7GW in the 'no DSR' variant on the High scenario in 2050, and an additional 8GW in the 'no DSR' variant on the Very High scenario in 2050). The use of depleted oil fields or saline aquifers is likely to be more technically challenging for CO_2 storage. Therefore in the 'no DSR' variants, storage of CO_2 in depleted oil fields or saline aquifers would need to have been demonstrated to be technically and commercially viable.

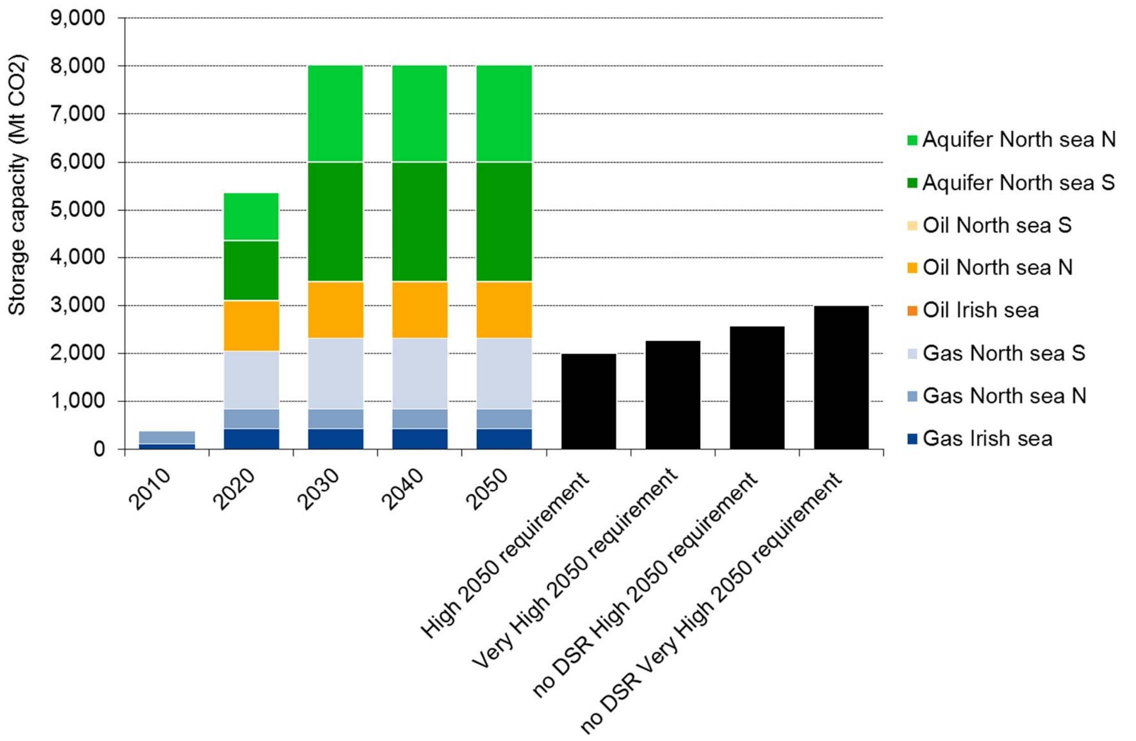
The large number of planning approval, licensing and consents are required for each of the stages of CCS is likely to be arduous. Many of these are procedural but can take a long and uncertain period of time to obtain. Our expectation is that a CCS project which does not encounter any delays would still be expected to take six years from inception to commissioning with planning approval, licensing and consents taking half of that time. In

114 'UK Carbon Capture and Storage Commercial Scale Demonstration Programme: Delivering Projects 2-4' Office for Carbon Capture and Storage, December 2010.

115 'Carbon Capture and Storage, Milestones to Deliver Large Scale Deployment by 2030 in the UK, A report by Pöyry to the Committee on Climate Change' Pöyry Energy Consulting, October 2009.

order to achieve the levels of CCS presented in these scenarios, it is important to ensure that these processes are as streamlined as possible, so as not to deter potential investors.

Figure 27 – Viable UK carbon storage availability to 2050: Known sites ($MtCO_2$)



A key issue is the need to obtain rights of way to build pipelines, either through land acquisition or consents from land owners. It is generally regarded that long pipelines (for example longer than 100 km) can be challenging to build due to the number of stakeholders than need to give their consent, and the need to evaluate a range of route options to mitigate difficulties. However a large fraction of the existing coal-fired and gas-fired plants in UK are less than 100 km from an onshore gas terminal, where many believe CO_2 pipelines will converge before going offshore. It is therefore likely that CCS developments would be predominantly coastal. The most promising location for CCS development is Humberside which has both depleted gas field storage and has several large coal and gas stations in the area.

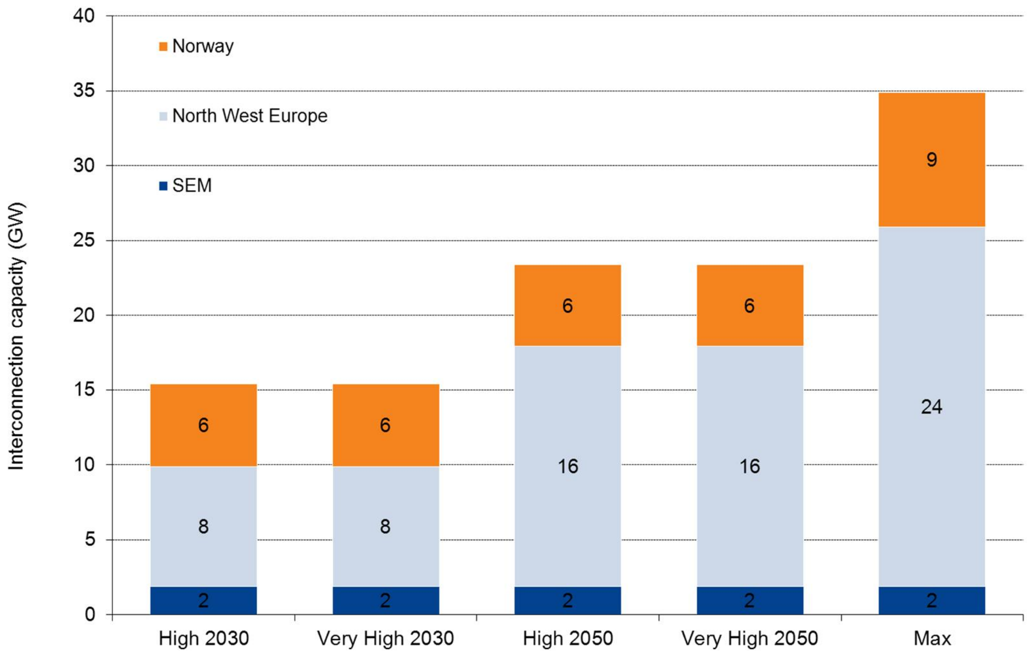
5.4 Non generation sources of flexibility

This section describes the deployment trajectory for two key sources of flexibility from outside the generation sector[116] – interconnection and demand-side.

5.4.1 Interconnection

Figure 28 shows the assumed level of interconnection capacity for each scenario, with assumptions varying by year rather than scenario (i.e. interconnection assumptions are the same in the High and Very High scenarios in 2030 and in 2050). There is an additional 3GW of interconnection capacity in the Max scenario (compared to 2050) to try to help the system accommodate higher levels of renewable penetration. The estimated costs of the interconnection capacities in each scenario is presented in Annex A.

Figure 28 –Interconnection capacity (GW)



5.4.1.1 Deployment trajectory

In all of the scenarios, there is assumed to be significant growth in interconnection capacity. Currently, there is 3.0GW interconnection between GB and NW Europe[117] (i.e. France, Belgium and the Netherlands), and 0.9GW of interconnection between GB and the SEM.

---

116 There is only a small assumed increase in bulk storage, which is described in Section 3.3.4.2.

117 This includes the BritNed interconnector between GB and the Netherlands.

In addition, there are a number of projects currently at the planning stage[118]:

- 0.7GW interconnection with the SEM (Imera);
- 0.8GW interconnection with France (Imera); and
- 1.0GW interconnection with Belgium (National Grid and Elia).

Projects that are currently at an earlier stage of development would increase interconnection with North West Europe by a further 2.0GW. There is also a proposal for the development of a 1.0GW link with Norway.

If all of these projects were realised, interconnection capacity would be:

- 6.8GW with NW Europe;
- 1.6GW with SEM; and
- 1.0GW with Norway.

This means that between 2020 and 2030, there could be a need to build between 5.5GW (if all projects listed above were realised) and 12GW of interconnection capacity in both the High and Very High scenarios. Ofgem's view is that total interconnection capacity could be 8GW by 2020 (i.e. an additional 4GW built between 2010 and 2020) [119], which would mean that another 8GW would need to be built after 2020. In particular, most of the interconnection with Norway in our scenarios for 2030 would need to be built after 2020.

Between 2030 and 2050, there is another 8GW of interconnection built between GB and NW Europe in both the High and Very High scenarios.

Moving from the Very High to the Max scenario sees a further increase of 8GW in interconnection between GB and NW Europe, and an increase of 3GW in interconnection between GB and Norway.

5.4.1.2 Decision points and milestones

Section 4.2.3 discusses how interconnection can provide flexibility to the system. In developing these scenarios, we have assumed that the deployment of high renewables is supported by greater system flexibility. Hence, we have assumed a significant expansion of interconnection (although we have not tested what the optimal level of interconnection would be on a cost-effective basis). In Section 6.1.4, we explore the impact on system performance if interconnection capacity is lower than in our main scenarios.

In terms of technical constraints, the main challenge to delivering the physical interconnection is the required annual build rate. The build rate between 2020 and 2030 will be between 0.5GW to 1.2GW a year, depending on developments up to 2020. The build rate then falls to 0.4GW per year after 2030.

It is useful to look at the experience of the BritNed (between GB and the Netherlands) and NorNed (between Norway and the Netherlands) interconnectors, as a guide to the construction challenge for subsea HVDC interconnectors with NW Europe and with Norway.

---

118 'Electricity interconnector policy', Ofgem, January 2010.

119 Ibid.

Construction work started on the BritNed link (a 260km, 1GW link) in 2008 with the link being commissioned in early 2011. Much of the initial construction work was around preparing the convertor stations at either end of the link. The construction of the NorNed link (a 580km, 0.7GW link) took 3 years.

Therefore, the achieving the deployment trajectory to 2030 would need two to four projects under construction at any one time between 2020 and 2030. This falls to one project at a time after 2030.

In fact, the biggest technical constraint on the delivery of the assumed flexibility from interconnection is not the physical build time but rather the:

- **Length of pre-construction phase** (gaining permits etc), which was estimated to be around 7 years for NorNed and BritNed.
- **Capacity of local transmission network** – this was particularly a problem for BritNed, owing to congestion in the Maasvlakte area in the Netherlands. Local network upgrades will typically take the form of high-voltage overhead lines, which currently face significant opposition in many European countries. Therefore effective capacity of interconnectors often limited by ability of local transmission networks to accommodate flows.

These challenges will significantly increase the project development time, with the result that delivery of interconnection from 2020 is likely to require plans being put in place in the near term.

Gaining public, regulatory and political support for the required investment in interconnectors will be crucial in delivering the integrated electricity system of the future. The likelihood of such acceptance will depend on the actions of the possible winners and losers from increased interconnection, both within markets and in terms of national interest. National interests cannot be assumed away in the light of the local remit of regulators in assessing the case for investment.

There are a number of key issues in clarifying winners and losers, and the role played by local concerns:

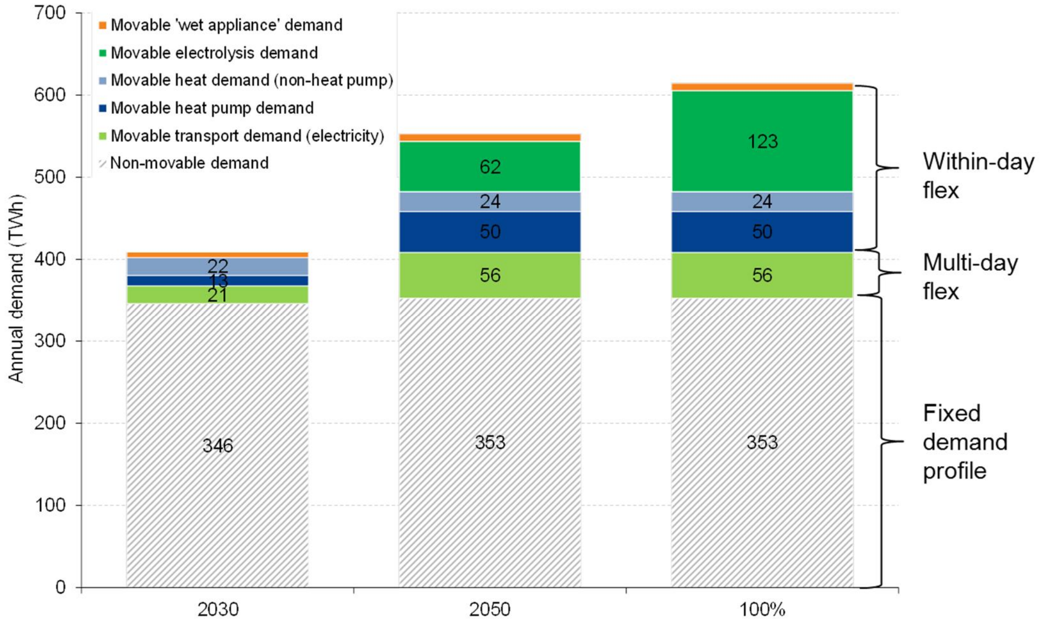
- efficient interconnector investment will not deliver complete price convergence;
- electricity market integration will not eliminate volume and price volatility;
- welfare distribution matters even if only two countries are involved;
- efficient levels of interconnector investment will be harder to achieve if benefits accrue to countries not linked by the interconnector; and
- gaining public acceptability is key to delivery of effective interconnection capacity.

