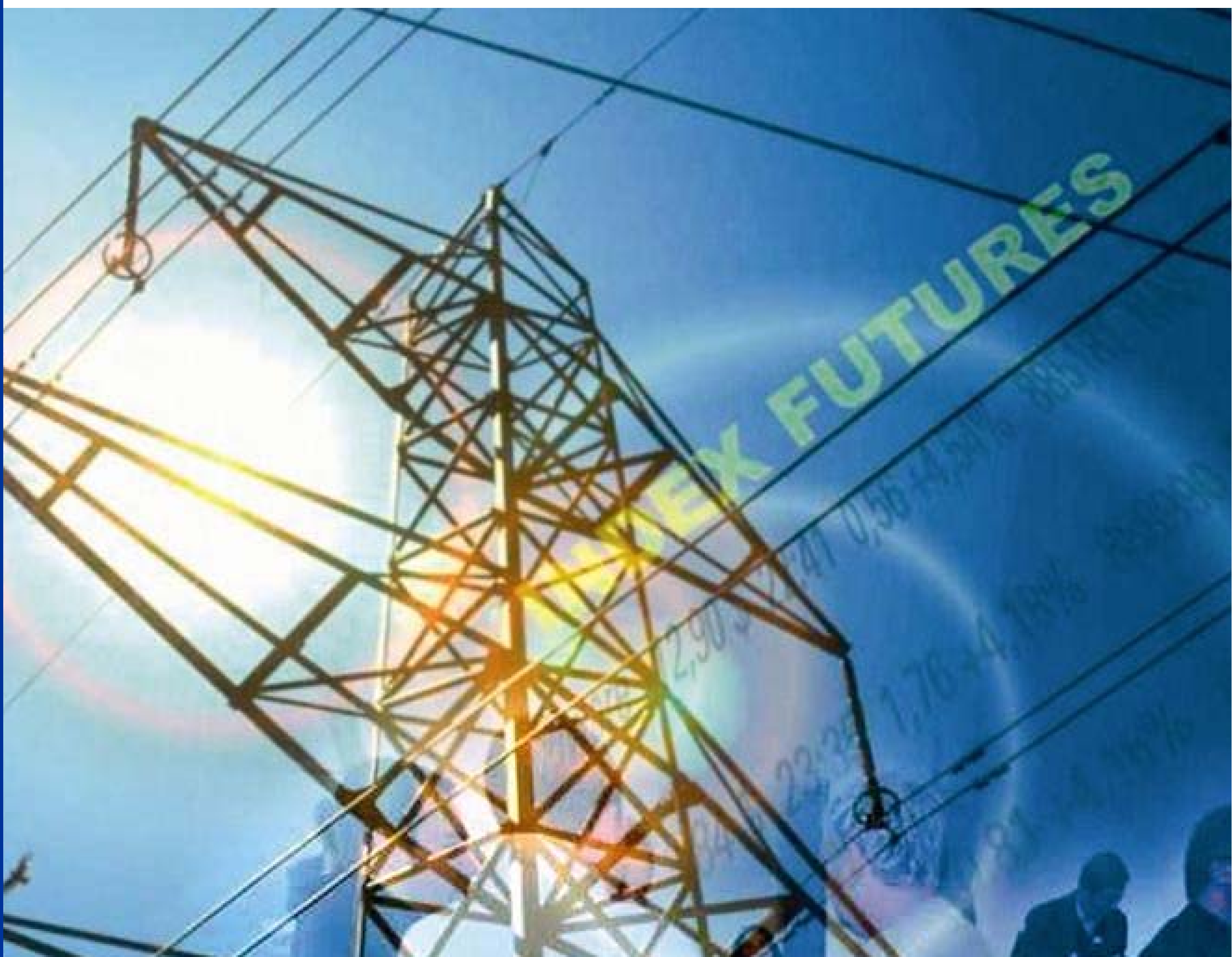
IMPLICATIONS OF THE UK MEETING ITS 2020 RENEWABLE ENERGY TARGET

A report to WWF-UK and Greenpeace UK

August 2008

IMPLICATIONS OF THE UK MEETING ITS 2020 RENEWABLE ENERGY TARGET



Contact details

Name	Email	Telephone
Gareth Davies	gareth.davies@poyry.com	01865 812204
Brendan Cronin	brendan.cronin@poyry.com	01865 812209

Pöyry Energy Consulting is Europe's leading energy consultancy providing strategic, commercial, regulatory and policy advice to Europe's energy markets. Part of Pöyry Plc, the global engineering and consulting firm, Pöyry Energy Consulting merges the expertise of ILEX Energy Consulting, ECON and Convergence Utility Consultants with the management consulting arms of Electrowatt-Ekono and Verbundplan. Our team of 250 energy specialists, located across 15 European offices in 12 countries, offers unparalleled expertise in the rapidly changing energy sector.

Pöyry is a global consulting and engineering firm focusing on the energy, forest industry, infrastructure and environment sectors.

Important

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

Disclaimer

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

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

TABLE OF CONTENTS

[This page is intentionally blank]

EXECUTIVE SUMMARY

Introduction

In January 2008, the European Union published its Climate and Energy package setting out proposals to achieve reductions in EU greenhouse gas emissions of 20% by 2020. As part of this package, the UK has a target to deliver 15% of energy from renewable sources by 2020, a commitment that requires a ten-fold increase in renewable energy consumption from current levels.

The UK government's Renewable Energy Strategy consultation, published in June 2008, presents an illustrative scenario where renewable generation accounts for 32% of total electricity generation by 2020 – more than double the projected share under current policies.

This study, commissioned by WWF-UK and Greenpeace UK, presents high-level scenarios to investigate what implication such changes in renewable penetration will have on the need for new conventional generation capacity. In particular, since the UK's main renewable generation resource is wind, it considers the impact of a growing reliance on an intermittent resource on the overall required installed capacity to maintain a sufficiently robust electricity supply.

Approach to Study

Our approach to this study has been to develop scenarios of annual and peak electricity demand and renewable generation capacity over the period to 2030 and investigate what impact these have on peak capacity margins when combined with assumed closure profiles for existing conventional generation.

From this starting point, we then identify additional conventional generation requirements to ensure maintenance of a set peak capacity margin. For the purposes of this analysis, the capacity margin is set to maintain the larger of a 20% peak capacity margin or a margin to ensure sufficient expected generation to fully cover the loss of wind generation at peak times. This does not imply that we consider a 20% peak capacity margin to be appropriate, or that it is beneficial for the system to plan to fully insure against the loss of intermittent generation at the peak, but we use these as indicative target capacity requirements.

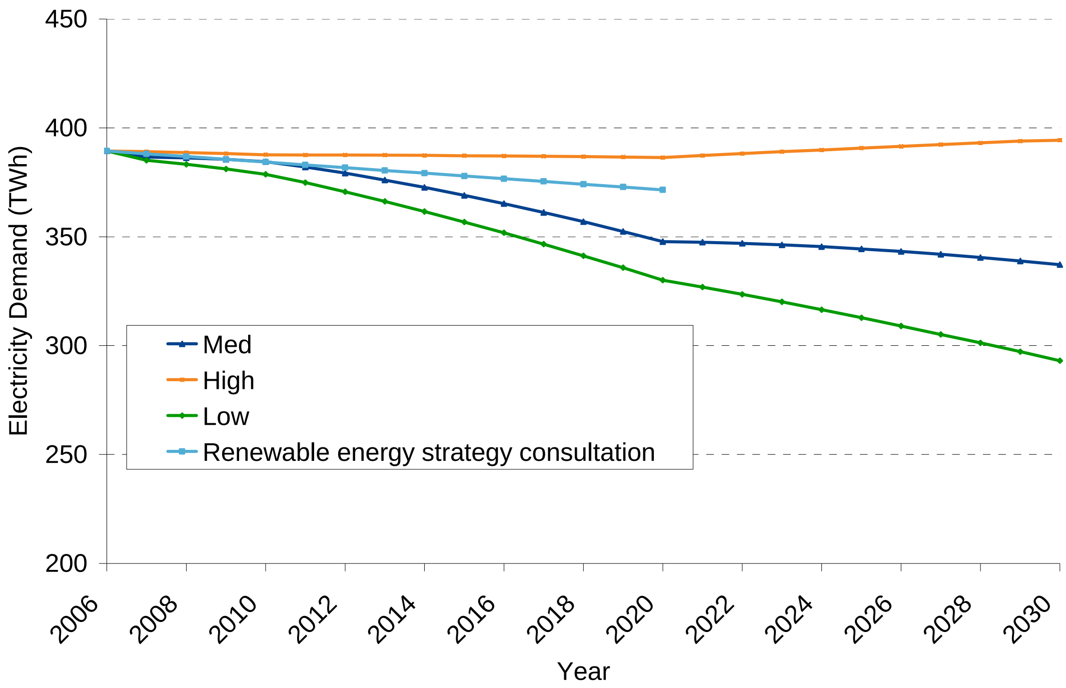
Furthermore, we look at the interaction between demand variability and wind variability across time in order to understand the duration for which this additional capacity is required. This then allows us to assess the need for demand-side or supply-side (peak or baseload) investment activities.

Electricity Demand Scenarios

Our electricity demand scenarios are derived from top-down assessments of total energy demand profiles taken from European Union projections and the UK's National Energy Efficiency Action Plan. Assumptions regarding the share of energy demand by sector and the mix of fuel sources (gas, electricity, heat, solid fuel and liquid fuels) within each sector are then applied.

The level and evolution of electricity demand depends on a range of assumptions regarding electrification of transport and/or heat and the potential for improvements in energy efficiency (either through improved energy intensity or through technological efficiency improvements). The three resultant scenarios (high, medium and low) are shown below.

Figure 1 – Electricity Demand Scenarios



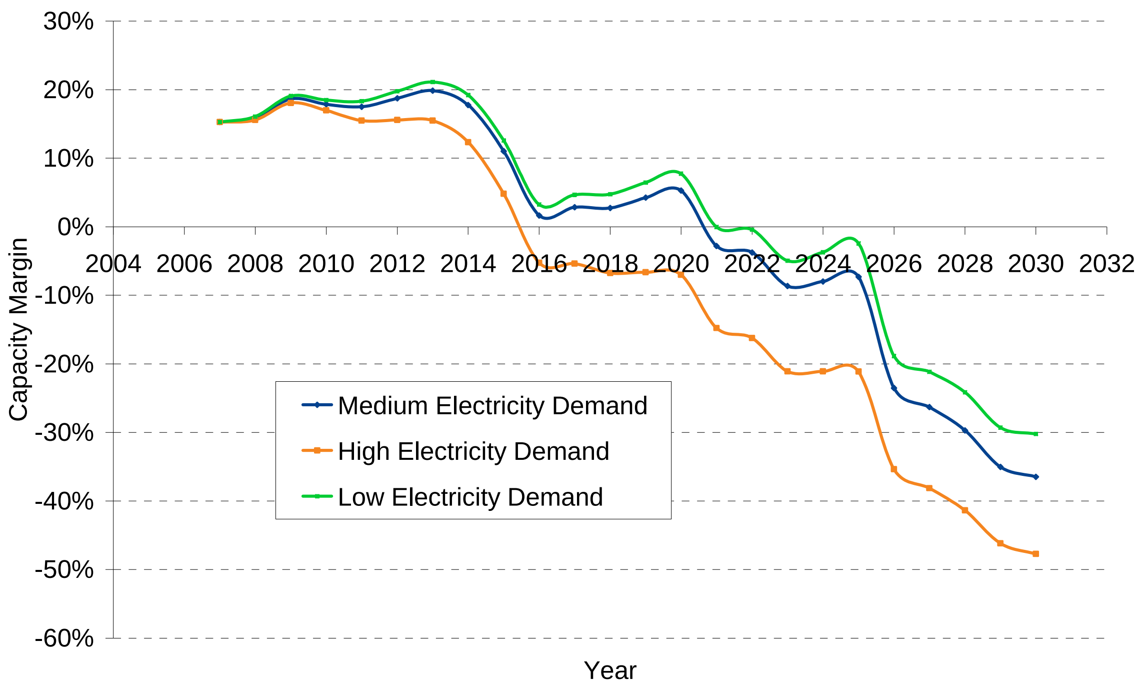
Source: Poyry Energy Consulting

Peak demand projections are also derived based on fixed sector level demand profiles. By 2020, these range from 66GW (in the High scenario) to 56GW (in the Low scenario). Further reductions are observed post-2020 in the Low scenario, though the trend reduction is somewhat reduced as a result of accelerating transport electrification.

Set against this, current transmission connected generation capacity of around 78GW is expected to fall to 57 GW by 2020 and 30 GW by 2030. With no new generation, the peak capacity margin (i.e. the extent to which available capacity on the system exceeds peak demand) would fall from a level of 15% in 2008 to around 0% by 2016, as shown in Figure 2.

Under these circumstances, between 10 GW and 20 GW of additional conventional capacity would be required by 2020 to ensure a 20% peak capacity margin, and by 2030 we would have needed to see somewhere between 25 GW and 45 GW of new capacity on the system.

Figure 2 – Implied peak capacity margin with no new entry



Source: Pöyry Energy Consulting

Renewable Growth Scenarios

The impact of the EU renewable energy target on the electricity sector depends not only on the share of the renewable energy target that must be delivered by the electricity sector, but also on the technology by which it is achieved. We consider two scenarios of renewable electricity penetration:

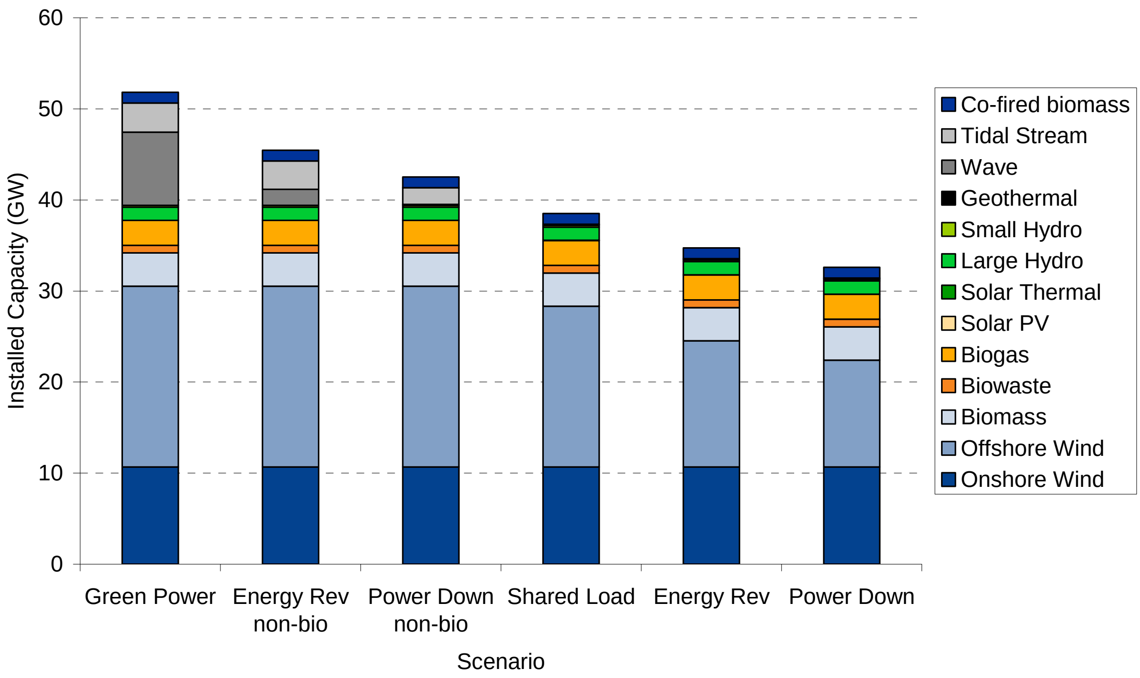
- a 35% share of electricity output – this reflects a contribution in line with BERR's preliminary proposal in the renewable energy strategy consultation; and
- a 45% share of electricity output – this higher level reflects a view that renewable electricity will bear the brunt of the compliance burden, whether due to limited scope for development of the renewable heat and transport sectors or because of political pressure to limit the scale of renewable penetration in the other sectors (in particular, in transport biofuels).

Applying these shares to each of the three electricity demand scenarios provides us with six scenarios of the volume of renewable electricity generation. This results in renewable electricity contributing between 110 and 170 TWh of electricity by 2020 (this compares with an illustrative target of 120 TWh and a 32% share of electricity output in the Renewable Energy Strategy Consultation).

The pattern of deployment and the mix of capacity under each scenario is derived from supply curves of renewable potential calculated within Pöyry's EURENO model, a previous version of which was used to analyse the cost of compliance with the 2020 target for the Department of Business and Regulatory Reform (hereafter referred to as BERR)[1]. As can be seen in Figure 3, the scenarios predict a total renewable capacity in 2020 of between 32GW and 52GW, depending on the scenario, of which between 22GW and 31GW is onshore and offshore wind.

In the higher electricity demand scenarios, where renewable output is in excess of 140 TWh by 2020, build rate assumptions on technologies lead to the use of wave and tidal resource to meet the target, further contributing to the volume of intermittent or variable capacity on the system.

