UK GENERATION AND DEMAND SCENARIOS FOR 2030

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F	05.07.11	Updated after peer review
G	19.08.11	Revision of scenarios, further updates in analysis and results
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CONTENTS

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EXECUTIVE SUMMARY

This report presents scenarios for electricity demand and generation for the UK in 2030, to indicate how very high levels of decarbonisation of electricity supply could be achieved with a high fraction of generation from renewable sources and without new-build nuclear, while still retaining a secure electricity system. It is generally accepted that for the UK to meet the emissions reductions deemed essential by 2050, electricity supply must be largely decarbonised by 2030.

Two scenarios for electricity demand in 2030 are developed: the Central demand scenario assumes electricity demand reduction measures in broad agreement with figures produced by DECC and the Committee on Climate Change, and the Ambitious scenario assumes a greater level of demand reduction due principally to very significant lifestyle changes, based on results produced by UKERC. Both scenarios include the effect of significant electrification of heat supply and transport by 2030, with the result that in the Ambitious scenario, annual electricity demand (338 TWh) is similar to today (340 TWh), and is substantially greater in the Central scenario (425 TWh). Therefore the result of substantial demand reduction efforts is that electricity consumption is similar to or greater than today, but also supplies a large part of the energy requirements for transport and heating.

Demand reduction is shown to bring significant benefits. For example, compared to the Central demand scenario, the Ambitious demand scenario reduces the total capital cost of generating capacity and interconnections to other systems by the order of £40 billion.

Due to the large fraction of demand for heat and transport anticipated by 2030 (around 20%), it is shown that the shape of the diurnal (daily) electricity demand curve is likely to show smaller peaks than at present. This is because a large part of the heat load is expected to be 'deferrable' over timescales of hours, particularly as domestic and commercial buildings and hot water systems become better insulated. Almost all the electricity demand for transport is expected to be for electric cars and vans, and much of this demand is also expected to be deferrable within-day. Maximum demand is around 70 GW in the Central scenario and around 56 GW in the Ambitious scenario, compared to 59 GW today. Previous studies have stated concerns that these new electricity loads will make net electricity demand more variable, but it is concluded here that these new loads will increase the amount of deferrable demand. The economics of electricity generation are likely to result in a significant part of this deferrable demand being spread throughout the day, and in particular being deferred into the night-time 'trough', thus reducing variations within the day.

However very little of this demand can be deferred on longer timescales, and so variability between days could increase, compared to the present.

Other studies have also raised concerns about electric heating and transport demands introducing greater levels of uncertainty (as distinct from variability) in electricity demand forecasting, but it is concluded here that these loads are inherently no less predictable than the current mix of electricity loads.

The renewable energy resource available to the UK is shown to be very significantly larger than electricity demand in 2030. The limit on renewable generation capacity is therefore economic, rather than the resource. In particular, with a high fraction of variable renewable generating capacity such as wind, there will be increasing periods where high renewables production coincides with relatively low electricity demand, causing electricity prices to fall. Therefore it becomes progressively harder to justify further expansion of renewables. The point at which this effect becomes significant cannot be estimated at present, because of uncertainty about future fuel prices (particularly gas), carbon prices or

equivalent, future costs of renewables technologies and competing generating technologies, and the interconnection capacity to other systems (to allow exports in times of surplus).

For this reason, it is not credible to try to pick a lowest-cost mix of renewables for the purposes of the study. Instead, a mix is selected based on the generating capacities that could credibly be installed by 2030. This includes a large fraction of onshore and offshore wind. It should be noted that the precise mix of renewables is not crucial to the conclusions of this study, as many of the renewables (wind, wave, tidal, solar) share broadly similar characteristics for resource size, capacity factors and variability. In these respects wind is perhaps the least 'grid-friendly' of the renewables technologies, so a mix with a high proportion of wind represents a conservative approach to the issues of system security.

As an approximation it is assumed here that it is economic to build renewables capacity in the UK approximately equal to UK peak demand plus the existing interconnection capacity. This results in annual electricity production from renewables of around 60% of UK annual electricity demand.

The rates of construction for this level and mix of renewables by 2030 appear achievable, when compared with construction rates suggested in Government studies and by the renewables industries.

Previous work on security of electricity systems with a high fraction of variable renewables have been reviewed, with some new analysis, and it is concluded that the principal problem is coping with an extended period of low renewables output. In northern Europe, the worst case is expected to be a prolonged period of anticyclonic weather, particularly in winter, causing low output from wind generation and wave generation, with low temperatures causing high electricity demand for heating, and low output from run-of-river hydro due to frozen groundwater. These extreme conditions are expected to occur infrequently. The principle of this study is that, if this issue can be resolved, then all other system security issues with variable renewables are also likely to be resolved.

For an extended period of low renewables production, deferrable demands are of little benefit. There are no significant electricity demands that can economically be deferred by several days or weeks. Similarly, there is no energy storage technology currently available within the UK which can store a large part of UK electricity demand for several days and weeks. In fact, there is an argument that the duration of the critical extended period of low renewables production could be defined not by days or weeks, but 'until the deferrable demands and energy storage run out'.

There are two remaining potential solutions to this issue:

- interconnections to neighbouring electricity systems;
- conventional thermal generation kept as a reserve.

Both options are analysed.

From other published work on interconnections, the evidence is that large-scale interconnections to continental Europe and Scandinavia provide very significant benefit. In effect, the problem is no longer the security of the UK system: the problem becomes the security of the combined European electricity systems. In particular, interconnection to Scandinavian hydro resources and solar generation in southern Europe and North Africa provide diversity and storage. New technology makes substantial subsea interconnections to Norway and northern Spain entirely feasible. Interconnection to geothermal power generation in Iceland is also possible.

The use of hydro and pumped-storage capacity would become very significant in this context, and particularly Norwegian hydro for the UK. Current Norwegian hydro reservoir capacity is understood to be of the order of one quarter of UK annual electricity demand, and this could be increased significantly by conversion of existing installations to pumped storage. However there are several other countries with eyes on Norwegian hydro.

The alternative to interconnections, i.e. conventional thermal generation, is assumed here to be largely gas, with Carbon Capture and Storage (CCS) fitted as necessary to meet decarbonisation targets. Gas is the most flexible of the conventional generation technologies, which is beneficial in coping with variable renewables. It is shown that a secure electricity system with high levels of renewable generation can be provided, and (assuming that CCS can be made to work technically and economically) can achieve high levels of decarbonisation. The total UK thermal generation capacity required is significantly less than the capacity today.

'Stretch' scenarios are also considered, whereby the additional interconnection capacity is assumed to permit substantial exports of renewable electricity from the UK, thereby increasing the amount of renewable generation capacity which is economically justified. In these cases, UK renewable generation output reaches around 87% of annual electricity demand.

To summarise: there are several feasible ways to produce a secure electricity system for the UK in 2030, with a high fraction of variable renewables. The most important issues for further investigation are economic, rather than technical.

1 INTRODUCTION

WWF UK has contracted GL Garrad Hassan (GLGH) to produce scenarios for electricity demand and generation in the UK[1] in 2030. The aim of the work is to address the question:

How could the UK meet electricity demand in 2030 and achieve near decarbonisation of the power sector by that same date, without endangering security of supply, relying on new nuclear capacity or the use of unsustainable biomass?

The aim of 'near decarbonisation' is defined as achieving a carbon intensity of electricity generation of no more than 50 gCO_2/kWh.

The work has been structured as follows.

Section 2 develops two scenarios for electricity demand in 2030: the Central and Ambitious demand scenarios.

Section 3 reviews the issues of security of electricity supply in a situation with very high penetration of variable renewables. It is shown that the principle difficulty is dealing with extended periods with very little renewable generation. In the case of the UK, this would be due to extended anticyclonic conditions in winter, with low temperatures and little production from wind, wave or hydro generation. Two solutions are proposed: very extensive interconnection with other electricity systems, and gas-fired electricity generation.

Section 4 analyses the renewable generation capacity that is feasible by 2030. It is shown that on an annual basis, the practicable resource is well in excess of UK electricity demand. It is also shown that the limits to renewable generation capacity are economic rather than technical, in that as penetration increases, there will be increasing periods when electricity prices are low or when supply exceeds demand (for example, during periods of high winds and low demand). Therefore the economics of further renewable generation plant become less attractive. This applies whether renewables are funded through a market mechanism such as ROCs, or some mechanism more directly driven by Government, such as feed-in tariffs.

Within the scope of this work, and because of the great uncertainty about the costs of the renewables technologies in 2030, it is not possible to determine the economic limit on renewables capacity. Therefore total renewables capacity is assumed to be limited to peak UK electricity demand plus the capacity of existing interconnectors to other systems (to take account of exports during periods of surplus). This is a general assumption but is believed to be in the right area.

Within this limit, a mix of renewable generation capacity is developed for each of the Central and Ambitious demand scenarios, which takes account of resource and likely build rates.

[1] Climate change and energy policy is a UK issue. However the electricity system of Northern Ireland is separate from the Great Britain (GB) system, and together with the Republic of Ireland is operated as one electricity system, with only limited connections to the GB system. In this report, electricity demand and generation figures are for the GB system. Therefore there is a small approximation in assuming that these and their related emissions are representative of the UK. However, in comparison with other assumptions and approximations necessary when considering the period to 2030, the effect will be small.

It is shown that the electricity system can be secure, if there is:

- Either a very significant increase in interconnections to other electricity systems. This assumes that the resulting combined electricity system is itself secure.
- Or a substantial quantity of gas-fired generation (though still significantly less than current UK fossil and nuclear generation).

Combinations of these two alternatives are of course possible.

Four scenarios are analysed and compared:

- Electricity system security ensured by gas-fired generation:
  - Central demand scenario (termed A1)
  - Ambitious demand scenario (A2)
- Electricity system security ensured by gas-fired generation plus additional interconnection to other electricity systems:
  - Central demand scenario (termed B1)
  - Ambitious demand scenario (B2)

Sections 5, 6 and 7 consider these options in more detail, and compare the scenarios. Table 11 summarises the main results for the four scenarios.

Two 'Stretch' scenarios (C1, C2) with substantially higher renewable generation capacity are also analysed.

Section 8 summarises the main conclusions.

Additional information and detail is included in Appendices.

2 ELECTRICITY DEMAND SCENARIOS

2.1 Methodology

Estimating electricity demand twenty years into the future is subject to considerable uncertainty. In order to deal with this uncertainty while avoiding making many detailed assumptions, this work defines two separate scenarios for electricity demand:

- A 'Central' scenario based on robust published analysis, chosen to be uncontroversial.
- An 'Ambitious' scenario, i.e.with greater demand reduction than assumed in the Central scenario. The purpose of including this scenario is to show to what extent aggressive demand reduction will reduce the need for electricity generating capacity of all types.

For the Central scenario, publications by and for DECC[2] and CCC[3] have been reviewed.

For the Ambitious scenario, work by UK Energy Research Centre (UKERC) on possible demand reduction given extensive 'lifestyle' changes has been used [13]. These changes are assumed to occur in the forms of energy use most directly controlled by the individual: the residential and transport sectors. Energy use in the home is assumed to be reduced by behavioural changes such as reducing internal temperatures, reducing use of hot water, installing better insulation, and buying low-energy appliances. Transport energy use is assumed to be reduced by many factors, including teleworking, videoconferencing, car clubs, and changes in the social acceptability of flying, large cars, and single-occupancy car journeys.

2.2 Central scenario

2.2.1 Targets

Electricity demand in the UK in 2030 will be driven by emissions reduction and demand reduction targets. Several studies have concluded that, in the timescale to 2030, the electricity sector is one of the areas where progress on emissions reductions can be made most rapidly, at relatively low cost, and with relatively low uncertainties.

No target for emissions or for electricity demand yet exists for 2030. The UK is legally bound to reduce its greenhouse gas emissions in 2050 by at least 80%, compared to the 1990 baseline level of 777 $MTCO_2e$ [4]. Based on this obligation, the CCC published its Fourth Carbon Budget report in December 2010 [7]. This is advice to Government on emissions targets which should be adopted for the period 2023-2027, and policies to reach those targets. As part of the work for this report, the CCC has produced estimates of emissions reductions that should be achieved in 2030. The main conclusions for 2030 are:

[2] UK Government Department of Energy and Climate Change: http://www.decc.gov.uk/

[3] Committee on Climate Change: http://www.theccc.org.uk/. An independent body set up to advise UK Government.

[4] $MTCO_2e$: Million tonnes of CO_2 equivalent. A unit for emissions, which includes emissions other than CO_2 by equating them in terms of their effects on climate change. However for the power sector, the vast majority of the effect is due to CO_2.

- Greenhouse gas emissions should be reduced by 60%, to 310 $MTCO_2e$. To put this in context:
    - The UK target for 2020 should be set at 37% reduction, to 486 MTCO2e per year (average for 2018-2022 carbon budget period [7]).
    - The 2050 target for 80% reduction equates to 155 $MTCO_2e$ per year.
- This 'indicative' target is termed the Domestic Action figure, and should be achieved without making use of international trade in emissions.
- A second 'Global Offer' target of 63% can be used as part of international climate change negotiations. For this, some use of international trade in emissions would be permissible. The UK could offer to shift to this target, if this aids international agreement on climate change.
- The electricity sector should be almost completely decarbonised by 2030 (average emissions intensity figures forecast to be of the order of 50 gCO_2e/kWh[5]).

2.2.2 Annual electricity demand

GLGH has found four studies which provide estimates of electricity demand in 2030:

- DECC 2050 Pathways Analysis report, July 2010, with subsequent revisions in March 2011 [8]. This defines several 'pathways' by which the 2050 target could be achieved. The pathways are presented in order to indicate the range of possible solutions, without decisions on which is preferable. The figure in Table 1 is provided by the detailed spreadsheet which underpins the report, and is available on the same website.
- CCC Fourth Carbon Budget, Dec 2010 [7].
- Pöyry Energy Consulting, "Options for low-carbon power sector flexibility to 2050", Oct 2010 [5]. This was produced for CCC and used as input to the Fourth Carbon Budget. The electricity demand assumptions were provided by CCC.
- Redpoint/Trilemma, "Electricity Market Reform, Analysis of Policy Options", Dec 2010 [11]. Again, demand assumptions were provided by CCC.

These documents are closely related, in that they use similar or identical tools and assumptions. However the electricity demand estimates they produce for 2030 are not identical. They are summarised in Table 1, which is followed by additional detail.

Current UK electricity demand is around 340 TWh per year. The figure for 2010 is 328 TWh [36], but this is assumed to be affected by the economic recession, as explained further in Section 2.3.1.

[5] gCO2e/kWh: grams of CO_2 equivalent per kWh of electricity.

	DECC Pathway Alpha	CCC Low	CCC Med	CCC High	Pöyry CF1	Pöyry CF2	Redpoint Central	Redpoint High
Annual electricity demand [TWh]	519 Note 1	385	425	435	328	399	375	500
Made up of:								
Electric heating [TWh]	100	24	51	51	34	90	-	-
Electric transport [TWh]	41	15	30	43	4	16	-	-
Other electricity demand sectors [TWh]	378	346 Note 2	344 Note 2	341 Note 2	290	293	-	-

Note 1: The DECC figure is understood to include autogeneration, i.e. electricity demand supplied from generation on-site. CCC estimate this as 40 TWh in 2030. This is excluded from the other estimates of annual electricity demand.

Note 2: Calculated by subtraction of other items from Annual Electricity Demand.

Table 1: Comparison of electricity demand estimates for 2030

Note that 'demand' is the electricity delivered to consumers. The total electricity generated will be greater; the difference is principally the losses in the electricity distribution and transmission systems (7% in the DECC figures)[6]. Net imports and exports will also have an effect, though currently this is very small.

In Table 1, electric heating and electric transport have been specifically identified as sub-elements of electricity demand, where known, because:

- Both could be important in responding to variability, especially of renewable generation. This is considered in Task 2.
- Both could substantially affect total electricity demand, in response to policy decisions.

[6] Given the uncertainties in demand estimation in 2030, the relatively small impact of transmission and distribution losses has not been taken into account in subsequent calculations.

Note that ‘electric transport’ is almost entirely due to road transport, principally cars and vans. Electricity consumption by rail is very small in comparison. The ‘Other Electricity Demand Sectors’ category is equivalent to the range of uses of electricity in the present day, principally residential lighting and appliances, commercial or public sector lighting and appliances, and industrial use.

The DECC figures are for Pathway Alpha, which is based on an even spread of effort between the low-carbon generation technologies, energy efficiency measures, and behavioural change. Most of the other pathways show similar total demand figures for 2030.

The CCC analysis distinguishes between Low, Medium and High Abatement scenarios. These scenarios illustrate the effects of increasing levels of effort to reduce emissions.

The Pöyry report considered two cases for 2030, Counterfactual 1 and 2. CF1 assumed a demand mix similar to today’s, with no significant additional electrification of heat or of transport, whereas CF2 assumed reasonable volumes of electric vehicles, and provision of heat using heat pumps.

The Redpoint figures are based on demand assumptions provided by CCC. The difference between the Central and High figures is due to different assumptions regarding heating and transport.

In this report, the CCC Medium case is taken as the Central scenario, for the following reasons:

- Each of these studies appears to use self-consistent assumptions, methodology and analysis, and therefore there is no justification for ‘picking and choosing’ different elements of electricity demand from different studies.

- The CCC report is more recent than the DECC 2050 Pathways report. Also, the CCC report notes that the DECC study is ‘supply-focused’. In particular, the DECC study was intended to show how demand could be satisfactorily met, and did not include demand reduction as an option in any form of optimisation.

- The electricity demand assumptions used in the Pöyry and Redpoint reports are stated to have been provided by CCC.

- The CCC Medium Abatement case is the case where there has been the greatest emphasis on attempting to meet emissions targets at lowest cost and risk, though it is recognised that such judgements are made in the context of substantial uncertainty. In contrast, other studies have been designed to illustrate the range of alternative cases.

As noted earlier, the DECC figures include losses in the distribution and transmission systems (around 7%), and also the effect of autogeneration. Given the relatively small effect compared to the uncertainty in demand estimation in 2030, the Central demand estimate is assumed to include the effect of losses, i.e. it is the net demand.

Note that other work for WWF [10] on electricity demand for cars alone estimates 29 TWh/y in the very demanding ‘Stretch’ scenario. The CCC figure of 30 TWh/y adopted here also includes electric vans. Therefore this is compatible with but less demanding than in [10].

Appendix 1 shows the demand duration curve.

2.2.3 Evolution of electricity demand to 2030

The CCC study predicts a gradual increase in electricity demand between now and 2030, as shown in Figure 1. Applying the same general trend to the Central demand assumption results in a trend as shown in Appendix 8.

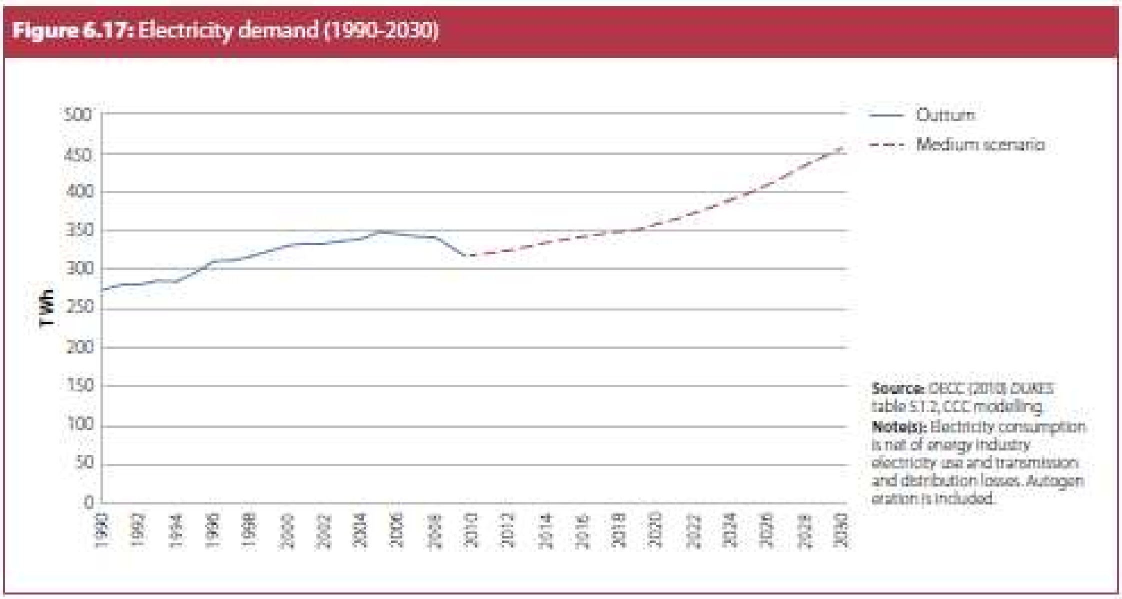

Figure 1: CCC Fourth Carbon Budget estimate of electricity demand growth (from [7])

2.2.4 Diurnal demand curves

Figure 2 shows variation in electricity demand for 2009/10 [20], for days of maximum and minimum demand, and 'typical' days in summer and winter. All were weekdays, except for the day of minimum demand, which was a Sunday. Maximum demand was 58.5 GW and minimum demand was 19.6 GW.