In addition, the degree of flexibility provided by the interconnector is subject to the amount of flexibility available at the other end of the interconnector. Therefore, the benefits from interconnection will be influenced by European developments (e.g. development of demand-side flexibility, and growth in different types of renewable generation).

5.4.2 Demand-side flexibility

Figure 29 summarises the amount of movable demand by end-use category in each scenario. This section describes the trajectory towards these levels of movable demand in more detail, supported by a discussion of the key milestones and decision points. , Annex A shows information on the assumed cost of installing appropriate smart technology to facilitate demand-side flexibility in all scenarios.

Figure 29 – Annual amount of movable demand in each scenario (TWh)



5.4.2.1 Deployment trajectory

The amount of movable demand does not vary between the High scenario and the Very High scenario, i.e. like interconnection, movable demand varies by year rather than scenario. In 2030, movable demand (65TWh) is about 15% of total demand. Just over half of the movable demand (35TWh) is in heating, with the remainder primarily in the transport sector.

As electrification continues after 2030, the amount of movable demand increases to about 200TWh (broadly in line with the absolute growth in overall electricity demand), equating to around a third of total demand. The use of electrolysis to produce hydrogen for transport[120] results in transport sector providing most of the movable demand. However, most of the flexibility is concentrated within-day (through limits on storage capacity).

In the Max scenario, the electricity demand from electrolysis doubles to replace the hydrogen produced by IGCC plant in the High and Very High scenarios. This increases movable (and total) electricity demand by 60TWh, meaning that movable demand is about 40% of total electricity demand.

5.4.2.2 Decision points and milestones

In our scenarios, we assume that supporting infrastructure and technologies are deployed in time and at sufficient scale to deliver the levels and characteristics of flexible demand defined in the scenarios.

120 Assumptions in relation to the demand for hydrogen were provided by the CCC as part of the annual demand assumptions. Therefore, they have not been derived as part of this study.

The two key components of flexible demand are:

- the control system and associated infrastructure that shifts the movable demand; and
- the end-use technologies (and storage) that allow the demand to be moved.

The control system and associated infrastructure can be considered to be 'smart infrastructure' normally characterised by the deployment of smart meters and smart grids.

One programme for the deployment of smart infrastructure is laid out in the Smart Metering Implementation Programme[121] published in summer 2010. The prospectus envisages smart meters will be rolled out from 2013 onwards (on a provisional basis) with a scheduled completion date of 2020. The time between 2010 and 2013 will be taken by the:

- introduction of supporting legislation and regulatory framework;
- agreement of technical specifications;
- implementation of the DataCommsCo (DCC) to identify and procure cost effective and technically robust smart metering and data management solutions; and
- completion of the trial and testing of smart meter functionality.

The important issue for our scenarios is that the smart meters and control systems procured by the DCC are capable of controlling the flexible technologies as modelled in our scenarios.

The end-use technologies that allow demand to be moved can be split into two categories. The first category can shift demand but cannot return electricity to the grid. This includes heating and (residential) wet appliances. The second category are technologies that are flexible in terms of demand but can also return electricity to the network, which is primarily electric vehicles.

Therefore, the amount of movable demand depends on (assuming the existence of smart infrastructure):

- the electrification of heat and transport;
- access to storage; and
- technical assumptions about ability to access the potential for flexible demand[122].

As there is not assumed to be any retrofitting of heat storage, the assumed storage must be put in place at the same time as the heat pump.

Finally, perhaps the most important assumption relates to behavioural response, with consumers exploiting the significant technical potential for demand-side flexibility. This remains a significant area of uncertainty.

---

121 'Smart metering implementation programme prospectus', DECC and Ofgem, 2010.

122 As the focus of this study is on technical constraints, we assume that adequate commercial incentives are in place to deliver the level of movable demand shown for each scenario..

6. ANALYSIS OF TECHNICAL CONSTRAINTS

In this chapter, we present further analysis of the technical constraints on the accommodation and delivery of the high renewable scenarios assessed in this study. The constraints are grouped into four broad categories:

- factors that will affect the ability of the system to accommodate high levels of renewable generation (Section 6.1);
- requirements for investment in and operation of transmission and distribution networks (Section 6.2);
- availability of renewable resource (Section 6.3); and
- deliverability of annual build rates (Section 6.4).

We also consider the prospects for the system becoming locked into certain trajectories, whereby developments in the near-term may narrow the range of future possible options[123].

6.1 Limits on ability of system to accommodate high renewables

We have used variant analysis to make a detailed quantitative assessment of the impact of the following factors on the performance of the system in accommodating high levels of renewable generation:

- **Weather patterns;**
  - how does the system perform under more extreme weather patterns?
- **Renewable generation mix;**
  - how does the system perform if there is a more diverse renewable generation mix?
- **Sources of system flexibility;**
  - how does the system perform if demand side response is less flexible?
  - how does the system perform if, in addition to a less flexible demand side, interconnection build is less than expected?
  - how does the system perform if there is increased solar deployment in Spain (with supporting interconnection) that changes the pattern of flows of electricity into and out of GB?
  - how does the system perform if, in addition to increased solar deployment in Spain, hydrogen can be stored for up to a week (rather than a day) ?

The following sections present the results for each of the variants in turn.

123 For example, construction of large amounts of plant which is inflexible, either for economic or technical reasons may preclude larger deployment of wind at a later stage.

We have used the assessment criteria described in Chapter 4 to evaluate the performance of the system in each case on the same assessment criteria:

- **security of supply,** as measured by the amount of additional peaking capacity required to meet the constraint on expected energy unserved (EEU) [124];
- **utilisation of available low variable cost generation**[125]**,** as measured by the amount of available low variable cost generation not used (or shed) by the system; and
- **delivery of low-carbon system** – as measured by the annual level of CO_2 emissions[126].

6.1.1 Extreme weather patterns variants

We used two variants to understand the impact of extreme weather on the performance of the system in accommodating high renewable generation. These variants used 'synthetic years', which combined the historical months with the most extreme results for the following weather patterns:

- highest wind variability from one period to another; and
- highest number of lulls (with a lull defined as period of at least 72 hours with wind output below 15% installed capacity).

For example, January in the variable wind year has the greatest variability of any of the historical January months. Likewise, the selected January in the many lulls variant has the most lulls of any of the historical January months. The same decision process was applied to all other months in the composite years.

We find that, in general, the extreme weather patterns lead to the system performing slightly worse than in the main scenarios either in terms of shedding or CO_2 emissions. In general, the gap between the main scenarios and the variants widens with higher levels of renewable penetration.

6.1.1.1 Security of supply

We kept the same installed capacity mix in the variants as in the main scenarios – this reflects the fact that generation investment decisions would be based on a range of expected weather patterns (as captured in our historical years) rather than just one potential outlier.

The level of EEU exceeds the specified constraint in the low wind year in the High and Very High scenarios. However, the level of expected energy unserved in the low wind year variant remains at or below 0.003% of total electricity demand.

---

124 The EEU constraint is around 2GWh of in 2030 and around 4GWh in 2050 and the Max scenario, with the difference reflecting the fact that annual electricity demand was about twice as high in 2050 (and in the Max scenario) than in 2030.

125 Low variable cost generation is defined as nuclear and renewables excluding biomass. The shedding of nuclear generation is included in the metric as this captures when intermittent renewables generation displaces nuclear plant (with no benefit in terms of CO_2 reductions).

126 Around 80-90gCO_2/kWh of demand in 2030 and close to zero in 2050.

The level of peaking build in the main scenarios means that EEU is zero in the High and Very High scenarios in the variable wind variant. The EEU exceeds the specified constraint in the Max scenario but is still only 0.001% of annual electricity demand.

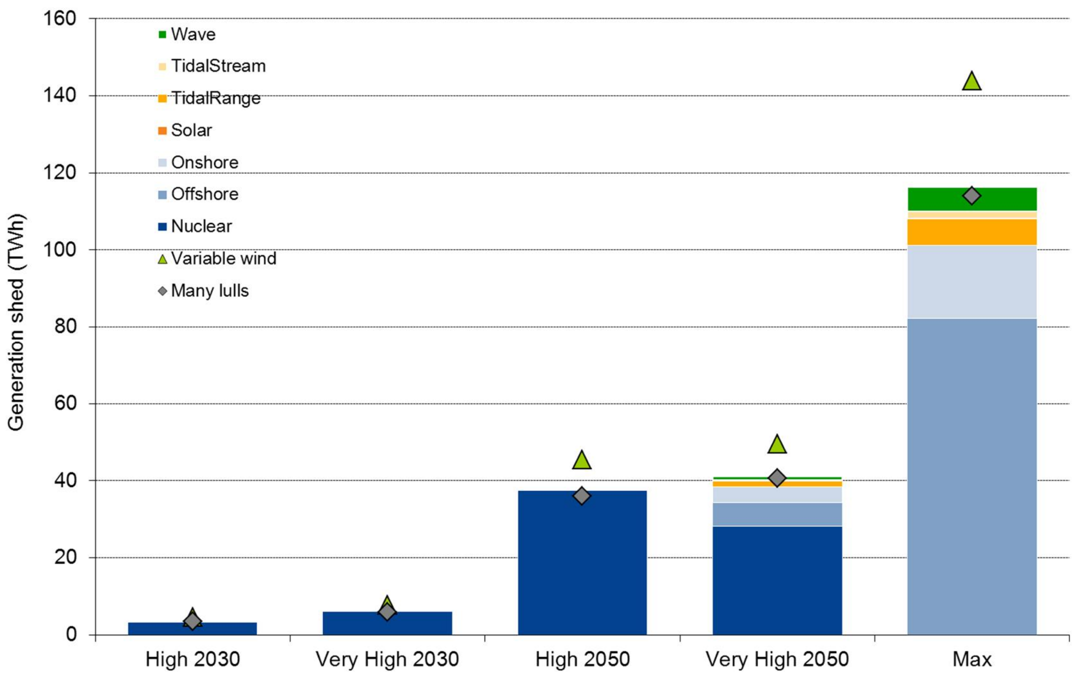
6.1.1.2 Shedding of low variable cost generation

Figure 30 shows the shedding of low variable cost generation in the main scenarios (stacked columns), the variable wind variant (green triangles) and low wind variant (grey diamonds). As with the main scenarios, the shedding of low variable cost generation is over 100TWh in the Max scenario, around 40-50TWh in 2050 and below 10TWh in 2030.

Increasing variability of wind leads to greater shedding – the variable wind variant (green triangles in Figure 30) has shedding levels that are around 20% higher than main scenarios in 2050 and about 25% higher than the main Max scenario. The increase in shedding results from its asymmetric relationship with wind level (i.e. shedding occurs in a relatively small number of high wind periods). Therefore, shedding increases when there are more high wind periods (either because the higher wind level increases shedding in the periods in which shedding took place in the main scenarios and/or it increases the number of periods in which shedding does not take place). However, the opposite effect does not occur if there is an equal increase in the number of low-wind periods.

The low wind variant reduces shedding very slightly compared to the main scenarios. However, the effect is minor, because shedding occurs in a relatively small number of periods of excess wind, the frequency of which is largely independent of the number of lulls.