Figure 3 – Comparison of renewable mixes across scenarios



Source: Pöyry Energy Consulting

Effect on Peak Capacity Margins

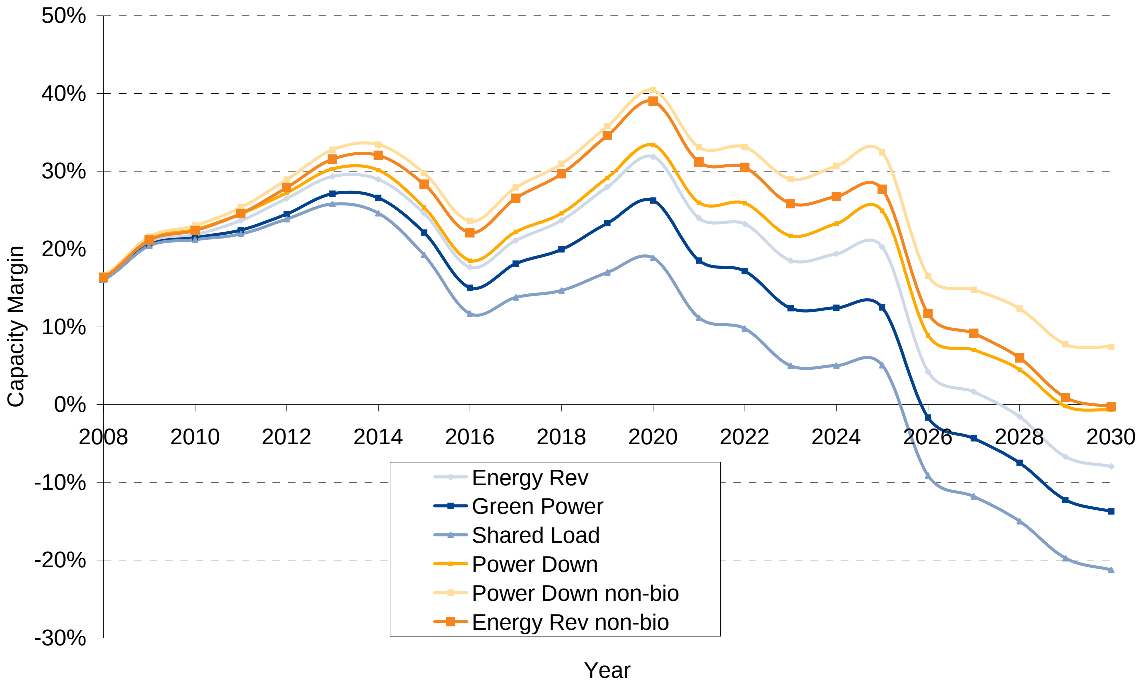
If barriers to renewable deployment on this scale, including planning, network access, supply chain constraints and imperfect policy support mechanisms, are overcome, then this new generation will have a significant impact on the peak capacity margin, as shown in Figure 23:

- While we still observe a sharp fall in the peak capacity margin around 2015/16, this takes us to a range between 10% and 25%. Subsequently, measured margins improve, so that, by 2020, even the lowest measured margin is still close to 20%.
- In the mid 2020's, margins begin to decline substantially, reflecting the fact that renewable generation is assumed to plateau at its 2020 level but conventional plant continues to close.

[1] Pöyry Energy Consulting (2008), 'Compliance Costs for meeting the 20% Renewable energy target in 2020', commissioned by BERR

- Higher margins are observed in scenarios where (a) the contribution from renewable electricity is higher (i.e. the 45% electricity share scenarios); and (b) the peak electricity demand is lower.

Figure 4 – Implied capacity margins with new renewable capacity (%)



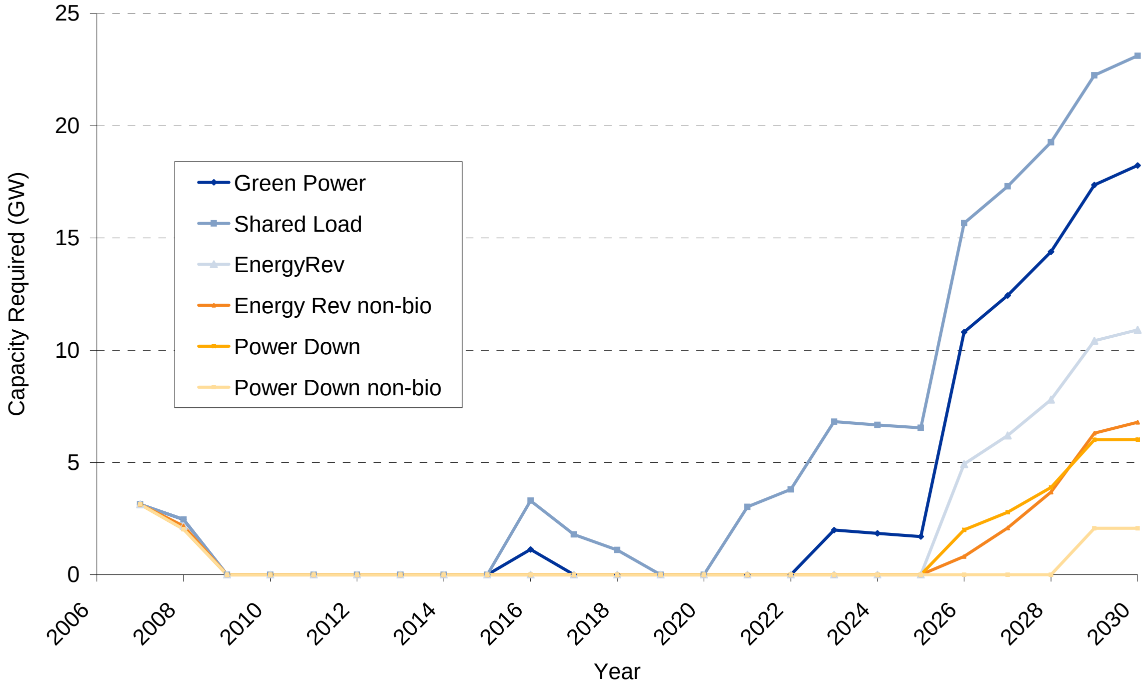
Source: Poyry Energy Consulting

Residual conventional capacity requirements

Prior to the introduction of the renewable capacity, it was identified that somewhere between 10GW and 20GW of new firm capacity would be required to maintain 20% peak capacity margins in 2020, depending on the scenario considered. The addition of up to 50GW of new renewable capacity changes this conclusion, as shown in Figure 5. Figure 5 does include the additional electrical capacity which becomes available as a result of the take-up of CHP systems for heating. It also includes 1GW of interconnection capacity from the UK-Netherlands interconnector, which is currently under construction.

Now, a sustained requirement for additional firm capacity does not emerge until after 2020, and in most cases in the period from 2025 onwards. Importantly, there is a short-term requirement around 2015/2016 in the 'Shared Load' and 'Green Power' scenarios (which are the scenarios with the higher electricity demand) due to a step reduction of around 11GW as many existing coal plant close to comply with EU legislation on large combustion plant emissions, but this does not persist because further renewable generation arrives in the period 2016 to 2020 in order to ensure compliance with final and interim targets. This may, however, lead to short-term tightness in the market if the implication is that conventional capacity does not respond to meet the gap because of lack of investment incentives.

Figure 5 – Additional firm capacity to retain a 20% capacity margin



Source: Poyry Energy Consulting

The identified peak requirement says nothing about the persistence of any shortfalls (something that should inform the type of capacity response required – baseload, peak or demand-side management), nor does it address the possible impact of intermittent generation on the supply-demand balance during non-peak periods. To account for this, we undertook an analysis of the persistence of any shortfall in the margin by analysing the correlation between capacity availability and demand levels for characteristic days in each month for snapshot years (2016, 2020, 2025, and 2030).

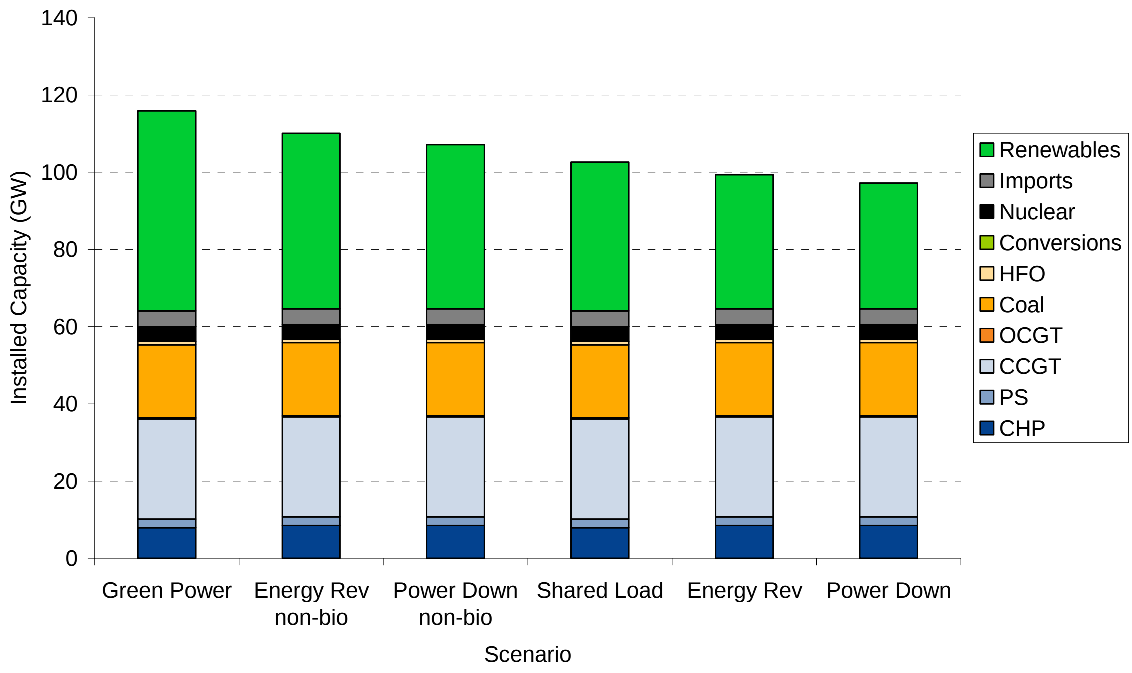
Three results were of interest:

- In only one scenario, Shared Load, is there a shortfall (relative to a 20% margin) in 2016, and here the gap is short-lived.
- Sustained capacity requirements do not emerge until after 2020. This is the period where conventional capacity closure assumptions are not offset by additional renewable generation entry.
- The largest shortfalls occur in the summer months. This reflects the assumption of both low wind availability (wind power has an expected capacity factor of 20% in summer) and high planned outages of conventional generation. It may be expected that this would incentivise some plant to alter their maintenance programmes, though this would increase the risk of outages at other times of the year.

Implications of the Analysis

Taking account of required conventional capacity, the different scenarios result in varying levels of installed capacity (and mix) in the longer-term. Total capacity ranges from 98GW to 118GW by 2020. Figure 6 shows breakdown of installed capacity by technology. It can be noted that in 2020 all conventional generation is existing generation. New conventional generation only needs to be added in the mid-2020's to maintain the capacity margin.

Figure 6 – Total installed capacity by scenario 2020



Source: Pöyry Energy Consulting

Knowing the installed capacity mix over time, we are able to investigate how other indicators of policy goals (gas consumption, carbon emissions, and biomass use) are affected at a high-level:

- Gas consumption – total UK gas consumption falls anywhere from 15% to 42% due to a combination of reduced load factors of CCGT plant with greater renewable penetration and reductions in direct gas demand for space and water heating with the growth in renewable heat sources.
- Carbon emissions – across the scenarios, total UK carbon emissions are between 23% and 34% lower than 1990 levels in 2020, with reductions in 2030 between 25% and 47%. The major reductions occur in scenarios with lower energy demand and hence illustrate the importance of improvements in energy efficiency for continuing progress towards longer-term carbon emission reduction targets.
- Biomass use – biomass accounts for between 4% and 6.5% of total renewable energy use across the scenarios. Biomass contributes between 7% and 8% of total electricity generation by 2020 across scenarios.

These figures are, however, indicative, being based on the assumption that the additional capacity required after 2020 is made up of gas powered generation units. In the longer term, gas generation may be replaced by carbon capture and storage technologies, as they become commercial or the expansion of industrial CHP beyond the baseline assumed capacity of 8 to 8.5GW (well below the technical potential identified in a recent Poyry study for Greenpeace UK)[2].

Limitations of the Study

It should be noted that the scenarios presented above all represent a radical shift away from the business as usual pathway. The results of this analysis are highly sensitive to some of the input assumptions and there are circumstances in which higher capacity requirements may be identified.

- Electricity demand – the projections used in the study, derived from the European Union and the UK National Energy Efficiency Action Plan, reflect two possible views of how electricity demand may evolve. If annual demand does not fall as modelled, and/or peak demand changes are not proportional to annual demand shifts, then further conventional generation will become necessary earlier.
- Speed of renewable development – the scenarios presented in the report depend on commercialisation of some technologies, removal of planning and connection constraints and development of an appropriate support scheme. If these are not forthcoming, then the technical potential of renewable electricity may not be realisable and there will be further need for conventional capacity to meet any additional generation requirement.
- No analysis of wholesale electricity prices – we have not explicitly modelled the effect that enhanced renewable penetration may have on wholesale electricity price formation over time. Higher renewable output may lead to a change in the distribution of wholesale prices, with periods of zero prices (when there is high output of zero marginal cost renewables) and periods of very high prices (when there is low renewable availability and remaining conventional plant must charge higher prices to recover their costs of operation). This may affect entry and exit decisions. For example, it may influence decisions relating to investment to ensure compliance with Phase 2 of the Large Combustion Plants Directive in 2016, resulting in early plant closures or limited operating capabilities.

With over 10GW of conventional plant at different stages of planning and consent at present, and also, in the longer-term the possibility of expanding renewable generation beyond that assumed in the renewable growth scenarios, there is the potential to adjust to some of these uncertainties as events unfold. However, it should be noted that it is assumed in this report that this consented capacity is not built.

Conclusions and Insights

Within the limitations of the modelling, this study has shown that:

- under the demand assumptions, a major need for new generation capacity does not emerge until after 2020, even if we assume that peak capacity must fully account for the risk of a no-wind day event;
- if we are to fully mitigate against no-wind days, effective capacity margins may have to rise to between 25% and 35% in 2020 and after;
- while higher intermittent penetration does increase the variability of generation output, the no-wind scenario is a very-low probability event;

---

[2] 'Potential for CCGT CHP generation at industrial sites in the UK', Pöyry Energy Consulting report commissioned by Greenpeace-UK, April 2008.

- the pattern of intermittency results in short duration capacity shortfalls often best suited to peaking plant or demand-side management;
- additional renewable capacity is likely to incentivise changes in the operating pattern and load factors of conventional generation, with the consequence that we observe lower overall gas demand (and import dependence) and lower carbon emissions; and
- without greater flexibility on the demand-side, capacity margins immediately post-2015 will be lower as there is little incentive for new conventional entry to cover this short-term gap. However this gap eases by 2020 with the addition of more renewable capacity.

As such, there are several lessons for policy development:

- there is a need to establish a long-term framework for renewable electricity investment and operation quickly;
- saving energy will contribute to security and climate change objectives – there is a strong need to facilitate demand-side adjustments in the longer-term if we are to progress towards larger carbon reductions post-2020; and
- there should be a clearer statement of an appropriate definition and level of supply security that addresses the spectrum of risks to electricity and energy supply systems, rather than partial analysis of single technologies.

[This page is intentionally blank]

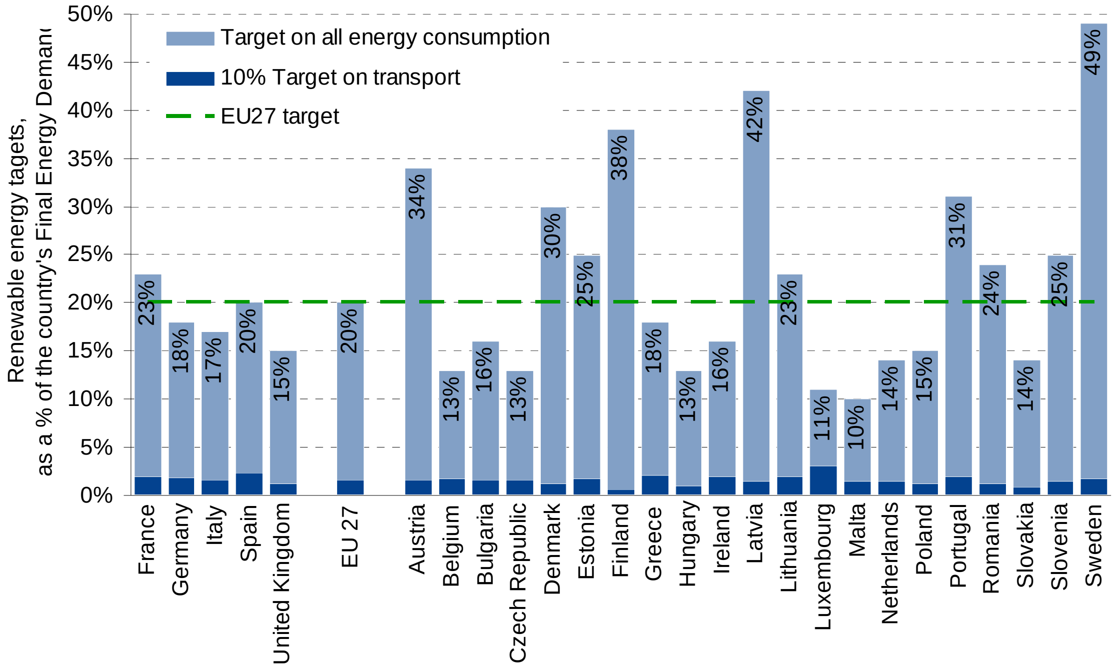
1. INTRODUCTION

1.1 Overview of policy developments

1.1.1 The EU Energy and Climate package

In January 2008, the European Union published its Climate and Energy package setting out proposals to achieve reductions in EU greenhouse gas emissions of 20% by 2020. A core element of this package is the proposed target to source 20% of EU final energy consumption[3] from renewable sources by 2020 (including a specific 10% share of biofuels in the road transport fuel mix). The contribution to meeting this renewable energy target from individual countries varies significantly, as shown in Figure 7, with shares ranging from 10% (for Malta) to 49% (for Sweden).

Figure 7 – Proposed EU renewable energy targets



Source: Pöyry Energy Consulting

The UK's target share is to deliver 15% of energy from renewable sources by 2020, which represents a significant challenge for the UK. To put this in perspective, the current contribution from renewable energy is around 1.5%[4] and projections prior to the publication of the EU Climate and Energy package predicted a renewable energy share of

[3] Including aviation, electricity consumed in the generation of electricity and losses from electricity transmission and distribution.

[4] The current share is 1.43%, based on data in the Digest of UK Energy Statistics, UK Department of Business, Enterprise and Regulatory Reform (hereafter referred to as BERR)

around 5.5% by 2020.[5] Thus, growth in renewable energy must be three times that previously anticipated over the next decade or so.

1.1.2 *The Renewable Energy Strategy consultation*

Recognising this fact, the UK government published its Renewable Energy Strategy consultation in June 2008, as a first step to identifying a means of facilitating a step change in our renewable energy use. The consultation document presented an illustrative renewable energy mix across the three main sectors (electricity, heat and transport) for achieving the 15% target, reproduced in Table 1 below.