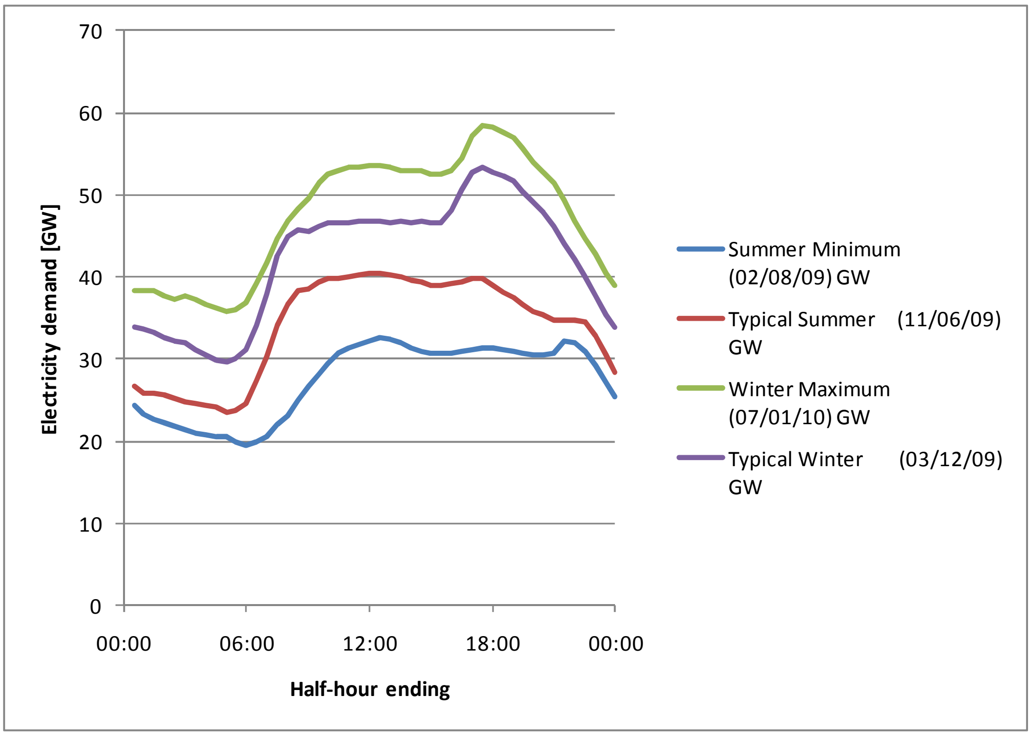

Figure 2: GB daily demand profiles, 2009/10 (from [20])

Figure 3 shows these profiles scaled up for 2030.

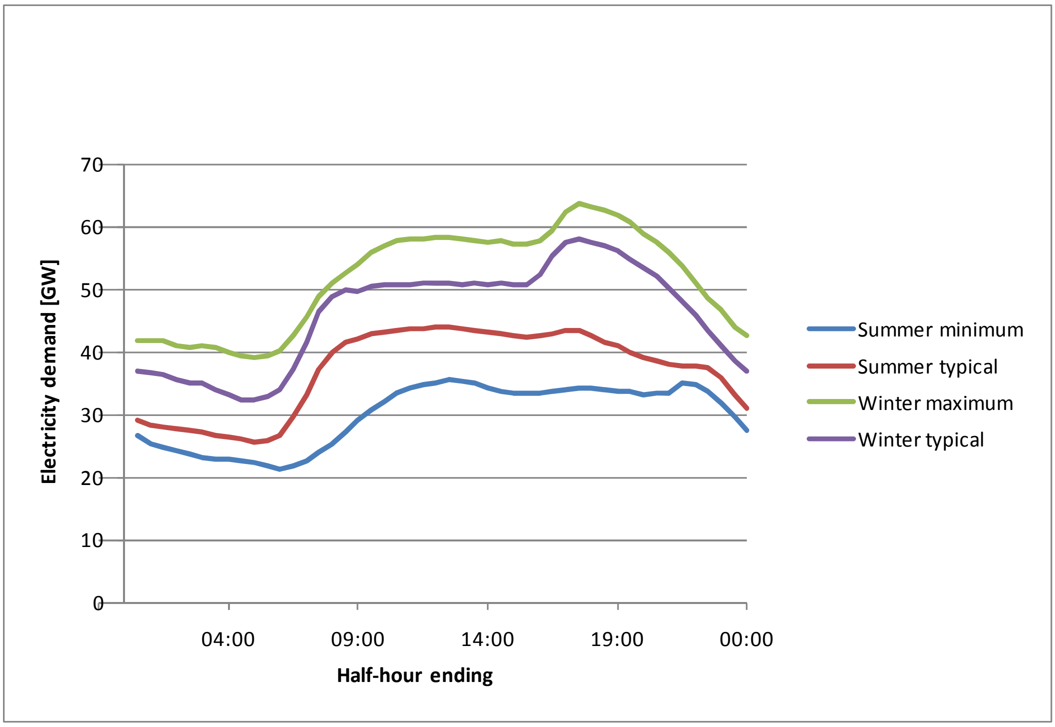

Figure 3: Daily demand profiles for 2030, excluding additional demand management and the effect of electrification of heat and transport

The scaling is done by the ratio of total 2009/10 electricity demand, i.e. the area under the curve in the figures in Appendix 1 (316 TWh), to the ‘Other electricity demand sectors’ figure in the Central demand scenario (CCC Medium case in Table 1, 344 TWh). The resulting profiles are an estimate of daily demand profiles in 2030, excluding electrification of heat and transport, with no demand management beyond what is currently achieved, and assuming no significant changes in relative importance of different load types and consumer behaviour.

Figures 4 and 5 show the effect of simple assumptions about inclusion of the electric heating and electric vehicle charging for the Summer Typical and Winter Typical days in 2030.

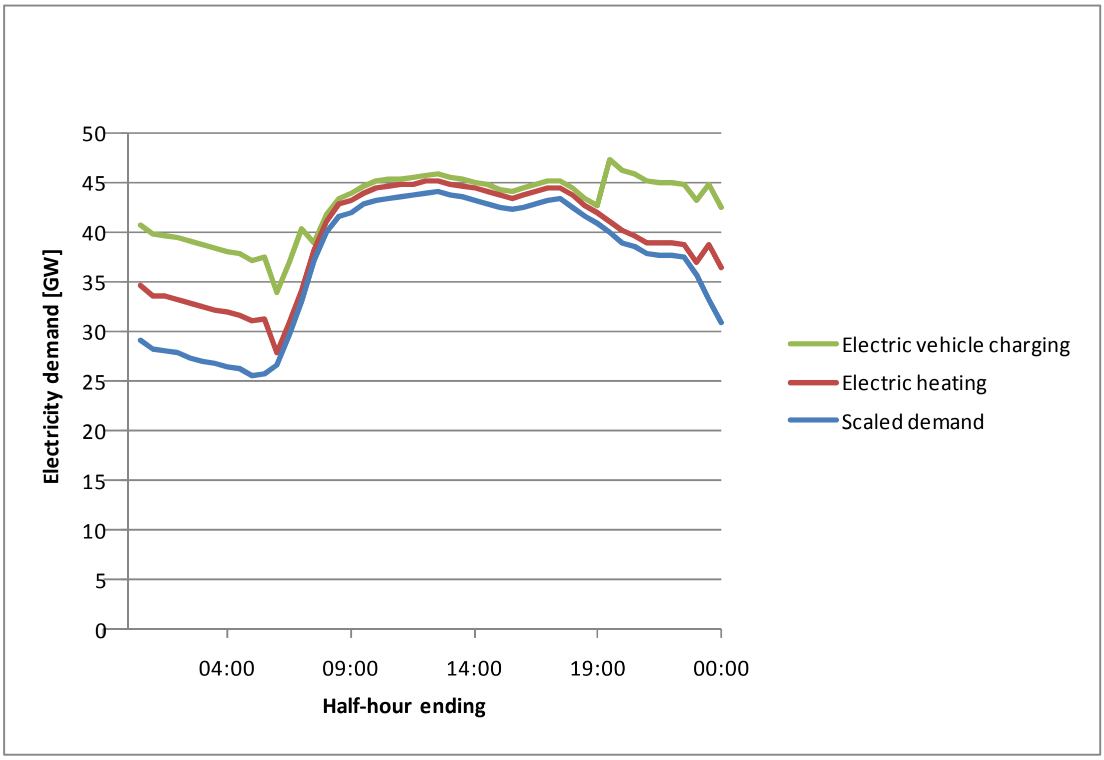

Figure 4: Summer Typical day for 2030, with addition of electric heating and transport demands

For summer, it is assumed that:

- Electric heat demand is 20% of the annual electric heat demand.
- Half of this electric heat demand (principally domestic and commercial hot water in well-insulated tanks) can be scheduled during the night and early morning, with the other half required effectively continuously. The scheduling is most likely achieved by time-of-day tariffs, or possibly direct control by electricity suppliers responding to short-term electricity price signals.
- Electric vehicle charging demand is equally spread between summer and winter.
- 20% of the electric vehicle charging demand occurs during the day (i.e. workplace charging) and the remaining 80% is constrained to the period 19:00 to 07:00, again most likely by price signals.

It is important to note that these assumptions are relatively crude, for simplicity: in reality it is likely that management of these loads will be much more sophisticated. Nevertheless, the assumptions used here are believed to give informative results, without over-optimism. It is unwise to assume that all consumers will respond in an economically rational way at all times, so complete smoothing of peaks cannot be assumed.

The following points are apparent from Figure 4:

- The electric vehicle and heating demand are together able to approximately fill the night-time trough. If managed optimally, this eases the generation scheduling task and improves economics of base-load generation.

- There are critical periods around 6am and 7pm. More intelligent management of these loads (especially the heating load) than is assumed in this simple analysis would allow these peaks and troughs to be smoothed further, although it is not at all clear how important drivers will feel it is to charge their vehicles immediately on returning home.

Note also that forecasting of the electric vehicle and electric heating demand is in principle no more difficult than forecasting of components of electricity demand at present. These loads are affected by a number of factors (such as temperature, hours of darkness, holiday periods, late-night shopping, and sporting events) which are already taken into account in demand forecasting.

It is important to assess the effect on variability of demand. The Fourth Carbon Budget Report [7] notes that:

> *Decarbonisation will also increase the level and the variability of demand, through the electrification of heat and transport. In particular, demand for electricity from the heat sector could add significantly to the need for flexibility by increasing the variability, seasonality and peakiness of electricity demand.*

However, this statement does not take into account the deferrable nature of these loads. It is entirely reasonable to assume that a large part of these loads is deferrable within-day, particularly as buildings become more energy-efficient. Given the very significant economic advantages of smoothing the diurnal demand curve, in particular in future when most generation is likely to be high-capital-cost (i.e. with strong cost advantages in maintaining a high capacity factor), it is highly likely that these loads will be deferred within-day. Therefore within-day variability is likely to be ***reduced.*** There will however be increased variability between days, influenced by factors such as those listed above. This should not make demand significantly less predictable.

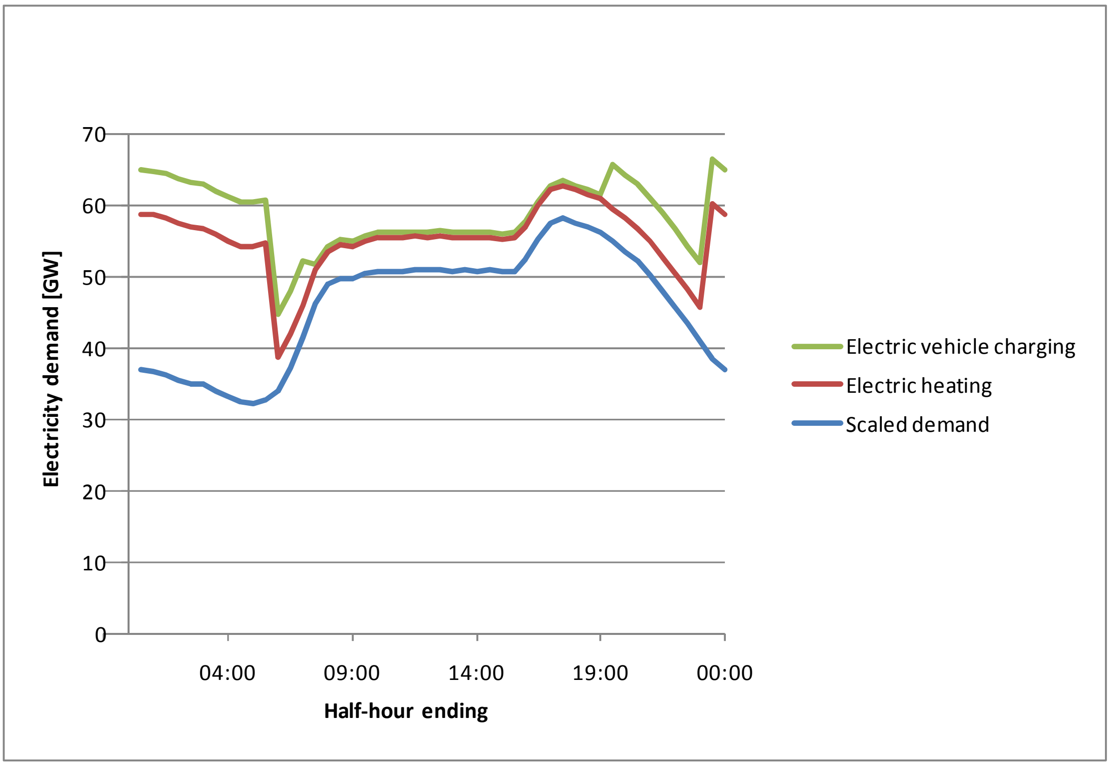

Figure 5: Winter Typical day for 2030, with addition of electric heating and transport demands

For winter, it is assumed that:

- Electric heat demand (space heating and hot water) is 80% of the annual figure.
- Half of this electric heat demand (principally domestic and commercial space heating in well-insulated buildings[7], and hot water in well-insulated tanks) can be scheduled during the night and early morning, with the other half required effectively continuously. For instance, this might include heat pumps used to heat older buildings, where insulation is poor.
- Electric vehicle charging demand is as for summer.

The following points are apparent from Figure 5:

- The assumed electric vehicle and heating demand are more than enough to fill the night-time trough.
- The critical periods around 6am and 6pm are more extreme in winter than in summer. Again, more intelligent management of the EV and heating loads than is assumed in this simple analysis should allow these peaks and troughs to be smoothed considerably. Note that this would result in *less* of the deferrable demand actually having to be deferred into the overnight

[7] Therefore if building insulation levels do not improve substantially, the job of managing the electric heating load becomes harder.

period, i.e. a greater fraction of the electric heating and electric vehicle charging demand would be provided during the day.

2.3 Ambitious scenario

2.3.1 Annual electricity demand

Table 2 below shows the Ambitious demand scenario, and for comparison the Central demand scenario as described above.

The Ambitious demand scenario is based on work by the UK Energy Research Centre [13]. As noted earlier, this included a scenario (termed LS-LC) where the effects of significant lifestyle changes were assumed, beyond the changes likely to be caused by policy decisions. Total electricity consumption in this scenario is 338 TWh, which is 80% of the total for the Central scenario. This appears to be a reasonable estimate to take as 'ambitious'.

To provide a point of comparison, UK annual primary energy demand (i.e. all energy, not just electricity) in the Ambitious demand scenario[8] is 1767 TWh [13], compared to around 2500 TWh today [8].

Table 2 also shows 36 TWh for electric transport in the Ambitious scenario. This is taken direct from the UKERC LS-LC scenario. In contrast to the other sectors, this is higher than in the Central scenario. This is because a very substantial shift to electric transport is assumed.

There is no figure in the UKERC results which directly summates all electric heating loads, so in Table 2 this is assumed here also to scale linearly. This means that there is less electric heating than in the Central demand scenario, which should be read as meaning that electrification of heating loads has been accompanied by substantial reduction in total heating requirements.

The figure for 'Other' is obtained from the total by subtraction.

Present-day electricity demand is around 340 TWh/y [7]. The latest figure is 328 TWh/y for 2010 [36], but this is affected by the recession. There may well be a 'bounce back' after the recession, so 340 TWh is a more robust figure. Therefore the Central demand scenario figure of 344 TWh in 2030 indicates no significant reduction in 'other' demand sectors. The CCC Fourth Budget report makes it clear that this is the result of the combination of anticipated demand reduction measures, and increases in population, number of households, and individual incomes.

[8] The CCC analysis behind the Central demand scenario does not include an equivalent figure for comparison.

	Central demand scenario (CCC Medium)	Ambitious demand scenario	Factor
Annual electricity demand [TWh]	425	338	0.80
Made up of:			
Electric heating [TWh]	51	41	0.80
Electric transport [TWh]	30	36	1.20
Other electricity demand sectors [TWh]	344	261	0.76

Table 2: Derivation of 'Ambitious' demand scenario for 2030[9]

The load duration curve associated with this scenario is shown in Appendix 1.

2.3.2 Evolution of electricity demand to 2030

As for the Central demand scenario, the trend to 2030 is shown in Appendix 8.

2.3.3 Diurnal demand curves

Figures 6, 7 and 8 are similar to Figures 3, 4, and 5, for the Ambitious demand scenario.

As before, Figure 6 shows an estimate of daily demand profiles in 2030, excluding electrification of heat and transport, and assuming no significant changes in relative importance of different load types and consumer behaviour. Figures 7 and 8 show the effect of the simple assumptions about inclusion of the electric heating and electric vehicle charging for the Summer Typical and Winter Typical days in 2030 (as defined for the Central demand scenario).

Conclusions are similar to those discussed under the Central demand scenario. However, note that the relative size of the deferrable demand in winter is now greater, so that simple assumptions about scheduling of these loads actually lead to peak demand occurring overnight. Clearly this is counter-productive, and in reality less of the deferrable demand will be deferred into the overnight period, leaving a smoother diurnal demand curve than is shown in Figure 8.

[9] As noted in Section 2.2, these estimates are assumed to include the effect of losses in transmission and distribution systems.