Figure 30 – Shedding of low variable cost generation in extreme weather variants (TWh)



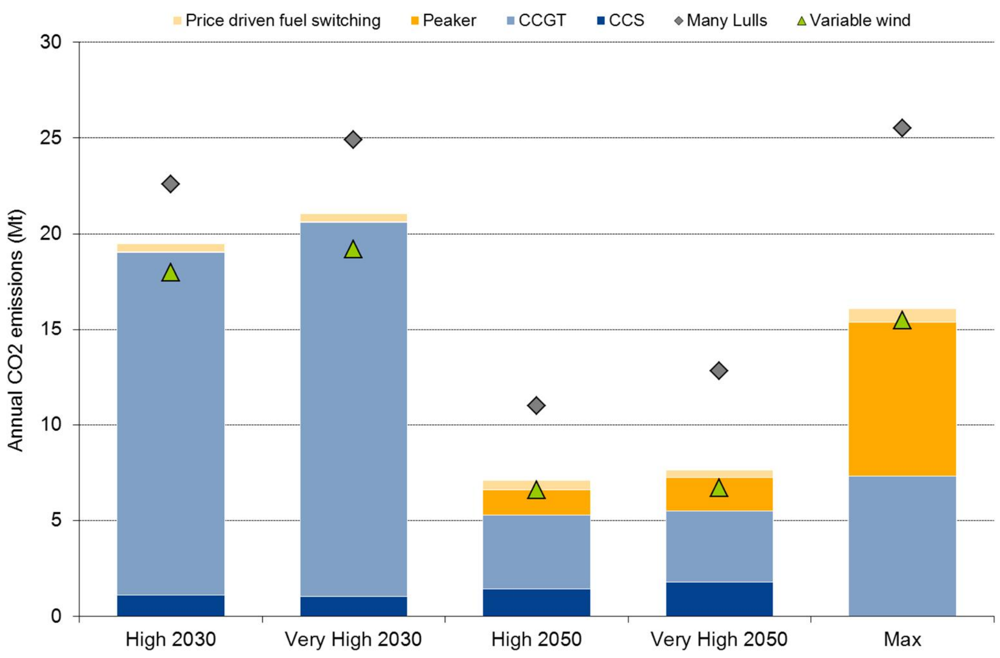
6.1.1.3 Decarbonisation

Figure 31 shows the level of CO_2 emissions in the main scenarios (stacked columns), the variable wind variant (green triangles) and low wind variant (grey diamonds). The relative level of emissions across the scenarios in the variants is the same as in the main scenarios.

CO_2.emissions are higher in the variant with greater frequency of low wind periods – as capacity assumptions are the same as in the main scenarios, the increased emissions are driven by higher load factors of plants that emit CO_2. The load factor increases because there is less output from intermittent renewable generation (primarily wind), with nuclear and non-intermittent renewable generation unable to make up the shortfall[127].

In 2030, the additional emissions primarily come from CCGTs with a small contribution from peakers. Although CCGT production is also higher in 2050, a more significant role is played by peakers and CCS plants. In the Max scenario, the increased emissions come from both CCGTs and peakers (with an assumed absence of CCS in his scenario).

Figure 31 – CO_2 emissions for extreme weather variants ($MtCO_2$)



6.1.2 Diverse renewables mix variant

The objective of this variant was to understand the implications for system performance of reducing the share of renewable generation coming from wind. The fall in wind output is offset by an increase in other forms of intermittent renewable generation so that there is virtually no change in the annual level of output required from intermittent renewable generation. Even in this variant, wind provides well over half of renewable generation, with significant increases in capacity over NREAP levels (particularly by 2050).

---

127 Figure 9 and in Figure 10 in Section 4.1.3 show annual load factors by technology in the main scenarios and synthetic years.

This variant was carried out on the High scenario because it has a higher penetration of wind generation (as a proportion of renewable generation) of our three scenarios than the Very High scenario. Wind penetration levels are as follows:

- in 2030, 83% in the High scenario compared to 77% in the Very High scenario; and
- in 2050, 91% in the High scenario compared to 79% in the Very High scenario[128].

For the low wind variant in 2030, we increased the contribution from the following technologies compared to the main High scenario:

- tidal range – an increase of 13GW (31TWh), based on the Very High scenario in 2050; and
- solar – an increase of 22GW (19TWh), based on the Very High scenario in 2030.

This enabled a reduction in (offshore) wind capacity of 14GW[129] (53TWh), with wind's share of renewable generation falling to 60%[130] (much lower than all of the main scenarios).

In 2050, the non-wind intermittent renewables were set at the same level as in the Very High scenario in 2050. This mean that that compared to the High scenario in 2050 there was increased output from:

- tidal range – an increase of 13GW (31TWh);
- solar – an increase of 35GW (29TWh); and
- wave – an increase of 6GW (14TWh).

This enabled a fall of 23GW (79TWh) in offshore wind capacity (to 54GW) whilst keeping renewable penetration stable at 60%. The proportion of renewable generation coming from wind fell to 70% (below the level in all of the main scenarios).

In general, the performance of the system improves with a more diverse renewable generation mix. Compared to the High scenario, the variants have a lower requirement for peaking capacity build, reduced levels of shedding and decreased CO_2 emissions.

This suggests that the assumed sources (and magnitude) of flexibility are better able to cope with high levels of renewable penetration when the renewable mix is less heavily dominated by wind. A key driver of this result is that variations in tidal range and solar output tend to be much stronger within-day than day to day (compared to wind). This complements much of the flexibility from the demand-side, which typically can provide flexibility within-day but not over several days.

6.1.2.1 Security of supply

The areas of the circles in Figure 32 shows the amount of peaking capacity required to meet the constraint on EEU in our main High scenario (top two bubbles) and in the diverse renewables mix variant (bottom two bubbles). The vertical axis shows the proportion of renewable generation that comes from wind, and therefore, the top two bubbles are from the main High scenario and the bottom two bubbles from the diverse renewables mix variant. The horizontal axis shows renewable penetration as a

---

128 Wind penetration is 84% in the Max scenario.

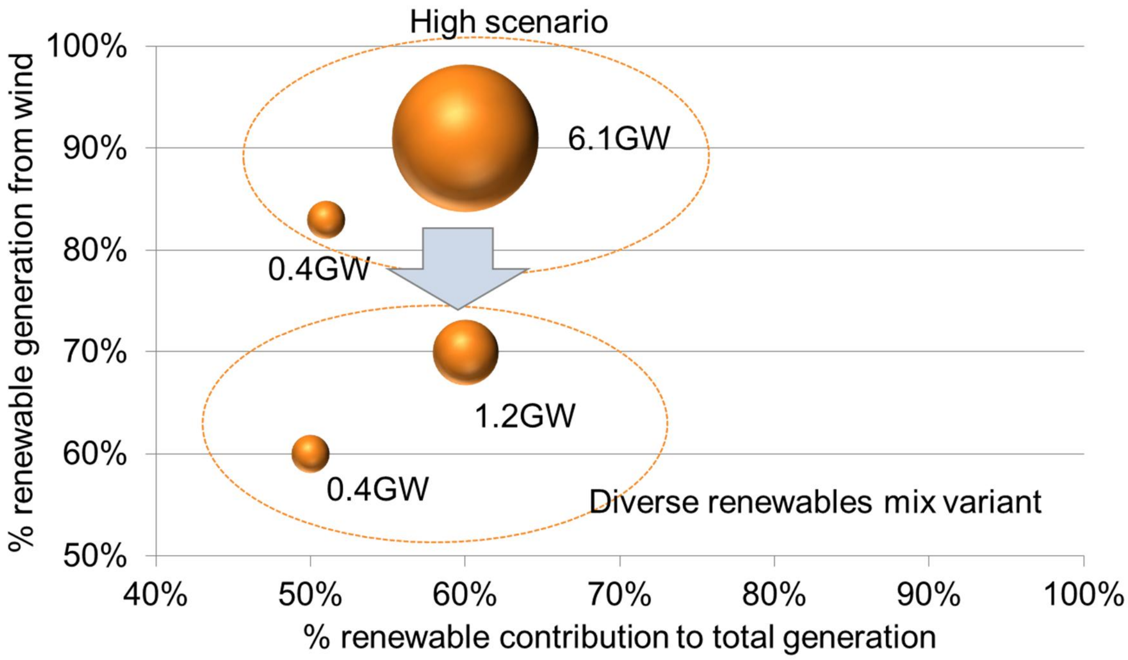
129 In the 2030 variant, there was assumed to be 24GW of offshore wind.

130 Total renewable penetration fell slightly from 51% to 50%.

percentage of total electricity generation, with the small bubbles on the left hand side for 2030 (around 50% penetration) and the bubbles on the right hand side (around 60% penetration) for 2050.

In both cases, the amount of peaking capacity build required in 2030 is close to zero. However, in 2050, peaking capacity build is much lower in the diverse renewables mix variant (1.2GW) than in the High scenario (6.1GW).

Figure 32 – Peaking plant build in the High scenario and in the diverse renewables mix variant (GW)

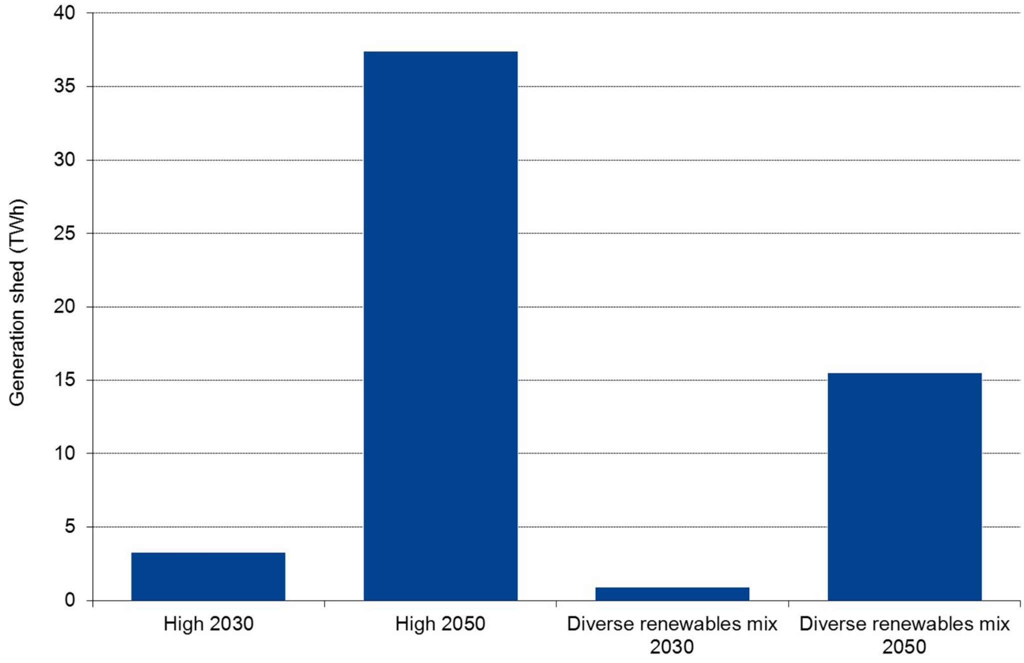


6.1.2.2 *Shedding of low variable cost generation*

Figure 33 shows that there is a significant decrease in shedding in the diverse renewables mix variant (particularly in 2050) compared to the High scenario.

In the variant, installed offshore wind capacity has been replaced with other forms of intermittent generation (e.g. tidal range or solar) whose output is more weakly correlated with wind. This reduces the incidence and duration of periods of high output from intermittent generation (e.g. as solar generation falls to zero overnight), which is the periods in which shedding happened in the main scenario.

Figure 33 – Shedding of low variable cost generation in the High scenario and in the diverse renewables mix variant (TWh)



6.1.2.3 Decarbonisation

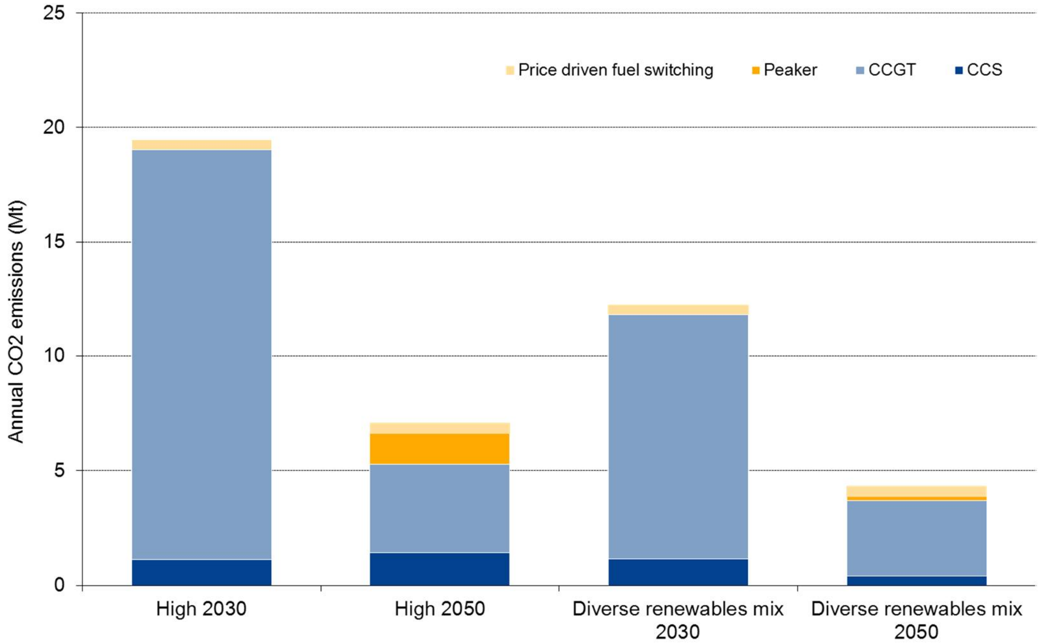
Figure 34 shows CO_2 emissions by source for the High scenario and for the diverse renewables mix variant. The key result is that in both 2030 and 2050, emissions are lower in the variant than in the main scenario.

In 2030, the change in pattern of intermittent generation from the more diverse renewables mix allows an extra 3GW of nuclear plant to be deployed. This results in the early closure of an additional 10GW of CCGT capacity (compared to the main scenario), which does not cover its fixed costs. This reduces emissions by 7MtCO_2, with emission intensity falling from 47gCO_2/kWh (of demand) to 27gCO_2/kWh.