Table 1 – Illustrative renewable mix to meet the 2020 renewable energy target

	Renewable energy in final energy consumption, 2006 (TWh)	Renewable energy in final energy consumption, 2020 (TWh)	All energy final energy consumption 2006 (TWh)	All energy final energy consumption 2020 (TWh)
Heat (excluding electricity for heat)	4	90	735	635
Electricity	19	120	393	375
Transport	2	55	653	730
All sectors	**25**	**265**	**1781**	**1740**

Source: BERR, Renewable Energy Consultation, June 2008

This illustrative mix requires radical change in all three sectors. In heat and transport, renewable sources are not well established and the key challenge is establishing them as a credible alternative to conventional sources. Even with these optimistic targets in the other areas, renewable electricity is still expected to shoulder the majority of the burden of compliance, accounting for 47% of total renewable energy supplied. Under BERR's illustrative scenario, renewable generation will account for 32% of total electricity generation by 2020, more than double the projected share under current policies.

1.2 Aim of the study

In the 2007 Energy White Paper, the government highlighted the investment challenge facing the GB generation sector. Transmission connected capacity then was at 76GW and underlying analysis projected that, by 2020, at least 22.5GW of this was expected to have closed[6] and by 2030 between 30 and 35 GW of new capacity was forecast to be required to cover a combination of closures and demand growth.

This study, commissioned by WWF-UK and Greenpeace UK, investigates what implications the compliance with the renewable energy target will have on the need for new capacity, over and above that which is expected to arise from renewable sources during the next 15-20 years. In particular, since GB's main renewable generation

[5] Poyry (2008), Compliance Costs for meeting the 20% Renewable Energy Target in 2020, A report for BERR.

[6] The majority of closures were scheduled closures of the current nuclear fleet and the loss of oil and coal-fired plant that opted-out of the EU Large Combustion Plants Directive, thereby having to close by 2016.

resource is wind, it considers the impact of a growing reliance on an intermittent resource[7] on the overall required installed capacity to maintain a sufficiently robust electricity supply.

Whereas higher volumes of renewable capacity should reduce required generation investment in other technologies, uncertainty remains over the materiality of this reduction, due in part to debate over the volume of capacity that will emerge, but also reflecting the extent to which higher capacity margins are required to ensure security of supply and network stability as intermittent generation becomes more prevalent.

For example, the UK Business Council for Sustainable Energy (UKBCSE)[8] has estimated that, maintaining current electricity demand conditions, in 2020, up to 17GW of capacity will be required to provide back-up for renewable generation of 55GW that includes 39GW of onshore and offshore wind. This contributes to a total installed generation capacity of around 120GW, compared with 80GW at present.

The impact of the renewable energy target depends on how it affects the pattern of electricity supply relative to demand. Thus, we ask the following questions:

- How do we expect energy and electricity demand (both peak and annual) to evolve over the period?
- What mix of renewable generation is necessary and feasible to meet the renewable energy target?
- How do we define required generation capacity?
- What additional capacity may be required over and above the predicted renewable generation entry?
- Are there any unintended consequences of meeting the renewable energy target for meeting the capacity gap?

We do not restrict ourselves to investigating a business as usual position or the BERR illustrative scenario, rather we undertake an assessment of several scenarios of paths of energy and electricity demand over the period out to 2030, under varying assumptions regarding the burden of compliance that will fall onto the renewable electricity sector.

1.3 Structure of the report

The remainder of this study is structured as follows:

- chapter 2 outlines the approach and methodology for the analysis;
- chapter 3 discusses the energy demand scenarios, the initial capacity requirement and alternative renewable generation scenarios;
- chapter 4 summarises the implications for the capacity requirement under our core scenarios, identifying incremental conventional build and the implied capacity mix;
- chapter 5 highlights the limitations of the current analysis; and
- chapter 6 presents conclusions and insights from the analysis.

[7] In the longer-term, or with higher capacity requirements, intermittent marine technologies will also add to this volume.

[8] UKBCSE (2008), Implementing the EU Renewable Energy Target in the UK Emerging Issues for Consideration.

Additional modelling details are contained within the Annexes to this report.

1.4 About Pöyry Energy Consulting

Pöyry Energy Consulting is Europe's leading energy consultancy providing strategic, commercial, regulatory and policy advice to Europe's energy markets. Part of Pöyry Plc, the global engineering and consulting firm, Pöyry Energy Consulting merges the expertise of ILEX Energy Consulting, ECON and Convergence Utility Consultants with the management consulting arms of Electrowatt-Ekono and Verbundplan. Our team of 250 energy specialists, located across 15 European offices in 12 countries, offers unparalleled expertise in the rapidly changing energy sector.

Pöyry is a global consulting and engineering firm focusing on the energy, forest industry, infrastructure and environment sectors.

2. OVERVIEW OF APPROACH

Our approach to this study involves several stages of scenario development and analysis, to ensure consistency between overall energy demand, electricity demand and carbon and renewable energy targets. The key stages are:

- derivation of electricity demand scenarios, capturing changes in annual demand and annual and daily profiles;
- construction of indicative renewable generation penetration profiles, utilising the renewable electricity supply curve developed by Pöyry during the BERR compliance cost study;
- definition of required generation capacity; and
- Identification of additional capacity requirements over and above the assumed renewable build.

We are then able to compare the differences that emerge across scenarios in total generation capacity, the generation mix, and other useful policy indicators including total gas use and import dependence and carbon emissions.

Core methodology is described in more detail below.

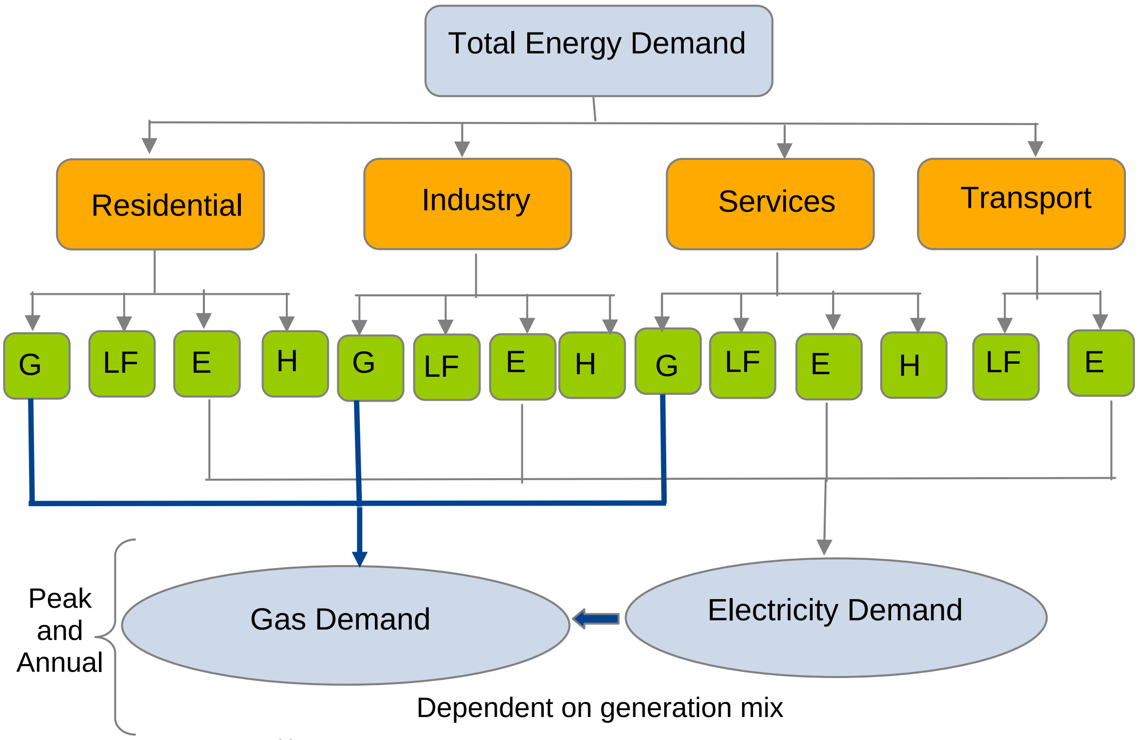
2.1 Electricity demand

Our electricity demand projections are constructed in a top-down fashion, starting from a total energy demand assumption, as illustrated in Figure 8. Total energy demand is apportioned between four main end-use sectors in the economy – residential, industry, services (including public sector) and transport – and within each sector energy consumption is then split between sources (gas (G), liquid fuel (LF), electricity (E) and direct heat (H)).

Over the period of the analysis (out to 2030), changes in energy use across the end-use sectors and in the shares of specific fuels within a sector are applied, producing a path of electricity demand across time. Combining these with sector-specific demand profiles, within-day and monthly demand patterns can be constructed.

It should be noted that the electricity demand scenarios which are presented in this report are lower than demand scenarios which are published by National Grid (which are also the demand scenario’s used in Pöyry’s market reports). The National Grid forecasts are closer to a ‘business as usual’ prediction. The electricity demand scenarios presented here represent electricity demand which could only be achieved with significant changes in energy efficiency and reduction in end use demand.

Figure 8 – Calculation of electricity demand from gas demand

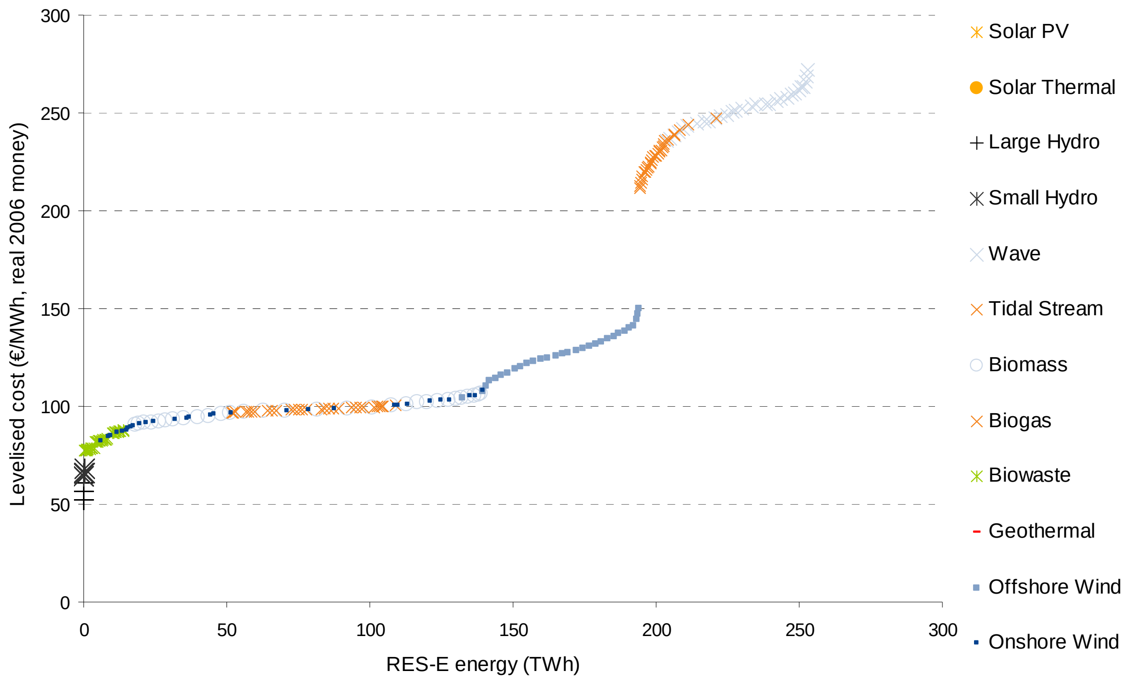


Source: Pöyry Energy Consulting

2.2 Renewable generation scenarios

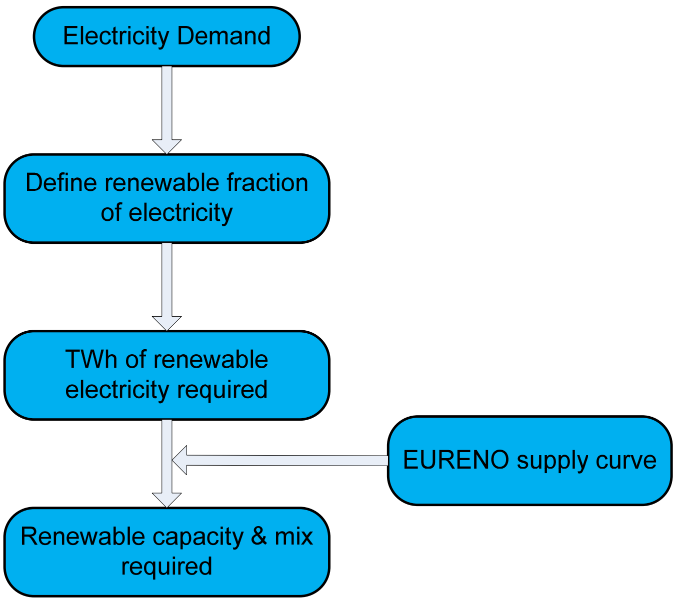
For a given electricity demand level and an assumed share of renewable electricity in total electricity output we can calculate the renewable build requirement. The mix of generation to meet the TWh requirement, and the timing of its entry, is determined using Pöyry's Eureno supply curve for renewable technologies. The UK renewable electricity supply curve to 2020 can be seen in Figure 9. Since this derives an output-based figure, an implied capacity is obtained by applying the load factor assumptions in the Eureno model. A table of load factors can be seen in Figure 39 in the Annex. Figure 10 provides an overview of the process of calculating the renewable capacity mixes.

Figure 9 – Indicative UK renewable electricity supply curve to 2020



Source: Pöyry Energy Consulting

Figure 10 – Calculation of renewable capacity & renewable generation mix



Source: Pöyry Energy Consulting

2.3 Required generation capacity

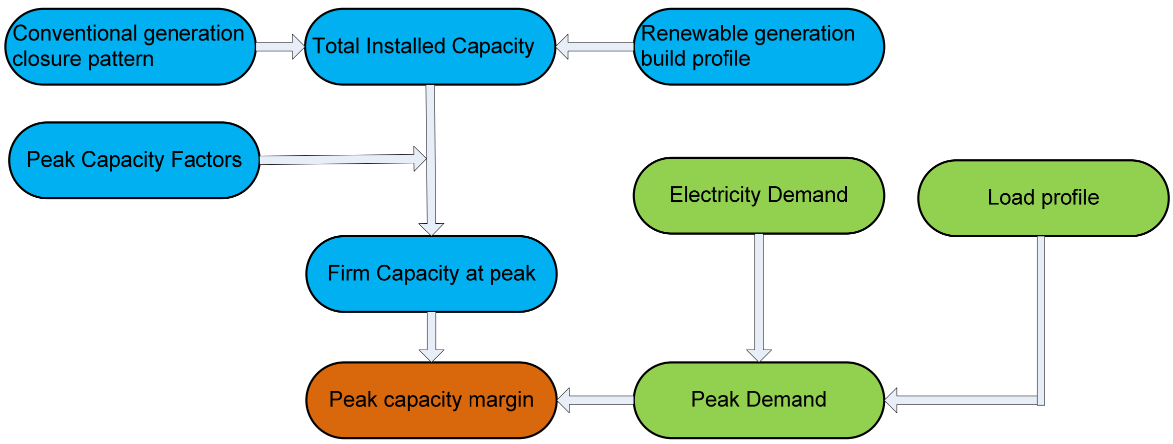
2.3.1 *Peak capacity margin*

The total generation capacity that must be installed is normally assumed to be at a level such that the electricity system can maintain an appropriate level of security of supply. One of the main measures of security of supply on the electricity system is the peak capacity margin. The peak capacity margin reports the extent to which capacity available is in excess of peak demand, a higher margin enabling the system to withstand more extreme shocks to the supply-demand balance (be these due to higher demand or forced outages of capacity) without affecting continuity of supply.

Using installed capacity to calculate the capacity margin will not generally produce a realistic assessment of the reliability of the system at peak times since it is unlikely that all plant will be available at that time. There is always the probability of a forced outage of a plant (e.g. a closure due to technical failures or interruption in fuel supply) and the availability of intermittent generation sources (such as wind) is variable and not necessarily coincident with demand peaks.

Consequently, an effective capacity margin is calculated by applying a capacity factor to the installed capacity to reflect the expected availability of that technology at peak demand periods, as illustrated in Figure 11.

Figure 11 - Calculation of the peak capacity margin



Source: Pöyry Energy Consulting

There are alternative effective capacity factors that are used in analysis of capacity margins. For the purposes of this study, we consider the peak capacity factor (i.e. the expected availability on the peak day). Other studies, for example, the Energy Markets Outlook published by BERR or the assessment of renewable support schemes to meet the 2020 renewables target prepared for BERR use an average availability over a winter period (or annually). Since we would expect plant to be subject only to forced outages on the peak day (due to the price incentives to make plant available), the use of peak capacity factor would lead to a higher reported capacity margin than one using a winter average factor for the same installed generation capacity. A comparison of the capacity factors used in this report with other published capacity factors can be seen in Figure 38 in the annexes.

2.3.2 Required installed capacity

The required installed capacity at any point in time should be such that, given the predictability and reliability of the current generation mix and the volatility in demand patterns, only supply interruptions that are too costly to mitigate through provision of additional capacity (i.e. the benefit of investing to insure against this risk does not offset the cost of providing the insurance) will remain.

This would not be a fixed capacity requirement. It would change as the generation mix altered reflecting, for example, an increasing reliance on a single input fuel, or higher volumes of intermittent generation or the consequences of an ageing fleet. Furthermore, it would respond to alternative measures to mitigate risks of supply interruption such as new gas storage facilities, demand-side management improvements and development of complementary new technologies such as electricity storage options or the electrification of the road transport fleet.

Within the scope of this project, we have not been able to investigate what the optimal level of electricity supply security should be and how best to meet it, though this is an area where it is important policymakers provide more clarity on requirements and responsibilities if markets are to invest appropriately to deliver supply security. Instead, we define our required generation capacity to be that which will deliver a specific peak capacity margin. The chosen capacity margin is interpreted as being a proxy for a given level of security of supply.

For the purposes of this study, we define this target peak capacity margin according to one of two measures:

- the maintenance of an effective capacity margin that is comparable to long-term historic capacity margins in the order of 20%; or
- the maintenance of a capacity margin that would fully compensate for the unavailability of intermittent generation sources at peak times.[9]

The use of the latter measure does not imply that it is desirable to fully insure against a 'no-wind' day on the system since this is a low probability event.