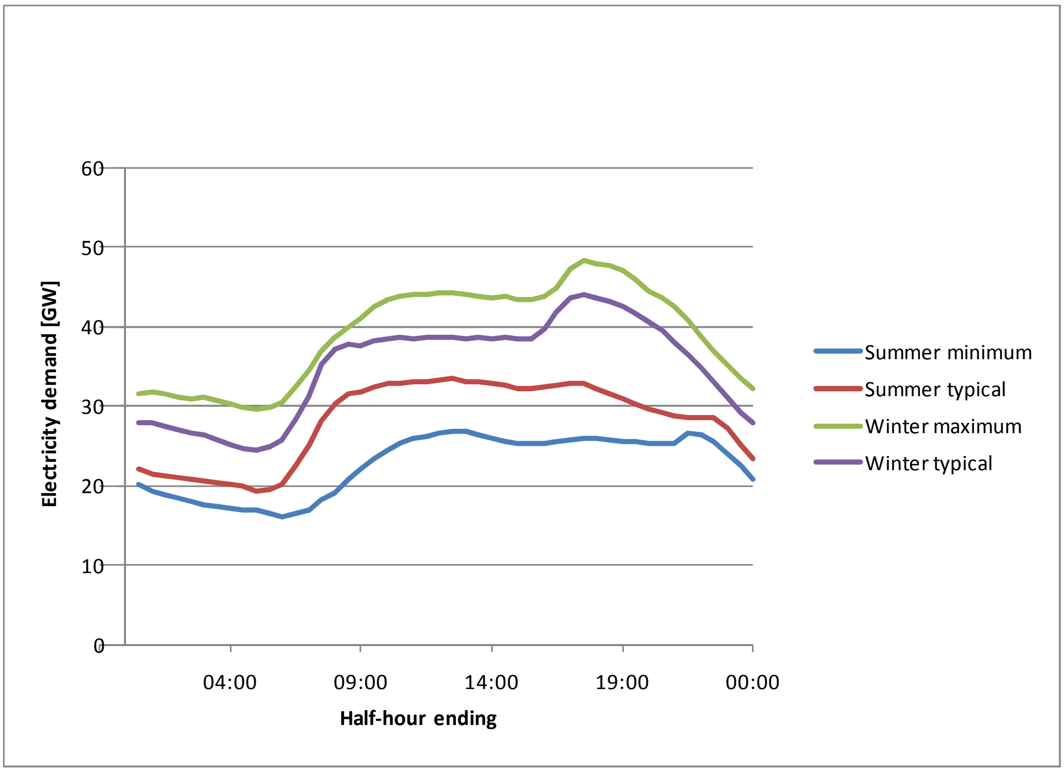

Figure 6: Daily demand profiles for 2030, excluding effect of electrification of heat and transport

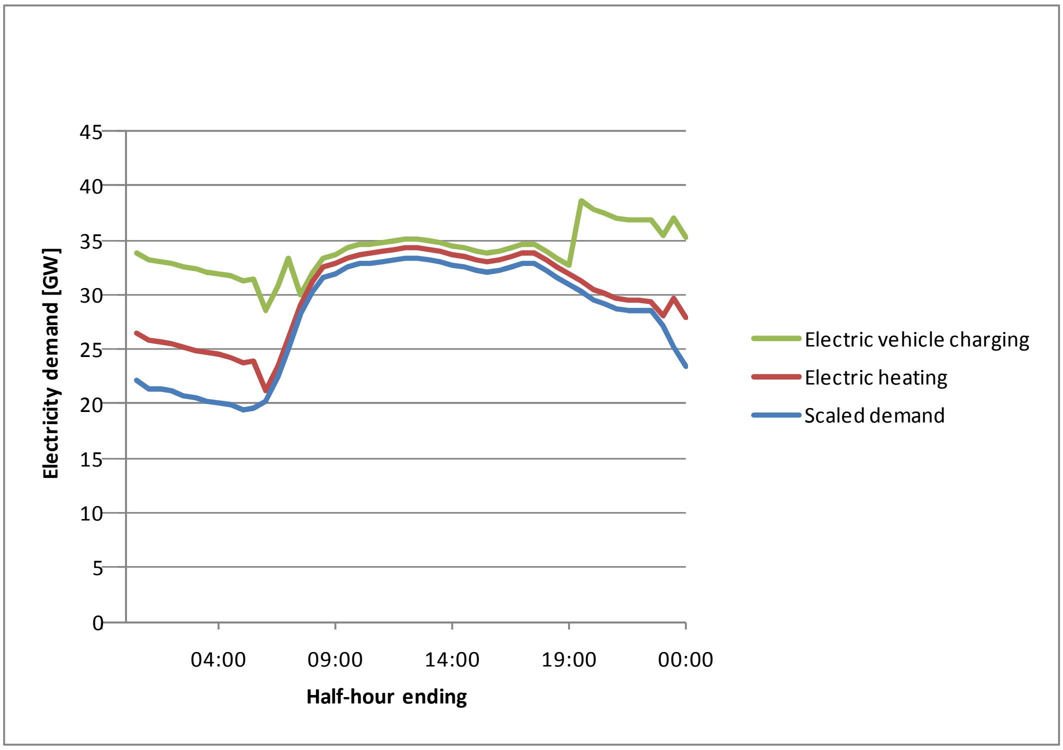

Figure 7: Summer Typical day for 2030, with addition of electric heating and transport demands

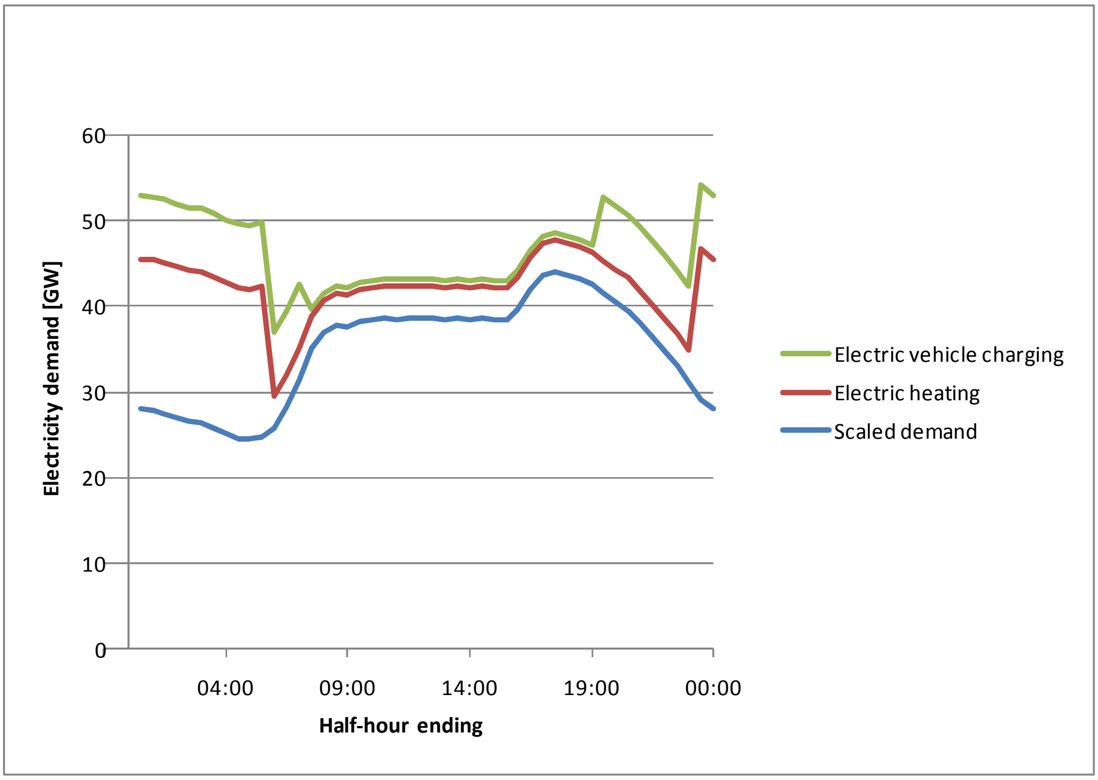

Figure 8: Winter Typical day for 2030, with addition of electric heating and transport demands

2.4 Conclusions

The heating and transport loads become very significant. It is very likely that much of these loads can be deferred within-day, particularly as buildings become better insulated. Economics are likely to drive much of these loads into the night-time trough, and the magnitudes are such that a substantial flattening of the diurnal demand profile is possible, i.e. a substantial reduction in within-day variation. The very simple assumptions used here about the deferral of the heating and electric vehicle demands highlight that the most problematic times are likely to be early morning and early evening. More intelligent scheduling of these loads should remove the short-duration peaks in demand shown here. The ability to defer these loads provides a useful tool in helping to adapt demand patterns to the intermittency of some renewables.

As will be seen later, the estimated peak demand has a very strong effect on the difficulty and the costs of ensuring a secure electricity system. Therefore management of electricity loads, especially heat during the winter, is an important area for detailed study. If this cannot be achieved, it may be sensible to retain gas for providing ‘peak heat’, either in conventional central heating or in district heating systems [35].

Deferral of these loads may be achieved by time-of-day pricing, or by responses to short-term wholesale electricity price signals.

It is important to note that, although heating and electric vehicle charging loads are variable, they are driven by known factors, and in principle should be as forecastable as electricity demand is at present.

Although within-day variability is reduced by these deferrable loads, variability between days will not be reduced. In fact it is likely to increase in percentage terms, principally because heating demand becomes a bigger fraction of total demand, and is sensitive to air temperature, wind speed and cloud cover.

3 SYSTEM SECURITY

3.1 General

The term 'security' in this context is a measure of the robustness of the electricity system, i.e. its reliability in the face of failures in the transmission system, or non-availability of generators. The transmission system is the network of high-voltage overhead lines and underground cables which transmit power from areas with a concentration of generators to the major load centres, principally cities. Distribution systems then take the power at lower voltage and distribute it to individual consumers[10]. Although distribution systems are more extensive and are the greatest contributor to loss of supply to customers, 'security' in this context does not include the distribution systems. This is because individual failures in distribution systems affect only small numbers of consumers for relatively short periods, and do not compromise the integrity of the whole system.

Detailed analyses of the security of electricity systems assuming high penetration of variable and intermittent renewables (principally wind) have been undertaken for several years now, with increasing levels of detail. A review is provided in [23].

The main conclusions of these and similar studies [5][9][12][14] can be summarised for UK conditions, as follows.

Variations in output power

Variability of output power from renewables, particularly wind, is often cited as a problem for power system operators. The discussion below is specifically for wind, but similar arguments will apply for wave and solar PV.

On timescales of seconds, the output power from a wind farm of several wind turbines varies very little, due to the averaging of wind speed across the rotor disk of each turbine, and across all turbines on the site. Even the most extreme changes are very small.

This smoothing effect is more pronounced for variable-speed turbines (now the dominant technology), because the variations in aerodynamic torque input to the rotor are further smoothed by acceleration and deceleration of the large rotor inertia, resulting in smaller variations in torque input to the generator.

On timescales of minutes or tens of minutes, the variation in output power from a single wind farm can be larger, but the variability of the summated output of geographically-distributed wind generation is very small

On timescales of around 30 minutes or an hour, reported worst-case changes for the summated output power of wind farms distributed across an area the size of the average European nation are no greater than around 20% of the installed wind generation capacity. Figure 9 shows a frequency distribution

[10] In a future with a large amount of microgeneration, it is likely that power will occasionally or maybe even often flow back 'up' from distribution systems into the transmission system. This does not affect the fundamental points of this report.

for two years of data collected by National Grid for around half the wind generation capacity in GB[11] [24]. The change in output from one half-hour period to the next has been analysed. On 35 occasions in two years (i.e. 0.1% of the time) the change exceeded 10% of installed wind capacity. The most extreme recorded change is 22% in half an hour.

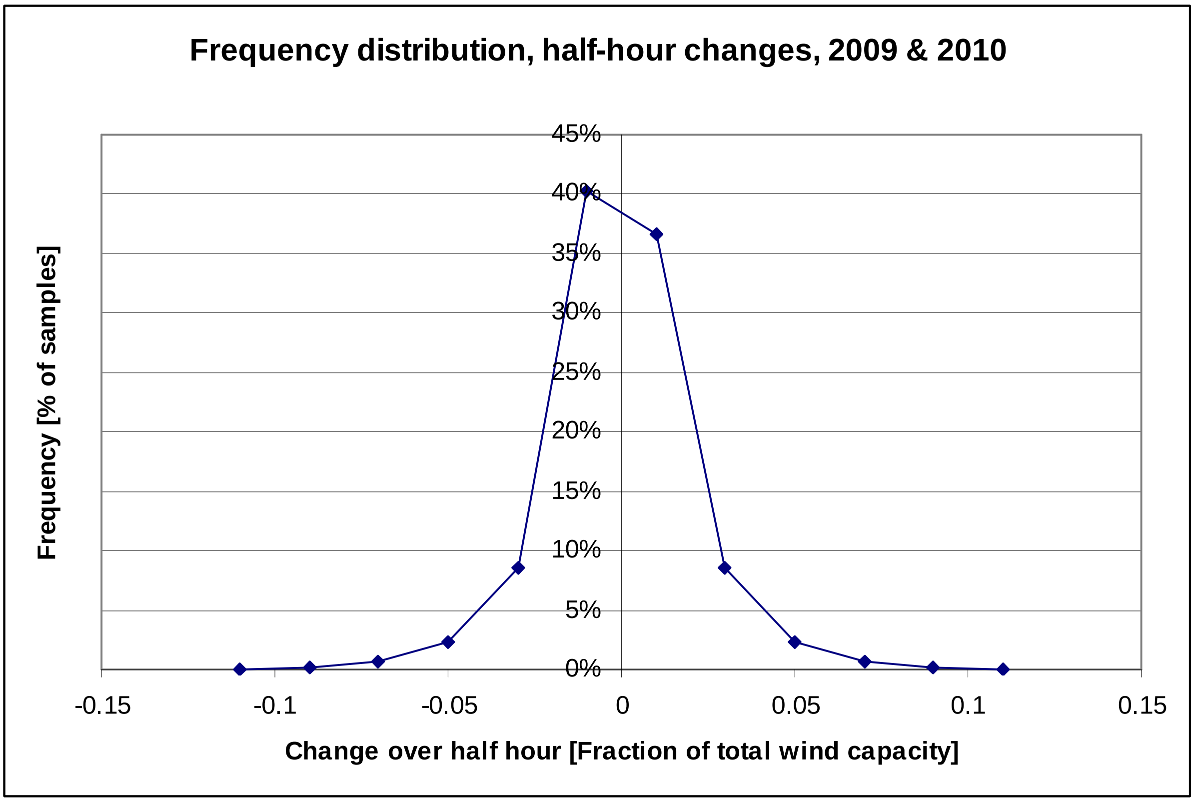

Figure 9: Frequency distribution of half-hour changes in summated output power from UK wind farms

On timescales of 12 or 24 hours, total wind production can vary from zero to full power. The most extreme cases are when wind farms are operating at full power in high winds, and the wind speed increases further, to the point where the wind turbines shut down to protect against high mechanical loads. Experience from Denmark is that changes in wind speed such as this are due to weather systems, which take several hours to move across areas the size of European countries [25], so the most extreme summated effect seen by a national electricity system is still only of the order of 20% per hour.

These extreme events can be forecasted (see below), or more correctly, periods when there is a risk of extreme events can be forecasted. This allows the effects to be mitigated, as discussed below.

[11] In fact, most of the wind farms represented in this dataset are the larger projects located in Scotland, so the results will not capture the full effect of geographical smoothing across all wind generation in GB. Therefore the results are likely to over-estimate the most extreme rates of change.

Even including mitigation options, the net effect of the variability of wind (and other similar renewables) increases the requirement for system balancing services. The costs of this have been analysed [23]: they need to be taken into account, but are not large, even at high penetrations of variable renewables.

Forecasting

Forecasting of power production from multiple wind farms is well-established and is used by system operators and electricity traders.

Mean errors for a few hours ahead are of the order of a few percent, becoming greater for longer time horizons [29].

Periods where rapid changes in wind output are likely can be foreseen, and the wind production can be gradually reduced in advance in order to mitigate the rapid changes. This causes loss of production and therefore economic losses. Such events are expected to occur very infrequently when wind penetration is low or moderate. As wind generating capacity becomes very high, the changes in wind production become greater in MW terms, and so there will be more events where it is necessary to reduce wind production to mitigate rapid changes.

Note also that for rapid rises in wind production, the effect can be mitigated without reliance on forecasting, by imposing a ‘ramp rate limit’ on wind generators (again implying some economic losses). If necessary, this function can readily be implemented in wind farm controllers.

Sudden failures

Sudden failure of a complete wind farm due to a fault on the wind farm electrical system is as feasible as the sudden loss of a large conventional generator for the same reason.

However a large conventional generator also has other non-electrical failure modes which can cause the loss of all generation suddenly. The unit size of wind turbines is very much smaller than the unit size of conventional generating plant: of the order of 5 MW, compared to the order of 500 MW. Therefore ***individual wind turbine unit failure makes fewer demands on the system***.

‘Fault ride-through’

As wind penetration has increased, system operators have become concerned about the possibility of a single event causing multiple wind farms to shut down at the same time. The main concern is a major fault on the transmission system, which results in the voltage over a wide area of the transmission system suddenly reducing substantially until the fault is cleared, a period of several hundred milliseconds. Such a voltage dip could cause wind farms over the entire area to shut down suddenly. Conventional power stations use synchronous generators, which are less affected. The system operators therefore defined ‘fault ride-through’ criteria for wind turbines, and modern wind turbine technology can now meet these criteria satisfactorily.

Other factors which might cause simultaneous failures of wind farms (for example, sudden frequency drop) are well-defined, and wind turbines are able to respond as well as, or in some cases better than, conventional generators [26].

Transmission system
The majority of wind generation in GB, currently and in the future, will be located in areas without a concentration of existing conventional generators. An appreciable fraction of this will also be distant from the major load centres. Therefore there will be a need for a more extensive transmission system, which might increase the vulnerability to disturbances. However, in this work it is assumed that this is dealt with by normal transmission planning practices, and the transmission system can be made as reliable as the current system.

Interconnections
Interconnection to other systems is seen as very useful in dealing with variability of renewables, but is not the only solution [1]. This is considered in more detail in Section 5.

3.2 Implications for this study

The effects of wind generation have been discussed above. Other variable renewables (tidal, wave, solar PV) have been less studied, but the effects are expected to be the same or less marked than for wind. For example, the output of distributed wave generation is expected to vary more slowly than the output of distributed wind generation. Tidal generation is variable but extremely predictable. Biomass and geothermal are of course entirely dispatchable. Therefore, the net output of a mixture of renewable generation technologies will be less variable than for wind alone. In this respect, assuming that the future renewables mix is 'all wind' is a conservative assumption.

The conclusion for system operators, from the issues discussed above, is that in ***all respects bar two, intermittent renewable generation is (or can be made to be) no different in its effects on system security than conventional generation.*** The two principal differences are:

- Variations in total output on timescales of half an hour and longer, which can be forecasted adequately a few hours ahead, but which the system operator cannot effectively influence[12].

- Output is set by the wind, not by contracts or market prices.

There have been extensive studies, on the GB system and on other systems, on the effects of these two factors. This often involves detailed modelling of the additional costs imposed on the electricity system in dealing effectively with these two issues, by time-series modelling of the behaviour of actors in an electricity market, using real wind and electricity demand data, and including the effect of randomised failure events. Within the scope of this study it is not feasible to repeat this kind of analysis. Instead, this work is based on the fundamental point that the preferred options for dealing with the second of these issues are also likely to deal with the first.

In particular, the requirement to be able to survive an extended period (several weeks) of extreme cold weather in winter, due to an anticyclone, during which time the output of wind, wave and run-of-river hydro will be close to zero, means that deferrable demand alone will not be a solution. 'Deferrable

[12] Given the administrative powers and the communications equipment, system operators can limit the output power of individual wind farms or groups of wind farms very effectively and rapidly, in order to limit rapid changes in output. However the economic cost of the lost production would be substantial, so this is in effect a measure of last resort.

demand' includes control of domestic, commercial and industrial space and water heating, refrigeration, and electric vehicle charging. This can be a very useful tool for moving demand within-day (for example, charging of electric vehicles overnight, or electric heating of domestic hot water in the early morning). However very little of this demand can be deferred by more than a day, and certainly not for a period of a week or more. Similarly, any storage technology to overcome this problem needs storage capacity of several days or weeks.

The ECF 2050 roadmap for Europe [9] identified three main solutions to the problem of variability of a high penetration of renewables:

- Greater interconnection between countries, including possible connection to large solar installations in southern Europe or North Africa.
- 'Backup' generation
- Energy storage.

The ECF study found that greater interconnection brought the greatest benefits at the lowest cost.

The current study investigates two means of providing a secure electricity system with high penetration of variable renewables. Based on current knowledge, these two means are very likely to be the most attractive for the UK:

- Interconnection;
- Gas-fired backup generation.

Both the above options will cope with extended cold calm periods, and both can also adjust output over a wide range on timescales of half an hour or slower.

It should be noted that in reality, the economic optimum is likely to include some mixture of interconnection, storage, backup generation and other measures.

3.3 Energy storage

Energy storage (beyond pumped-storage hydro) is not considered here, because storage technologies capable of large-scale energy storage for several days or weeks are not yet commercially available.

As noted earlier, within-day deferrable demand (particularly heat[13], and electric vehicle charging) is expected to become very important. This is likely to offer 'storage' benefits at lowest cost, but will not provide much benefit for periods beyond a day. In effect, this deferrable demand provides benefits very similar to pumped-storage hydro.

[13] This does not assume installation of heat stores in domestic and commercial buildings, except for normal hot-water supply. Well-insulated buildings have significant thermal mass which provides some thermal storage.

Developments in longer-term storage would offer significant benefits in reducing generation capacity and improving security, but the technologies currently proposed suffer from high costs and significant energy losses. Further R&D in this area could offer significant benefits.

3.4 Other required functions

It is assumed here that the renewable generation will, by 2030, have the capability to provide all necessary ancillary functions required for operation of an electricity system. These functions are currently provided principally by conventional generation.

This statement is already true for hydro and geothermal generation, which can use conventional synchronous generators directly.