Increased diversity in the renewables mix leads to a lower requirement for all non-renewable capacity in 2050. A fall of 5GW in installed peaking capacity compared to the High scenario reduces the capacity component of wholesale prices, affecting the investment case for other plants. As a result, CCS gas capacity falls by 2GW and nuclear capacity is reduced by 1GW.

However, the fall in nuclear capacity is more than offset by an increase in the achieved load factor of nuclear. This means that nuclear generation in the variant is 12TWh higher than in the High scenario. The increased nuclear generation displaces output from CCGTs and peakers, which lowers emissions in the variant compared to the High scenario.

Figure 34 – CO_2 emissions in the High scenario and in the diverse renewables mix variant ($MtCO_2$)



6.1.3 *No DSR variants*

We used the no DSR variants to test the impact on in the High and Very High scenarios[131] of assuming that there was no active demand-side response (DSR) available for the system to use to balance variations in intermittent generation.

In general, we found that the absence of active DSR significantly worsened system performance, with more peaking (and other thermal capacity) required, greater shedding and higher CO_2 emissions.

Section 3.3.4.3 describes our approach to modelling active DSR from transport (including electrolysis), heating and residential washing appliances in the main scenario. Section 5.4.2 summarises the levels of movable demand. Most sources of active DSR (heating, electrolysis, residential washing appliances) primarily shift demand around within the same day. However, electric vehicles are an important source of flexibility across days.

In the variants, we make the following changes to demand-side flexibility:

- charging of 'flexible' electric vehicles follows a fixed overnight profile;
- electricity demand from 'flexible' heating follows fixed (peaky) profile for heating energy demand (i.e. there is assumed to be no storage);
- electricity demand from 'flexible' residential washing follows the fixed profile of residential demand; and
- electricity demand from electrolysis is assumed to be flat across the day.

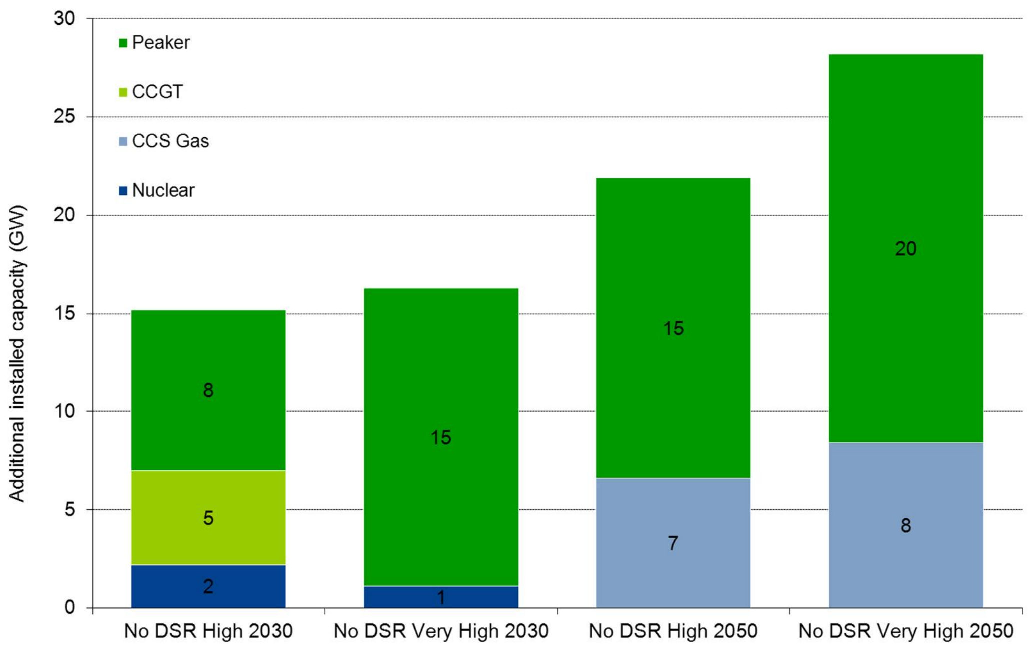
131 We did not test the Max scenario, because the system already performs badly (particularly in terms of shedding) with assumed high levels of active DSR.

6.1.3.1 Security of supply

Figure 35 shows how removing active DSR increases the requirement for non-renewable generation capacity. The biggest rise is in peaking capacity, particularly in the Very High scenario. However, there is also significant growth in the installed capacity of CCS gas, which is the most suitable low-carbon technology for operating at lower load factor.

In the variant on the High scenario in 2030, there is an additional 5GW of CCGT capacity – this is not the result of new build but reflects plants staying open until their scheduled retirement date (whereas they closed early in the main scenario).

Figure 35 – Additional non-renewable capacity in the no DSR variants (GW)

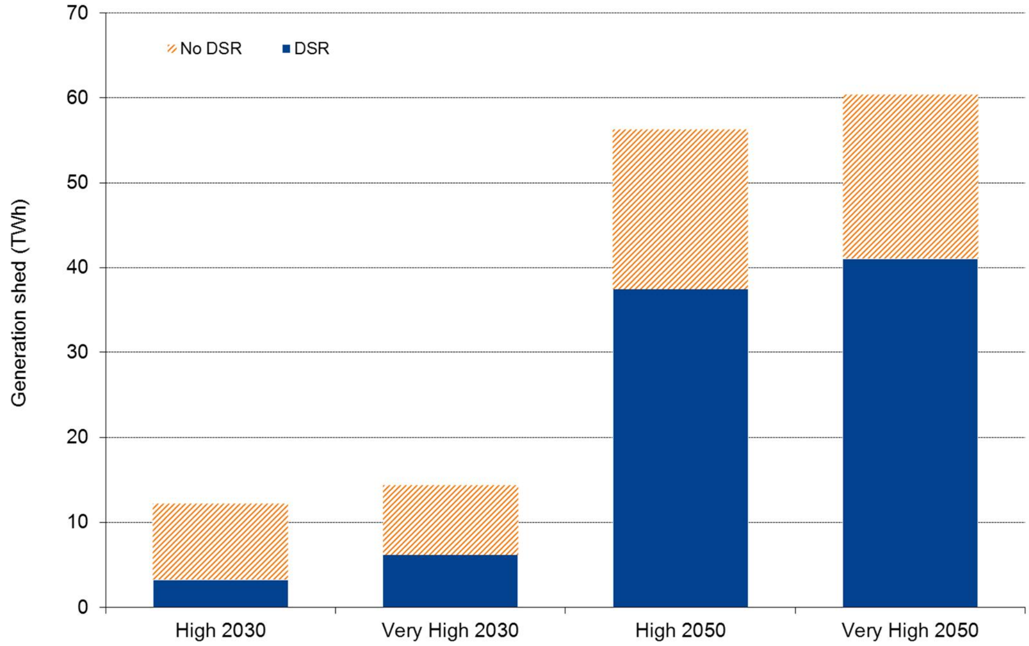


6.1.3.2 Shedding of low variable cost generation

The increased shedding in the no DSR variants is shown as hatched orange blocks in Figure 36, with the dark blue blocks representing shedding in the main scenarios. This highlights the important role played by active DSR in shifting demand from periods with high intermittent generation (compared to inflexible demand) to periods in which there is less intermittent generation (compared to inflexible demand).

The impact on shedding is similar in the two scenarios (which have different levels of renewable penetration) but is much greater in 2050 (around 20TWh) than in 2030 (about 9TWh). This is consistent with the pattern of shedding in the main scenarios, which is much higher in 2050 than in 2030 (as discussed in Section 4.3.2).

Figure 36 – Shedding of low variable cost generation in the main High and Very High scenarios and in the no DSR variants (TWh)



6.1.3.3 Decarbonisation

Removing active DSR significantly increases the level of unabated fossil fuel capacity (as illustrated in Figure 35). However, Table 6 shows that the low load factors of these plants means that the variant does not lead to a less marked increase in emissions.

Indeed, in the no DSR variant on the High scenario in 2030, emissions are lower than in the main scenario. This reflects the fact that the increase in nuclear capacity (with a high load factor) actually displaces output from CCGTs (despite the increased CCGT capacity).

Table 6 – CO_2 Emissions in the main High and Very High scenarios and in the no DSR variants ($MtCO_2$)

mtCO2	Main scenario	No DSR variant
High 2030	19.4	17.6
High 2050	7.1	9.2
Very High 2030	21.1	21.7
Very High 2050	7.7	11.3

6.1.3.4 Pattern of interconnector flows

In the absence of active DSR, the system is more reliant on other forms of flexibility (such as interconnection) to help to balance supply and demand.

As described in Section 3.3.4.1, the input flows across the interconnectors are based on relative wind levels (SEM) or the analysis in Pöyry's recent intermittency study[132] (NWE and Norway).

Table 7 shows that in all four cases, net imports are higher in the no DSR variant than in the main scenario, with the (absolute and percentage) increase rising with the level of installed wind capacity[133].

There are no circumstances in which *Zephyr* can increase flows above the input level. Therefore, the change in net imports must reflect the system behaving differently in the way it reduces flow below the input levels – either:

- increasing (gross) imports compared to the main scenario by less frequent deloading of intermittent renewables; and/or
- reducing (gross) exports compared to the main scenario by more frequent reduction of exports to avoid load loss in GB.

The second factor is the more dominant driver of the trend shown in Table 7. This is because deloading (or shedding) actually increases rather than falls, and there is a need for greater thermal capacity, reflecting more periods of a tighter supply-demand balance (and hence the need to curtail exports).

Table 7 – Increase in net imports in the no DSR variants compared to the main scenarios

Variant and main scenario	Increase in imports (TWh)	% increase on original imports	Installed wind capacity (GW)
No DSR High 2030	0.2	0.4	59
No DSR High 2050	0.7	1.7	68
No DSR Very High 2030	2.1	3.3	100
No DSR Very High 2050	4.5	8.2	120

6.1.4 No DSR and low interconnection (IC) variant

We used this variant to further stress the system in the High 2030 main scenario to see how it would perform if there was less flexibility available both from the demand-side (as in the no DSR variant) and from interconnection (reduced capacity).

132 'The challenges of intermittency in North West European power markets (public summary)', Pöyry Management Consulting, March 2011.

133 The interconnection capacity assumptions vary by year rather than scenario (i.e. interconnection assumptions are the same in the High and Very High scenarios in 2030 and in 2050).

Table 8 shows the difference between the interconnection capacities in the main scenario and in this variant. The interconnection capacities (and flows) in this variant are based on the Targets Met scenario in our NWE intermittency study[134]. Total interconnection capacity in the variant is 6GW,compared to about 15GW in the main scenario.

Table 8 – Interconnection capacities in main scenarios and in no DSR and low IC variant (GW)

Interconnector	Capacity in main scenario (GW)	Capacity in low i/c variant (GW)
GB – France	5.0	2.0
GB – Netherlands	2.0	1.0
GB – Belgium	1.0	0.7
GB – Norway	5.5	1.4
GB – SEM	1.9	0.9

In summary, the system performs worse in this variant in coping with periods of low and high output from intermittent renewable generation. This is shown by the following changes compared to both the main scenario and the no DSR variant:

- higher requirement for peaking capacity;
- greater shedding of low variable cost generation; and
- increased emissions.

In addition, there is a decrease of 25TWh in gross exports and a fall of 23TWh in gross imports. Consequently, net imports in the variant are about 2TWh higher than in the main scenario.

6.1.4.1 Security of supply

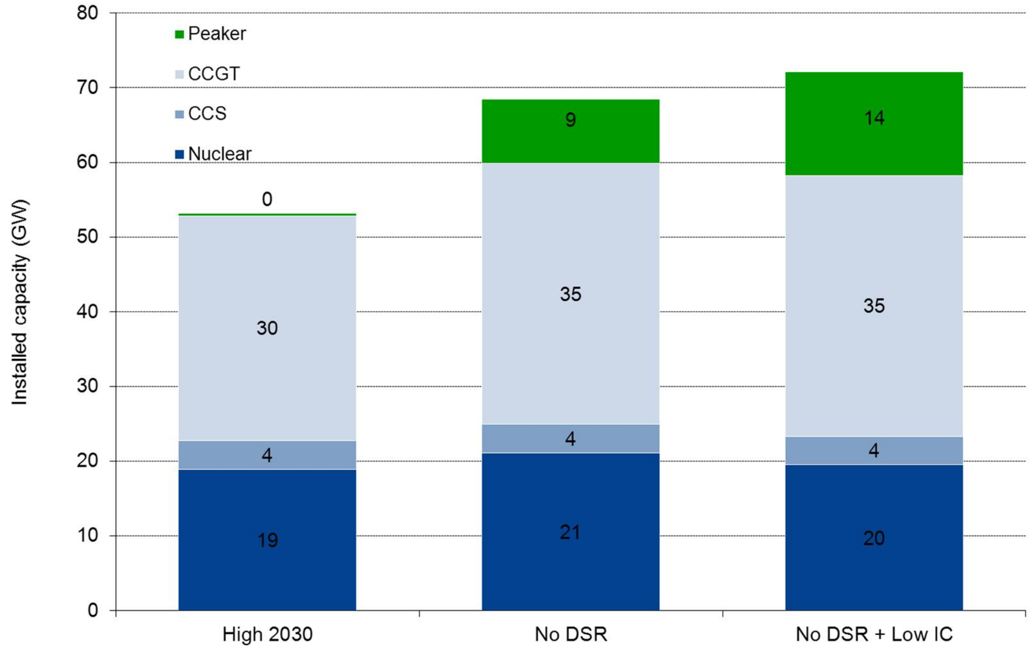
Figure 37 shows the installed non-renewable capacity, by plant type, that is required to meet the security of supply constraint[135] in the High 2030 main scenario, no DSR variant and no DSR and low IC variant.