As has been discussed in the Redpoint analysis for BERR as part of the Renewable Energy Strategy consultation, the chance of a no-wind event is 'close to zero' and analysis by Graham Sinden[10] has found that, over a 33 year period from 1970 to 2004, there would have been no wind speed conditions (either low or high) that would have prevented generation across the entire country. Furthermore, the timing of low wind availability and high electricity demand are not necessarily coincident. For example, a 2003 study by Oxera for BNFL[11] reported that there were only 23 hours in a year (or 0.25% of total hours) when electricity demand was expected to be between 90% and 100% and wind output was less than 10%.

[9] It should be noted that this does not mean compensation for 100% of installed intermittent capacity, just that portion of the capacity that is assumed to be available at peak times in the effective capacity margin calculation.

[10] Sinden, G. (2006) Characteristics of the UK wind resource: Long-term patterns and relationship to electricity demand. Energy Policy Journal.

[11] OXERA, The Non-market Value of Generation Technologies, June 2003.

Whether this event should be fully mitigated depends on the impact of the outage and the risk of occurrence. Arguably, as penetration increases the interaction between intermittent generation output and other system events on the demand and supply-side will increase, but to what extent these risks should be mitigated through additional capacity is unclear. Consequently, we have used the 'no-wind' margin as a way of investigating the impact of this one specific extreme risk event.

3. DEFINING THE SCENARIOS

To consider the implication of the EU 2020 renewable energy target, we must first set out the scale of the challenge (i.e. the overall requirement for new capacity as generation closes). The combination of the path of electricity demand and of assumed plant closure profiles defines the movement in the capacity margin with no new generation build and the effective firm capacity that must be delivered to ensure a 20% peak capacity margin is maintained. This is outlined in sections 3.1 to 3.3 below.

Subsequently, we construct several scenarios of potential renewable generation build, consistent with meeting the proposed UK's 15% target by 2020. These scenarios and the consistent set of assumptions on total renewable energy growth are described in section 3.4.

3.1 Electricity demand scenarios

3.1.1 Total Energy Demand

As outlined in Chapter 2, our electricity demand scenarios are determined from top-down assumptions on the path of energy demand and the attribution of this demand between sectors and across fuel types.

Two potential total energy demand scenarios (shown in Figure 12) have been developed for this study – a high and a low scenario. The rationale for this is to investigate not only the impact of supply-side changes from renewable generation, but to analyse how further demand-side adjustments may benefit security of supply.

The high energy demand scenario is based on the Baseline scenario from the European Commission's '*Energy in Europe: Trends to 2030 (2007 Update)'* for the UK which predicts a slight increase in final energy consumption end-use energy demand from 1886 TWh in 2006 to 1903 TWh in 2020 and 1914 TWh in 2030.[12] This figure includes aviation consumption, but Figure 12 also presents the path of energy consumption without aviation.

Our low energy demand scenario encapsulates a very different projection for total energy demand, with substantial reductions in overall energy use across the period. This path is based on the aspirational targets contained in the UK National Energy Efficiency Action Plan, produced in accordance with the requirements of the 2006 End-use Energy Directive. This directive requires a 9% reduction in end-use energy consumption by 2016. The UK target is to achieve double this reduction and achieve an 18% reduction in end-use energy demand against a baseline demand growth scenario. End-use demand falls to 1414 TWh in 2020[13] and 1274 TWh in 2030 in this scenario.

Alongside these projections, Figure 12 also shows the energy demand path underlying BERR's analysis in the renewable energy strategy consultation. As can be seen, the high

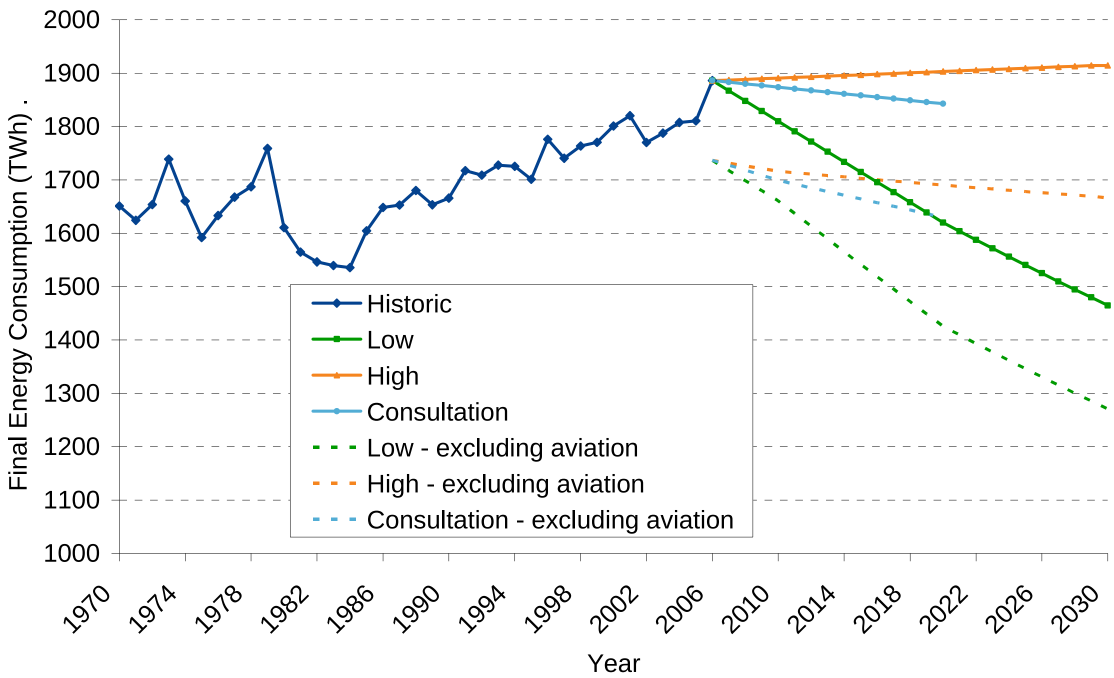
---

[12] These projections underpin much of the EC Impact Assessment on the renewable energy target and are therefore seen as an appropriate base case for energy demand.

[13] This compares with a central estimate, including White Paper policy proposals, of 1593 TWh reported in the Updated Energy Projections (February 2008).

energy demand scenario is above this path, whereas the low energy demand is significantly lower.

Figure 12 – Total energy demand scenarios



Source: Poyry Energy Consulting

3.1.2 Implied Electricity Demand

In 2007, the share of energy demand accounted for by each of the four main end-use sectors was as shown in Table 2, below.

Table 2 – End-use sector shares of primary energy demand (2007, 2020 and 2030) for both the high and low total energy demand scenario

	2007	2020 High	2020 Low	2030 High	2030 Low
Residental	32%	32%	32%	31%	32%
Services	14%	14%	13%	14%	13%
Industry	23%	24%	22%	25%	22%
Transport	31%	31%	32%	30%	33%

Source: Pöyry Energy Consulting

While we may expect sector growth rates and/or improvements in energy intensity to vary according to potential and current performance, the table shows that these proportions do not vary significantly – sector shares change by no more than ±3% relative to the 2006 base position.

However, within sectors, there are some major changes in the energy sources assumed over time, reflecting, in particular, three major technological/demand shifts:

- Electrification of transport – in 2007, 1.8% of total transport energy demand was sourced from electricity (primarily from the rail sector). In the future, developments in technology and growing commercial competitiveness are expected to increase electrification potential in the sector, wit the majority of growth in the private, public and freight fleet. The speed and extent of electrification has important implications for the electricity system, increasing demand but also shifting the overall profile of within-day demand. Uncertainty over the speed of development means we have developed two scenarios – a low scenario with 2.9% share by 2020 and a high scenario with a 6.9% share by 2020.
- Development of decentralised heating options – the take-up of decentralised direct heating technologies for heat supply (e.g. ground source heat pumps and solar thermal heating systems as well as further penetration of combined heat and power options) is seen as an alternative to centralised gas-based generation options. These alternative options, many of which are renewable, increase to 6% of total residential demand by 2020 in the low uptake case and 18.7% in the high uptake case.
- Electrification of heating – another alternative heating option is the electrification of space and water heating, replacing gas-based heating options. This trend may be seen as a potential path to achieving the renewables target if it was seen as easier to increase centralised renewable generation than to develop new heating grids. In these circumstances, gas demand is forecast to fall by between 8.7% and 27.6% by 2020 depending on the scenario.

The key assumptions underlying the electricity demand scenarios are summarised in Table 3.

Table 3 – Electricity demand scenario assumptions

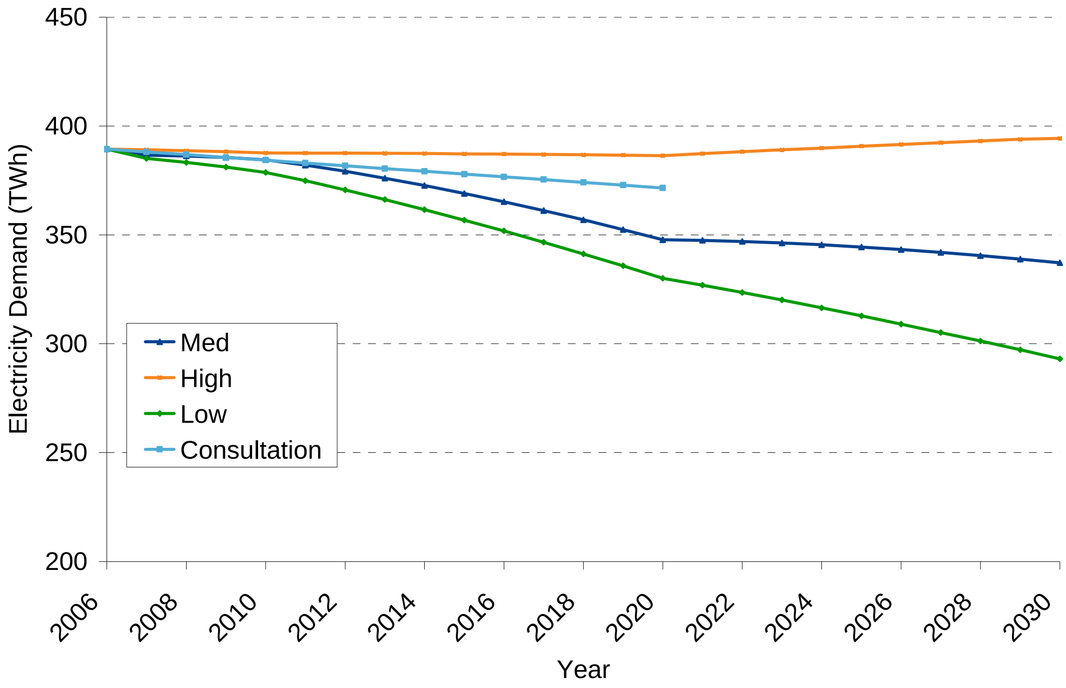
	High	Medium	Low
Total Energy Demand	High	Low	Low
Electrification of road transport by 2020	2.9%	6.7%	2.9%
Heat in residental consumption by 2020	6.0%	18.7%	18.7%
Change in direct gas consumption by 2020	-8.7%	-27.6%	-27.6%

Source: Pöyry Energy Consulting

As a result of applying these assumptions, the electricity demand scenarios are as shown in Figure 13. The demand used in the Renewable Energy Strategy consultation is also shown. It should be noted that all of these demand scenarios represent a departure from the business as usual scenarios (such as those published by National Grid), which forecast continued demand growth. However other recent reports, have suggested lower growth, for example, the Redpoint report which was commissioned by BERR[14] for the preparation of the renewable consultation had a level of demand which showed a slow decline from 375 TWh to 360 TWh by 2020, before increasing to 390 TWh by 2030.

It should be noted that the electricity demand modelled in this report is total electricity demand – which is supplied by both transmission and off-grid generation. Generation which was transmitted across National Grid's network was 373 TWh in 2007, total electricity generation in 2007 was 394 TWh. No assumptions have been made about how much total electricity generation may be transmission connected in the future.

Figure 13 – Electricity Demand Scenarios



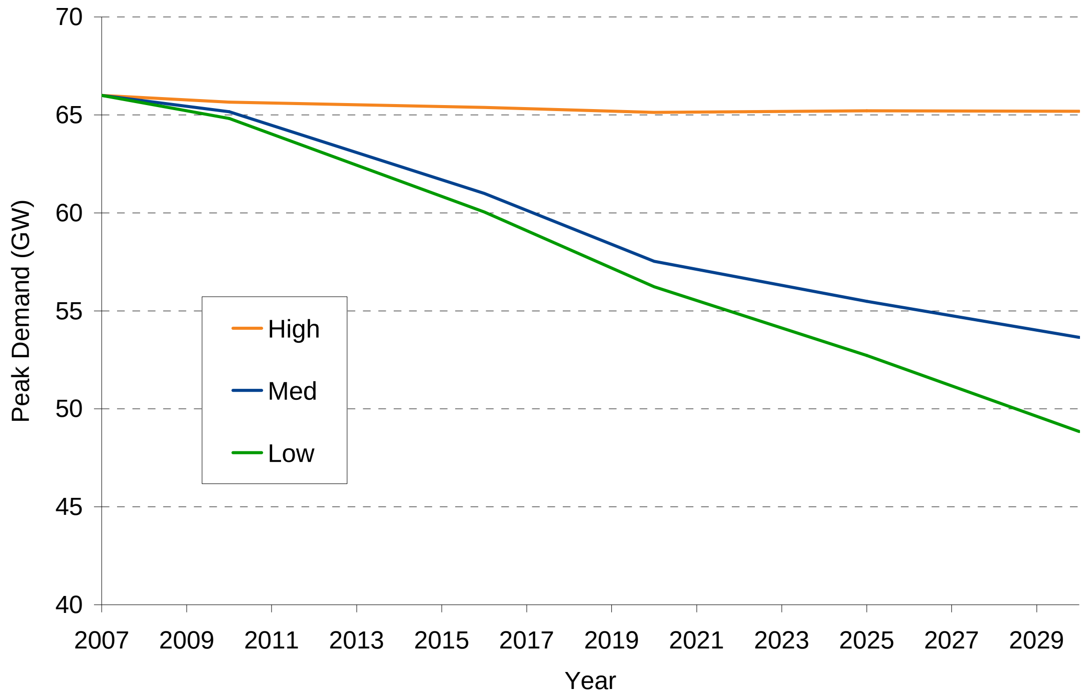
Source: Poyry Energy Consulting

In addition to considering annual demand, a corresponding peak demand projection was also required. The peak demand was calculated from generic sector level load profiles, as shown in Figure 37. These profiles are fixed across time and therefore may not accurately reflect peak demand changes, to the extent that behavioural changes or new technologies are able to alter the pattern of usage. The peak demand corresponding to each scenario is shown in Figure 14. The fall off in peak demand in the medium and low

[14] Redpoint Energy (2008) Consulting Implementation of EU 2020 Renewable Target in the UK Electricity Sector: Renewable Support Schemes.

electricity scenarios is very steep and will be very difficult to achieve without large energy efficiency efforts in all sectors of the economy.

Figure 14 – Peak electricity demand

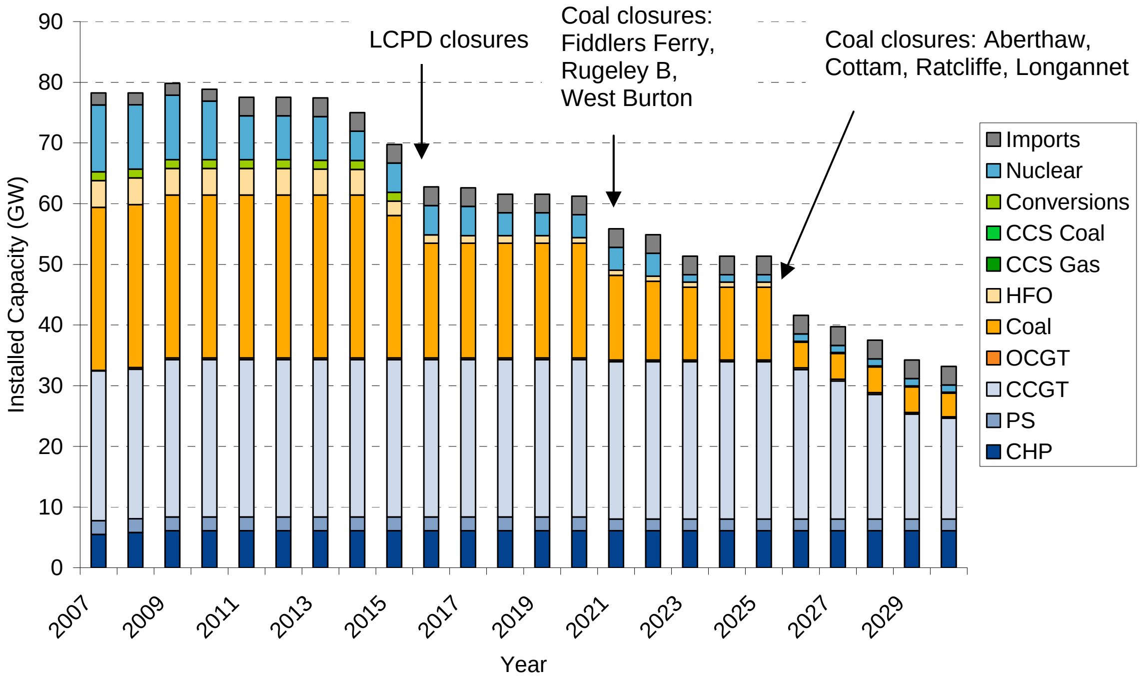


Source: Poyry Energy Consulting

3.2 Current generation capacity and closure patterns

Our assumptions on conventional plant closure are shown in Figure 15. By 2009, total installed GB generation capacity is 88 GW, including 8 GW of renewable generation, 28 GW of Coal, 26 GW of CCGT and 11 GW of nuclear power. If we assume that no new capacity is built post-2009, we anticipate generation capacity falling to around 68 GW by 2020 and 40 GW by 2030. A total of 11GW of coal and oil fired capacity exits the system by 2015 as a result of the impact of the Large Combustion Plant Directive. 7 GW of nuclear plant is retired by 2020. A further 9.5 GW of nuclear closures are expected by 2030, with the remaining closures assessed to be due to plant reaching the end of their operational lifetime. Since we do not explicitly model commercial operation patterns of plant, there is a possibility that some plant will close due to a lack of profitability over the time period.