Modern wind and PV technology uses power-electronic converters to interface with the electricity system, and these can provide all voltage control and fault current functions. The main remaining issues are:

- Frequency response: the ability to increase and decrease output automatically in response to changes in system frequency, in order to contribute to automatic control of frequency.
- Inertia: conventional electrical machines are synchronous, and so imbalances in generation and demand result in energy flowing into or out of all the spinning masses (inertias) connected to the system. This contributes significantly to the response to sudden disturbances.

Both of these functions are already available to some extent from wind generation at present[14], and there is no reason why these cannot be provided adequately in future, at acceptable cost. The same is true for all renewables generation with rotating generators.

PV devices and possibly some wave devices may not be able to provide the equivalent of inertia. However these are expected to be a relatively small part of total renewable generation, and it is not necessary for all generation in operation to be able to provide this function.

It is concluded here that it will in future not be necessary to run conventional generators simply to provide these services.

The rates of change in output of wind generation have been discussed above. As noted in Section 2, electricity demand in 2030 is expected to contain a large element of deferrable demand, which can be used to reduce the variability of net demand (i.e. demand less renewables production) which has to be met by interconnection and gas-fired generation.

[14] The dominant wind technology is variable-speed using power electronic converters. These do not provide the inherent contribution to inertia of synchronous generators. However it is established that the same function can in principle be provided using control functions implemented in the turbine controller.

4 RENEWABLE GENERATION IN 2030

4.1 Meeting the target

This section defines the mix of renewable generation necessary to achieve effective de-carbonisation of UK electricity supply in 2030. The aim is for the carbon intensity of electricity generation to be no more than 50 gCO_2/kWh in 2030, as recommended by the Committee on Climate Change [7].

Note that this methodology does not attempt to investigate whether this mix of renewables is the 'best' way to achieve decarbonisation, as compared to solutions including proportions of thermal generation with CCS, nuclear, and 'unsustainable' biomass: it seeks to demonstrate that this is possible, and 'what it might look like'.

4.2 Renewable resource

Estimates of the total 'practicable' UK renewable energy resource for electricity generation have been made by DECC and CCC [7] [8]. The term 'practicable' is important, as it includes assumptions about costs and public acceptance, for which there are significant uncertainties, some of which are noted by DECC and CCC. However, in the context of this study, these figures are the best available and are generally adequate for this purpose. The resource is summarised in Appendix 2, with comments on applicability for this study.

Note that the DECC 2050 Pathways analysis [8] attempts to show the effects of differing levels of effort in implementing changes, from Level 1 (no significant effort beyond that already proposed) to Level 4 (a 'heroic' level of effort). Full definitions are given in Appendix 4.

Appendix 2 shows, not surprisingly, that ***the total 'practicable' energy resource is enormous compared to electricity demand: almost four times the Central demand scenario***. Over half of this is offshore wind.

Table 3 sets out the renewable energy resources assumed in this study to be available for development in 2030. Subsequent sections estimate how much of this may actually be developed. The decisions behind the mix of renewables assumed in Table 3 have taken account of the substantial uncertainties in the size of resource for some of the technologies, and their relative costs.

Further detail is in Appendix 2.

Resource	Capacity [GW]	Output [TWh/y]
Offshore wind	82	310
Onshore wind	30	80
Tidal stream	2	7
Tidal range	4	8
Wave	3	7
Hydro (run of river)	3	10
Hydro (reservoir)	1	3
Solar PV	18	15
Geothermal	5	35
Biomass	12	95
Total: dispatchable	22	141
Total: non-dispatchable	138	429
Total	160	570

Table 3: Renewable energy resources assumed available in 2030

The table shows the dominance of wind, especially offshore. Compared to this, uncertainties in the development of the wave, tidal stream, tidal range and hydro resources by 2030 are almost irrelevant. In other words, Table 3 is robust to different assumptions for resource development by 2030, except for wind.

Solar PV is an exception, as the resource could turn out to be larger than onshore wind, and there are indications of possible substantial reductions in cost. A conservative estimate is used here.

Biomass is also an exception: the resource could in principle be as large, in energy terms, as onshore wind. But given the scarcity of sustainable biomass (biomass that meets sustainability criteria) it is assumed here that the use of bio-energy is first of all prioritized for those sectors of the economy where there are fewer alternatives such as aviation, shipping, and high grade heat for heavy industry.

4.3 Achieving a secure electricity system

Section 2 developed a Central demand scenario for UK electricity demand of 425 TWh/y.

Comparison with Table 3 above shows that, ***under these assumptions, there is sufficient renewable resource available over the year to more than meet this annual electricity demand***. It is also seen that as wind forms the majority of the renewable resource, there will be some positive matching with demand on a seasonal basis. However there will be periods with a surplus of renewable generation over demand, and periods with a substantial deficit. As noted earlier, this study considers options of interconnection and gas generation to meet this difficulty.

The target is to achieve a carbon intensity of at most 50 g/kWh in 2030. If electricity demand is 425 TWh, this implies maximum permissible carbon emissions from the electricity sector of 21,250,000 tonnes of carbon dioxide. For comparison purposes, the equivalent output of alternative forms of fossil generation are shown in Appendix 3. This shows, as expected, that unabated coal cannot provide any meaningful contribution. Unabated gas could provide around 10 – 13 % of annual electricity demand without breaching the carbon intensity target, assuming all other generation has zero emissions, and gas with CCS could meet 100% without breaching the target.

For the CCS options, the Fourth Carbon Budget report [7] shows that the unit costs of electricity for all options for gas and coal generation with CCS are estimated to be roughly equivalent, within the uncertainties in the future prices for fuel and emissions, and for CCS technology. As Appendix 3 shows that gas with CCS allows significantly more conventional generation without breaching the emissions target, as gas options are likely to be more flexible in operation than coal options, and as the unit costs of the gas options are less sensitive to low load factors than coal options, coal with CCS is ignored as an option here.

The conclusion is that substantial volumes of gas CCS generation could in principle be used in conjunction with renewables, without breaching the emissions target for 2030. This of course assumes that CCS for gas-fired generation can be made to work at commercial scale well before 2030.

Clearly however, there are benefits in prioritising renewables to minimise the amount of abated gas-fired generation; improving energy security, minimising use of finite CO_2 reservoir capacity, minimising the environmental effects of gas extraction and carbon dioxide storage, limiting the required build rates for CCS facilities during the 2020s, and limiting the consequences should CCS fail to deliver the expected benefits in the quantities or timescale anticipated. Depending on how costs develop in future, there may also be cost savings.

The question therefore becomes:

> ***Given the available renewable generation shown in Table 3, how much interconnection capacity or gas generation capacity is required to ensure the UK electricity system is robust and secure at all times?***

This can be approached through the issue of security of supply. Full evaluation of security of supply issues is complex and requires probabilistic analysis. However a simple yet robust evaluation of the question can be achieved by considering in particular the case of peak electricity demand in conjunction with sustained cold anticyclonic conditions in winter. As noted earlier, if a secure electricity system can be maintained in these infrequent and extreme conditions, other challenges of dealing with high penetration of intermittent renewables are also likely to be satisfied. Recent DECC work [8] includes a 'stress test' where cold low-wind conditions are assumed for 5 days. In this study, a more severe test is applied: in effect, ***these conditions are assumed to persist for long enough that all forms of deferrable demand and conventional energy storage can make no substantial contribution.***

4.3.1 Central demand scenario

From Section 2, it is seen that electricity demand is likely to be considerably smoother over the day than it is now. However there will be substantial variation over the year. Figure 5 shows that in the typical winter day, demand in 2030 may peak around 65 GW, and from Figure 3 the peak winter day may be 5 GW higher, i.e around 70 GW. Although heating demand in 2030 is expected to be more sensitive to low temperatures than at present, there will be some scope for deferring this demand at peak periods. Therefore 5 GW is considered a reasonable estimate.

Note that the renewable resources in Table 3 are substantially greater than peak demand (160 GW compared to 70 GW). Therefore it will be very difficult economically to justify building all this renewable generation capacity by 2030. Determining how much will get built, and which technologies, requires detailed economic modelling beyond the scope of this study. Such economic modelling would in any case be subject to substantial uncertainties about costs and other factors.

Therefore in this work, the renewables capacity defined in Table 3 has been scaled pro-rata[15], so that the total renewables capacity assumed to be constructed approximately equals the peak demand plus the interconnector capacity[16]. This is an estimation of the amount of renewables capacity that might prove economic in 2030.

The result of the above assumptions is shown in Table 4, with further detail in Appendix 7.

Resource	Capacity [GW]	Contribution at peak demand (in anticyclonic conditions) [GW]	Notes
Peak demand		70	
Required capacity of generation plus interconnectors		77	Includes plant margin of 10% above peak demand, to cover for plant failures. Plant margin is from [27].
Total renewables	73.6	13	See Appendix 7. Total is dominated by biomass, wind and geothermal.
Pumped storage	5	5	GLGH assumption. Current UK capacity is 2.8 GW. A further 0.6 to 1.2 GW is actively under development by SSE. Further developments are likely to 2030.
Contribution from existing interconnectors	3	3	Existing interconnectors are 2 GW to France, 1 GW to Netherlands [17].
Gas generation or additional interconnection capacity required for system security	56	56	By subtraction, so that the output of renewables, pumped storage, interconnections and gas meets the required capacity including plant margin.

Table 4: Meeting peak demand during anticyclonic conditions: Central demand scenario

[15] Except for reservoir hydro, as scaling pro-rata is likely to reduce capacity below that already existing.
[16] This assumes that around times of high renewables production, the interconnections are used for export: this clearly assumes a market for the electricity at the other end of the interconnector.

Note that Table 4 assumes substantial use of the available biomass, for electricity generation (~5 GW). If instead the available sustainable biomass resource is used to meet other needs, the combined interconnector capacity or gas-fired generation capacity required increases to around 61 GW.

The figure for interconnection capacity or gas-fired generation capacity can be compared with the current UK total for fossil and nuclear generating capacity of around 76 GW, i.e. substantially more than will be needed in 2030. A forecast for future gas generating capacity is provided by CCC in [7]. Current capacity is 24 GW. Substantial additional gas generation capacity is currently proposed, consented or under construction, and based on this CCC assumes that there could be 35 to 40 GW of gas capacity by 2020. This includes assumptions about retiral rates of existing plant. The outcome will of course depend on electricity market conditions, gas prices and carbon prices. No forecast for 2030 is stated, but clearly a further 15 to 20 GW by 2030 is a feasible build rate. In [7], it is also shown that around 20 GW of the existing capacity is suitable for the addition of CCS plants.

Table 4 assumes no substantial increase in pumped storage (PS) capacity in the UK, beyond that already existing and proposed. This is partly because of concern about availability of sites, but also because the storage capacity of PS is typically of the order of a few tens of hours at full output. As the diurnal demand curve is expected to be fairly flat in 2030, due to deferrable loads (as shown earlier), there is only limited opportunity to recharge PS generation during daily troughs in demand. Therefore during extended anticyclonic conditions, the contribution of PS would be limited, even if further PS capacity was built. Another way to look at this is to recognise that PS and deferrable demand serve approximately the same functions. This is an area that will require detailed investigation as further experience is gained with high penetrations of intermittent renewables.

4.3.2 Ambitious demand scenario

The same process as for the Central demand scenario is applied in Table 5. The annual electricity demand in this scenario is 338 TWh. Peak demand (from Figures 6 and 8, and assuming more sophisticated management of the deferrable demands than is shown in Figure 8) is likely to be around 51 GW on the typical winter day, and around 56 GW on the winter peak.

Resource	Capacity [GW]	Contribution at peak demand (in anticyclonic conditions) [GW]	Notes
Peak demand		56	
Required capacity of generation plus interconnection		62	Includes plant margin of 10% above peak demand, to cover for plant failures. Plant margin is from [27].
Total renewables	59	10	See Appendix 7. Total is dominated by biomass, wind and geothermal.
Pumped storage	5	5	GLGH assumption. Current UK capacity is 2.8 GW. A further 0.6 to 1.2 GW is actively under development by SSE. Further developments are likely to 2030.
Contribution from existing interconnectors	3	3	Existing interconnectors are 2 GW to France, 1 GW to Netherlands [17].
Gas generation or additional interconnection capacity required for system security	44	44	By subtraction, so that the output of renewables, pumped storage, interconnections and gas meets the required capacity including plant margin.

Table 5: Meeting peak demand during anticyclonic conditions: Ambitious demand scenario

Adding 10% plant margin produces a total requirement of 62 GW. Following the same process as in Table 4 results in a requirement for additional interconnector capacity or gas-fired generation of 44 GW, or 48 GW if biomass is not used for electricity generation.

4.4 Costs of renewables

For both scenarios, indicative costs for the renewables capacities listed in Tables 4 and 5 are shown in Table 6. The costs are taken from a recent report for DECC [18], except where noted. The case used here assumes a discount rate of 10% and project start in 2017 (Case 5 in the DECC study), as this includes some learning effects and is more appropriate for generation capacity running in 2030 than other cases studied.

It must be emphasised that these costs are only indicative. For a full understanding of the factors affecting cost estimates and the wide ranges possible, see [18]. Particular care must be taken when comparing costs from different studies.

Technology	Cost of electricity [£/MWh]	Capital cost [£/MW]	Notes
Offshore wind	142	£2.0 m	Arup [37] anticipates very significant capital cost reduction: the figure here is the median for large projects (Round 3), real cost assuming financing in 2025. There is very significant uncertainty in future offshore wind costs, so the out-turn could be very much higher or lower than indicated here.
Onshore wind	86.3	£1.5 m	GLGH considers this reasonable for 2030. Agrees closely with Arup median figures [37].
Tidal stream	140-250 (200 assumed)	£5 m	From [7] and [28] (GLGH calculations). Very large uncertainty on capital costs (more than factor of 2). Broad agreement with [37].
Tidal range	275	£3.4 m	From [7] and [19], for Severn Barrage, at social discount rate (3.5%) and including optimism bias. Wide range (£2.7 – 4 m/MW). In [37], range is 2.0 to 3.5 m/MW. Cost of Electricity figure is taken from [37].
Wave	180-250 (210 assumed)	£4 m	From [7] and [28] (GLGH calculations). Very large uncertainty on capital costs (more than factor of 2). Broad agreement with [37].
Hydro (run of river)	80	£4.8 m	Capital cost data from [37], median case, real costs for project financed in 2025. Cost of electricity figure from same source, average for projects <5 MW and >5 MW.
Hydro (reservoir)	80	£4.8 m	As above: insufficient data to distinguish.
Solar PV	164	£1.6 m	From [37], average of projects <50 kW and >50 kW. Real costs for projects financed in 2025.
Geothermal	Uncertain (150 assumed)	£6.5 m	Industry source suggests £5.5 - £7.5 m/MW for projects under consideration in the UK, but very little real experience on which to base costs. Highly uncertain and site-dependent. Broad agreement with [37].
Biomass	130	£2.6 m	Capital cost is for small (50 MW) electricity-only wood pellet plant: agrees with [37]. No reliable costs for larger plant. Landfill gas and sewage gas are significantly cheaper, but resource is limited. Co-firing in large combustion plants is also significantly cheaper. Cost of Electricity is taken from [37], real costs for projects financed in 2025.

Table 6: Indicative costs of renewables

Based on Table 6, and using the renewables capacities defined above, renewables production and indicative capital costs are shown in Table 7. Note that for the bulk of the renewables capacity included in this calculation, the costs used are the real costs for projects financed in 2025.

Electricity demand scenario	**Central**	**Ambitious**
Total renewables capacity	73.6 GW	59 GW
Total renewables production (details in Appendix 5)	261 TWh/y	210 TWh/y
Production as fraction of total annual electricity demand	61%	62%
Total capital cost	£165 Bn	£133 Bn

Table 7: Indicative capital costs for renewables capacity

Note that capital costs are only part of the picture: Operation and Maintenance costs and other recurring costs need to be included to get a true picture, though of course for all but biomass there are no fuel costs. For several of the renewables, future O&M costs are as subject to wide uncertainty as the capital costs. As noted above, transmission system reinforcement costs are not included. Indicative capital costs are given here only to give some idea of the scale of potential investment required.

There are some very important caveats to be noted for the simple process outlined above:

- From current understandings of costs and risks, the proportions of renewables capacities used in the tables above are likely to overestimate the capacities of wave, tidal, solar and possibly geothermal actually installed, and underestimate the capacities of onshore and offshore wind. The out-turn in 2030 will depend heavily on relative costs of each technology, and as noted for many of these technologies the forecasts of future costs are extremely uncertain at this stage. Other important factors are technology-specific support mechanisms such as Feed-in Tariffs, and R&D support.

- The total capacity of renewables developed in the tables above is set to approximately equal maximum electricity demand plus existing interconnector capacity. This is considered a reasonable upper limit. If this capacity were installed, there would be times of the year when total renewables output would exceed UK electricity demand, causing very low electricity prices (depending on how the market was structured, prices could drop well before this point was reached). Interconnection capacity and deferrable demand will mitigate this, as would a breakthrough in energy storage technology, but not fully. It is not clear how much of a market UK renewables will find for exports to the rest of Europe: it could be considerable, but will depend on competing low-carbon generation in those other markets. Therefore, the economics of renewables projects will deteriorate as this point is approached, as will the marginal cost of the emissions savings. ***The limit on renewables capacity in the UK is therefore governed by project economics (possibly including export markets), not by the available resource.***

- In a situation of very high renewables capacity, biomass and geothermal are very valuable, particularly in meeting peak demand. Unfortunately the estimates of the available resource for both are highly uncertain, for different reasons, including sustainability issues in the case of biomass.

4.5 Trajectory to 2030

The renewables capacities required for the Central scenario are examined here to understand how these might develop between now and 2030, and also to check that the required build rates and development timescales are credible.

Figure 10 shows the assumed growth rates. Details of the assumptions and sources for this and the other scenarios are in Appendix 4.

The build rates are all considered feasible. All are less than (or in the case of wave energy, similar to) the 'Level 3' ('very ambitious') assumptions of effort defined by DECC [8]. Offshore and onshore wind are the main contributors, and their build rates are at or below the DECC Level 2 effort definition ('ambitious but reasonable').

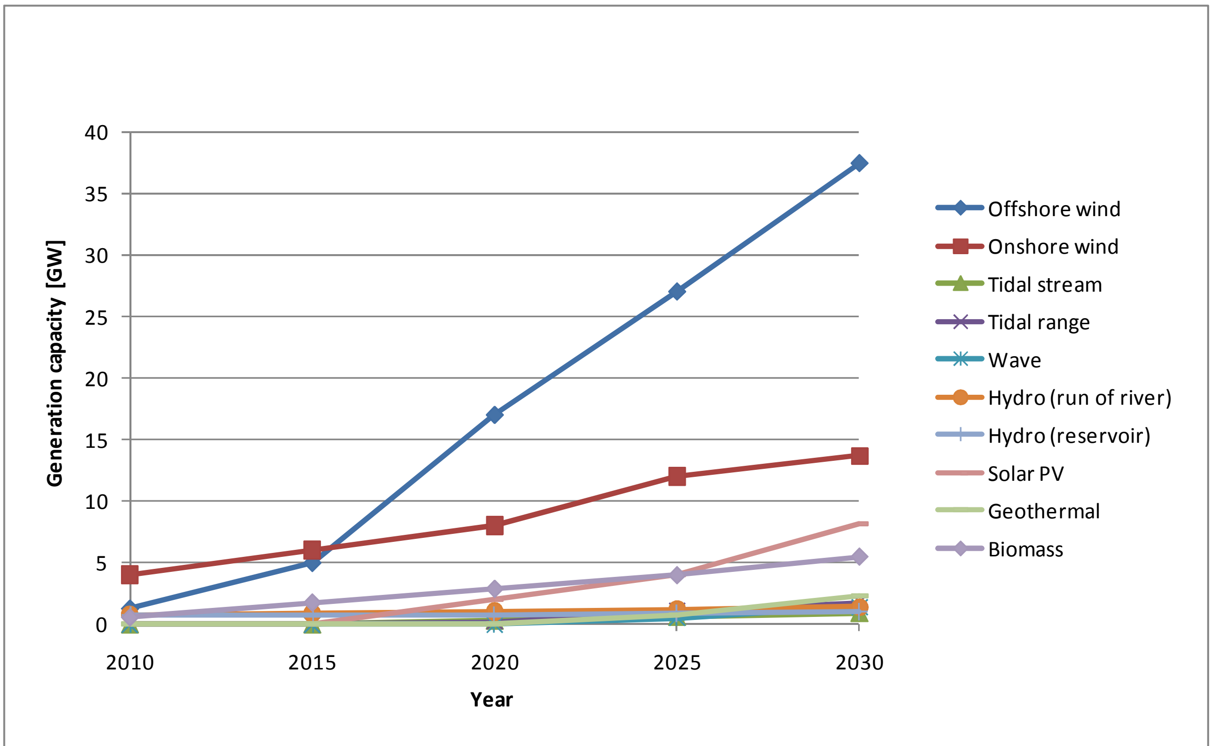

Figure 10: Growth of renewable generation capacity, Central demand scenario

GL Garrad Hassan

4.6 Conclusions

Some conclusions can be drawn from the arguments presented above.