The chart highlights how import flows act as an imperfect substitute for peaking capacity in the main scenario. Compared to the no DSR variant, a reduction of 9GW in total interconnection capacity leads to a requirement for an additional 5GW of peaking capacity

134 'The challenges of intermittency in North West European power markets (public summary)', Pöyry Management Consulting, March 2011.

135 As proxied by the level of EEU being around 2GWh.

Figure 37 – Installed non-renewable capacity in the 2030 High main scenario, no DSR variant and the no DSR and low IC variant (GW)

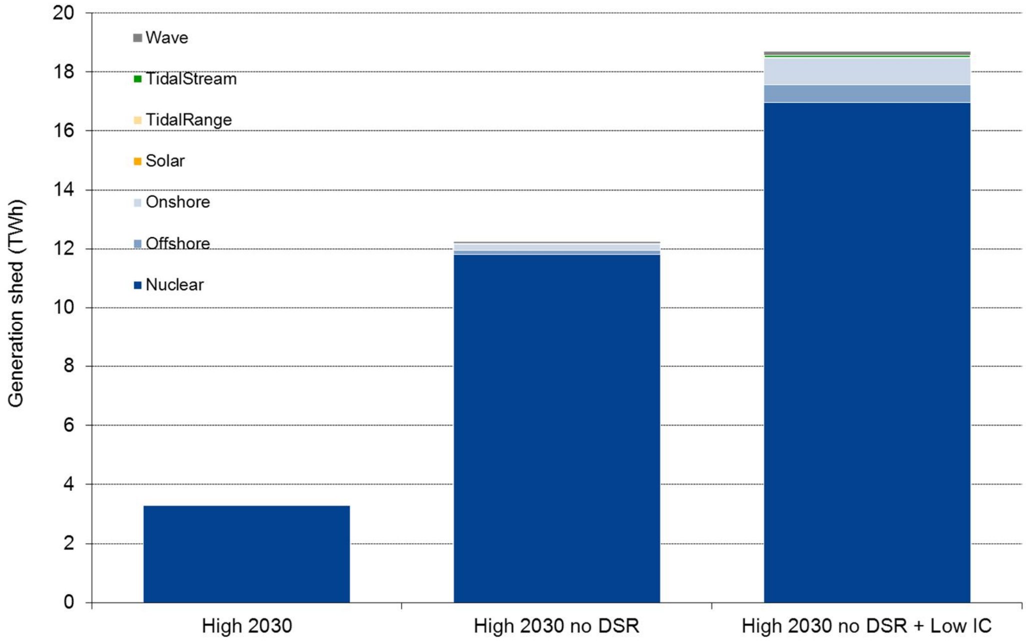


6.1.4.2 Shedding of low variable cost generation

The reduction in interconnection capacity reduces the ability of the system to cope with high levels of output from intermittent renewable generation, because it can no longer export as much during these periods. This is illustrated by Figure 38, which shows the amount of low variable cost generation shed in the High 2030 main scenario, the no DSR variant and the no DSR and low IC variant.

Figure 38 also shows in the no DSR and low IC variant, onshore and offshore wind start to be shed, compared to just nuclear generation in the main scenario and no DSR variant.

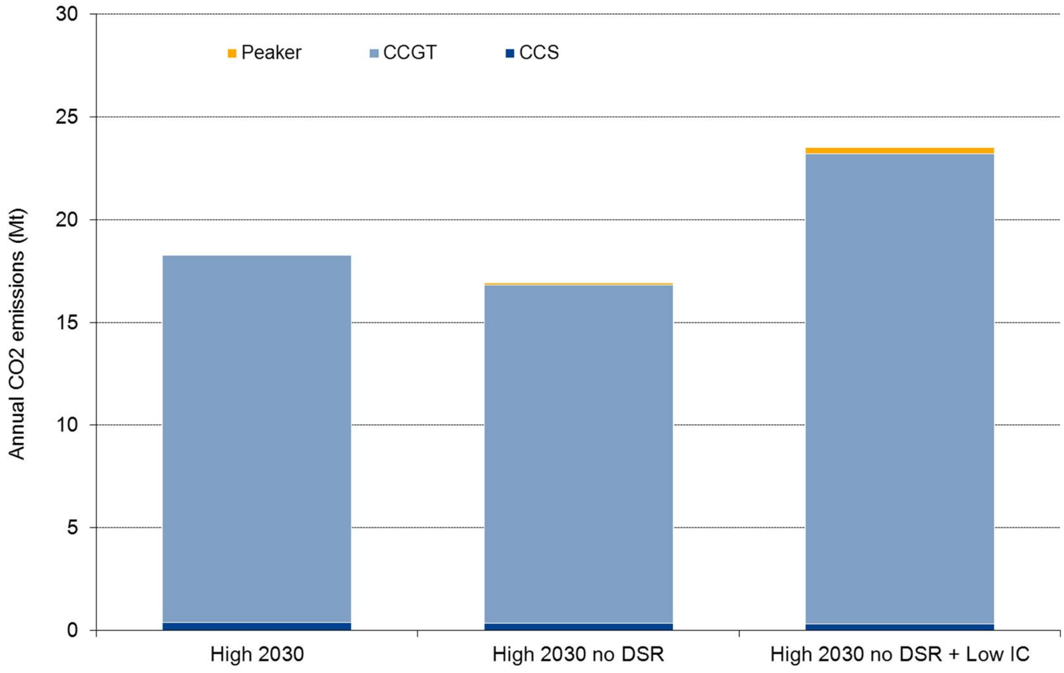
Figure 38 – Shedding of low variable cost generation in the High 2030 main scenario, no DSR variant, and no DSR and low IC variant (TWh)



6.1.4.3 *Decarbonisation*

A reduction in interconnection capacity leads to a marked rise in emissions, especially compared to the no DSR variant. These emissions primarily come from increased output from CCGTs (with a very small contribution from peakers). This result can be seen in Figure 39, which (for High 2030) compares emissions in the main scenario, no DSR variant, and no DSR and low IC variant.

Figure 39 – CO_2 emissions by source in the High 2030 main scenario, no DSR variant and no DSR and low IC variant ($MtCO_2$)[136]



6.1.5 *Spanish solar variant*

The purpose of this variant was to investigate the contribution that increased levels of Spanish solar capacity (supported by high interconnection capacities) could make to helping the GB system accommodate very high levels of renewable deployment.

Therefore, the variant provides insight into the possible impact of moves towards a more integrated European supergrid to help geographical diversity facilitate the deployment of renewables. It can be effectively seen as an alternative way of increasing the diversity of the renewables mix available to GB

The input flows used in the variant draws on the analysis underpinning Pöyry's recent intermittency study for North West Europe[137]. That study notes that there are a number of possible reasons why the impact of high renewable deployment would be less for North West Europe than for GB alone:

- greater geographic spread, so the weather is more likely to average out;
- higher levels of interconnection between countries;
- potentially different patterns to the maritime weather experienced by GB (and Ireland); and

136 To facilitate comparison between the main scenario and the variants, emissions from price-driven fuel switching by hybrid vehicles are not shown in this chart. This flexibility is not available in either the no DSR variant or the no DSR and low IC variant.

137 'The challenges of intermittency in North West European power markets (public summary)', Pöyry Management Consulting, March 2011.

- potential for Scandinavian and Alpine hydro systems to smooth renewable output.

To allow time for the delivery for the assumed levels of solar and interconnection capacity, this variant has been carried out in the Very High scenario in 2050. These are comparable to the 2050 figures in the '80% renewables, 20% DSR' case in the European Climate Foundation (ECF) study[138] on the delivery of high renewables penetration across Europe.

The main impact of this variant on our assessment criteria is a reduction of 5TWh (about 12%) in shedding of low variable cost generation. There is a very small fall in emissions and minor changes in non-renewable capacity.

Increased solar capacity in Spain impacts the GB *Zephyr* model through changes in the pattern of input flows across the interconnectors between GB and North West Europe. Compared to the main scenario, greater Spanish solar capacity leads to increased net imports of 14TWh, which is driven by higher gross imports (10TWh) and lower gross exports (4TWh). This means that around 4GW less offshore wind capacity is need to meet the target level of renewable penetration (80% of total generation in GB) in the variant compared to the main scenario.

6.1.5.1 Security of supply

The increased Spanish solar capacity has limited impact on the level of non-renewable capacity. Although there is a reduction of 1.6GW in installed nuclear capacity, this is offset by the requirement for an extra 1.3GW of peaking capacity to ensure that the variant meets the security of supply constraint.

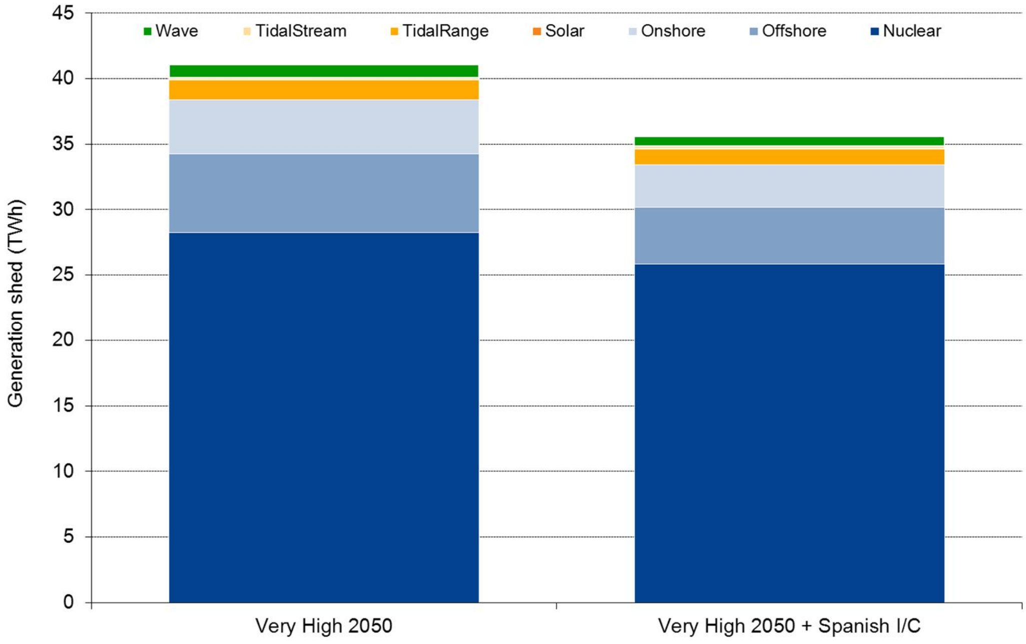
6.1.5.2 Shedding of low variable cost generation

Figure 40 illustrates the impact of increased Spanish solar capacity on the shedding of low variable generation in the Very High 2050 scenario. There is a reduction in about 5TWh in shedding, primarily of nuclear and offshore wind (both of which have lower installed capacity in the variant compared to the main scenario). The decrease in shedding is consistent with with the results of the more diverse renewable mix variant (see Section 6.1.2).

---

138 'Roadmap 2050. Practical guide to a prosperous low-carbon Europe'. European Climate Foundation, 2010.

Figure 40 – Shedding of low variable cost generation in the Very High 2050 main scenario and Spanish solar variant (TWh)



6.1.5.3 Decarbonisation

Increased net imports would be expected to put downward pressure on emissions , and indeed there is a (very small) fall in annual emissions (0.2MtCO_2 p/a). This occurs despite the small increase in peaking plant and reduction in nuclear capacity.

6.1.5.4 Comparison with ECF study

The ECF study contains scenarios for the development of high renewable penetration across Europe[139]. One of the key aspects of these scenarios is the use of a supergrid to provide access to a more diverse renewable mix in terms of technologies and locations. There are comparable levels of interconnection between GB and Europe in our study and in the ECF study.

Our variants suggest that increased access to Spanish solar provides only limited benefits to the GB system based on our assessment criteria. However, this does not necessarily mean we disagree with the ECF findings given the difficulties in comparing the studies.

139 'Roadmap 2050. Practical guide to a prosperous low-carbon Europe'. European Climate Foundation, 2010.