Figure 15 – Closure pattern of current installed conventional capacity



Source: Poyry Energy Consulting

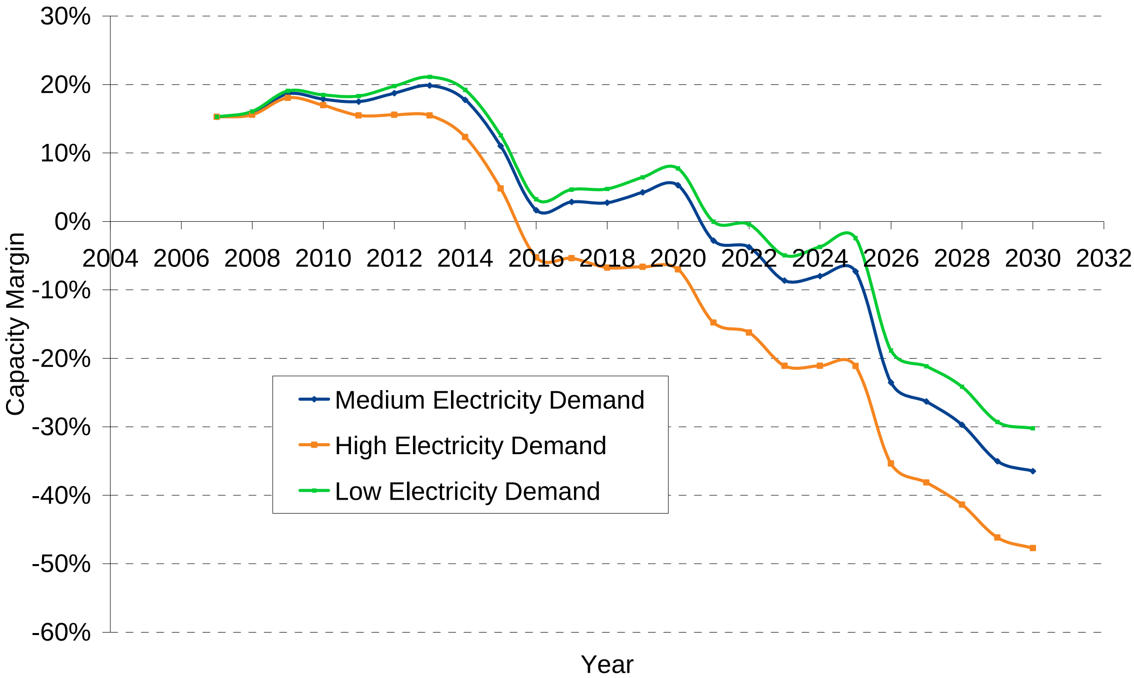
3.3 Implication for capacity margin and required generation

Combining the electricity demand scenarios and the plant closure pattern, the scale of the challenge facing the electricity sector is clear. Effectively, as shown in Figure 16, the peak capacity margin falls from a level of 15% in 2008 to around 0% by 2016. The timing of the fall coincides with the loss of up to 11GW of coal- and oil-fired plant in 2015 and 2016, though the speed of decline is partly mitigate in the medium and low scenarios by a corresponding decline in the peak electricity demand figure.

The additional capacity required at peak to ensure a 20% peak capacity margin is maintained is shown in Figure 17. As can be seen, the pattern of requirement is similar across the scenarios, with a step change around 2015 and a sustained increase from 2020. The firm capacity required by 2020 ranges between 10 GW and 20 GW, but by 2030 rises to somewhere between 25 GW and 45 GW. Note that this actually means a higher level of installed capacity as we must adjust for plant availability using the peak capacity factor.[15]

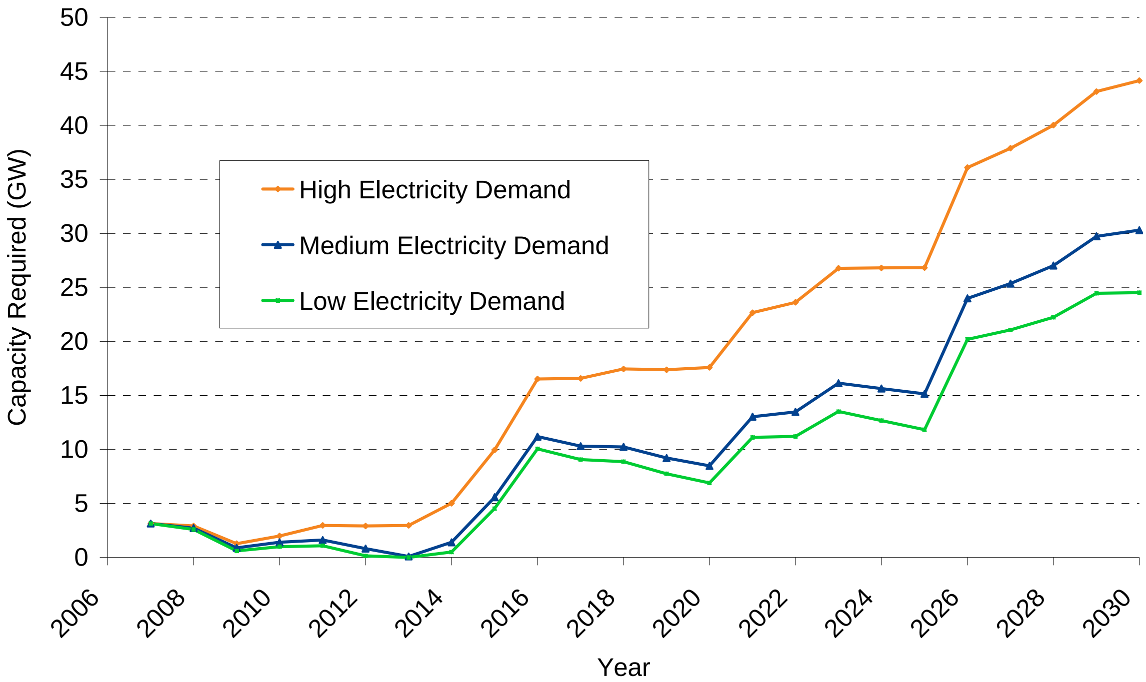
[15] For example, if a new gas-fired CCGT has a peak capacity factor of 96% then to provide 1GW of peak firm capacity we would need 1,042MW of CCGT capacity installed.

Figure 16 – Implied peak capacity margin with no new entry



Source: Pöyry Energy Consulting

Figure 17 – Implied effective capacity required to maintain a 20% peak capacity margin



Source: Pöyry Energy Consulting

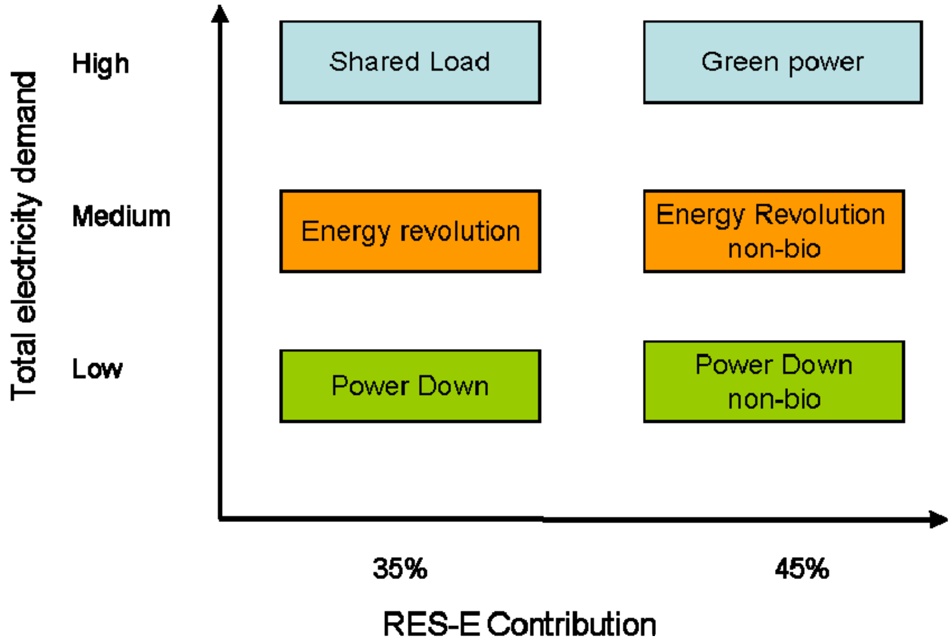
3.4 Renewable generation scenarios

The impact of the EU renewable energy target proposals depend on the volume of renewable generation capacity delivered and the type of capacity delivered. We have developed scenarios in conjunction with WWF-UK and Greenpeace to reflect levels of contribution from the renewable electricity sector. These scenarios assume two possible levels of renewable electricity penetration:

- a 35% share of electricity output – this reflects a contribution in line with BERR's preliminary proposal in the renewable energy strategy consultation; and
- a 45% share of electricity output – this higher level reflects a view that renewable electricity will bear the brunt of the compliance burden, wither due to limited scope for development of the other sectors or because of political pressure to limit the scale of renewable penetration in the other sectors (in particular, in transport biofuels).

The renewable electricity contribution is then matched against each of the three electricity demand scenarios to produce six high-level renewable entry scenarios, as shown in Figure 18. The 'non-bio' Energy Revolution and Power Down scenarios have a 5% biofuels target and so require the higher fractions of renewable electricity. The Green Power scenario also contains the lower, 5%, biofuels target as it also contains a high level of renewable electricity.

Figure 18 – Schematic of market scenarios



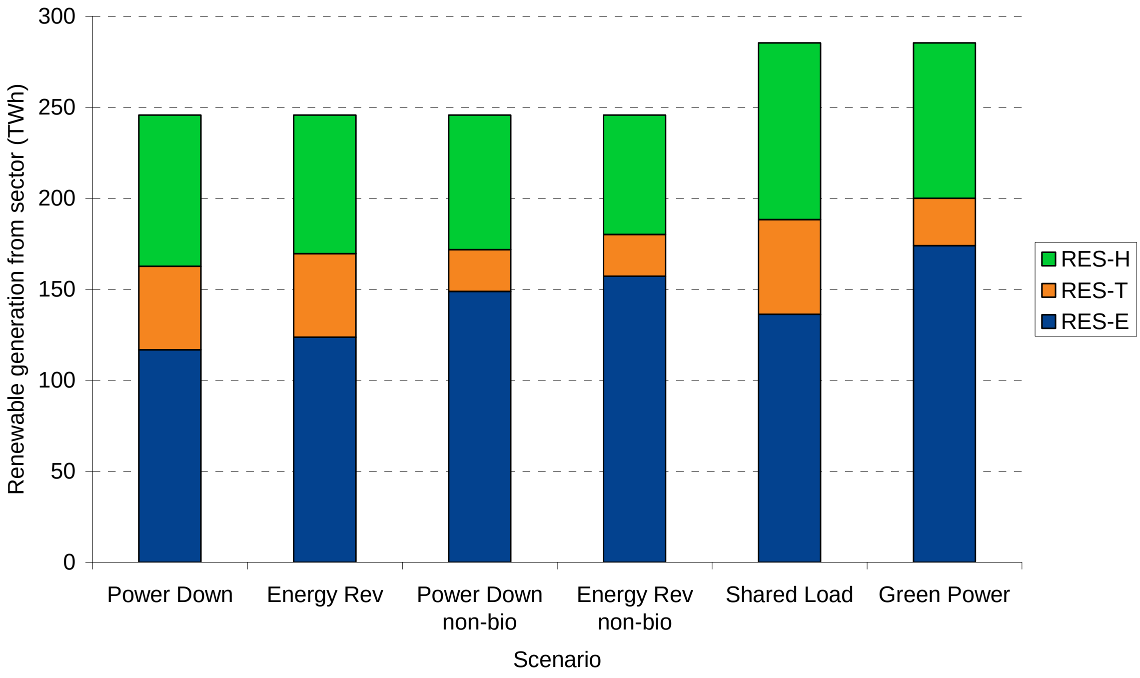
Source: Pöyry Energy Consulting

3.4.1 *Implied renewable sector mix*

It is possible to derive the required contributions from each sector (electricity, transport and heat) to the final renewable energy target. The contributions from renewable electricity (RES-E) and renewable transport (RES-T) are fixed as the scenarios specify a level of renewable electricity generation and a level of renewable transport energy. Thus, the renewable heat requirement is calculated as the residual required to meet the final renewable energy target.

Figure 19 shows contribution of each sector to the renewable energy target in 2020 for each scenario. The total contribution from, renewable electricity sources is between 110 and 170 TWh of electricity. The renewable consultation published in June 2008 by BERR proposes a preliminary target of 120 TWh.

Figure 19 Contribution of electricity, transport and heat to total energy consumption in 2020



Source: Poyry Energy Consulting

The scenarios which contain a high level of end-use energy demand (shared load and Green power) require a high level of energy from renewable sources. The additional requirement in the high end-use energy demand is made up mainly from renewable heat sources. Currently there are negligible levels of heat sources from renewables sources, scaling this up to almost 100 TWh will be a great challenge. The Power Down non-bio and Energy Revolution non-bio scenarios which contain the low biofuels target also require a much greater percentage of renewable energy from electricity.

3.4.2 Implications of strict limits on the Renewable Transport Fuel Obligation

Concerns have been raised recently about the environmental sustainability of liquid biofuels as well as concerns that the demand for feedstocks for liquid biofuels is leading to increased food prices[16]. We have partially addressed this through the lower transport biofuel contribution in the Green Power and 'non-bio' scenarios. However, further adjustments would be needed if the RTFO were to remain at current levels of around 2.5%.

Depending on the scenario, this would place a much greater burden on the other sectors to increase their energy from renewable sources so as to still meet the overall EU renewable energy target. Between 11 and 39 TWh of additional renewable energy would

[16] These issues have been highlighted in reports such as the Renewable Fuel's Agency's 'Review of the Indirect Effects of Biofuels', published in July 2008 and led by Professor Ed Gallagher.

be required depending on the overall energy demand and current biofuel share in each scenario.

Figure 20 shows the change in renewable electricity or renewable heat if the burden of the additional renewable energy required was passed to that sector.

In the scenarios where renewable electricity already makes a large contribution to the overall renewable energy target (the 'Green Power'", 'Shared Load', 'Energy revolution non-bio' and 'Power Down non-bio' scenarios), the reduced biofuels target pushes the requirements from renewable electricity to very high levels. At these levels we would be forced to place greater reliance on emerging technologies, such as wave and tidal, and expensive technologies, such as solar PV, to meet the EU target.

In these circumstances, it is likely that the burden would therefore fall on the heat sector. While some, or even all, of the incremental heat provision may also be biomass-based, the demand for agricultural crops for biofuel production would fall.

Figure 20 – Impact of RTFO remaining at 2.5% in 2020

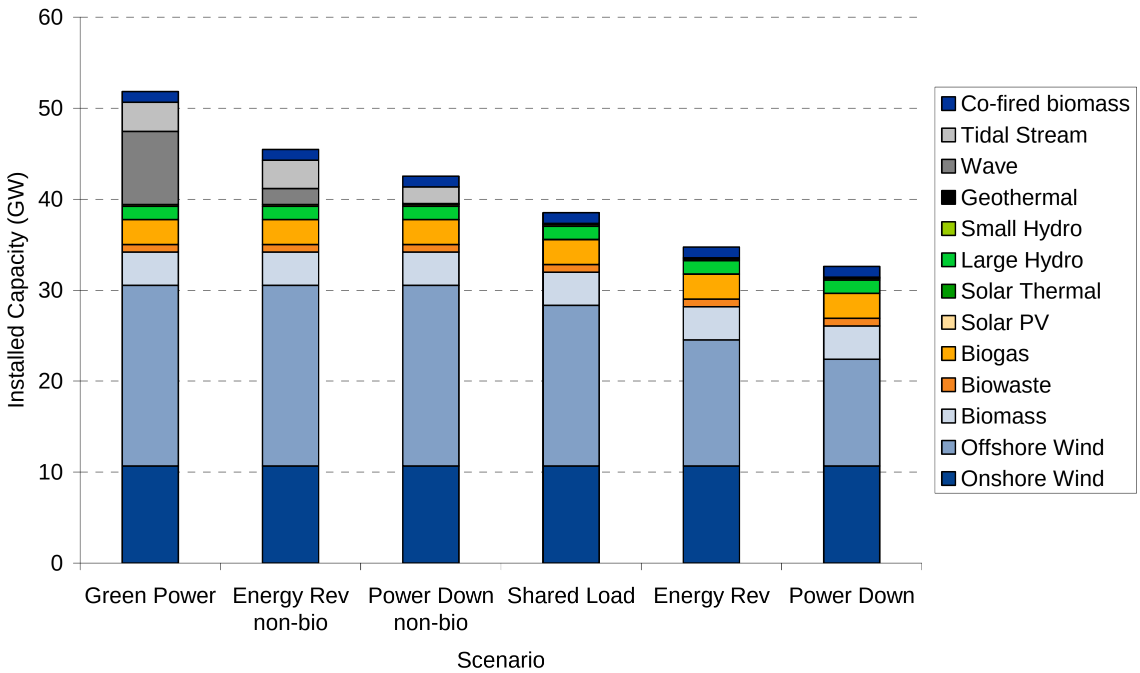
	Modelled 2020 RTFO	Additional Energy needed from other sectors if RTFO was held at 2.5% (TWh)	Required renewable electricity generation if burden was all passed to electricity (TWh)	Required renewable electricity generation if burden was all passed to heat (TWh)
Green Power	5%	13	187	98
Shared Load	10%	39	175	136
Energy Rev	10%	34	158	111
Energy Rev non-bio	5%	11	169	77
Power Down	10%	34	151	118
Power Down non-bio	5%	11	160	85

Source: Pöyry Energy Consulting

3.4.3 *Implied renewable capacity*

The evolution and mix of renewable capacity required to meet the 2020 scenario can also be estimated. This is done using Pöyry's EURENO model which is based on cost and resource limits taken from the Green-X model which was use to inform EU energy policy. The renewable build evolution for the shared load scenario can be seen in Figure 21. It should be noted that although wind power contributes a very large fraction of new renewable capacity, it will contribute much less on a generation basis, as it has a low load factor compared to most other renewable technologies. Evolution of renewables build for other scenarios can be found in Annex B. Figure 21 shows the renewable installed capacity by generation technology for each scenario. It can be seen that the level of onshore wind in each scenario is identical, as this resource potential has been maximised in each scenario. In the 'Green power' scenario, all wind energy and biomass energy potential has been maximised and in order to reach the 45% renewable electricity required in this scenario, wave and tidal stream technologies must be exploited. Such technologies are not yet commercial and so this scenario would rely on rapid development and commercialisation of these technologies. Figure 22 compares the evolution of renewable capacity build across each scenarios for selected years. The build rate of renewable generation is extremely rapid, however a study by SKM commissioned by BERR for the renewable energy strategy consultation states that there is a total exploitable resource of 86 GW of renewable generating capacity which could be exploited by 2020 within the limitations of the technology that is expected to be available by that time[17].