- Although costs and resource sizes are uncertain (highly uncertain in some cases), it is clear that a high-renewables electricity system in 2030 is likely to be dominated by onshore and offshore wind. The other renewables have a relatively small effect in comparison, as do the current levels of interconnection and of pumped storage. The large range of possible renewable generation technologies can be seen as a strength at this stage, and diversification of the renewables mix will bring advantages. Diversification is more likely to occur in later years as a wider range of technologies approach and reach commercial exploitation.

- The limit on total renewables capacity is set by project economics, not by the available resource, especially for the intermittent renewables. This is because at very high penetrations, surpluses of electricity production will occur sometimes (possibly frequently), which will drive down electricity prices. Therefore the economics of further renewables capacity become progressively less attractive to project developers. This is mitigated by deferrable demand, though as noted already this is expected to be primarily available for within-day deferral. It is also mitigated by exporting to the rest of Europe: this is considered further later in this study.

- The installation rates assumed are achievable.

- A large increase in interconnection capacity, or a large amount of gas-fired generation (though in total less than current UK thermal generation capacity), is needed to cope with the extended cold period brought about by anticyclonic conditions in winter (Tables 4 and 5). Gas-fired generation is assumed rather than coal, as costs of both with CCS are similar, and gas produces fewer emissions[17].

- For the gas-fired option, assuming CCS works technically and economically, there is no difficulty in beating the emissions target of 50 g/kWh (see Appendix 3).

- Geothermal and biomass could be very useful in reducing the gas-fired generation capacity required, but their costs and resource size are very uncertain at present.

The effects of renewable generation technologies on UK employment have not been quantified. Background information on employment effects is given in Appendix 9.

[17] Recent reports suggest that in some circumstances unconventional sources of gas, such as shale gas, may result in net emissions similar to or greater than for coal.

5 INTERCONNECTION

5.1 Introduction

As noted in Section 4, around 56 GW of either additional interconnection capacity or conventional generation is required under the Central demand scenario, and 44 GW under the Ambitious demand scenario. This section considers additional interconnection capacity by subsea cables to continental Europe.

Currently the GB system has 3 GW of interconnection capacity to Europe. There is also interconnection capacity to the island of Ireland, with more in progress, but as the Ireland system is expected to have high renewables penetration, and as it is possible or even likely that anticyclonic conditions will cover both Ireland and GB in winter, as a conservative assumption no benefit is assumed here from interconnection with Ireland[18].

There is also 4 GW of pumped storage capacity in the UK, existing and proposed. It is assumed here that no substantial increase beyond 5 GW is likely, principally due to availability of sites. In addition, it is noted that pumped storage capacity is typically of the order of a few tens of hours at full output, or less. It therefore has limited usefulness in providing storage over several days or weeks. In particular, as noted previously, in the event of sustained low renewables production and high electricity demand, there may not be the 'night-time trough' that is a feature of electricity demand at present, so there will be less opportunity for recharging the pumped storage every 24 hours.

It should also be noted that it may be possible in future for the 'green benefits' of electricity to be traded along with the energy[19]. Therefore output of a UK renewable generator which is sold to a purchaser abroad via interconnections may result in the emissions reductions benefits accruing to the purchasing country. Similarly, import to the UK during times of low domestic renewables production would count towards UK targets, to the extent that it comes from qualifying sources.

5.2 Requirements

Taking the Central demand scenario, from Section 4 there is a requirement for 56 GW of new interconnections and/or gas generation. As an example, it is assumed that the current UK gas-fired generation capacity of 24 GW is maintained, giving a requirement for an additional 32 GW of interconnection capacity, i.e. a factor of 10 increase on current interconnector capacity. As discussed earlier, 24 GW of gas generation capacity in 2030 is entirely feasible.

For the Ambitious scenario, the requirement is for a total of 44 GW of new interconnections and/or gas generation. It is assumed that gas generation capacity will be less than for the Central scenario, and a figure of 20 GW is assumed here (scaling approximately pro-rata). Therefore 24 GW of additional interconnector capacity would be needed.

[18] GLGH believes that it is very likely that GB and Ireland will be operating in the same electricity market by 2030, and it is entirely possible they will be operated as one electricity system.

[19] Currently this is feasible within Europe, but requires bilateral or multilateral agreement between Governments.

Note that the relative proportions of gas generation and interconnection capacity assumed above are illustrative. Detailed economic modelling would be required in order to make any more definitive statement, and given the uncertainties in capital and operating costs of interconnectors and gas generation in 2030 the results may in any case be uncertain. However, the interconnector capacities chosen are in broad agreement with other studies.

Given this level of interconnection with other European systems, the UK system would technically be secure. However, this depends on two main factors:

- Electricity markets within Europe which can supply energy when required (in this case, during an extended anticyclone in winter) at an acceptable price. This is uncertain: it is known that such meteorological conditions can cover most of northern Europe, and are likely to occur several times each winter, with various levels of severity. Detailed investigation of this issue requires study of European electricity markets assuming high renewables penetration, including solar installations in southern Europe and possibly also North Africa. Studies in this area indicate that high penetration is possible, that diversity in renewable generation is beneficial, and that interconnection is a key enabler [5][9][12][30]. It is also noted that many European countries intend to make extensive use of biomass to meet their targets.

- Commercial arrangements which adequately recompense the owner of the interconnection. As the costs of an interconnection are almost entirely capital costs, owners will be seeking to maximise the usage of the equipment. The arrangements by which interconnector projects can be funded will therefore be important. Currently, interconnectors are generally funded as ‘merchant’ projects, i.e. the investors take the risk of inadequate usage or income. A regulated funding model (as used for transmission systems) would spread the financial risk across all electricity consumers.

These are economic issues which cannot be addressed in general terms in this study. This section seeks instead to provide some understanding of the costs and benefits of interconnectors, and how they might be used by the UK in a high-renewables world.

5.3 Unit costs

For the capacities and distances relevant to this study, it is reasonable to assume that all new interconnectors will use High Voltage DC (HVDC) technology. This technology is rapidly developing, driven in part by the requirement to connect large offshore windfarms to shore over considerable distances.

Generic costs are not generally available, and project-specific costs are often considered confidential. However, capital cost estimates are available for:

- The proposed West Coast subsea ‘bootstrap’ connection between Ayrshire and North Wales, planned for 2015 [21] (2000 MW, 400 km). The cost is approximately £1000/MW.km.

- The BritNed connector [22] recently commissioned (1000 MW, 260 km). The cost is approximately £2000/MW.km.

The capacity and the distances of these projects are representative of likely connections to mainland Europe. The average of these two costs is used here, i.e. £1500/MW.km. This is supported by generic figures in [30].

5.4 Interconnection to the electricity system of continental Europe

Considering a portfolio of connections to north western France, Belgium, the Netherlands and northern Germany, average distance will be of the order of 400 km. Note that it is necessary not just to connect coast to coast, but to connect to strong points on the transmissions systems, which may be some distance inland.

Table 8 summarises the costs.

Scenario	Central demand	Ambitious demand
Required capacity of gas generation plus new interconnectors	56 GW	44 GW
Assumed gas-fired generation capacity in 2030	24 GW	20 GW
Additional interconnector capacity (by subtraction)	32 GW	24 GW
Number of cables (2000 MW each)	16	12
Average distance assumed	400 km	400 km
Assumed normalised capital cost	1500 £/MW.km	1500 £/MW.km
Capital cost	£19 Bn	£14.4 Bn
Capital cost as fraction of indicative capital cost of renewables (Table 7)	12%	11%

Table 8: Indicative capital costs for additional interconnector capacity to northern Europe

The costs are significant, but form a relatively small part of the overall picture when compared to the costs of generation capacity (renewables and conventional). As noted above, the means by which interconnector projects can be funded will be important.

The number of cables required is high, and finding satisfactory routes and landfalls for this number will not be straightforward. Non-optimum routes may be necessary, increasing the distances and costs assumed in the table. Co-ordinated development of new interconnections in Europe (which might be considered a ‘Supergrid’) should clearly reduce problems of competition for routes, landfalls and connection points to the existing onshore networks.

It is useful to compare this with the findings of the Roadmap to 2050 [9] produced by the European Climate Foundation. This study considered high renewable energy penetrations (40, 60, 80% and 100% of electricity) for the EU27 countries plus Switzerland and Norway. The electricity transmission parts of the study were necessarily at coarse resolution: the UK and Ireland were considered as one node out of nine for all Europe. Secure electricity supplies were maintained, relying heavily on interconnection, and also on geographical distribution of renewables production, especially solar and wind. Results for the interconnection capacities required which are relevant to the UK case were:

- 60% renewable electricity, total 23 GW interconnections: 19 GW to France, 4 GW to Germany/Benelux. No connection to Norway was justified.

- 80% renewable electricity, total 35 GW interconnections: 21 GW to France, 5 GW to Germany/Benelux, and 9 GW to Norway

These results are not directly comparable with this work, for several reasons, but it is relevant that the detailed economic modelling showed that the optimum configuration included interconnection capacities of the order of those shown in Table 8.

5.5 Scandinavian energy storage

Interconnection to Norway would allow connection to the Nordpool system covering Scandinavia, which contains a very large amount of reservoir hydro capacity, particularly in Norway. Norway’s existing reservoir capacity is understood to be around 100 TWh [9], or roughly a quarter of UK annual electricity demand in the 2030 demand scenarios. Some (possibly most) of this reservoir capacity could be converted to pumped storage operation, which would greatly increase its effective annual storage capacity. Opportunities exist for 15 to 20 GW of new pumped storage capacity in southern Norway [33].

Currently SSE and Norwegian utilities are developing proposals for a DC link of up to 2000 MW.

A German study which investigated the use of Norwegian hydro to balance renewables [12] showed significant benefits, particularly a reduction in the amount of storage needed within Germany (principally Compressed Air Energy Storage in underground caverns). For an electricity system about 20% larger than the UK system envisaged here, the study found the need for 46 GW of interconnector capacity to Norway.

There are very significant uncertainties surrounding use of Norwegian hydro for matching UK intermittent renewables. The major uncertainties are:

- available capacity using existing reservoirs, converted to pumped storage where feasible;

- available capacity with new reservoirs, and the likelihood of achieving public acceptance of new reservoirs;

- how much of this capacity might be obtained for the use of UK electricity suppliers, given possibly intense competition for limited energy storage resource from other north European countries.

This is clearly an area of substantial importance in considering high-renewables scenarios, and resolving some of these uncertainties would be beneficial.

The distance to northern Spain (900 km) is not much greater than the distance to western Norway (800 km). Such a connection would not provide the energy storage benefits of a link to Norway, but it would bring substantial benefits in geographical smoothing of wind production, and possibly even greater if solar capacity increases in Spain and Portugal.

Interconnection with Iceland was first proposed many years ago, and is currently under consideration. This would bring benefits of low-carbon geothermal generation. The connection distance is roughly twice that for Norway or Spain.

5.6 Use of interconnection capacity for export of renewable electricity

The methodology developed in Section 4 fundamentally assumed that renewable generation capacity in the UK would be limited to a level approximately equivalent to maximum demand plus ***existing*** interconnector capacity. This assumes that, at times of low electricity demand and high renewables production, there are only limited opportunities for export of electricity to continental Europe. Electricity prices in the GB system would be low during these periods, and this would effectively limit the amount of renewables capacity that would get built.

However, an alternative assumption is that the large interconnector capacity identified in this Section can be used to allow substantial exports. This assumes that markets exist, i.e. that UK renewables can compete against low-carbon generation elsewhere in Europe.

Section 7.3 considers the effect of this assumption on renewable generation capacity and production.

6 GAS-FIRED GENERATION

6.1 Introduction

Section 4 established requirements for conventional generation and/or interconnections, in order to provide a secure electricity supply at the time of peak demand, assuming sustained anticyclonic conditions resulting in high heating demand and low production from wind, wave and run-of-river hydro. Section 5 considered the use of interconnections to other systems in this situation. This section reviews the use of gas-fired generation as an alternative.

This is often termed ‘backup’ generation, as it is used to match the output of the renewables generators. However ‘backup’ is an ill-defined term, often referring to plant kept in reserve against a failure of a single generator, or some other credible severe combination of failures. This is not the case here. Given the low capacity factors of some of the renewable generation, some gas generation will be running frequently.

6.2 Gas-fired generation characteristics

As noted earlier, the conventional generation is assumed here to be largely gas, because costs of coal and gas options with CCS are expected to be very similar, and gas achieves lower emissions[20].

The gas generation is likely to be some mixture of:

- Open-cycle gas turbines (OCGT) without CCS. These are very simple installations with low capital cost. They have relatively low efficiency (because they do not recover heat from the exhaust gases) and therefore high running costs. They are used for ‘peaking’ operation, i.e. running only at times of peak demand, for perhaps a few hundred hours per year. They can be started and stopped relatively quickly and frequently. Emissions are higher than other gas-fired options, but as the plant is used infrequently this may be acceptable.

- Combined-cycle gas turbines (CCGT) without CCS. These recover heat from the gas turbine exhausts, by raising steam which then drives a steam turbine. Capital cost is higher than for OCGT, but due to the higher efficiency, fuel costs (per MWh of output) are lower. They are therefore used for baseload or mid-merit operation, i.e. running for several thousand hours per year. Depending on design, there are limits on how fast and how often they can be started and stopped. Emissions are lower than OCGT (see Appendix 3).

- CCGT with CCS. As for CCGT, with the addition of a carbon capture plant. This has not been demonstrated at commercial scale yet, or even large prototype scale, though individual elements of the process are well understood. Very substantially lower emissions than CCGT are expected. Efficiency is reduced, as it is anticipated that around 20% of the energy

[20] If coal with CCS turned out to be more attractive than gas, the discussion would not be significantly affected. Note also that recent reports suggest that in some circumstances unconventional sources of gas, such as shale gas, may result in net emissions similar to coal.

produced may be needed to drive the CCS plant[21]. Due to the CCS plant, it is likely that there will be more stringent limits on rate and frequency of startups. Also, the high capital cost will encourage operators to achieve as high a capacity factor as possible for these plants.

Indicative costs for these technologies are listed in Table 9.

Technology	Unit cost [£/MWh]	Capital cost [£/MW]	Notes
OCGT	131.4	£430 k	From [18]. Unit cost (£/MWh) assumes high capacity factor, such as baseload.
CCGT	96.5	£750 k	As above. More recent work shows 88.4 £/MWh [38]. (DECC assumptions, 2017 project start)
CCGT with CCS	102.6	£1.4 m	As above. More recent work shows 94.8 £/MWh [38]. (DECC assumptions, 2017 project start)

Table 9: Indicative costs of gas generation

It has been proposed that CCS plants attached to generators could be turned off at times of very high electricity demand: the electricity demand of the CCS plant is therefore removed, effectively providing 'peaking' capacity from the generating plant. Emissions during that period would be high, but may be acceptable for short periods, and overall this may be more attractive than building additional peaking plant. This option depends on technology and has not been demonstrated.

6.3 Gas-fired generation capacity

As established earlier, a total of 56 GW of gas-fired generation capacity and additional interconnection capacity is required under the Central demand assumption, and 44 GW under the Ambitious demand assumption. In this section, it is assumed this is all gas generation. This defines two scenarios A1, A2, which are set out in Table 10. This shows the electricity production required from the gas generation.

Appendix 6 gives details of indicative mixes of gas generation types that will meet the capacity and production figures in Table 10.

It is seen that the average capacity factor for the gas generation is very low. A more detailed discussion is in Section 7.1.

[21] This figure is uncertain and will depend on technology and detailed design but is unlikely to lie outside the range 5 to 30%.

Scenario	Central demand, Scenario A1	Ambitious demand, Scenario A2
Total gas generation capacity	56 GW	44 GW
Total renewables capacity	73 GW	59 GW
Annual electricity demand	425 TWh/y	338 TWh/y
Total renewables production	261 TWh/y	210 TWh/y
Required production from gas-fired generation	164 TWh/y	128 TWh/y
Average capacity factor for gas generation	33%	33%

Table 10: Security provided by gas generation (Scenarios A1 and A2)

6.4 Trajectory to 2030

At present there is a total of 24 GW of CCGT capacity in the UK, of which 20 GW is assessed as being suitable for retrofit of CCS [7]. There is a further 24 GW of capacity which is currently under construction, approved, or going through the planning system, though not all of it will get built. All of this is stated to be ‘CCS ready’, i.e. has the necessary space and technology to allow a CCS plant to be added, although the locations may not be ideal.

The limitation is the timescale for development and demonstration of CCS technology. Assuming CCS is commercially available from 2020, Scenario A1 requires around 1.8 GW of CCS plant to be built each year to 2030. This appears credible.

Trends to 2030 are set out in more detail in Appendix 8.

6.5 District heating and CHP

There is clearly scope for using waste heat from the baseload gas generation, both for industrial CHP and for district heating. The other plant operates at capacity factors too low to satisfy heating demand, even though periods of operation are likely to coincide with high heat demand.

Using waste heat in this way can substantially reduce total UK emissions, if it replaces heat provided by fossil fuels.

The amount of heat load that could be supplied in this way cannot be established at this point. Utilisation of this heat depends critically on the availability of heat loads close to the generators.

6.6 Gas storage requirements

Gas storage currently available to the UK system is equivalent to around 20 TWh of electricity in total [32], assuming conversion to electricity at approximately 40% net efficiency. This is around 5% of UK annual electricity demand for 2030.

In the event of a future with high renewables and gas generation (i.e. roughly doubling UK gas generating capacity of 24 GW), and assuming the gas generation is operated at full output during a cold calm spell in winter, this storage is equivalent to around 2 weeks consumption. This assumes it could all be made available for electricity generation, which is optimistic, even considering that a substantial part of the heating load will have been transferred from gas to electricity by 2030 [35]. Therefore substantial reinforcement of gas storage capacity is likely to be needed.

Assuming instead a future with substantial electrical interconnection to other systems, with gas generation capacity roughly equivalent to existing UK capacity, the need for additional gas storage in the UK is likely to be significantly reduced.

7 COMPARISON OF SCENARIOS

7.1 Annual output and emissions

Table 11 compares scenarios. Scenarios A1 and A2 (where security is provided by gas generation) were defined in Section 6. Scenarios B1 and B2 are also defined, where security is provided by gas generation and additional interconnection capacity, as discussed in Section 5. The relative proportions of interconnection capacity and gas capacity in Scenarios B1 and B2 are illustrative (chosen to give total gas generation capacity roughly similar to today's levels), and both A and B scenarios should be seen as points on a continuum.

The resulting emissions and emissions intensity are calculated[22]. Further detail of the mix of gas generation capacity assumed in these calculations is in Appendix 6.

For comparison, current UK fossil and nuclear generation is 76 GW, including 24 GW of gas. Therefore all scenarios have less thermal generation than the current UK fleet, and the B1 and B2 scenarios have total thermal generation equivalent to current UK gas-fired generation.

Gas generation compared to interconnection

In scenarios A1 and A2, a relatively small fraction of the gas-fired generation capacity is required to have CCS to meet the decarbonisation target. Under scenarios B1 and B2, roughly the same amount of CCS is required. Therefore the effect of using interconnection to provide security is to reduce the amount of non-CCS gas generation required.

In scenarios A1 and A2, the average capacity factor for the gas generation fleet is shown to be low[23]. This is likely to lead to a distinct separation into baseload generation with CCS, running with relatively high capacity factors, and peaking plant, i.e. with low capital cost but high running costs, some of it without CCS.

In scenarios B1 and B2, there is much less gas generation capacity, yet the total annual production required from the gas-fired generation is the same as scenarios A1 and A2. Therefore the average capacity factor of the gas-fired generation is significantly higher, similar to today's levels.

[22] Emissions figures as in Appendix 3 are assumed, with no allowance for poorer emissions when gas plant is operated at low loads or is subject to frequent starts and load changes. Figures are therefore indicative only, for comparison between options. However the net effect of this approximation is believed to be relatively small.

[23] This does not mean that any individual generator will spend substantial time operating at low output. It is likely that generation would be scheduled as at present, to ensure that most conventional generation, when it runs, operates close to its optimum point. So the low average capacity factor means that much of the gas plant will spend much of the time shut down.