These difficulties are driven by the following factors:

- approach;
  - **The focus of our study (as agreed with the CCC) is on GB,** and therefore we have not developed scenarios for Continental Europe to the same extent as the ECF study.
  - **There may be differences in the assumptions about flexibility available to the system** – e.g. amount and flexibility of demand-side.
- generation mix;
  - In the Very High scenario, **we** already **have more intermittent renewable generation** (167GW for GB) deployed than in the 80% Renewables/20% DSR scenario in the ECF study (152GW for GB and Ireland). At these higher levels of intermittent renewables, the benefits of renewable diversification through a 'supergrid' may be limited.
  - **We have a different non-renewable generation mix in GB** – for example, our Very High scenario has 12GW of nuclear plant on the system in 2050 compared to 4GW in the 80% Renewables/20% DSR scenario in the ECF study.
- results;
  - **The published results from the ECF study do not allow an direct comparison on the results for our assessment criteria** – for example in terms of shedding of low variable cost generation.
  - Published results in the annex of the ECF study give a Europe wide requirement for back-up capacity of 270GW in the Very High, 20% demand response case, which suggests that **significant amounts of peaking capacity is required in both studies**.

6.1.6 Spanish solar and weekly hydrogen storage variant

The purpose of this variant is to explore options to help the system accommodate the extremely high level of renewable deployment in the Max scenario. In this variant, we assume increased levels of Spanish solar capacity (supported by high interconnection capacities) **and** an increase in the duration of hydrogen storage to allow within-week flexibility (as opposed to within-day flexibility in the main scenario).

These changes help the system to accommodate higher levels of renewables with renewable penetration in the variant increasing to 96.5% (of GB generation) compared to 94% in the main scenario (based on the same installed capacity).

Although the system performs better against our assessment criteria in this variant than in the main scenario, they still suggest that overall the system struggles to accommodate these extremely high levels of renewable penetration:

- need for peaking capacity is reduced but remains high at 17GW;
- shedding of low variable cost generation is lower but still high at 109TWh; and
- emissions have fallen but at 11mtCO_2 remain above the 2050 levels in the High and Very High scenarios.

6.1.6.1 Security of supply

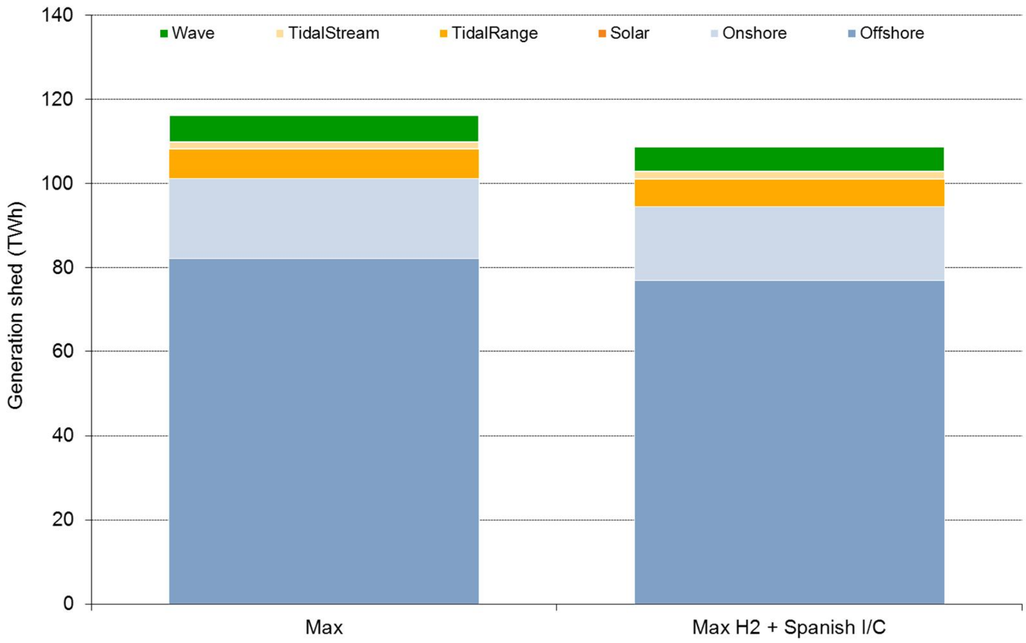
The requirement for peaking capacity is 3GW lower in the variant than in the main scenario. Therefore, the increased Spanish solar and weekly hydrogen storage must help the system to meet periods of high demand (net of intermittent renewable generation). There is also a fall of 4GW in the amount of CCGT capacity installed.

6.1.6.2 Shedding of low variable cost generation

In the main scenario, shedding accounts for around 20% of demand. As shown in Figure 41, shedding is lower in the variant (by 7TWh) than in the main scenario, particularly for offshore wind.

The increased duration of hydrogen storage is likely to be most helpful in reducing shedding (given that the installed renewable capacity is the same in the variant as in the main scenario). This is because it offers an opportunity to shift 'excess' intermittent renewable generation into periods of relatively low intermittent generation in the same week.

Figure 41 – Shedding of low variable cost generation in the Max main scenario and Spanish solar and weekly hydrogen storage variant (TWh)



6.1.6.3 Decarbonisation

In the Max scenario, there is assumed to be no generation from nuclear or CCS. Therefore, all generation comes from renewable and unabated fossil fuel sources. As a result, an increase in level of renewable penetration (from 94% to 96.5%) reduces the amount of generation (and hence emissions) from unabated fossil fuel generation.

Total emission s in the variant are about 5MtCO_2.lower than in the main scenario, which represents a fall of emissions of about a third.

6.1.7 *Provision of reserve and response*

For this study, we have concentrated on using *Zephyr* to understand the impact of high intermittent renewable deployment on an electricity system that is not constrained by requirements for reserve and response. This reflects the time and resource constraints available for this study, given the complexity and uncertainty of modelling reserve and response in a high wind world in 2030.

Currently the provision of frequency response over very short time scales is typically the binding constraint on the GB system because there are limited sources of supply. If no further sources of frequency response are developed, then there could be an additional 2GW of peaking capacity required. The peaking capacity is not needed to provide response itself but to generate when for example, pumped storage is providing response. However, we note that developments on the demand-side are expected to lead to increased potential for frequency response, for example from domestic refrigeration (up to 700MW) and electric vehicles. This would then reduce the peaking capacity build needed to support the provision of response.

Reserve is required over longer timescales, of up to four hours. Increased deployment of wind is expected to lead to higher requirements for reserve to enable the system to cope with errors in wind forecasts at the four hour stage. This highlights the fact that the requirement will be very sensitive to the expected error in wind forecasts over short timescales. Given the high intermittent renewable deployment in the scenarios analysed in this study, it would be expected that there would be significant investment in improving wind forecasting, hence reducing the size of the reserve requirement.

At the same time, there are a large number of potential sources of reserve in the generation sector and increasingly on the demand-side. Therefore, the impact of reserve requirements will be affected by the ability of the system in practice to effectively access these sources of reserve.

6.2 Supporting transmission and distribution infrastructure

In our scenarios, we have assumed that energy networks are reinforced to meet the needs of the electricity system. In this section, we look at the resulting changes needed on the energy transportation networks. We look first at the quantitative impacts on the electricity transmission and distribution network infrastructure, before looking qualitatively at the implications for other energy networks.

We find that both the electricity transmission and distribution networks could need major reinforcement as renewable generation capacity increases to the levels described in our scenarios. Annex A contains estimates of the costs associated with the reinforcement of the transmission and distribution networks in each scenario.

6.2.1 *Electricity transmission network*

The pattern of flows across the electricity network will change as more renewables and other generation, located differently to today, come onto the system. The level of flows between zones will also increase, as renewable resource is predominantly located away from demand centres, and electricity demand is expected to grow significantly particularly between 2030 and 2050.

The combination of these trends means that the transmission network needs to be significantly reinforced to accommodate the new sources of generation. Inadequate network reinforcement will limit the realisation of renewable resources, if renewable electricity cannot be transported from generation site to demand source.

Therefore timely, sufficient investment in the (onshore and offshore) transmission network is essential to ensure renewable generation is accommodated. The projected power flows across key GB transmission network boundaries (as produced by *Zephyr)* are used to determine the amount of transmission network investment required above the baseline. Our baseline for network reinforcement is based on the analysis presented in the National Grid Seven Year Statement[140]. The calculation of the level of investment takes into account the trade-off between investment costs and constraint costs.

Assessing the optimal network configuration for accommodating high levels of renewables was outside the scope of this project. Therefore, our analysis is based on the existing pattern of transfer capacities between zones, and we have not considered any alternative configurations of transmission infrastructure (or alternative siting of renewable resource to alleviate network constraints). The high level of reinforcement needed under this approach illustrates the benefits of considering other types of network configuration to help accommodate high levels of renewable penetration.

For example, the ENSG have proposed 'bootstrapping' as an alternative to the reinforcement of a number of sequential onshore boundaries[141]. Under the bootstrapping approach, offshore HVDC subsea cables are used to transport electricity from the north of GB (where much renewable resource is located) to the south (where most demand is located). This would therefore reduce need to reinforce the onshore transmission networks at each boundary between zones. Under current plans[142], there could be a 2GW subsea link down the west coast of GB (by 2015) and a 1.8GW subsea link down the east coast (by 2018).

We have assumed that offshore farms connect at an onshore hub – i.e. a hub and spoke network rather than point to point. Moreover we assume the hubs are at the points where Round 3 connections are planned to be. In practice, the offshore grid will develop as a result of the interactions between the regulators, Government, onshore TOs and the offshore TOs in a number of different countries, as illustrated by the formation of the Offshore Grid Initiative.

6.2.1.1 Deployment trajectory

Figure 42 summarises the transfer capacities needed between zones in each scenario. This illustrates the scale of reinforcement required after 2020, particularly in the Max scenario.

In the High and Very High scenarios, the total transfer capacity across all boundaries doubles from 50GW in 2020 to around 100GW in 2030. This is a result of the expansion of offshore wind, mainly at Round 3 sites.

A further 50GW of reinforcement is required between 2030 and 2050 in the High scenario. This represents a 50% increase in capacity between 2030 and 2050 (and is also approximately equal to the total boundary capacity in 2020).

---

140 'National Electricity Transmission System Seven Year Statement', National Grid, May 2010.

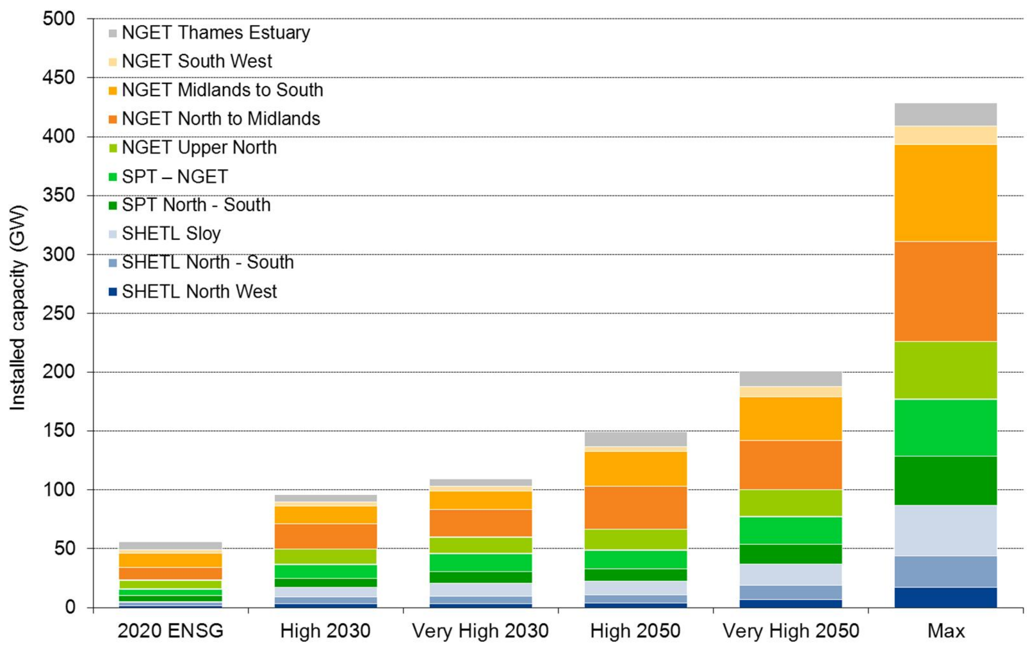
141 'Our Electricity Transmission Network: A Vision for 2020', ENSG, March 2009

142 'Ten-Year Network Development Plan 2010-2020'. ENTSO-E, June 2010.

The requirement for reinforcement after 2030 is even greater in the Very High scenario. Effectively, boundary capacity doubles again between 2030 and 2050 – an increase of 100GW. This is primarily a consequence of greater dependence on offshore wind to deliver high levels of renewable penetration.

Going beyond 80% renewable penetration leads to a very large increase in the requirement for reinforcement – more than double the capacity in the Very High 2050 scenario and an eightfold increase on 2020 ENSG levels. This reflects the replacement of all nuclear and CCS plant (which are assumed to locate closer to demand) with high levels of renewable generation.

Figure 42 – Indicative transmission network boundary capacity across scenarios (GW)



6.2.1.2 *Decision points and milestones*

Our analysis reinforces the point made in a number of other studies about the scale of the challenge for transmission network reinforcement poses[143,144]. This will need developments in a number of key areas including:

- supply chain capacity;
- planning process; and
- financing.