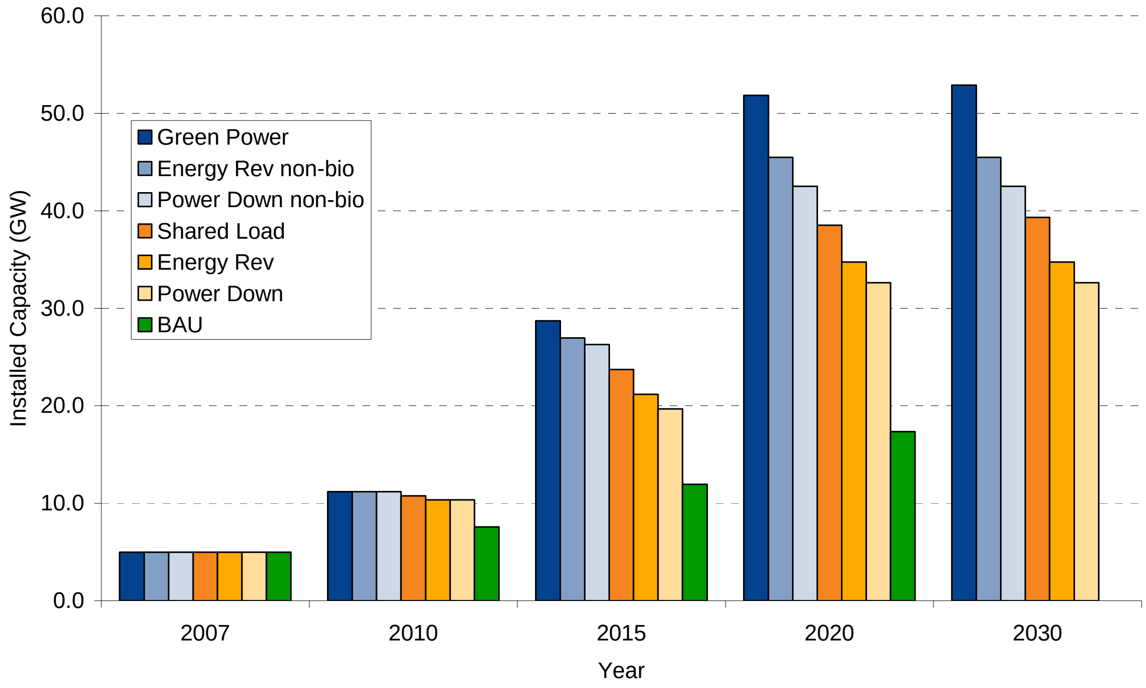
Figure 21 Comparison of renewable mixes across scenarios



Source: Pöyry Energy Consulting

17 Sinclair Knight Merz, 2008, 'Quantification of Constraints on the Growth of UK Renewable Generating Capacity'

Figure 22 – Comparison of renewable installed capacity



Source: Pöyry Energy Consulting

[This page is intentionally blank]

4. IMPACT OF RENEWABLE GENERATION SCENARIOS

The analysis in the previous chapter showed a net requirement for effective peak capacity of somewhere between 10GW and 20GW by 2020. At the same time, the renewable generation capacity assumed to be installed by 2020 is in the range of 30GW to 50GW. Consequently, it may be expected that this would have a major impact on the need for additional capacity.

In this chapter, we review the residual installed capacity gap after allowing for the various renewable capacity scenarios. In addition to looking at the peak requirement, we also consider what type of capacity would be required by assessing the duration of any shortfall across the year, taking account of different patterns of utilisation and availability over the year.

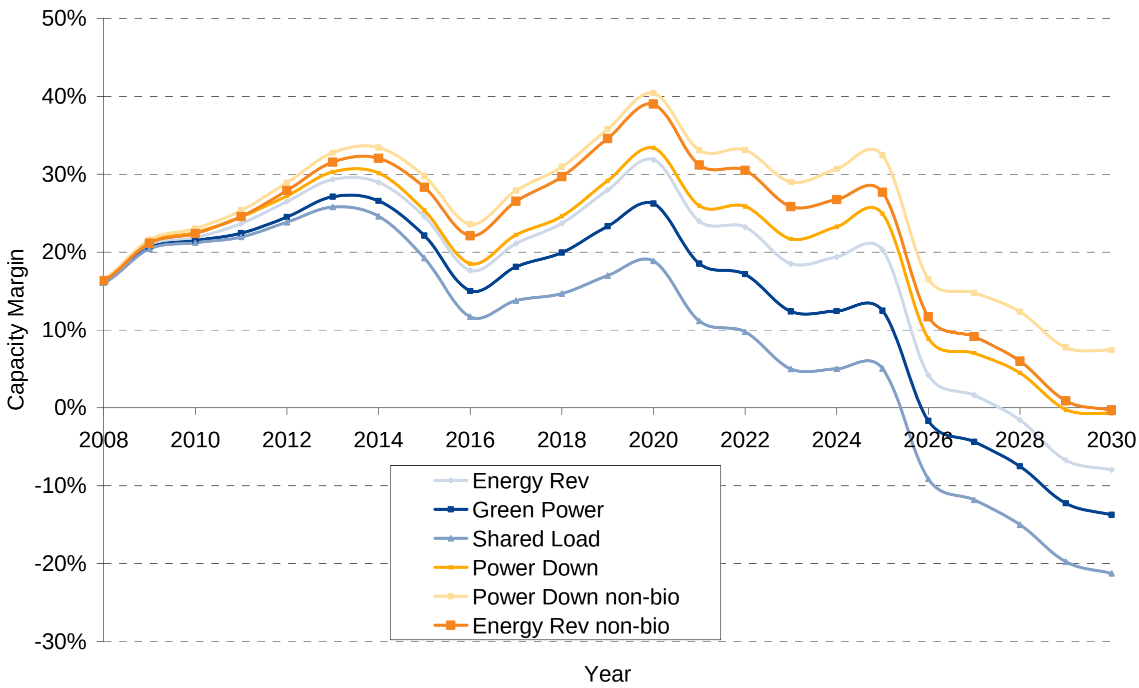
4.1 The impact on the peak capacity margin

Figure 23 shows how, when we combine the conventional plant capacity with the new renewable build scenarios, the peak capacity margin changes significantly from that reported in Figure 16. Several interesting insights can be gained from comparing the two patterns of evolution:

- As expected, the overall measured peak capacity margin is much improved. While we still observe a sharp fall in the peak capacity margin around 2015/16, this takes us to a range between 10% and 25%. Subsequently, measured margins improve, so that, by 2020, even the lowest margin (observed in the Shared Load scenario) is still close to 20%.
- It is only after 2020, when margins begin to decline substantially, largely reflecting the fact that renewable generation is maintained at its 2020 level or 20% of total demand (whichever is larger). However, in higher penetration scenarios, it also reflects the proximity to maximum potential that occurs for some technologies, limiting future growth prospects.
- The higher margins are observed in the scenarios where (a) the contribution from renewable electricity is higher (i.e. the 45% electricity share scenarios); and (b) the peak electricity demand is lower.

Interestingly, although we add up to 50GW of new capacity by 2020 in the Green Power scenario, the capacity margin does not exceed 27%. Indeed, it is higher in the Energy Revolution and Power Down non-bio scenarios. This is because of the difference in the contribution of demand-side and supply-side measures to the peak capacity margin. Whereas a reduction in peak electricity demand represents a one-for-one improvement to the absolute capacity margin, the addition of more installed renewable capacity does not. For wind, with a 40% peak capacity factor, an increase in installed capacity of 1GW will add 0.4GW to the capacity margin.

Figure 23 – Implied capacity margins



Source: Poyry Energy Consulting

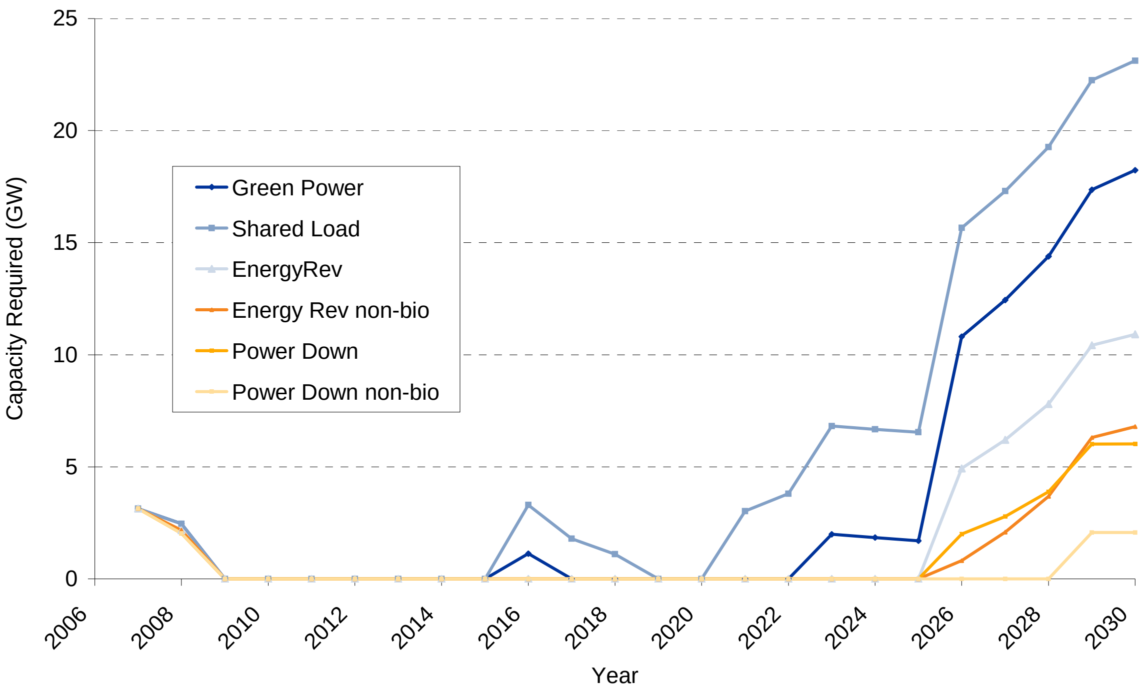
Figure 24 shows the additional firm capacity that is required to maintain a 20% capacity margin given the growth in renewable generation. In addition to the renewable growth, it also includes two other assumed new capacity additions:

- additional generation that may arise if there is a growth in the capacity of Combined Heat and Power (CHP_ projects as a consequence of higher demand via community heating and industrial CHP schemes. The UK currently has approximately 5 GWe of CHP capacity. Within the scenarios produced, this is forecast to rise to between 8 and 8.5GWe by 2030 across the scenarios; and
- the commencement of operation of the 1GW UK-Netherland interconnector, scheduled to come online in 2011. The interconnector provides additional access to continental markets at peak times. However, it may also be a means of spilling additional wind generation at off-peak times, thereby supporting more thermal generation on the system.

What is interesting to note from this graph is that, under most scenarios, a sustained requirement for additional firm capacity does not emerge until after 2020, and in most cases in the period from 2025 onwards. Importantly, there is a short-term requirement around 2016 in the Shared Load and Green Power scenarios (which are the scenarios with the higher electricity demand). However, this does not persist because further renewable generation arrives in the period 2016 to 2020 in order to ensure compliance with final and interim targets.

This may create a short-term problem for supply security if new conventional generation needed to maintain a 20% margin does not enter because of uncertainty over future operation patterns and profitability.

Figure 24 – Additional firm capacity to retain a 20% capacity margin



Source: Poyry Energy Consulting

4.2 Identifying the duration of any shortfall

The results presented so far are based on annual peak demand figures and average peak capacity availability. Focussing solely on this measure provides an incomplete picture of reliability since it says nothing about the persistence of any shortfalls (which should inform the type of capacity response required – baseload, peak or demand-side), nor does it address the impact of intermittent generation on the supply-demand balance during non-peak periods. That is, the correlation of wind output with demand across the year may be such that a greater effect on security of supply is felt at other times of the year – for example, wind speeds are generally lower in summer, when conventional plant traditionally have lower availability (due to planned maintenance outages). To enable us to analyse these impacts in greater detail, we have undertaken a relatively simplistic assessment of margins across characteristic days during the year.

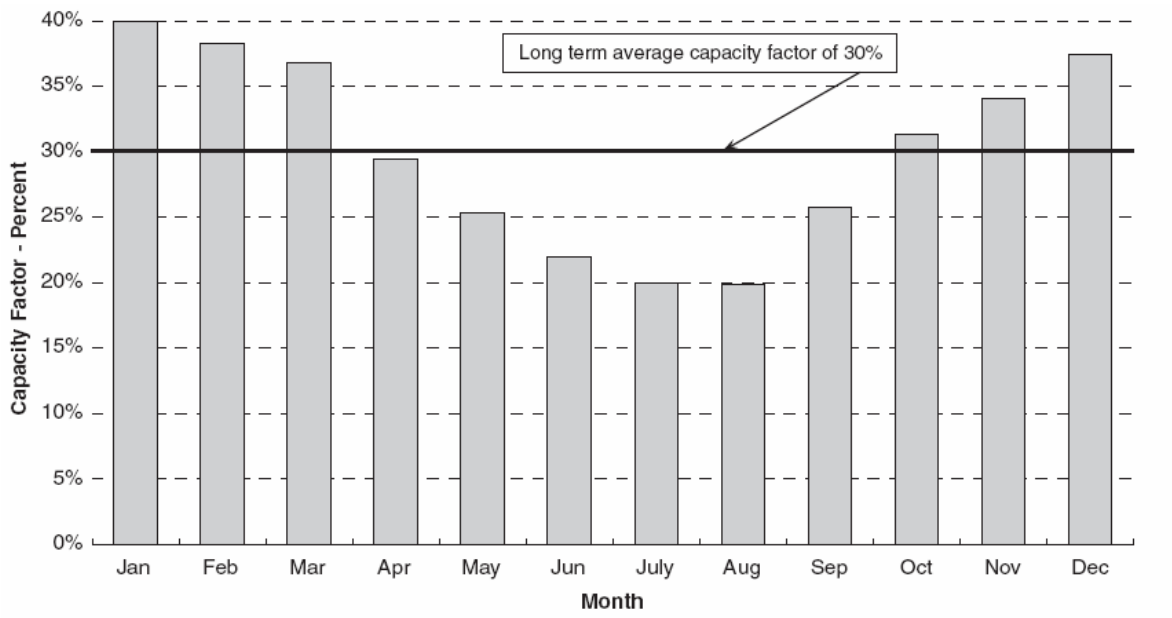
4.2.1 Calculating Firm Capacity at an hourly resolution

The variability in the effective capacity margin throughout the year is analysed using a model that calculates expected firm capacity on an hourly basis over the year. This hourly firm capacity is then compared to demand on characteristic days to assess the size and duration of any capacity gap.

In order to model firm capacity on an hourly basis, more detailed information on availability by technology is required. For most conventional technologies we have assumed seasonal outage rates as reported in Figure 38 in Annex A. These outage rates include both planned and forced outages and the general assumption is that availability in the summer months is lower, not reflecting higher forced outage rates, but higher planned outage rates.

For wind, we have assumed average monthly wind capacity factors as shown in Figure 25. The capacity factors assume a diversified UK mix and have been calculated using long-term wind speed data[18]. To these monthly patterns, a within day and within month fluctuation pattern was imposed using Pöyry data.[19] An example of an hourly firm capacity graph for a Shared Load scenario in 2025 can be seen in Figure 40.

Figure 25 - Average monthly capacity factor for wind



Source: '*UK wind resource: Long-term patterns and relationship to electricity demand*', Energy Policy Journal

4.2.2 Gap duration analysis

We have analysed these demand supply correlations at key points throughout the period (namely 2016, 2020, 2025 and 2030) and for characteristic days in four months (one per quarter). Figure 26 shows a demand/supply correlation on a characteristic day in July 2025. The method to calculate demand for the 'characteristic' or typical weekday for each month is described in Annex A.

From this graph, it is possible to plot a 'gap duration curve', which will show the length of time for which a 'gap' of a given size will persist. For this part section of the analysis, the capacity margin was set to the maximum of either 20% (which is the current accepted level of what is an acceptable capacity margin) or the capacity margin to ensure that we have enough firm capacity to deal with a day which no wind or wave generation is available (i.e. a flat calm day over the entire country). This can be summarised in the following equation.

---

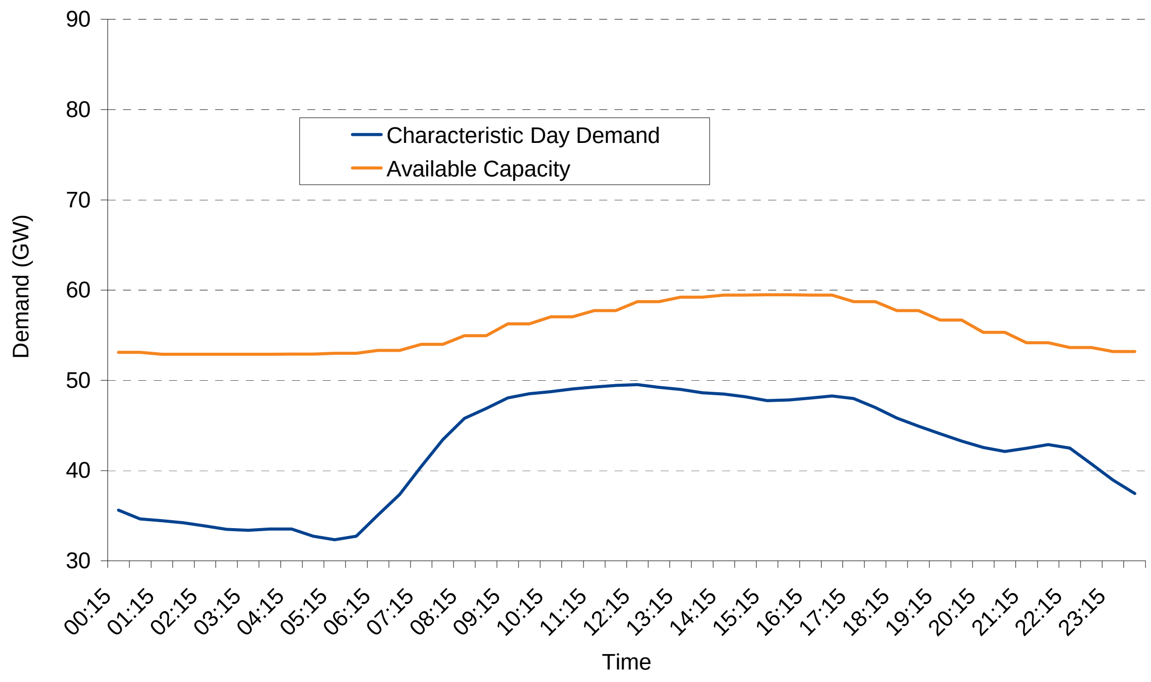
[18] Data taken from characteristics of the UK wind resource: Long-term patterns and relationship to electricity demand. Energy Policy Journal, in press, Graham Sinden, 2007.