Scenario	Security provided by gas generation		Security provided by gas generation and interconnection	
	Central demand Scenario A1	**Ambitious demand Scenario A2**	**Central demand Scenario B1**	**Ambitious demand Scenario B2**
Total renewables capacity	73 GW	59 GW	73 GW	59 GW
Total interconnection capacity (including 3 GW existing)	3 GW	3 GW	35 GW	27 GW
Total gas generation capacity	56 GW	44 GW	24 GW	20 GW
Annual electricity demand	425 TWh	338 TWh	425 TWh	338 TWh
Total renewables production	261 TWh	210 TWh	261 TWh	210 TWh
Renewables production as fraction of demand	61%	62%	61%	62%
Required output from gas generation	164 TWh	128 TWh	164 TWh	128 TWh
Total gas consumption for electricity generation [TWh of gas]	425 TWh	332 TWh	422 TWh	325 TWh
Average capacity factor for gas generation	33%	33%	78%	73%
Emissions from gas plant, assuming no CCS	63 m t $CO2_e$	49 m t $CO2_e$	62 m t $CO2_e$	48 m t $CO2_e$
Overall emission intensity (gas plus renewables) assuming no CCS	147 g/kWh	146 g/kWh	145 g/kWh	143 g/kWh
Emissions from gas plant, assuming all fitted with CCS	6 m t $CO2_e$	5 m t $CO2_e$	6 m t $CO2_e$	5 m t $CO2_e$
Overall emission intensity (gas plus renewables) assuming all with CCS	14 g/kWh	14 g/kWh	14 g/kWh	14 g/kWh
Gas generation required to have CCS in order to achieve emission intensity of 50 g/kWh[24]	18 GW out of 56 GW	14 GW out of 44 GW	17 GW out of 24 GW	13 GW out of 20 GW

Table 11: Summary of renewable and gas generation capacity and emissions by scenario

As an aside, the high capacity factors in the B scenarios are affected by the assumption in the analysis of there being no net import or export of electricity on an annual basis. In reality, because most gas burned in the UK in 2030 will be imported, there is a choice (when imports are required) between

[24] To resolution of 1 GW, to achieve emission intensity below the target.

importing gas for electricity generation, and importing electricity. Therefore there could in 2030 be a net import of electricity on annual basis, which would result in lower capacity factors for UK gas generation than estimated here.

A related point is that Tables 11 and 12 do not show the true potential economic benefits of interconnection, as they do not show any benefit from the trading opportunities. High interconnection capacity will allow the UK to import electricity when it is cheaper to do so than to burn gas, and vice versa. Further, in reality it is unlikely that the 'no net import or export' assumption is the economic optimum for the UK: in any year economic factors are likely to result in the UK being either a net importer or a net exporter of electricity, and the economic benefits of this are not shown in the Tables.

Effect of the Ambitious demand assumption

Comparison of the Ambitious demand scenarios (A2, B2) with the Central demand scenarios (A1, B1) shows substantial reductions in generation and interconnection capacity, and in total emissions.

It is important to note that the calculations in the table assume that over the year, imports and exports approximately balance. The calculations of emissions and emissions intensity in the table assume that the emissions intensity of exports is approximately the same as the emissions intensity associated with imports.

7.2 Costs

Appendix 6 shows possible mixes of the gas generation options which achieve the required total capacity, energy production and emissions intensity (other mixes are also possible).

For the cases where security is provided by gas generation (A1, A2), this is based on assumed annual capacity factors of:

- 0.8 (i.e. 7000 hours per year) for the baseload CCGTs with CCS
- 0.15 (i.e. 1310 hours per year) for CCGTs without CCS
- 0.02 (i.e. 175 hours per year) for OCGTs without CCS

For the cases where security is provided by gas generation and substantial additional interconnection capacity (B1, B2), the average capacity factor for gas generation is much higher, 0.8 or above for all CCGTs. The CCGT capacity without CCS is operated as baseload or mid-merit plant.

Table 12 summarises the generation mixes, and the indicative capital cost of the gas generation. Other capital costs established earlier are also shown. Capital cost is listed here only for comparison of options. The annual cost of the gas consumed is shown in the table, again only for comparison of options. Future gas costs are based on DECC forecasts in 2009 ('Mid' estimate), and could vary significantly: current gas costs are lower.

Operating costs and carbon costs are a large part of overall costs, and are not shown here. Note that the costs and income from imported and exported energy are not shown.

Scenario	Security provided by gas generation		Security provided by gas generation and additional interconnection	
	Central demand Scenario A1	Ambitious demand Scenario A2	Central demand Scenario B1	Ambitious demand Scenario B2
Total gas capacity	56 GW	44 GW	24 GW	20 GW
Made up of:				
OCGT	9 GW	7 GW	2 GW	2 GW
CCGT	29 GW	23 GW	5GW	5 GW
CCGT with CCS	18 GW	14 GW	17 GW	13 GW
Total capital cost of gas generation[25]	£51 Bn	£ 40 Bn	£28 Bn	£23 Bn
Capital cost of renewable generation (Table 7)	£165 Bn	£133 Bn	£165 Bn	£133 Bn
Capital cost of additional interconnection (Table 8)	n/a	n/a	£19 Bn	£14 Bn
Total of capital costs above	£216 Bn	£173 Bn	£212 Bn	£170 Bn
Cost of gas fuel	£11.3 Bn/y	£8.8 Bn/y	£11.2 Bn/y	£8.6 Bn/y

Table 12: Indicative capital and fuel costs

7.3 Stretch scenarios

Section 4 showed that renewables capacity in the UK was likely to be limited by economics rather than resource. In particular, it was assumed that total renewables capacity would be limited to approximately the peak demand plus the existing interconnector capacity (3 GW).

25 Around 24 GW of gas plant currently is in operation in the UK, of which 20 GW may still be running in 2020 [7]. Therefore this capital cost does not represent the total additional investment expenditure needed.

In Section 5.6, it is noted that a substantial increase in the interconnection capacity between the GB system and other systems could allow UK renewables capacity to be increased. This is because this could allow substantial sales of renewable electricity to customers abroad, at times when there is a surplus in the UK. If adequate prices could be obtained, this would increase the amount of renewable generating capacity economically justified in the UK.

It is important to note that it is by no means clear that adequate prices could be obtained. For example, it is possible that at times of high wind production in the UK, there may be high production from wind generation in other northern European countries, resulting in low electricity prices on occasions. There will of course also be times when there will be high renewables production in the UK and low renewables production in other European countries, especially those with a substantially different mix of renewables resources. Also, other European states may find it difficult to meet their obligations for emissions reductions or for renewable electricity, and therefore require imports. This could have significant economic benefits for the UK [31].

To evaluate the effects, should it prove economic, two 'Stretch' scenarios have been developed. In the A and B scenarios, it is assumed that renewable capacity is limited to approximately the level of maximum demand plus the existing interconnection capacity to northern Europe. In the Stretch scenarios (C1, C2), it is assumed that additional interconnection capacity is built as in the B scenarios, and that renewable capacity increases to approximately the level of maximum demand plus the total interconnection capacity. This allows a very substantial increase in renewable capacity.

The results are shown in Table 13, in the same format as Table 11. Further details are in Appendix 10.

The results show a very substantial reduction in gas consumption, and it is possible to meet the emissions intensity target without CCS.

However, it is very important to note that this calculation assumes no net import or export on an annual basis, and that all the emissions reduction benefits accrue to the UK. This implies either of two options:

- Either the electricity imported to the UK has, on average, the same emissions intensity as the exports (which requires it to be largely from renewable sources);
- Or electricity exported from the UK is sold without its 'green benefits'

The C1, C2 and the B1, B2 scenarios represent indicative points on a continuum, and there is no means at present of judging what might be the 'best' mix of renewable capacity and interconnection capacity. The scenarios are chosen to indicate what is possible, and what the important inter-relationships are. Given current uncertainties around future European market rules, generation mixes and electricity prices, it is not considered useful to attempt to cost the Stretch scenarios at this time.

The C1, C2 scenarios show that it is possible to meet emissions reduction targets without CCS, given enough interconnection capacity and renewables capacity.

Scenario	**Security provided by gas generation and additional interconnection, substantial RE exports via interconnectors**	
	Central demand Scenario C1	**Ambitious demand Scenario C2**
Total renewables capacity	105 GW	83 GW
Total interconnection capacity (including 3 GW existing)	35	27
Total gas generation capacity	20 GW	16 GW
Annual electricity demand	425 TWh	338 TWh
Total renewables production	373 TWh	295 TWh
Renewables production as fraction of demand	88%	87%
Required output from gas generation	52 TWh	43 TWh
Total gas consumption for electricity generation [TWh of gas]	113 TWh	80 TWh
Average capacity factor for gas generation	30%	31%
Emissions from gas plant, assuming no CCS	20 m t $CO2_e$	16 m t $CO2_e$
Overall emission intensity (gas plus renewables) assuming no CCS	46 g/kWh	48 g/kWh
Emissions from gas plant, assuming all fitted with CCS	2.0 m tonnes $CO2_e$	1.6 m tonnes $CO2_e$
Overall emission intensity (gas plus renewables) assuming all with CCS	5 g/kWh	5 g/kWh
Gas generation required to have CCS in order to achieve emission intensity of 50 g/kWh	No CCS required	No CCS required

Table 13: Summary of renewable and gas generation capacity for 'stretch' scenarios

8 CONCLUSIONS

The major conclusions are summarised here.

8.1 Electricity demand

Substantial demand reductions are possible and indeed highly recommended, to meet the UK's decarbonisation targets. This also allows substantial reductions in total generating capacity. Compared to the Central demand scenario, the Ambitious demand scenario (i.e. assuming significant lifestyle changes) brings reduction in capital cost of renewables generation, gas generation and interconnections of the order of £40 bn (Table 12).

The addition of the anticipated electric heating and electric vehicle charging demands in 2030 is likely to lead to substantial smoothing of the diurnal load curve, compared to today. These loads are very likely to be largely deferrable within-day, but with very limited deferral beyond a day. These loads are also available for short-term balancing of variable renewables production.

Peak electricity demand has a strong effect on the costs of ensuring a secure electricity system. In particular, it determines the size and therefore the capital costs of thermal generation capacity and/or interconnector capacity. This is true even with no substantial capacity of variable renewables.

However if there is a substantial capacity of variable renewables, the thermal generation capacity or interconnector capacity will be utilised less during the year. Therefore 'peaking capacity', either of thermal generation or interconnectors, becomes relatively more expensive. To put it another way, the economic benefits of reducing peak demand become greater.

Therefore, the behaviour of consumers and the ability to defer electricity loads, particularly heat loads, is an important area for future study.

8.2 Renewables capacity in 2030

Variability of renewable energy production on timescales of hours is low, and predictable. The worst case is an extended period of anticyclonic cold calm weather in winter, which may extend for weeks. If the electricity system can be made secure against this event, all other issues associated with high renewables capacity are likely to be resolved.

The limit on the UK renewables capacity is economic, rather than the size of the resource. In effect, when renewables capacity approaches the size of maximum electricity demand, and assuming there is no substantial interconnection capacity to other systems, there will be periods when there is no purchaser for the energy, or prices will be very low. This sets a limit on the renewables capacity which will get built. This holds true even if renewables are funded through some fixed feed-in tariff, because there will be a point at which Government decides the increasing unit costs are unjustified. As a rough approximation, a figure of around 60% of UK electricity production appears realistic.

Renewables capacity in 2030 is likely to be dominated by onshore and offshore wind.

It is possible that additional interconnection capacity would allow substantial exports of renewable production from the UK, which might provide economic justification for increased renewables capacity. Two 'Stretch' scenarios indicate that in these circumstances renewable generation could credibly meet around 87% of UK electricity demand.

8.3 Renewables plus interconnection

Interconnection to continental Europe can provide a secure electricity system, and is a direct alternative to providing generating capacity within the UK. The UK system will be secure if the combined system of which it is part is secure. Other studies indicate that by providing substantial interconnection within Europe, including Scandinavia, southern Europe and possibly North Africa, the entire system could be secure with high renewables penetration. This is a critical issue and requires further detailed study. To optimise this will require not just interconnection capacity, but also international co-operation in energy markets, regulation and system operation.

Connections to France, Belgium, the Netherlands and Germany are feasible. Connections to western Norway (particularly to make use of the storage capacity of the existing hydro reservoirs, possibly modified to pumped storage operation) and to northern Spain are also credible. Interconnection with geothermal generation in Iceland has also been proposed.

The total conventional (i.e. thermal) generation fleet in the UK can be reduced to around the size of the current gas-fired generating fleet, i.e. less than half of current total UK thermal generation.

8.4 Renewables plus gas generation

As an alternative to substantial new interconnection capacity, an electricity system based on renewables plus gas can be secure and stable (Scenarios A1, A2). A substantial fleet of gas generation is required, but substantially less than the current UK total for fossil and nuclear generation.

It is likely that gas storage capacity within the UK would need to be expanded.

Note that (assuming CCS can be made to work), gas generation with a large amount of CCS capacity could theoretically meet the carbon intensity target in 2030 without renewables. Therefore in this context the benefits of renewables are that they reduce emissions further, reduce the need for some of the gas generation capacity, reduce the need for CCS plant, improve energy security, conserve finite carbon dioxide storage reservoir capacity, and reduce the environmental effects of gas extraction and carbon dioxide storage. Renewables also limit the downside should CCS not deliver the expected performance on time: until CCS is demonstrated at commercial scale, this is an important consideration. Depending on future capital costs, fuel and carbon prices, increasing renewable generation may also reduce overall costs.

8.5 General

The optimum set of choices for the UK will minimise risk as well as cost. It is likely to include energy demand reduction policies, a substantial renewables component, greater levels of interconnection than currently planned, fossil fuel (most likely gas) with CCS, and a small component of unabated fossil generation to run for very limited periods.

In the context of a high-renewables world, critical issues to be resolved to reduce uncertainty are:

- Costs and performance of CCS.
- The relative costs and benefits of substantial interconnection with Europe, compared to a large gas-fired generating fleet in the UK. To understand costs, electricity markets within Europe must be modelled, assuming high levels of renewables generation in those markets.
- Technical scope, costs and market arrangements for making use of Scandinavian hydro, geothermal energy, and pumped storage.
- Behaviour of consumers and the prospects for deferring substantial amounts of electricity demand within-day, particularly heating loads in winter.
- Prospects for bulk energy storage technologies.

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APPENDIX 1

ELECTRICITY DEMAND DURATION CURVES

The 'demand duration curve' indicates for how much of the year total demand is at any particular level. Figure A1.1 shows the demand duration curve for the GB system for 2009/10 [20]. As an example, it shows that demand exceeded 50% of peak demand, for 80% of the year.

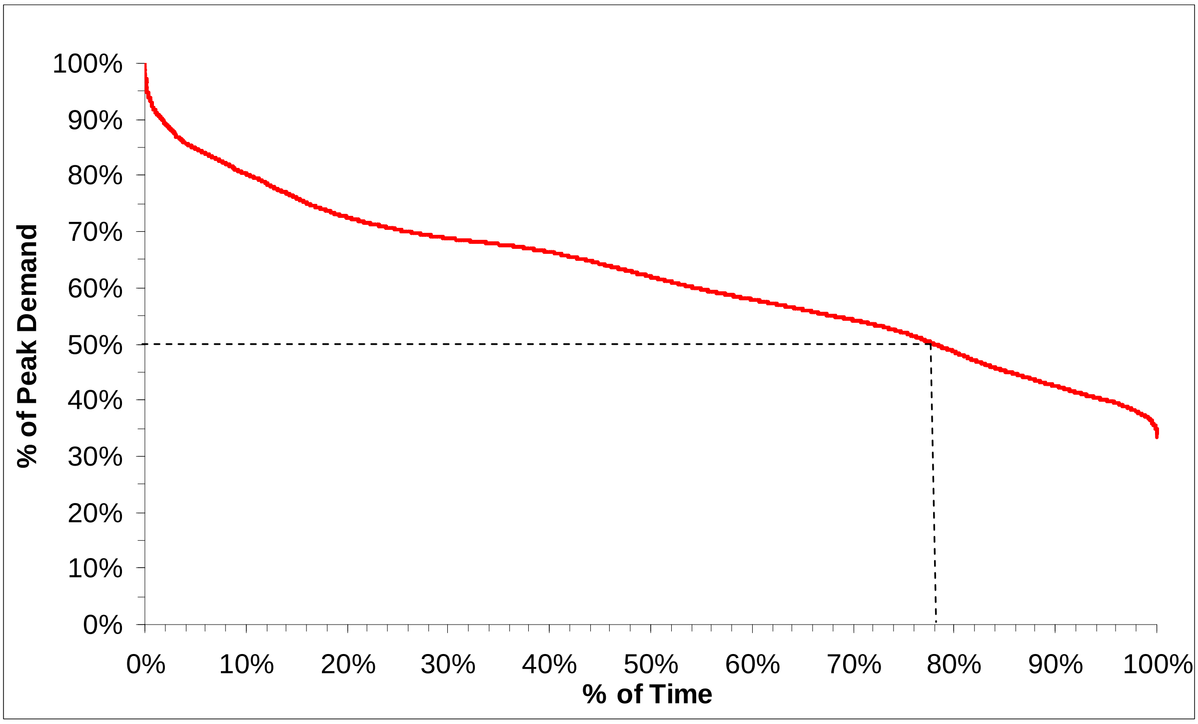

Figure A1.1: GB load duration curve for 2009/10 (from [20])

Figures A1.2 and A1.3 show the same data (now in MW rather than % of peak demand), and also the result when the curve is scaled up for 2030, to result in the total electricity demand for the 2030 Central and Ambitious demand scenarios. This is done excluding and including the effect of electrification of heat and transport.

There are two inherent assumptions:

- The shape of the underlying electricity demand does not change appreciably between 2009/10 and 2030;
- The additional heat and transport loads are distributed evenly throughout the day and year, in proportion to the 'other' demand sectors.

These assumptions make the results misleading. In practice, it is expected that there will be strong economic pressures to 'defer' the heating and electric vehicle loads away from the peak demand periods. The figures below therefore are likely to overestimate the peak demands, making the curves 'flatter'. This effect is analysed qualitatively in Sections 2 and 4.