The delivery of this reinforcement will need clear and early signals about what rates are required so that supply chain capacity can be appropriately expanded. For example the availability of skilled labour could be a potential limiting factor. There is relatively little that

143 ‘Ten-Year Network Development Plan 2010-2020’, ENTSO-E, June 2010.

144 ‘European grid study 2030/2050’, Energynautics, January 2011.

could be done to alleviate this in the short term but over time the availability of suitably skilled and experienced people could be built up. Similarly if say transformer or cable manufacturing capacity was a limit again looking say 10 years ahead this could be built up to the required level.

The ability to obtain planning permission is a fundamental determinant of the delivery of expanded transmission capacity. Historically this process has led to long delays in network reinforcement – for example, the upgrade of the Beauly-Denny power line took five years to pass through the planning process (from application to approval), which gives an indication of potential lead times.

A key factor in the ability to finance the required transmission network reinforcement will be the revenue that the transmission companies are allowed to collect under the price control arrangements. The next transmission price control, running from 1 April 2013 to 31 March 2021, will be the first under the RIIO process.

The stated objective of the RIIO process is to encourage network companies to play a full role in the cost-effective delivery of a sustainable energy sector[145]. It is designed to do this through a number of ways:

- rewarding those companies that deliver the networks needed to drive a move to a low carbon energy sector, with companies that do not deliver being penalised;
- ensuring efficient companies are able to attract equity and debt through a transparent and stable approach to financeability; and
- limiting the impact on consumer bills of the significant investment needed in the energy networks.

Greater deployment of distributed generation could also help to reduce the requirement for transmission network reinforcement. While deployment of this type of renewable generation helps, it has limited application and is mainly limited to solar PV (see Section 5.2.3) and micro wind (see Section 5.2.1).

6.2.2 Electricity distribution network

There are two key drivers of the need for reinforcement of the distribution system:

- **increased levels of peak electricity demand** – as a result of continued electrification of demand (e.g. deployment of electric heating, and the roll-out of electric vehicles); and
- **deployment of flexible demand which shifts in response to changes in intermittent renewable generation** (e.g. through smart grids) – this could alleviate the impact of electrification on peak demand but if as renewable deployment grows, it is possible that demand side response will boost peak electricity demand.

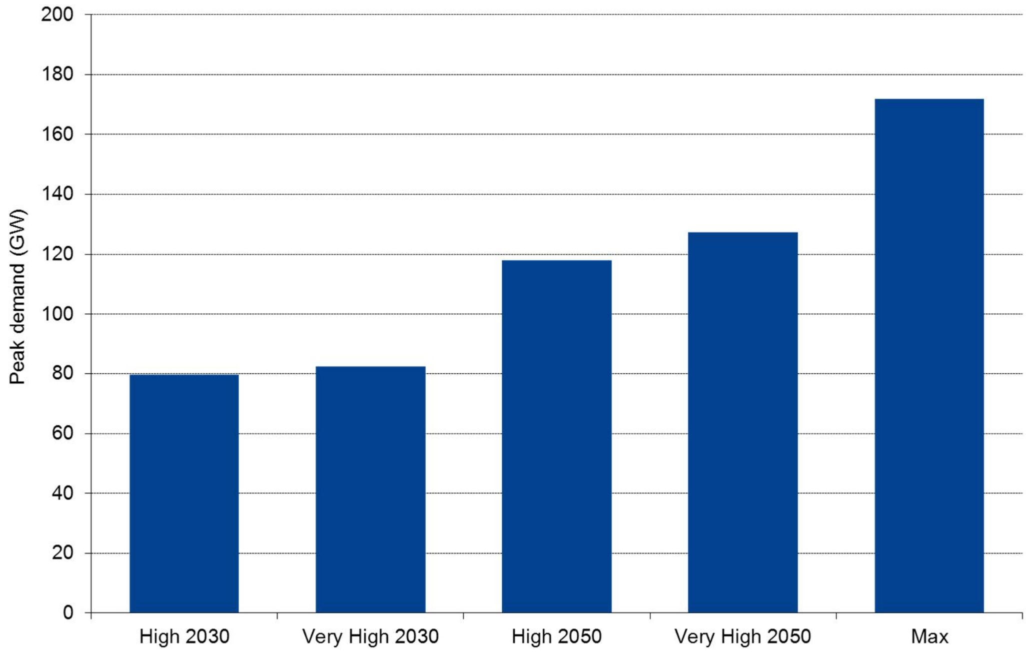
6.2.2.1 Deployment trajectory

Figure 43 shows the distribution network capacity for our scenarios (based on the level of peak demand). Distribution network capacity increases with higher renewable penetration (i.e. compare the High scenario and Very High scenario in the same year) and higher annual demand (i.e. compare Very High 2030 to High 2050).

145 'Decision on strategy for the next transmission price control – RIIO-T1', Ofgem, March 2011.

The demand assumptions are the same in our High and Very High scenarios (for 2030 and 2050 respectively). Therefore, the difference in peak demand in the scenarios is driven by the interaction between flexible demand and intermittent renewable generation.

Figure 43 – Distribution network capacity requirements (GW)



6.2.2.2 Decision points and milestones

Historical network expansion rates have been high – in the 1970's the network build rate was 7% per year. However, people were working with a smaller network, meaning that this may not be a reasonable expectation for the future. We have had discussions with a DNO, who indicated that the current network investment rate is equivalent to 1% of current network capacity including asset replacement. They have indicated that they expect this rate to triple (i.e. to 3%) between 2020 and 2030.

The level of peak demand in 2030 is comparable to the peak demand projected for 2020 in the ENSG studies. An assumption of 2% expansion on a compound basis would be sufficient to build the required capacity in the High and Very High scenarios by 2050.

6.2.3 Other energy networks

Other energy networks can help the electricity system to accommodate high levels of renewables by either:

- providing input fuels for the electricity system (e.g. gas for power generation);
- providing substitute fuels (e.g liquid transport fuel which allows fuel switching by hybrid vehicles); or
- transporting outputs from the electricity system (e.g. CO_2)

6.2.3.1 Input fuel networks

Of the input fuel networks, the gas transmission network is most directly affected by the level of renewable penetration through the impact on the operation of gas plant.

The gas transmission network (and supporting supply infrastructure) must be able to provide high peak deliverability whilst annual throughput is low. This reflects the fact that in all of the scenarios, at least half of gas demand from power generation comes from unabated gas plants running at average load factor below 20%.

The installed capacity of gas plant in the main scenarios is:

- High scenario – 34GW in 2030 and 15GW in 2050;
- Very High scenario – 36GW in 2030 and 19GW in 2050; and
- Max scenario – 34GW.

This compares to the 2009 figure of around 30GW (based on figures from DECC and National Grid). Therefore, there does not appear to be a problem of meeting peak gas demand from power generation in the scenarios, given that it is comparable to current levels and that there is expected to be reduced demand for gas for heating in the low-carbon scenarios.

Therefore, the main challenge will be maintaining a gas system that can deliver the required peak gas demand (given declining indigenous supplies) and operating the gas system flexibly enough. This will raise a number of economic challenges in ensuring the commercial viability of the required infrastructure, similar to those faced in encouraging deployment of peaking generation.

In 2010, Pöyry carried out a detailed quantitative assessment of the impacts of intermittent renewable generation on the gas system in GB[146]. Looking out to 2030, this considered the impact of up to 45GW of wind being deployed in GB (compared to 2030 levels of 59GW in our High scenario, and 100GW in our Very High scenario).

That study concluded that increased volatility of demand (and declining indigenous supplies) will create opportunities for more day-to day and within-day flexibility of supplies, as well as seasonal swing. There are a number of options for the provision of this increased flexibility – new storage facilities, increased interconnection and expanded LNG import capacity. The gas market needs to be able to incentivise adequate and timely delivery of these resources. At the same time, there will be increased requirements for the gas grid to be operated flexibly to manage line-pack to provide within-day flexibility.

Given the much higher levels of wind deployment presented in this report, the challenges for the gas grid will be even greater in these scenarios, particularly around the delivery of flexibility (rather than capacity).

6.2.3.2 Substitute fuel networks

Similarly, the fuel switching by hybrids in the scenario is largely driven by range limitations rather than by high electricity prices. Therefore, the transport fuel network will need to be developed to support the deployment of hybrids as projected by the CCC, with relatively little additional stress in the scenarios from the use of fuel switching to help balance intermittent renewables.

We do not assume that there is any fuel switching capability for heating. Therefore, the operation of gas distribution networks will be much more strongly affected by the

---

146 ‘How wind generation could transform gas markets in Great Britain and Ireland. A multi-client study (public summary)’, Pöyry Energy Consulting, June 2010.

development of alternative heating systems, such as heat pumps, rather than by the level of renewable electricity penetration.

6.2.3.3 Networks for transporting outputs

Section 5.3.2 discusses the development of a CCS network to support the deployment of CCS generation assumed in the scenarios in this study.

6.3 Resource availability

Achieving the levels of renewable generation assumed in our deployment trajectories will require substantial levels of renewable resource to be realised. This is particularly important for offshore wind in the context of our scenarios.

It is difficult to envisage the UK achieving the high levels of renewable generation considered in this study without substantial deployment of offshore wind (both fixed and floating). In all of our main scenarios, wind contributes at least 80% of renewable generation. Even in the diverse renewables mix variant, wind still accounts for about 60% of generation from renewables in 2030 and around 70% of generation from renewables in 2050. Resource availability does affect other technologies, but these are less important in delivering the overall scenarios.

As discussed in Section 5.2.2, studies have suggested that there is a very high level of offshore wind resource available to GB. Therefore, the key question is the extent to which this resource potential can be realised. The concept of a 'resource pyramid' has been developed in other industries (e.g. oil and gas) where estimates of initial recoverable energy decrease as further analysis is carried out. For example, more detailed site surveying can discover subtleties that rule out certain sites or mean that energy production is less than that forecast. The same concept could be applied to renewable energy resources[147]. As a result, the actual energy output from a renewable resource is expected to be lower than initial projections of potential.

The reliance on wind could be decreased in our scenarios by allowing other renewable sources to contribute more. However, there are limits on the extent of this substitution process given the constraints on estimated resource from other renewables. For example, generation from other renewable technologies in level 4 of the DECC pathways is 140TWh from solar and180TWh from marine (tidal range, tidal stream and wave). DECC described level 4 'as the extreme upper end of what is thought to be physically plausible by the most optimistic credible observer'.

This total of 320TWh is 10TWh less than the total generation supplied by wind in the High scenario in 2050 (equivalent to about level 2 of the DECC Pathways). It is also worth noting that this would be the absolute maximum potential for solar and marine energy, while the levels of wind generation assumed in our trajectories are slightly above level 2 of the DECC pathways analysis.

Therefore while there may be scope for deploying some more renewable generation as part of a balanced renewables mix, it is likely that significant amounts of offshore fixed and floating wind will need to be deployed as part of a trajectory to 60% renewables generation or beyond.

147 'A valuation of the UK's offshore renewable energy resource', The Offshore Valuation , 2010.

6.4 Build rate constraints

The time dependent scenarios in this study present the following snapshots of the renewable penetration in 2030 and 2050:

- High scenario – 51% in 2030 and 60% in 2050; and
- Very High scenario – 64% in 2030 and 80% in 2050.

In Chapter 5, we discussed the average annual build rates required to deliver these scenarios[148]. This highlighted the build rate is likely to be most challenging to deliver between 2020 and 2030.

Technology performance, supply chain capability and network readiness are the main technical constraints (in addition to the ones already discussed in this chapter) on the ability of the system to deliver the required build rates.

Although the scope of this study is limited to technical constraints, it is also important to recognise the importance of non-technical constraints. The key non-technical constraints, discussed briefly in the following sections are policy, finance and public opinion

There is some interaction between technical and non-technical constraints – e.g, policy can helps to support technology to move through the RD&D cycle ensuring the delivery of (some of) the estimated resource.

6.4.1 Technology maturity

Figure 44 characterises the three stages of technology maturity with examples of the current position of different technologies deployed in the scenarios. To play a significant role in the energy system in 2030, technologies now in the first stage need to have moved right through the cycle to reach the third stage before 2030.

It remains unclear how quickly some of the technologies will in practice be able to move between the different stages in the cycle. This means that more reliance on deployment of solutions presently seen as prospective, or even emerging, exposes the scenario to greater risks in terms of timing, cost and/or likelihood of delivery.

[148] In practice, build rates are generally non-linear over time, often following a characteristic S-shape.

Figure 44 – Stages of technology maturity

	Prospective	Emerging	Established
Technology status	Pre-demonstration	Demonstration	Commercial
Challenge	Needs to move onto next stage by 2020 for roll out by 2030	Challenging to widely deploy by 2020	Deployment constraints are physical not technological
Technology Examples	CCS, floating offshore wind, wave and tidal stream	Fixed offshore wind	Onshore wind, nuclear, CCGT

6.4.2 Supply chain

The existing capacity of the supply chain and how quickly (and sustainably) the capacity can be increased are two key factors in determining the potential build rate for a technology. A delay in expanding the supply chain capacity (for example to build a new factory or train workers) results in bottlenecks that constrain the annual build rate of the technology.