[19] Tidal power is assumed to follow the same shape as the tidal range pattern (which is a near diurnal sine wave). In practice the fluctuation in capacity factor for tidal may be less due to the geographical dispersion of tidal generators.

$$\text{Capacity margin} = MAX\left(20\%, \frac{\text{Firm capacity of wind and wave generation}}{\text{Peak Demand on characteristic day}}\right)$$

In early years, the required capacity margin is always set to 20%, as there is very little wind on the system. However in later years, the capacity margin increases above this to ensure that we have enough predictable capacity to satisfy demand.

Figure 26 – Available capacity and characteristic day demand: Shared Load 2025

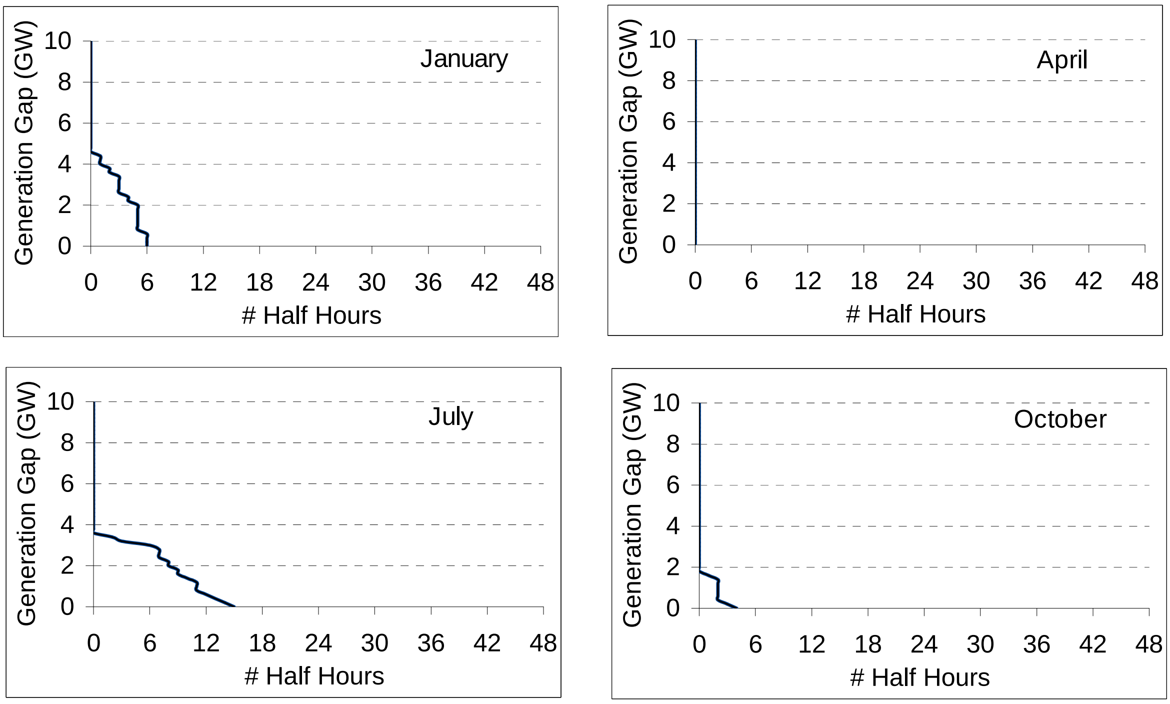


Source: Poyry Energy Consulting

Figure 27 shows the resultant gap duration curve for the Shared Load scenario over 4 selected months during 2025. What this shows is that, in 2025, there are limited periods when the effective capacity margin is not sufficient to ensure a 20% margin. It should be noted that these are not periods of actual shortfall – they are periods when the system would not have a sufficient buffer in existing generation to meet shocks that were of the order of 20% of peak capacity. Thus, they increase the risk of supply interruptions at these times.

The limited duration of shortfall suggests that some form of peaking, rather than baseload, capacity is required (this peak capacity may be either demand-side or supply-side provision). These gap duration curves have been analysed across all scenarios for the snapshot years and form the basis of suggestions on required capacity. This analysis is expanded upon later.

Figure 27 – Gap duration curves: Shared Load 2025



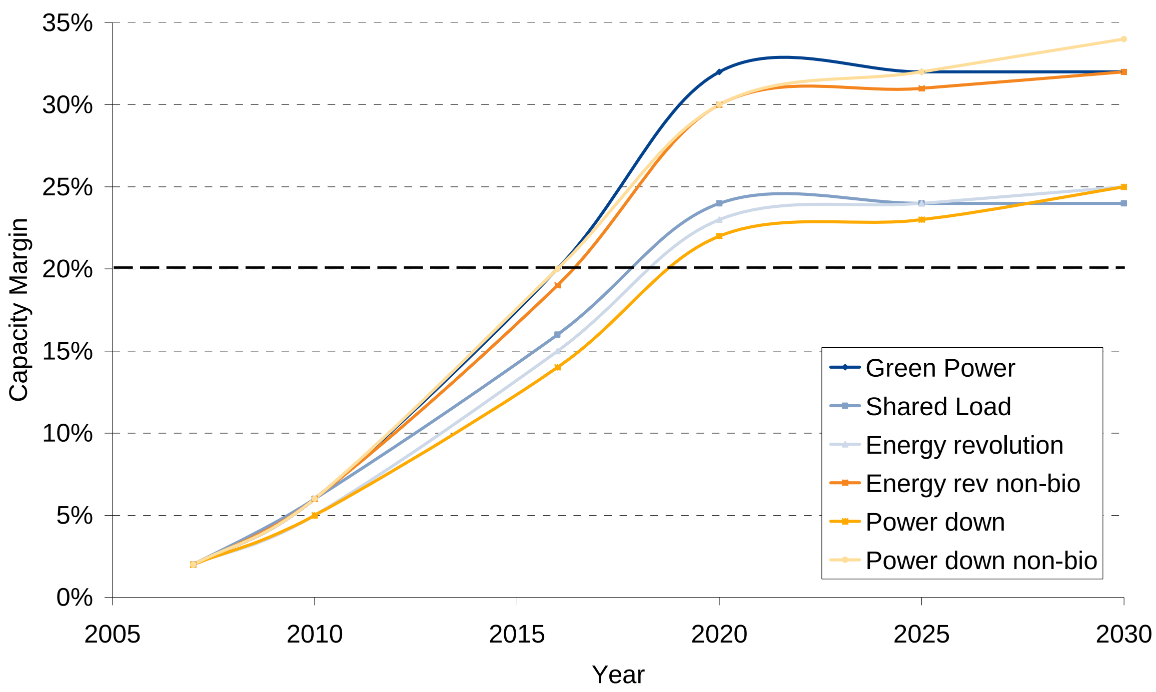
Source: Poyry Energy Consulting

In addition to analysing the extent to which a capacity gap exists, we have also investigated the level of capacity margin that would be required to fully mitigate against a 'no-wind' day on the system. The results of this are shown in Figure 28 below.

What this shows is that a peak capacity margin of 20% should be sufficient to cover the loss of intermittent output up to 2016 in high renewable penetration scenarios and out to 2018 to 2020 in the low renewable penetration scenarios (i.e. 35% share). Actually, even where the peak margin required rises above 20% it does not always mean that additional generation above what is already on the system, will be required.

This is because the high required margins here arise in the Energy Revolution and Power Down scenarios where peak demand is falling and therefore the assumed conventional capacity provides a higher effective capacity margin. Thus, rather than plant closing as it is not required or commercial to operate, net capacity is maintained at a higher level than would otherwise be anticipated.

Figure 28 – Evolution of safe capacity margin needed to meet a 'no-wind, no-wave' day



Source: Pöyry Energy Consulting

4.3 Implications for additional generation requirements

Figure 29 presents the results of the gap duration analysis for the four snapshot years across the six scenarios. It shows the capacity gap in a representative day for the specified months and the duration for which that gap persists.

Three results are of interest here:

- In only one scenario, Shared Load, is there a shortfall (relative to a 20% margin) in 2016, and here the gap is short-lived.
- Sustained capacity requirements do not emerge until after 2020. This is the period where conventional capacity closure assumptions are not offset by additional renewable generation entry.
- The largest shortfalls occur in the summer months. This reflects the assumption of both low wind availability (wind power has a capacity factor of 20% in summer) and high planned outages of conventional generation. It may be expected that this would incentivise some plant to alter their maintenance programmes, though this would increase the risk of outages at other times of the year.

Figure 29 – Hourly capacity gap results (GW)

	2016 Jan	2016 Apr	2016 Jul	2016 Oct	2020 Jan	2020 Apr	2020 Jul	2020 Oct	2025 Jan	2025 Apr	2025 Jul	2025 Oct	2030 Jan	2030 Apr	2030 Jul	2030 Oct
Green Power																
<3 hours	0	0	0	0	0	0	0	0	2.5	0	5	1.5	20	13	19	17
3-6 hours	0	0	0	0	0	0	0	0	0.5	0	4	0	18	12	18	15
6-12 hours	0	0	0	0	0	0	0	0	0	0	4	0	14	11	18	14
12+ hours	0	0	0	0	0	0	0	0	0	0	1	0	13	10	15	12
Shared Load																
<3 hours	2	0	0	0	0	0	0	0	5	0	4	2	22	13	19	17
3-6 hours	0	0	0	0	0	0	0	0	2.5	0	4	0.5	19	12	18	16
6-12 hours	0	0	0	0	0	0	0	0	0	0	4		16	11	18	14
12+ hours	0	0	0	0	0	0	0	0	0	0	2		15	10	15	13
Energy revolution																
<3 hours	0	0	0	0	0	0	0	0	0	0	0	0	8	4	9	6
3-6 hours	0	0	0	0	0	0	0	0	0	0	0	0	6	4	9	5
6-12 hours	0	0	0	0	0	0	0	0	0	0	0	0	5	3	8	5
12+ hours	0	0	0	0	0	0	0	0	0	0	0	0	5	2	7	4
Energy rev non-bio																
	0	0	0	0	0	0	0	0	0	0	0	0	6	3	10	5
3-6 hours	0	0	0	0	0	0	0	0	0	0	0	0	5	3	9	4
6-12 hours	0	0	0	0	0	0	0	0	0	0	0	0	4	2	8	4
12+ hours	0	0	0	0	0	0	0	0	0	0	0	0	3	2	6	3
Power down																
<3 hours	0	0	0	0	0	0	0	0	0	0	0	0	4	0	5	4
3-6 hours	0	0	0	0	0	0	0	0	0	0	0	0	3	0	4	3
6-12 hours	0	0	0	0	0	0	0	0	0	0	0	0	0.5	0	4	0.5
12+ hours	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0
Power down non-bio																
<3 hours	0	0	0	0	0	0	0	0	0	0	0	0	3	0	6	2
3-6 hours	0	0	0	0	0	0	0	0	0	0	0	0	2	0	5	1
6-12 hours	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	0.5
12+ hours	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0

Source: Pöyry Energy Consulting

Drawing on this analysis, indicative projections of additional firm capacity have been derived, with a split between demand-side management (DSM) opportunities, peaking generation and baseload generation.

It should be noted that these figures are indicative only and do not reflect modelling of firm investment decisions. In particular, it is worth noting the following:

- in scenarios where significant energy demand reductions have already taken place, it may be that there is less scope for cost-effective demand-side management;
- investment in peaking capacity may actually involve baseload investment with current baseload plant moving up the merit order and operating at lower load factors. These commercial decisions are not analysed, though it is fair to say that the net effect on generation capacity is less impacted by these variations; and
- there are several options for baseload capacity- since the majority of baseload investment is not required until after 2020, there is opportunity for a range of new technologies to meet this gap, including carbon capture and storage (CCS) technologies and greater expansion of industrial CHP, among others, such as several renewable marine technologies.

Figure 30 – Firm capacity required to maintain capacity margin (GW)

	2016	2020	2025	2030
Green Power				
DSM	0.0	0.0	1.1	1.1
Peaking plant	0.0	0.0	3.2	6.3
Baseload	0.0	0.0	1.1	13.7
Shared Load				
DSM	2.1	0.0	0.0	1.1
Peaking plant	0.0	0.0	2.1	6.3
Baseload	0.0	0.0	2.1	15.8
Energy revolution				
DSM	0.0	0.0	0.0	0.0
Peaking plant	0.0	0.0	0.0	2.1
Baseload	0.0	0.0	0.0	7.4
Energy rev non-bio				
DSM	0.0	0.0	0.0	1.1
Peaking plant	0.0	0.0	0.0	3.2
Baseload	0.0	0.0	0.0	6.3
Power down				
DSM	0.0	0.0	0.0	1.1
Peaking plant	0.0	0.0	0.0	2.1
Baseload	0.0	0.0	0.0	2.1
Power down non-bio				
DSM	0.0	0.0	0.0	1.1
Peaking plant	0.0	0.0	0.0	3.2
Baseload	0.0	0.0	0.0	2.1

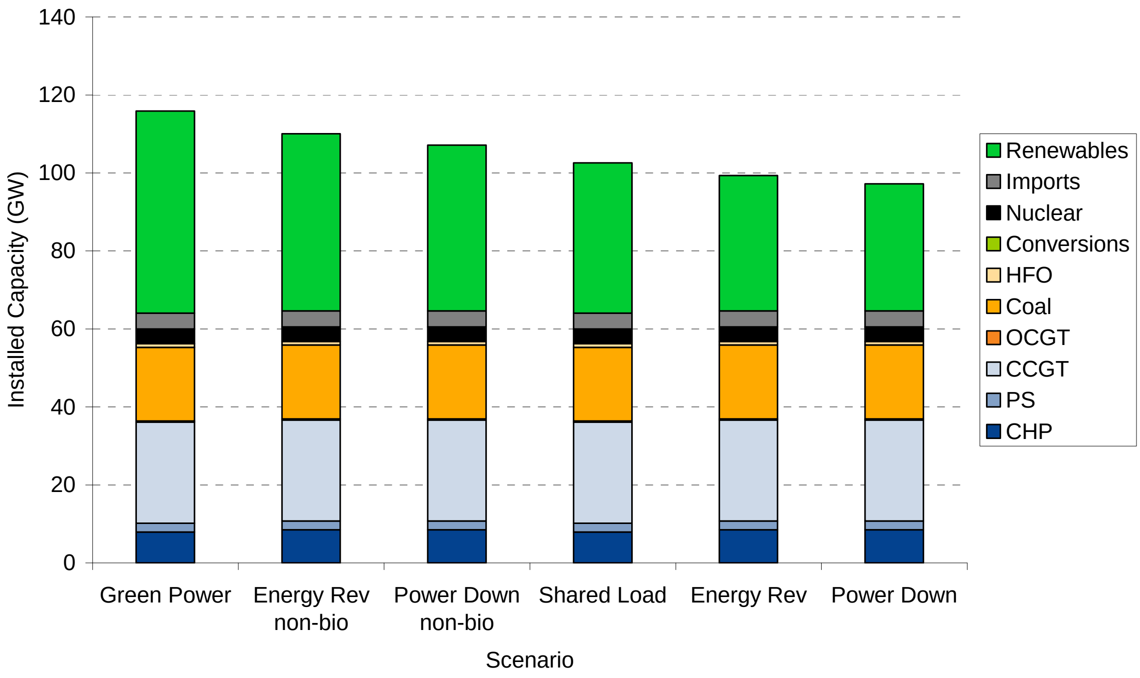
Source: Pöyry Energy Consulting

The implication is that, given the assumptions on electricity demand reductions and conventional capacity availability, meeting the renewable energy target may remove the need for net new investment in non-renewable technologies. However, even with the large injection of renewable capacity, between 5GW and 23GW may be required by 2030 if we were to fully mitigate against peak wind loss. While it is extremely debatable whether the market or government would want to mitigate this specific risk, it illustrates an extreme market impact of higher renewables.

Furthermore, the analysis suggests more flexible, peaking type capacity is as important – particularly in the low electricity demand scenarios – than is baseload generation, reflecting the need to respond to shorter-term variability in output with intermittent generation sources.

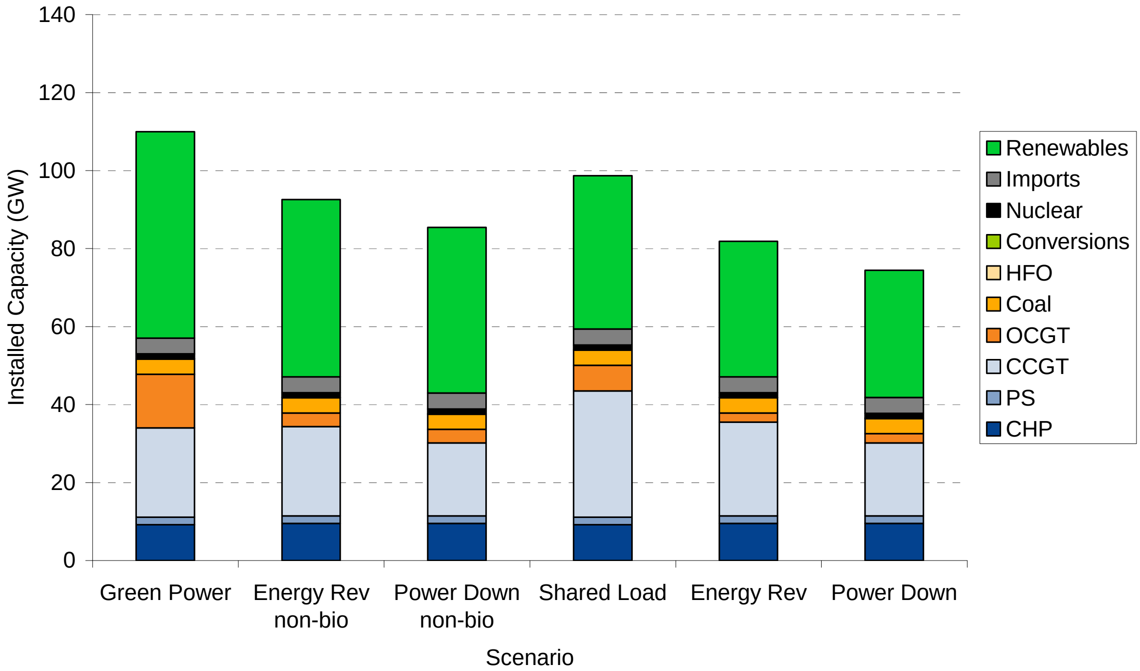
The different scenarios therefore result in varying levels of installed capacity (and mix) in the longer-term. Figure 31 and Figure 32 show the installed capacity in 2020 and 2030 across scenarios. The 2030 capacities are lower than the 2020 capacities as the large level of renewables that are built to meet the 2020 targets mean that no additional capacity is required to replace the capacity that exits the system between 2020 and 2030.