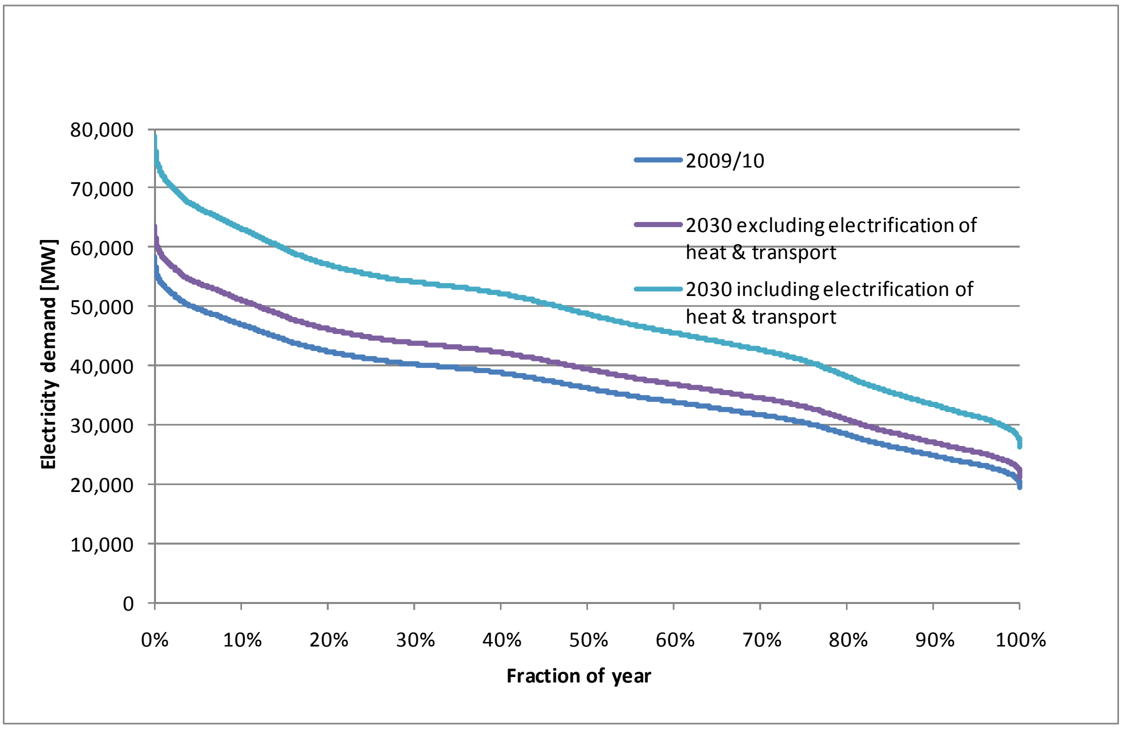

Figure A1.2: Demand duration curve, scaled for 2030 Central demand scenario (including and excluding heat and transport loads)

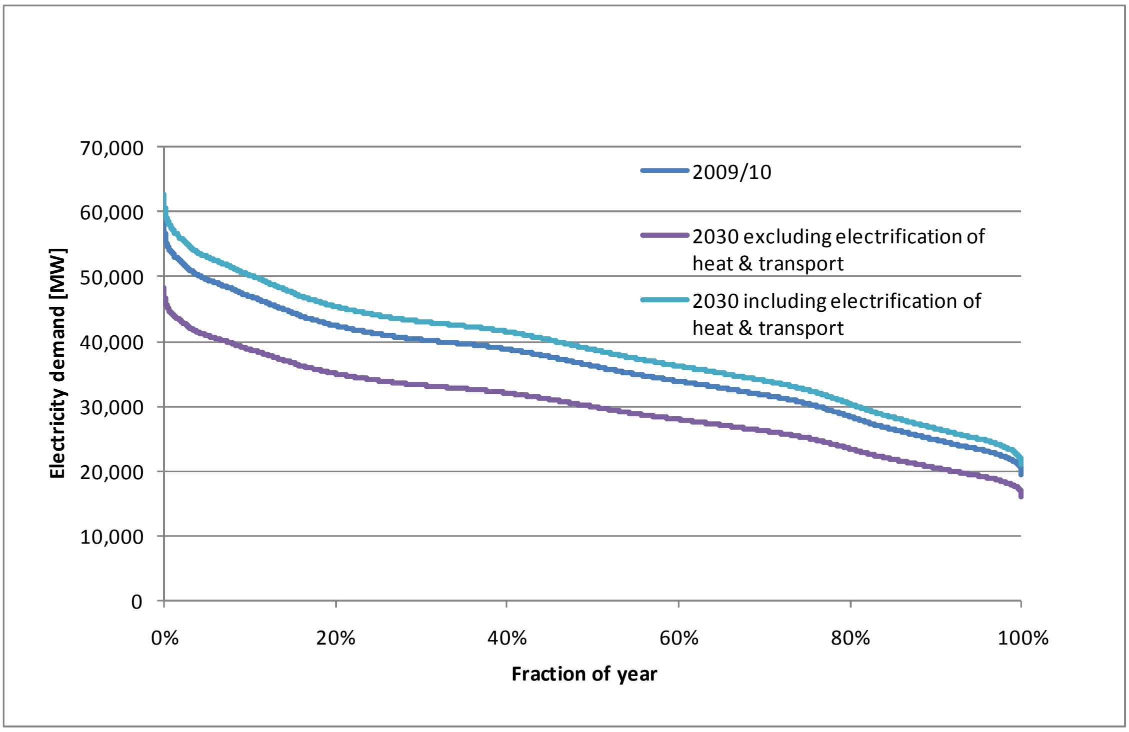

Figure A1.3: Demand duration curve, scaled for 2030 Ambitious demand scenario (including and excluding heat and transport loads)

APPENDIX 2

PRACTICABLE RENEWABLE ELECTRICITY RESOURCE AND ASSUMED MIX FOR 2030

Resource	Practicable resource (principally from CCC [7])		Assumed available resource mix for 2030		Notes
	Capacity [GW]	Output [TWh]	Capacity [GW]	Output [TWh]	
Offshore wind	235	926	82	310	DECC work [8] includes floating as well as ground-mounted offshore wind, and describes this as an '*extremely ambitious but ultimately deliverable scenario which reflects the outer limit of technical ambition*' It assumes net capacity factor increases to 45% by 2050. GLGH assumption for 2030: DECC Level 4 assumption is 103 GW by 2030, with a net capacity factor of 43%, i.e. 388 TWh. The Level 3 assumption is 260 TWh. Assume 80% of DECC Level 4 figures for 2030. More recent analysis for DECC [37] states a High estimate of 52 GW and 180 TWh/y in 2030.
Onshore wind	28	74	30	80	Substantial differences between published estimates, mainly due to uncertainties about public acceptability. CCC assumes a 30% capacity factor for onshore wind, which GLGH believes is reasonable, given technical improvements, changing economics, and the gradual development of the less windy sites.

					GLGH assumption for 2030: DECC Level 3, i.e. assuming a high level of effort and public acceptability, but not 'heroic' levels of effort. This is slightly higher than CCC estimates of 'practicable' resource. More recent analysis for DECC [37] states a High estimate of 24 GW and 58 TWh/y in 2030.
Tidal stream	33	116	2	7	DECC assumes a capacity factor of 40%. Total resource size has very large uncertainties at present. GLGH assumption for 2030: DECC Level 4. GLGH believes this is a credible rate of development. More recent analysis for DECC [37] states very similar figures: a High estimate of 2.2 GW and 6.6 TWh/y in 2030.
Tidal range	20	39	4	8	Around half of this is the conventional Severn Barrage. Alternatives for the Severn may turn out to be more economically attractive, with slightly reduced energy production. The conventional Severn Barrage scheme is currently not proceeding[26]. GLGH assumption for 2030: Given uncertainties about development of the tidal range resource, particularly the Severn, DECC Level 3 effort is assumed here. This is equivalent to developing about one-third of the known resource outside the Severn estuary.

[26] WWF is opposed to the conventional Severn Barrage but supports research into alternative sustainable ways of harnessing the tidal resource of the Severn estuary.

					More recent analysis for DECC [37] states a High estimate of 1 GW and 1.8 TWh/y in 2030, which are significantly lower than assumed here.
Wave	20	40	3	7	DECC assumes a capacity factor of 25%, which GLGH believes is reasonable. GLGH assumption for 2030: DECC Level 4. More recent analysis for DECC [37] states a High estimate of 2.5 GW and 7.4 TWh/y in 2030, very similar to the figures assumed here.
Hydro (run of river)	4	13	3	10	Omitted from CCC work. Figures are from DECC 2050 Pathways. These figures exclude projects designed as pumped-storage, as net energy production is close to zero. GLGH assumption for 2030: GLGH believes the DECC Level 4 assumptions for 2030 (3.5 GW and 11 TWh) are likely to be conservative, given the low risks of hydro compared to alternatives. It is further assumed that 75% of this hydro capacity is run-of-river, and 25% is reservoir hydro. No independent figures are available to support this, but it is believed realistic, given that most future hydro developments are expected to be relatively small run-of-river schemes. More recent analysis for DECC [37] states a High estimate of 2.5 GW and 7.4 TWh/y in 2030 (total for hydro <5 MW and >5 MW, no distinction between run-of-river and reservoir hydro).
Hydro (reservoir)	Included above	Included above	1	3	See above.

Solar PV	165	140	18	15	Capacity factor of 9.7% assumed. GLGH assumption for 2030: A very wide range is possible. DECC Level 3 effort assumes 15 TWh, and Level 4 125 TWh. This reflects the uncertainty about costs, and the attractiveness to domestic and commercial building owners compared to other options. More recent analysis for DECC [37] states a High estimate of 19 GW and 19 TWh/y in 2030, very close to the figures assumed here.
Geothermal	5	35	5	35	Capacity factor of 80% assumed. GLGH assumption for 2030: Given the relatively low risk, the attractiveness of geothermal as a base-load generator, and the possible use of the waste heat for heating, full development of the estimated resource is assumed by 2030 (DECC Level 4). More recent analysis for DECC [37] states a High estimate of 4 GW and 31 TWh/y in 2030. Given the uncertainties, this is good agreement.
Biomass	23	178	12	95	Because of the competing uses of biofuels, and uncertainty about value and costs in each of these markets in future, the contribution of biomass to electricity production is extremely uncertain. The sustainability of each option needs careful consideration. The figures given here are DECC Level 4 figures for 2050, assuming maximum possible use is made of solid biomass for electricity production. GLGH assumption for 2030: DECC Level 4 estimate for 2030 is used here as an indication of the possible maximum contribution to electricity generation.

					More recent analysis for DECC [37] states a High estimate of 8 GW and 56 TWh/y in 2030, for solid biomass.
Total: dispatchable			22	141	Comprises biomass, geothermal, tidal range, and reservoir hydro. Note however that all have some constraints on dispatchability, compared to conventional thermal plant. It is assumed here that the tidal range resource is sufficiently distributed geographically to give substantial time-averaging of output. As biomass dominates this section, the notes on uncertainties in electricity generation from biomass are important in interpreting these numbers.
Total: non-dispatchable			138	429	Comprises onshore and offshore wind, tidal stream, wave, run-of-river hydro, and solar PV.
Total	**533**	**1561**	**160**	**570**	

APPENDIX 3

PERMISSIBLE PRODUCTION FROM FOSSIL GENERATION

For comparison purposes, the table below shows the maximum permissible annual production from several forms of fossil generation, assuming a target for carbon intensity of at most 50 g/kWh in 2030. If electricity demand is 425 TWh, this implies maximum permissible carbon emissions from the electricity sector of 21,250,000 tonnes of carbon dioxide.

Generation type	**Specific CO_2 emissions [g/kWh]**	**Maximum permissible production [TWh/y]**	**Comments**
Unabated coal	882	24	From [11]. Would not be permissible under the Emissions Performance Standard
Unabated gas OCGT	440	48	From [15]
Unabated gas CCGT	376	57	From [11]
Coal with CCS	88	240	Assumes CCS captures around 90%
Gas with CCS	38	Not limited by carbon intensity target	Assumes CCS captures around 90%

APPENDIX 4

DEVELOPMENT OF RENEWABLES CAPACITY TO 2030

The tables below show the cumulative installed capacity (in GW) of renewables generation to 2030, under each scenario. Production from renewables generation is also shown.

The figures have been reached by comparing the capacities derived for 2030 in each scenario with the capacities in 2010, and estimating required feasible growth rates between these dates. The figures are not based on known individual projects. Energy production is based on capacity factors appropriate for 2030, so for some technologies may overestimate production slightly in earlier years.

Central demand scenario (A1, B1)

Year	**2010**	**2015**	**2020**	**2025**	**2030**	**Comments**
Offshore wind	1.3	5	17	27	37.4	Below even DECC Level 2 effort assumption. Could grow faster than assumed here.
Onshore wind	4	6	8	12	13.7	At or below DECC Level 2 assumptions.
Tidal stream	0	0	0.3	0.6	0.9	Similar to DECC Level 2 assumption
Tidal range	0	0	0.2	1.0	1.8	Less than DECC Level 3 assumption
Wave	0	0	0	0.5	1.4	Consistent with DECC Level 3 assumption
Hydro (run of river)	0.8	0.9	1	1.2	1.4	2010 figures from [8]. 50% estimated to be run-of-river hydro. Growth rates are well within DECC assumptions.
Hydro (reservoir)	0.8	0.8	0.8	0.9	1	2010 figures from [8]. 50% estimated to be reservoir hydro. Only slight increase necessary to 2030.
Solar PV	0	0	2	4	8.2	Similar to DECC Level 2 assumption
Geothermal	0	0	0	0.8	2.3	Build rates are within DECC Level 3 assumptions.
Biomass	0.6	1.8	2.9	4.0	5.5	Less than DECC Level 3 assumptions (Mar 2011 revision)
Total	7.5	14.5	32.2	52.0	73.6	
Total production [TWh]	25.7	54.8	117.4	186.3	261.5	
Total production [% of electricity demand]	7%	16%	32%	48%	61%	

The build rates shown in the table are all believed to be reasonable. For comparison, the ‘effort levels’ defined by DECC in the 2050 Pathways study [8] are listed here.

- **Level 1:** assumes little or no attempt to decarbonise or change, or only short-run efforts: and that unproven low carbon technologies are not developed or deployed.
- **Level 2:** describes what might be achieved by applying a level of effort that is likely to be viewed as ambitious but reasonable by most or all experts. For some sectors this would be similar to the build rate expected with the successful implementation of the programmes or projects currently in progress.
- **Level 3:** describes what might be achieved by applying a very ambitious level of effort that is unlikely to happen without significant change from the current system; it assumes significant technological breakthroughs.
- **Level 4:** describes a level of change that could be achieved with effort at the extreme upper end of what is thought to be physically plausible by the most optimistic observer. This level pushes towards the physical or technical limits of what can be achieved.

Ambitious demand scenario (A2, B2)

Year	**2010**	**2015**	**2020**	**2025**	**2030**	**Comments**
Offshore wind	1.3	5	15	22	30	Assumed rapid growth to 2020, slower thereafter
Onshore wind	4	6	8	10	11	Saturation effect assumed post 2020
Tidal stream	0	0	0.2	0.4	0.7	
Tidal range	0	0	0.2	0.8	1.4	
Wave	0	0	0	0.5	1.1	
Hydro (run of river)	0.8	0.9	1.0	1.0	1.1	
Hydro (reservoir)	0.8	0.8	0.8	0.9	1	
Solar PV	0	0	1	3	6.5	
Geothermal	0	0	0	0.5	1.8	
Biomass	0.6	1.2	2.4	3.0	4.4	
Total	7.5	13.9	28.6	42.1	59	
Total production [TWh]	25.7	50.0	104.7	149.6	209.7	
Total production [% of electricity demand]	8%	15%	31%	44%	62%	

Comments for Scenario A1 apply except where noted.

Build rates are similar to or less than for Scenario A1.

APPENDIX 5

RENEWABLE GENERATION PRODUCTION ESTIMATES

For each of the demand scenarios, the corresponding renewable energy technologies capacity and production used in Section 4 is summarised here. This is based on total renewables capacity approximately equal to maximum demand, plus exports through existing interconnector capacity (Scenarios A1, A2).

	Capacity factor	**Central demand scenario** **Capacity [GW]**	**Central demand scenario** **Production [TWh]**	**Ambitious demand scenario** **Capacity [GW]**	**Ambitious demand scenario** **Production [TWh]**
Offshore wind	0.43	37.4	140.9	30	113.0
Onshore wind	0.3	13.7	36.0	11	28.9
Tidal stream	0.4	0.9	3.2	0.7	2.5
Tidal range	0.223	1.8	3.5	1.4	2.7
Wave	0.25	1.4	3.1	1.1	2.4
Hydro (run of river)	0.4	1.4	4.9	1.1	3.9
Hydro (reservoir)	0.4	1	3.5	1	3.5
Solar PV	0.097	8.2	7.0	6.5	5.5
Geothermal	0.8	2.3	16.1	1.8	12.6
Biomass	0.9	5.5	43.4	4.4	34.7
Total		73.6	261.5	59	209.7

APPENDIX 6

INDICATIVE MIX OF GAS GENERATION

1. Ssecurity provided by gas generation

Central demand scenario (A1)

	Emissions intensity [kt/TWh]	Capital cost [£/MW]	Capacity [GW]	Capital cost [£ Bn]	Assumed capacity factor	Production [TWh/y]	Emissions [MT/y]	Net emissions intensity [g/kWh]	Gross efficiency	Gas consumption [TWh/y]	Gas cost [£ bn/y]
OCGT	440	£430 k	9	3.9	0.02	1.58	0.69	-	0.4	3.9	0.1
CCGT without CCS	376	£750 k	29	21.8	0.15	38.11	14.33	-	0.532	71.6	1.9
CCGT with CCS	38	£1400 k	18	25.1	0.8	126.14	4.79	-	0.361	349.4	9.3
Total			56	50.8		165.83	19.82	47		425.0	11.3

Data are taken from [18] where possible. CCGT efficiency includes degradation, auxiliary power, and requirements of CCS plant. OCGT efficiency data is not given in [18] and is approximate, but has little effect on totals. Gas cost is DECC 2009 ‘Mid’ estimate, and could vary very significantly.

Ambitious demand scenario (A2)

	Emissions intensity [kt/TWh]	Capital cost [£/MW]	Capacity [GW]	Capital cost [£ Bn]	Assumed capacity factor	Production [TWh/y]	Emissions [MT/y]	Net emissions intensity [g/kWh]	Gross efficiency	Gas consumption [TWh/y]	Gas cost [£ bn/y]
OCGT	440	£430 k	7	3.0	0.02	1.23	0.54	-	0.4	3.1	0.1
CCGT without CCS	376	£750 k	23	17.3	0.15	30.22	11.36	-	0.532	56.8	1.5
CCGT with CCS	38	£1400 k	14	19.6	0.8	98.11	3.73	-	0.361	271.8	7.2
Total			44	39.9		129.56	15.63	46		331.7	8.8

2. Security provided by gas generation and additional interconnection capacity

Central demand scenario (B1)

	Emissions intensity [kt/TWh]	Capital cost [£/MW]	Capacity [GW]	Capital cost [£ Bn]	Assumed capacity factor	Production [TWh/y]	Emissions [MT/y]	Net emissions intensity [g/kWh]	Gross efficiency	Gas consumption [TWh/y]	Gas cost [£ bn/y]
OCGT	440	£430 k	2	0.9	0.02	0.35	0.15	-	0.4	0.9	0.0
CCGT without CCS	376	£750 k	5	3.7	0.8	35.04	13.18	-	0.532	65.9	1.7
CCGT with CCS	38	£1400 k	17	23.8	0.86	128.07	4.87	-	0.361	354.8	9.4
Total			24	28.4		163.46	18.20	43		421.5	11.2

Ambitious demand scenario (B2)

	Emissions intensity [kt/TWh]	Capital cost [£/MW]	Capacity [GW]	Capital cost [£ Bn]	Assumed capacity factor	Production [TWh/y]	Emissions [MT/y]	Net emissions intensity [g/kWh]	Gross efficiency	Gas consumption [TWh/y]	Gas cost [£ bn/y]
OCGT	440	£430 k	2	0.9	0.02	0.35	0.15	-	0.4	0.9	0.0
CCGT without CCS	376	£750 k	5	3.7	0.8	35.04	13.18	-	0.532	65.9	1.7
CCGT with CCS	38	£1400 k	13	18.2	0.82	93.38	3.55	-	0.361	258.7	6.9
Total			20	22.8		128.77	16.88	50		325.4	8.6

APPENDIX 7

RENEWABLE GENERATION PRODUCTION AT PEAK DEMAND ASSUMING ANTICYCLONIC CONDITIONS

This Appendix provides details of the renewable generation production assumed from each renewable technology at the time of peak demand, assuming anticyclonic conditions, under different scenarios. This expands on the figures for 'Total Renewables' provided in several tables in the main text and Appendices.

1. Central demand, security provided by gas generation (Scenario A1, B1) (see Table 4)

Resource	**Capacity [GW]**	**Contribution at peak demand [GW]**	**Notes**
Peak demand		70	
Required capacity of generation plus interconnectors		77	Includes plant margin of 10% above peak demand, to cover for plant failures. Plant margin is from [27].
Offshore wind	37.4	1.9	5% assumed in anticyclonic conditions
Onshore wind	13.7	0.7	5% assumed in anticyclonic conditions
Tidal stream	0.9	0.4	Assume geographical dispersion, and mean output at critical periods.
Tidal range	1.8	0.6	Assume significant time-averaging of tidal cycle due to dispersion around coasts. Also some limited ability to delay or advance production to meet peak periods.
Wave	1.4	0.1	5% assumed in anticyclonic conditions
Hydro (run of river)	1.4	-	Assume frozen groundwater across UK
Hydro (reservoir)	1	1	Reservoirs are unaffected by freezing
Solar PV	8.2	-	Assume peak demand occurs after dark
Geothermal	2.3	2.3	Fully dispatchable, and likely to be operated to achieve full output at times of high demand
Biomass	5.5	5.5	Fully dispatchable, and likely to be operated to achieve full output at times of high demand
Total renewables	73.6	13	Rounded figure to avoid unjustified implied accuracy. Total is dominated by biomass, wind and geothermal.
Pumped storage	5	5	GLGH assumption. Current UK capacity is 2.8 GW. A further 0.6 to 1.2 GW is actively under development by SSE. Further developments are likely to 2030, including converting existing hydro reservoirs to pumped storage.
Contribution from existing interconnectors	3	3	Existing interconnectors are 2 GW to France, 1 GW to Netherlands (due 2011) [17].
Additional interconnection or gas capacity	56	56	By subtraction, so that the output of renewables, pumped storage, interconnections and gas meets the required capacity including plant margin.