The development of supply chain capacity will be affected by the policy environment as investors in supply chain capacity must be sure that they stand a good chance of making an adequate return. Therefore, policy signals must provide adequate lead time for expansion of the supply chain.

6.4.3 Network readiness

Section 6.2 discussed the role of energy networks in supporting high levels of renewable deployment. The ability to connect to the electricity network connection has historically raised difficulties for wind generation in GB.

This has resulted in the introduction of Connect and Manage arrangements for access to the electricity transmission network[149]. Under these arrangements, all new generation will be able to apply for an accelerated connection based on the time taken to complete their 'enabling works'. Wider network reinforcement will be carried out after the generation has been connected. which will effectively socialise the costs of constraints resulting from insufficient grid capacity.

Therefore, the key challenge has moved on from facilitating connection of wind generation to ensuring that the grid can accommodate their output (to avoid shedding). Inadequate

149 'Government Response to the technical consultation on the model for improving grid access', DECC, July 2010.

network investment could significantly increase the amount of shedding from the level in our scenarios[150].

If there is insufficient distribution network capacity available, this may constrain the ability of flexible demand to respond to high levels of intermittent renewable generation. This could give rise to conflict between using flexible demand to balance overall supply and demand, and using it to reduce the requirement for distribution network capacity.

6.4.4 Policy

To facilitate delivery of these build rates, it is important for policy makers to ensure that support is tailored to the stage of technology development.

For a prospective or emerging technology, policy needs to incentivise investment in getting technology through the research and development stage. Examples of technologies requiring this type of support are CCS and floating offshore wind. A lack of incentive to invest in emerging or prospective technology could have a knock on effect on the time at which the technology becomes commercially viable and hence a higher build rate would be required to meet a milestone for deployment.

The policy framework (including possible support schemes) for an established technology needs to encourage investment in physical assets (e.g. by altering the perception investors have of risk associated with a potential technology). One example is the rapid expansion of PV in Germany, partly driven by the certainty of returns on investment linked to feed in tariffs.

Key policy issues include:

- Is it likely that support for the technologies will continue over the lifetime of the project; will it be stable or is it likely to change?
- Will support mechanisms be in place and appropriate to incentivise supporting industry?
  - Will the support for technologies remain at the right level – long term horizon for debt and equity is longer than government sitting i.e. 20-25years.
- Will planning regimes remain the same or could they change? As shown in previous studies for the CCC, historically, planning delays have led to delays in onshore wind projects being built in the UK[151]. The result is a perception of higher risk associated with investment in a generation technology.

6.4.5 Financial

An ability to attract private finance is a necessity for most renewable energy projects and associated supply chain businesses. Difficulties in obtaining project finance will lead to slower deployment rates of a technology. To gain funding, energy projects will need to compete successfully for funding against one another and also other industries.

---

150 The shedding shown in each scenario in Chapters 4 and 6 is solely caused by an imbalance between supply and demand, and does not include any shedding that would result from insufficient network capacity to transport electricity between generation and demand.

151 'Timeline for wind generation to 2020 and a set of progress indicators', Pöyry Energy Consulting, July 2009

The source of finance and the risk these debt providers are willing to bear (and the expected rate of return) varies as a technology matures, which will affect the type of finance provider. Venture capital and private equity funds look for higher returns and tend to be interested in demonstration stage technologies with or without subsidies.

High capital requirements of commercial energy projects tend to rule out venture and private equity funds. Therefore in order to attract other sources of funding that are willing to lend the capital (e.g. infrastructure funds), the investment must be seen as less risky. Hence technology must be proven and any government support for the technology must be transparent and long lasting to convince investors that there are acceptable levels of risk.

The rate of return required by the equity provider also changes depending on the perceived risk associated with individual projects. To a certain extent this is influenced by all of the factors discussed in this section of the report, which has the potential to create a negative feedback loop and limit the build rate of individual technologies.

Finally, liquidity of funds is important as most of the low carbon generation technologies are highly capital intensive and, consequently, high levels of capital will be required if the deployment milestones are to be achieved.

6.4.6 Public acceptance

Public acceptance has a significant impact on the ability of projects to gain planning permission and in turn this influences the potential level of resource that can be used for onshore wind generation. It could also limit the number of sites on which new nuclear plant could be sited. As a result this has the potential to delay build rates and could cause milestones to be missed.

The degree of public acceptance will be affected by public perception of environmental and health risks from different technologies, which is likely to change over time particularly in response to events both in GB and in other countries.

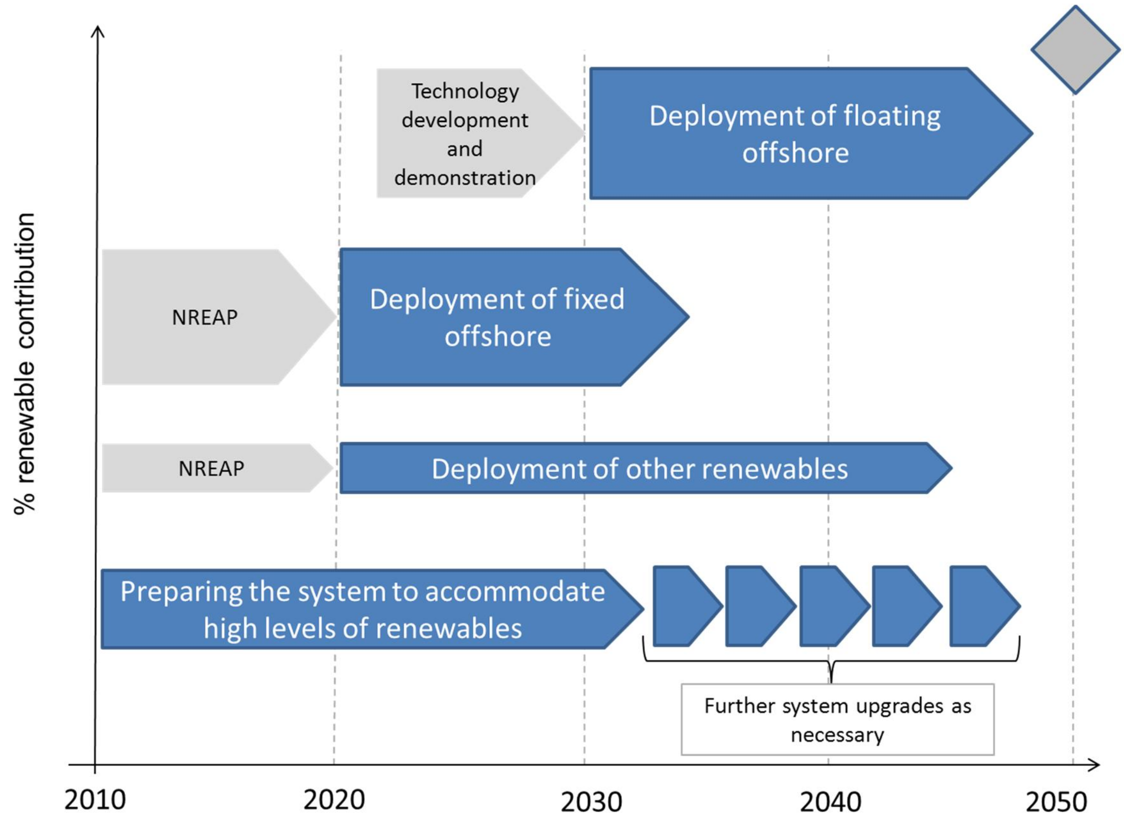
6.5 Lock-in

Lock-in refers to a situation where developments in the near-term mean that a deployment trajectory stops being viable in the timescale under investigation. In this study, the key concern relates to the impact on 2050 deployment levels if the electricity system does not develop as expected in the near-term.

One way of managing the situation would be to put in place a set of metrics (in the form of a roadmap) that allowed progress towards targets to be measured. This means that action could be taken to get back on track where necessary.

Figure 45 describes a stylised trajectory to high levels of renewables penetration, which illustrates the importance of near-term developments to delivery of 2050 deployment levels.

Figure 45 – Steps required to achieve high renewables penetration



The renewable deployment in the scenarios is this study is front-loaded, with build rates before 2030 higher than build rates after 2030. This means that a lower annual build rate to 2030 would not necessarily mean that the 2050 level of renewable deployment could not technically be reached. Rather the issue relates to competition between generation, whereby slower renewable deployment could lead to non-renewable generation being built by 2030 that then restricts the scope for deploying renewables after 2030.

This risk increases with the target level of renewable penetration for 2050 as higher renewable penetration leads to less scope for other plants to play an active role in 2050. For example, if renewable build to 2030 was in line with the High scenario, then there would be just under 20GW of nuclear by 2030. Given the high capital cost and long-lived nature of the nuclear capacity, this may restrict the ability of the system to move towards the Very High scenario (in which there would only be just over 10GW of nuclear in 2050).

Renewable deployment may be delayed for a number of (possibly linked) reasons:

- **slower development in power system flexibility** – for example through delayed electrification, the absence of storage alongside heat pumps, inadequate smart infrastructure, or delayed interconnection expansion;
- **delays in network reinforcement** – particularly transmission (although delayed distribution reinforcement could slow the development of demand-side response);
- **slower renewable technology development** – this is less likely to be a constraint for 2030 than for 2050 (by when new technologies may be required); and
- **failure to deliver required supply chain developments**.

A lack of progress in network reinforcement or upgrades could limit the deployment rate of renewable generation. This is because there would be insufficient infrastructure to cope with the increased flows. Given the lead time for network reinforcement, this illustrates the advantages of pre-emptive investment and therefore possibly releasing anticipatory funding through the price control review process. This must be balanced against the costs to consumers of funding investments that turn out to be less useful than expected.

ANNEX A – COST ESTIMATES

This report has discussed the technical constraints on delivering scenarios with (very) high levels of renewable deployment. As part of this study, we have estimated the costs of resolving some of these potential technical constraints. These costs are presented in Table 9.

In its report on the renewable energy review, the CCC compares these costs to the levelised costs of deploying renewable generation, based on a separate study that it has commissioned.

Any interpretation of the results shown in Table 9 should take into account the following issues:

- the scenarios were not required to be cost-optimising (i.e. delivering optimal level of flexibility for level and mix of renewable deployment);
- Table 9 contains point estimates but in practice there will be uncertainty (and hence a range) around these estimates(as there is for the estimated levelised costs of renewable generation); and
- many of the key issues around the resolution of technical constraints (e.g. through greater flexibility) are not 'cost-driven' - e.g. how can you get household customers to deliver demand side response in practice?

Table 9 – Annualised costs for system flexibility measures (£bn/a)

£bn/a	High 2030	Very High 2030	High 2050	Very High 2050	Max
Interconnection	0.5	0.5	0.7	0.7	1.0
Bulk storage	0.6	0.6	0.6	0.6	0.6
Smart Meters / Grids	2.0	2.0	2.0	2.0	2.0
Transmission	1.1	1.4	2.2	3.1	7.7
Distribution	1.2	1.3	2.7	3.1	4.8
Peaking capacity	0.02	0.1	0.3	0.5	0.5
Total	5.4	5.9	8.5	10.0	16.6

There are three types of cost included in Table 9:

- input assumptions into our analysis – the levels of interconnection, bulk storage and smart meters and grids (based on the deployment trajectories discussed in Sections 3.3.4 and 5.4.1);
- non-generation outputs of the modelling process – transmission and distribution networks (as discussed in Sections 3.4 and 6.2); and
- generation outputs of the modelling process – peaking capacity.

Shedding of low variable cost generation will increase the levelised costs of deploying renewable generation (and hence has not been included in Table 9 as the renewable deployment costs have been calculated in a separate study commissioned by the CCC).

QUALITY AND DOCUMENT CONTROL

Quality control		Report's unique identifier: 2011/232
Role	Name	Date
Author(s):	Gary Keane Oliver Pearce	March 2011
Approved by:	Andrew Nind	March 2011
QC review by:		March 2011

Document control			
Version no.	Unique id.	Principal changes	Date
v1_0	2011/232		March 2011

Pöyry is a global consulting and engineering firm.

Our in-depth expertise extends to the fields of energy, industry, urban & mobility and water & environment.

Pöyry has 7000 experts operating in 50 countries.

Pöyry's net sales in 2009 were EUR 674 million and the company's shares are quoted on NASDAQ OMX Helsinki (Pöyry PLC: POY1V).

Pöyry Energy Consulting is Europe's leading energy consultancy providing strategic, commercial, regulatory and policy advice to Europe's energy markets. The team of 250 energy specialists, located across 15 European offices in 12 countries, offers unparalleled expertise in the rapidly changing energy sector.

Pöyry Management Consulting
King Charles House
Park End Street
Oxford, OX1 1JD
UK

Tel: +44 (0)1865 722660
Fax: +44 (0)1865 722988
www.ilexenergy.com
E-mail: consulting.energy.uk@poyry.com

PÖYRY

www.poyry.com

Pöyry Management Consulting (UK) Ltd, Registered in England No. 2573801
King Charles House, Park End Street, Oxford OX1 1JD, UK