2. Ambitious demand, security provided by gas generation (Scenario A2, B2) (see Table 5)

Resource	Capacity [GW]	Contribution at peak demand [GW]	Notes
Peak demand		56	
Required capacity of generation plus interconnection		62	Includes plant margin of 10% above peak demand, to cover for plant failures. Plant margin is from [27].
Offshore wind	30	1.5	5% assumed in anticyclonic conditions
Onshore wind	11	0.6	5% assumed in anticyclonic conditions
Tidal stream	0.7	0.2	Assume geographical dispersion, and mean output at critical periods.
Tidal range	1.4	0.3	Assume significant time-averaging of tidal cycle due to dispersion around coasts. Also some limited ability to delay or advance production to meet peak periods.
Wave	1.1	0.1	5% assumed in anticyclonic conditions
Hydro (run of river)	1.1	-	Assume frozen groundwater across UK
Hydro (reservoir)	1	1	Reservoirs are unaffected by freezing.
Solar PV	6.5	-	Assume peak demand occurs after dark
Geothermal	1.8	1.8	Fully dispatchable, and likely to be operated to achieve full output at times of high demand
Biomass	4.4	4.4	Fully dispatchable, and likely to be operated to achieve full output at times of high demand
Total renewables	59	10	Rounded figure to avoid unjustified implied accuracy. Total is dominated by biomass, wind and geothermal.
Pumped storage	5	5	GLGH assumption. Current UK capacity is 2.8 GW. A further 0.6 to 1.2 GW is actively under development by SSE. Further developments are likely to 2030, including converting existing hydro reservoirs to pumped storage.
Contribution from existing interconnectors	3	3	Existing interconnectors are 2 GW to France, 1 GW to Netherlands (due 2011) [17].
Additional interconnection or gas capacity	44	44	By subtraction, so that the output of renewables, pumped storage, interconnections and gas meets the required capacity including plant margin.

APPENDIX 8

TRENDS FROM 2010 TO 2030

The tables below indicate how important quantities may change between the current situation and 2030. The trends are indicative only, and several important points should be noted.

- The capacities of generation technologies assumed for 2010 are based largely on DUKES data for 2009 [34], to cover the main generation technologies. Generation capacity which is not a major contributor is not included.

- Trends in generation capacity and production take account of similar work in [7] and [8] but are not identical. Unless there is information to the contrary, approximately linear transition between 2010 and 2030 is assumed.

- UK generation is assumed to be entirely renewables and gas by 2030, and the existing coal and nuclear plants are assumed to be retired gradually.

- It is assumed that there is no net import or export over the year, i.e. annual production equals consumption. The calculation of emission intensity inherently assumes that the emissions intensity of any imports is identical to the emissions intensity of any exports.

- Emissions and fuel consumption calculations assume no reduction in generator efficiency through operation at low load factors. Note that low average load factors do not mean that individual gas-fired generators are operating frequently at low loads (and therefore lower efficiency). Instead, when there is low electricity demand, some generators will be shut down, and those which are running will be operating at high output, close to their peak efficiency.

- The costs used in the estimation of wholesale electricity costs (£/MWh) are extremely uncertain, and must be taken only as an indication of the relative contributions of elements to overall costs. The costs are not based on the capital costs (£/MW) used elsewhere in this report, though the same sources have often been used. Costs are taken from [7] and 18], using where possible costs that are appropriate to the level of development of the technology at the time, but not 'First of a Kind' costs. Most importantly, the costs assume capacity factors appropriate to present-day use: some gas plant in a high-renewables future will have much lower capacity factors, so the costs used here are underestimates.
    - Gas without CCS is assumed to cost £80/MWh.
    - Gas with CCS is assumed to cost £103/MWh.
    - Coal and other thermal plant without CCS (termed here 'Other fossil') is assumed to cost £60/MWh.
    - Costs appropriate to the existing nuclear fleet are not known, though this becomes less important as the nuclear fleet is retired in later years. £70/MWh was assumed purely on requirements for competitiveness.
    - Costs of transmission reinforcement, use of transmission systems, use of interconnectors, balancing and other services are not included.

- Renewables capacity is assumed to develop as in Appendix 4. Costs are as in Section 4.4.

Scenario A1: Security ensured by gas-fired generation, Central demand assumption

Year	**2010**	**2015**	**2020**	**2025**	**2030**
Electricity generation capacity [GW]	76.5	84.5	92.2	110	129.6
Renewables	*7.5*	*14.5*	*32.2*	*52*	*73.6*
Gas (without CCS)	*23*	*29*	*31*	*38*	*38*
Gas (with CCS)	*0*	*0*	*5*	*15*	*18*
Other fossil	*35*	*30*	*15*	*0*	*0*
Nuclear	*11*	*11*	*9*	*5*	*0*
Annual electricity consumption [TWh]	340	350	370	390	425
Annual electricity generation [TWh]	340	350	370	390	425
Renewables	*26*	*55*	*117*	*186*	*261*
Gas (without CCS)	*157*	*148*	*122*	*103*	*38*
Gas (with CCS)	*0*	*0*	*43*	*91*	*126*
Other fossil	*94*	*89*	*50*	*0*	*0*
Nuclear	*63*	*59*	*38*	*10*	*0*
Total electricity sector emissions [Mt CO2]	153.4	144.1	97.5	42.2	19.1
Gas (without CCS)	*59.1*	*55.5*	*45.9*	*38.7*	*14.3*
Gas (with CCS)	*0.0*	*0.0*	*1.6*	*3.5*	*4.8*
Other fossil	*94.3*	*88.6*	*50.0*	*0.0*	*0.0*
Overall emission intensity [gCO2/kWh]	451	412	264	108	45
Wholesale electricity costs [£ Bn]	25	27	35	42	51
Renewables	*2*	*6*	*15*	*24*	*35*
Gas (without CCS)	*13*	*12*	*10*	*8*	*3*
Gas (with CCS)	*0*	*0*	*4*	*9*	*13*
Other fossil	*6*	*5*	*3*	*0*	*0*
Nuclear	*4*	*4*	*3*	*1*	*0*

Scenario A2: Security ensured by gas-fired generation, Ambitious demand assumption

Year	**2010**	**2015**	**2020**	**2025**	**2030**
Electricity generation capacity [GW]	76.5	83.9	86.6	97.1	103
Renewables	*7.5*	*13.9*	*28.6*	*42.1*	*59*
Gas (without CCS)	*23*	*29*	*29*	*30*	*30*
Gas (with CCS)	*0*	*0*	*5*	*14*	*14*
Other fossil	*35*	*30*	*15*	*0*	*0*
Nuclear	*11*	*11*	*9*	*5*	*0*
Annual electricity consumption [TWh]	340	340	338	338	338
Annual electricity generation [TWh]	340	340	338	338	338
Renewables	*26*	*50*	*105*	*150*	*210*
Gas (without CCS)	*157*	*145*	*100*	*60*	*30*
Gas (with CCS)	*0*	*0*	*40*	*98*	*98*
Other fossil	*94*	*87*	*58*	*0*	*0*
Nuclear	*63*	*58*	*35*	*10*	*0*
Total electricity sector emissions [Mt CO2]	153.4	141.5	97.4	33.8	15.0
Gas (without CCS)	*59.1*	*54.5*	*37.6*	*30.1*	*11.3*
Gas (with CCS)	*0.0*	*0.0*	*1.5*	*3.7*	*3.7*
Other fossil	*94.3*	*87.0*	*58.3*	*0*	*0.0*
Overall emission intensity [gCO2/kWh]	451	416	288	100	44
Wholesale electricity costs [£ Bn]	25	27	31	37	40
Renewables	*2*	*6*	*13*	*20*	*28*
Gas (without CCS)	*13*	*12*	*8*	*6*	*2*
Gas (with CCS)	*0*	*0*	*4*	*10*	*10*
Other fossil	*6*	*5*	*3*	*0*	*0*
Nuclear	*4*	*4*	*2*	*1*	*0*

Scenario B1: Security ensured by gas and interconnection, Central demand assumption

Year	**2010**	**2015**	**2020**	**2025**	**2030**
Electricity generation capacity [GW]	76.5	78.5	81.2	89	97.6
Renewables	*7.5*	*14.5*	*32.2*	*52*	*73.6*
Gas (without CCS)	*23*	*23*	*20*	*16*	*7*
Gas (with CCS)	*0*	*0*	*0*	*16*	*17*
Other fossil	*35*	*30*	*20*	*0*	*0*
Nuclear	*11*	*11*	*9*	*5*	*0*
Annual electricity consumption [TWh]	340	350	370	390	425
Annual electricity generation [TWh]	340	350	370	390	425
Renewables	*26*	*55*	*117*	*186*	*261*
Gas (without CCS)	*157*	*148*	*152*	*103*	*36*
Gas (with CCS)	*0*	*0*	*0*	*91*	*128*
Other fossil	*94*	*89*	*63*	*0*	*0*
Nuclear	*63*	*59*	*38*	*10*	*0*
Total electricity sector emissions [Mt CO2]	153.4	144.1	120.3	42.2	18.4
Gas (without CCS)	*59.1*	*55.5*	*57.2*	*38.7*	*13.5*
Gas (with CCS)	*0.0*	*0.0*	*0.0*	*3.5*	*4.9*
Other fossil	*94.3*	*88.6*	*63.2*	*0*	*0.0*
Overall emission intensity [gCO2/kWh]	451	412	325	108	43
Wholesale electricity costs [£ Bn]	25	27	34	42	51
Renewables	*2*	*6*	*15*	*24*	*35*
Gas (without CCS)	*13*	*12*	*12*	*8*	*3*
Gas (with CCS)	*0*	*0*	*0*	*9*	*13*
Other fossil	*6*	*5*	*4*	*0*	*0*
Nuclear	*4*	*4*	*3*	*1*	*0*

Scenario B2: Security ensured by gas and interconnection, Ambitious demand assumption

Year	**2010**	**2015**	**2020**	**2025**	**2030**
Electricity generation capacity [GW]	76.5	77.9	77.6	83.1	79
Renewables	*7.5*	*13.9*	*28.6*	*42.1*	*59*
Gas (without CCS)	*23*	*23*	*20*	*16*	*7*
Gas (with CCS)	*0*	*0*	*0*	*13*	*13*
Other fossil	*35*	*30*	*20*	*0*	*0*
Nuclear	*11*	*11*	*9*	*5*	*0*
Annual electricity consumption [TWh]	340	340	338	338	338
Annual electricity generation [TWh]	340	340	338	338	338
Renewables	*26*	*50*	*105*	*150*	*210*
Gas (without CCS)	*157*	*145*	*140*	*86*	*35*
Gas (with CCS)	*0*	*0*	*0*	*93*	*93*
Other fossil	*94*	*87*	*58*	*0*	*0*
Nuclear	*63*	*58*	*35*	*9*	*0*
Total electricity sector emissions [Mt CO2]	153.4	141.5	110.9	35.9	16.7
Gas (without CCS)	*59.1*	*54.5*	*52.6*	*32.3*	*13.2*
Gas (with CCS)	*0.0*	*0.0*	*0.0*	*3.5*	*3.5*
Other fossil	*94.3*	*87.0*	*58.3*	*0*	*0.0*
Overall emission intensity [gCO2/kWh]	451	416	328	106	49
Wholesale electricity costs [£ Bn]	25	27	30	37	40
Renewables	*2*	*6*	*13*	*20*	*28*
Gas (without CCS)	*13*	*12*	*11*	*7*	*3*
Gas (with CCS)	*0*	*0*	*0*	*10*	*10*
Other fossil	*6*	*5*	*3*	*0*	*0*
Nuclear	*4*	*4*	*2*	*1*	*0*

Scenario C1: Security ensured by gas and interconnection, substantial renewables export, Central demand assumption

Year	**2010**	**2015**	**2020**	**2025**	**2030**
Electricity generation capacity [GW]	76.5	85.9	98.9	96.4	125
Renewables	*7.5*	*15.9*	*40.9*	*69.4*	*105*
Gas (without CCS)	*23*	*29*	*29*	*22*	*20*
Gas (with CCS)	*0*	*0*	*0*	*0*	*0*
Other fossil	*35*	*30*	*20*	*0*	*0*
Nuclear	*11*	*11*	*9*	*5*	*0*
Annual electricity consumption [TWh]	340	350	370	390	425
Annual electricity generation [TWh]	340	350	370	390	425
Renewables	*26*	*60*	*152*	*254*	*373*
Gas (without CCS)	*157*	*145*	*109*	*109*	*52*
Gas (with CCS)	*0*	*0*	*0*	*0*	*0*
Other fossil	*94*	*87*	*65*	*0*	*0*
Nuclear	*63*	*58*	*44*	*27*	*0*
Total electricity sector emissions [Mt CO2]	153.4	141.5	106.4	40.9	19.6
Gas (without CCS)	*59.1*	*54.5*	*41.0*	*40.9*	*19.6*
Gas (with CCS)	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Other fossil	*94.3*	*87.0*	*65.4*	*0.0*	*0.0*
Overall emission intensity [gCO2/kWh]	451	404	288	105	46
Wholesale electricity costs [£ Bn]	25	28	36	44	54
Renewables	*2*	*7*	*20*	*33*	*50*
Gas (without CCS)	*13*	*12*	*9*	*9*	*4*
Gas (with CCS)	*0*	*0*	*0*	*0*	*0*
Other fossil	*6*	*5*	*4*	*0*	*0*
Nuclear	*4*	*4*	*3*	*2*	*0*

Scenario C2: Security ensured by gas and interconnection, substantial renewables export, Ambitious demand assumption

Year	**2010**	**2015**	**2020**	**2025**	**2030**
Electricity generation capacity [GW]	76.5	80.7	84.9	84.3	99
Renewables	*7.5*	*14.7*	*35.9*	*59.3*	*83*
Gas (without CCS)	*23*	*25*	*20*	*20*	*16*
Gas (with CCS)	*0*	*0*	*0*	*0*	*0*
Other fossil	*35*	*30*	*20*	*0*	*0*
Nuclear	*11*	*11*	*9*	*5*	*0*
Annual electricity consumption [TWh]	340	340	338	338	338
Annual electricity generation [TWh]	340	340	338	338	338
Renewables	*26*	*56*	*135*	*218*	*295*
Gas (without CCS)	*157*	*142*	*122*	*108*	*43*
Gas (with CCS)	*0*	*0*	*0*	*0*	*0*
Other fossil	*94*	*85*	*51*	*0*	*0*
Nuclear	*63*	*57*	*30*	*12*	*0*
Total electricity sector emissions [Mt CO2]	153.4	138.6	96.6	40.7	16.2
Gas (without CCS)	*59.1*	*53.4*	*45.8*	*40.7*	*16.2*
Gas (with CCS)	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Other fossil	*94.3*	*85.2*	*50.8*	*0.0*	*0.0*
Overall emission intensity [gCO2/kWh]	451	408	286	120	48
Wholesale electricity costs [£ Bn]	25	27	32	39	43
Renewables	*2*	*7*	*17*	*29*	*40*
Gas (without CCS)	*13*	*11*	*10*	*9*	*3*
Gas (with CCS)	*0*	*0*	*0*	*0*	*0*
Other fossil	*6*	*5*	*3*	*0*	*0*
Nuclear	*4*	*4*	*2*	*1*	*0*

APPENDIX 9

EMPLOYMENT EFFECTS OF RENEWABLES TECHNOLOGIES

This Appendix provides guidance on available information on employment attributable to renewables technologies. The reports listed cover both analysis of measured data, and projections by renewables industry trade associations.

No reliable information was found that was relevant for UK conditions, for technologies other than wind, wave and tidal.

1. General

Federal Ministry for the Environment, Nature Conservation and Nuclear Safety, "**Gross employment from renewable energy in Germany in 2010**", March 2011 (in English)
http://www.bmu.de/english/renewable_energy/downloads/doc/47242.php

2. Wind

Renewable UK, "**Working for a Green Britain**", Feb 2011 (Vol 1) and July 2011 (Vol 2).
http://www.bwea.com/pdf/publications/Working_for_Green_Britain.pdf

This study by RenewableUK, the industry association for the UK, estimated approximately 9,100 full-time employees (FTEs) working in the wind industry in 2010. Offshore wind accounted for 3,100 or 34% of this figure - a reflection of the UK's position as a market leader in this sector. Since the UK has little domestic manufacturing of wind turbines or their principle components these figures are dominated by employees involved in development, construction, installation and support services rather than manufacturing.

The report also covers marine renewables.

Volume 2 provides predictions for employment to 2021, under three scenarios.

European Wind Energy Association, "**Green Jobs**"
http://www.ewea.org/fileadmin/ewea_documents/documents/publications/reports/Jobs_pamphlet_lr.pdf

Briefing document.

Spanish Wind Energy Association, "**Wind Power 2010**"
http://www.aeeolica.es/userfiles/file/en/Anuario-AEE-en-ingles-2010.pdf

Contains information on current employment, and estimates of effects of some policies on employment.

3. Marine (wave and tidal)

Carbon Trust, “Marine Renewables Green Growth Paper”, 2011.
http://www.carbontrust.co.uk/news/news/press-centre/2011/Documents/110503-marine-green-growth.pdf

Briefing document.

APPENDIX 10

'STRETCH' SCENARIOS: UTILISING INCREASED INTERCONNECTOR CAPACITY TO ALLOW INCREASED RENEWABLES CAPACITY

Section 4 showed that renewables capacity in the UK was likely to be limited by economics rather than resource. In particular, it was assumed that total renewables capacity would be limited to approximately the peak demand plus the existing interconnector capacity (3 GW).

In Section 5.6, it is noted that a substantial increase in the interconnection capacity between the GB system and other systems could allow UK renewables capacity to be increased. In effect, the total renewables capacity increases, because the additional interconnector capacity now provides UK renewables with substantial additional markets.

Therefore, the renewables capacity figures of Tables 4 and 5 are recalculated in Tables 4A and 5A below, on the assumption that UK renewables capacity in 2030 is approximately equivalent to maximum demand plus total interconnector capacity.

These 'stretch' scenarios are entitled C1 and C2.

Resource	**Capacity [GW]**	**Contribution at peak demand (in anticyclonic conditions) [GW]**	**Notes**
Peak demand		70	All notes and assumptions as for Table 4
Required capacity of generation plus interconnectors		77	
Offshore wind	53.6	2.7	
Onshore wind	19.6	1.0	
Tidal stream	1.3	0.4	
Tidal range	2.6	0.6	
Wave	2	0.1	
Hydro (run of river)	2	-	
Hydro (reservoir)	1	1	
Solar PV	11.7	-	
Geothermal	3.3	3.3	
Biomass	7.9	7.9	
Total renewables	105	17	
Pumped storage	5	5	
Contribution from existing interconnectors	3	3	
New interconnection capacity	32	32	Assumed
Gas-fired generation capacity	20	20	By subtraction

Table 4A: Meeting peak demand during anticyclonic conditions: Central demand scenario, assuming substantial renewables export through interconnectors (Scenario C1)

Resource	**Capacity [GW]**	**Contribution at peak demand (in anticyclonic conditions) [GW]**	**Notes**
Peak demand		56	All notes and assumptions as for Table 4
Required capacity of generation plus interconnectors		62	
Offshore wind	42.4	2.1	
Onshore wind	15.4	0.8	
Tidal stream	1.1	0.4	
Tidal range	2.1	0.5	
Wave	1.6	0.1	
Hydro (run of river)	1.6	-	
Hydro (reservoir)	1	1	
Solar PV	9.4	-	
Geothermal	2.5	2.5	
Biomass	6.3	6.3	
Total renewables	83	14	
Pumped storage	5	5	
Contribution from existing interconnectors	3	3	
New interconnection capacity	24	24	Assumed
Gas-fired generation capacity	16	16	By subtraction

Table 5A: Meeting peak demand during anticyclonic conditions: Ambitious demand scenario, assuming substantial renewables export through interconnectors (Scenario C2)

The renewables capacity figures assumed in the tables can be compared against the practicable resource and the build rates shown in Appendices 2 and 4. It is seen that for the Ambitious demand scenario (Table 5A), build rates are achievable.

Under the Central demand scenario (Table 4A), the renewable capacities required are significantly higher. For some technologies such as tidal stream, tidal range, wave and PV, there must be some concern that the generating capacities shown in Table 4A could be built by 2030. However, if this is not possible, the shortfall could be made up by further (relatively small) expansion of the onshore and offshore wind capacity. Appendix 4 shows that the build rates for wind are similar to or below DECC Level 3 definition (‘very ambitious’).

Table 7A is similar to Table 7, and summarises the results.

Scenario	**Central demand scenario (C1)**	**Ambitious demand scenario (C2)**
Total renewables capacity	105 GW	83 GW
Total renewables production	373 TWh/y	295 TWh/y
Production as fraction of total electricity demand	88%	87%

Table 7A: Total renewables capacity and production, assuming substantial renewables export through interconnectors (Scenarios C1 and C2)