Figure 31 – Installed capacity by scenario 2020



Source: Pöyry Energy Consulting

Figure 32 – Installed capacity by scenario 2030



Source: Pöyry Energy Consulting

4.4 Comparison with recent analysis

Table 4 shows how the results of this analysis compare, at a high level, with two recent analyses – the report by the UKBCSE[20] and the Redpoint analysis for BERR[21]. The Shared Load scenario is most comparable with the Redpoint (37%) scenario, given differences in the underlying electricity demand and assumed peak capacity factors, whereas Green Power and the UKBCSE position are also broadly comparable.

Interestingly, there is broad agreement between the Shared Load and Redpoint (37%) scenario, suggesting total generation capacity of around 100GW by 2020. The 'Green Power' scenario has a slightly lower capacity requirement than UKBCSE despite providing higher renewable output. This represents a more optimistic assessment of expected firm capacity availability from wind generation in core assumptions.

[20] UKBCSE (2008), Implementing the EU Renewable Energy Target in the UK Emerging Issues for Consideration.

[21] Redpoint Energy (2008) Consulting Implementation of EU 2020 Renewable Target in the UK Electricity Sector: Renewable Support Schemes.

Table 4 – Comparison of results with recent studies

	UKBCSE	Redpoint (SQ)	Redpoint (37%)	Shared Load	Green Power
Electricity demand	393	373	360	386	386
Peak electricity demand		64	62	65	65
Total installed capacity (GW)	122	84	99	103	116
Renewable capacity (GW)	55	16	37	39	52
of which Intermittent (GW)	40			29	42
Output from renewables (TWh)	145	n/a	n/a	136	174
Conventional capacity (GW)	67	69	62	64	64

Source: UKBCSE, BERR, Pöyry Energy Consulting

4.5 Implications for electricity market performance

Knowing the installed capacity mix on the system, it is possible to investigate how other indicators of policy goals are affected by the resultant mix. In particular, we highlight three:

- gas consumption;
- carbon emissions; and
- biomass use.

The out-turn on each depends on a range of factors, most notably the assumed technologies meeting the generation gap and the assumed load factors of capacity on the system. The initial analysis here assumes that additional capacity is all CCGT or OCGT, higher volumes of other technologies would have differing effects. For example:

- more CHP may lower total gas demand if it is biomass-based sources that are used a the input fuel; and
- use of CCS while lowering carbon emissions may increase gas demand if it is gas-fired CCS used (due to lower operating efficiencies of CCS plant) or lower gas demand (if it means higher utilization of coal-fired plant).

These considerations should be borne in mind when reviewing these illustrative results.

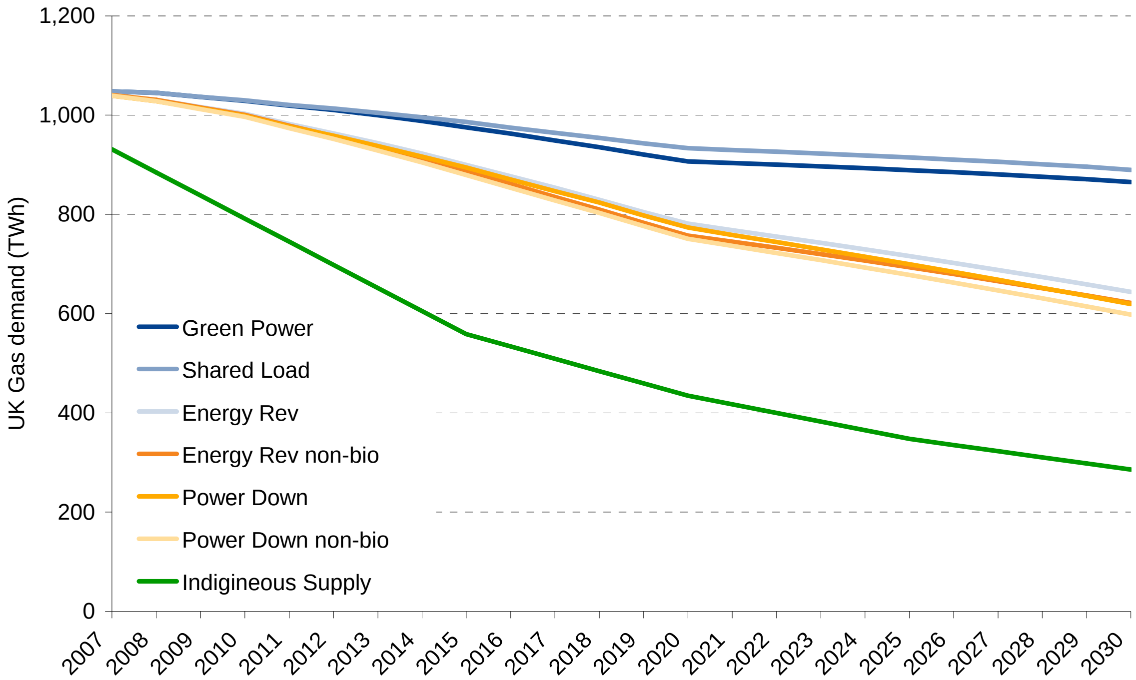
4.5.1 Gas demand

Figure 33 shows projected gas demand for each scenario. The main driver of gas demand in each scenario is the reduction in gas demand for heating (which is either 9% or 28% reduction by 2020, depending on the scenario). The indigenous production level of natural gas is also included on the graph for illustration[22]. It can be seen that in all scenarios gas demand falls. However, the drop off in indigenous production means that all scenarios would be heavily dependant on foreign supplies of gas. Figure 34 shows the evolution of gas demand for electricity generation across scenarios.

---

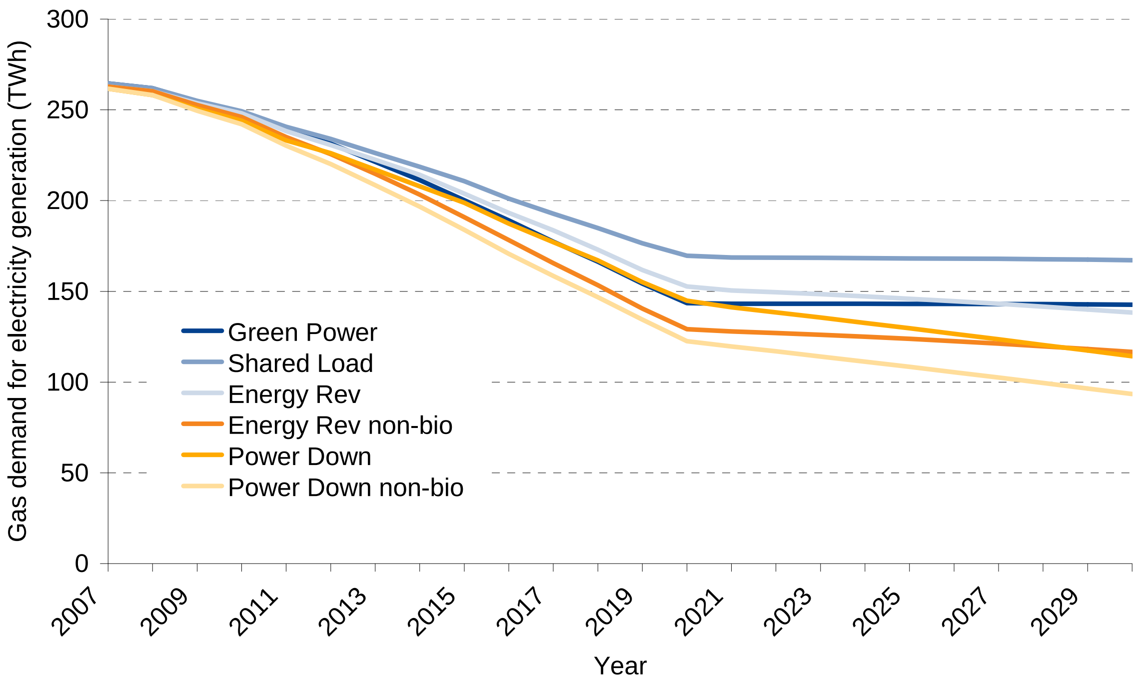
[22] This data is taken from the National Grid Transco's Ten Year Statement 2007.

Figure 33 – Projected UK gas demand across scenarios



Source: Pöyry Energy Consulting, National grid

Figure 34 – Gas demand for electricity generation across scenarios



Source: Pöyry Energy Consulting

4.5.2 Carbon emissions

Figure 35 shows the projected change in emissions from the UK power sector across the scenarios analysed relative to a 1990 baseline. After 2020, the emissions are dependant on the amount of new conventional generation which is commissioned. Shared load which requires the most conventional capacity after 2020 has the highest level of emissions.

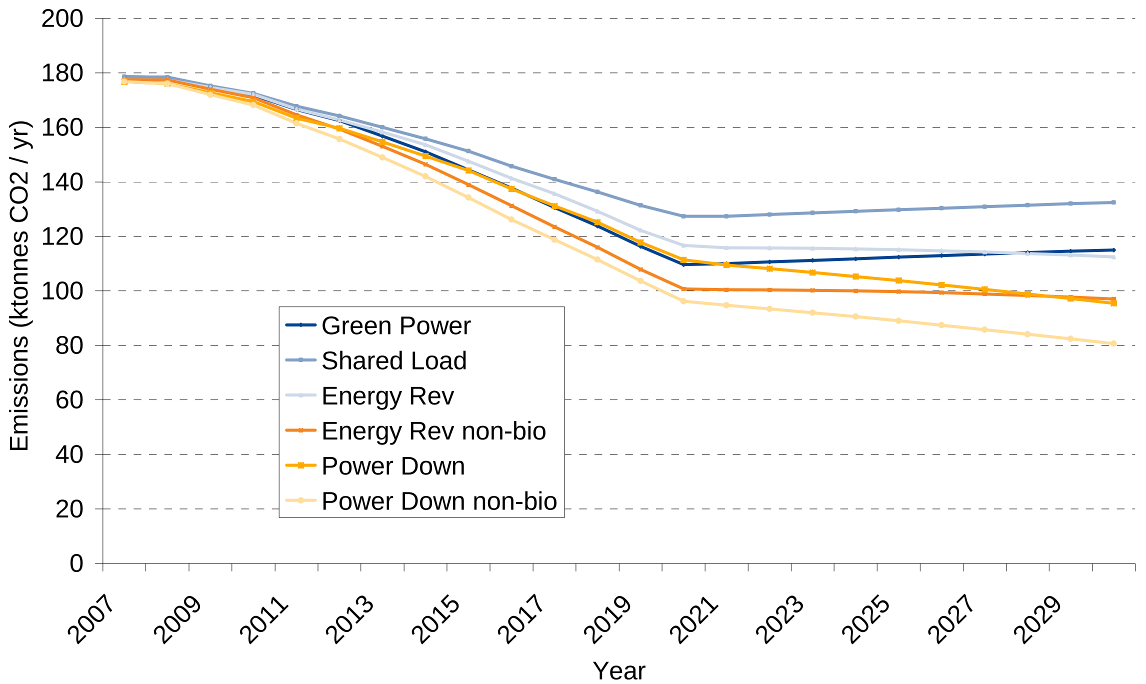
It has been assumed in this analysis that all new conventional generation will be from gas powered generation (either combined cycle or open cycle turbines). However, it is possible that in 2020 there may be other forms of dispatchable generation available. Carbon capture and storage for coal generation may have been successfully demonstrated, which could reduce dependence on gas import if it was used. There is a large potential for CHP schemes in the UK. A recent report by Pöyry Energy Consulting for Greenpeace indicates that between 11GW and 16GW of potential electric CHP capacity exists at current industrial sites [23]. The increased use of CHP could reduce gas demand and carbon emissions through increased efficiency of gas use.

Table 5 shows the change in total UK carbon emissions for each scenario. It should be noted that these are approximate numbers. Only the electricity sector was modelled in detail in this analysis. Carbon emissions from other sectors were calculated using the overall energy consumption by fuel source (gas, liquid, solid, direct heat and electricity) within each sector. Average emissions factors were used to calculate the total emissions. The UK is likely to commit to a 26%-32% reduction in carbon emissions by 2020 [24]. It can be seen that this criteria is met in all but one scenario (the “Shared Load” scenario which only achieves a 23% reduction). Much larger reductions are seen in the low total energy demand estimate. This pathway for total energy demand is an ambitious one, which can only be met with large changes in the pattern of energy use.

[23] Potential for CCGT CHP generation at industrial sites in the UK, Pöyry Energy Consulting report commissioned by Greenpeace-UK, April 2008.

[24] UK Government Draft Climate Change Bill, March 2007

Figure 35 – Projected emissions from the power sector



Source: Pöyry Energy Consulting

Table 5 – Change in total UK carbon emissions across scenarios

	2015	2020	2025	2030
Green Power	-19%	-26%	-27%	-28%
Shared Load	-18%	-23%	-24%	-25%
Energy Rev	-24%	-34%	-38%	-43%
Energy Rev non-bio	-26%	-37%	-41%	-46%
Power Down	-24%	-34%	-39%	-44%
Power Down non-bio	-26%	-37%	-42%	-47%

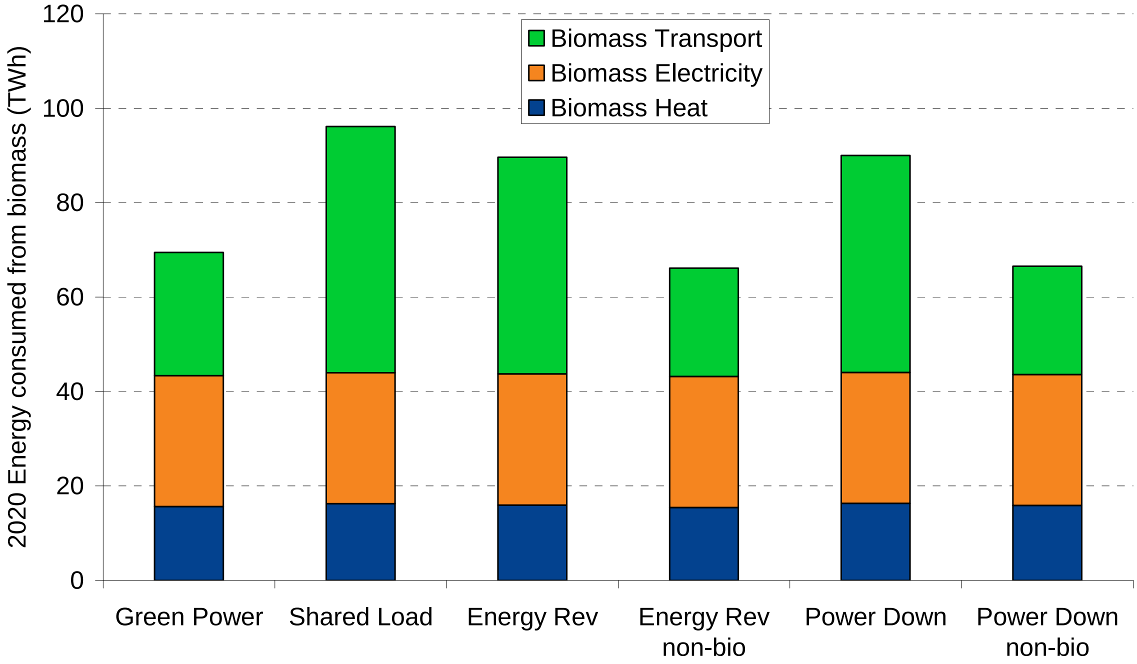
Source: Pöyry Energy Consulting

4.5.3 Biomass use

Figure 36 shows the amount of energy consumed in search sector which was sourced from biomass. The values here refer to final energy consumed. These have not been converted back to an amount of biomass figure, as this would require assumptions on conversion efficiency and source of biomass used – which would contain large uncertainties. This biomass figure includes co-fired biomass, but excludes biowaste. If biowaste was included, it would add an additional 5TWh of energy across all scenarios.

The total amount of energy consumed in 2020 is 1620 TWh in the low scenario and 1903 TWh in the high scenario (these numbers are 1425 and 1690 TWh excluding aviation). Thus it can be seen that biomass sourced energy accounts for between 4% and 6.5% of total energy consumed across the scenarios.

Figure 36 – Biomass sourced energy consumption by sector in 2020



Source: Pöyry Energy Consulting

5. LIMITATIONS OF ANALYSIS

It should be noted that the scenarios presented above all represent a radical shift away from the business as usual pathway. The results of this analysis are highly sensitive to some of the input assumptions. Some of the key assumptions and limitations are highlighted below.

5.1 Electricity Demand

On electricity demand, the high demand scenario is essentially flat between now and 2030 flat between now and 2030 (rising from 389TWh in 2007 to 394TWh in 2030). National Grid's base scenario[25] predicts 1.1% transmission connected demand growth for the next 7 years. If this was continued through to 2030, then demand would be 26% higher than currently – which could add an additional 16 GW to peak demand. Such an increase in electricity demand would require significant levels of conventional generation, though it would be hard to reconcile this with the EU energy efficiency targets.

The electricity demand profile is even more uncertain than the total level of demand. The profiles in this analysis have been modelled using constant residential, industrial and services profiles. These may change markedly over time reflecting different patterns of electricity use across sectors and this would affect the size and timing of peak demand and the correlation of demand with wind output.

5.2 Obstacles to the development of renewable capacity

To deliver the capacity assumed in the renewable growth scenarios, build rates for renewable electricity capacity will have to increase significantly. The renewable consultation published by BERR notes that the rates required are similar to the rate of gas powered generation which was built in the 1990's. However centralised gas powered generation poses much less supply chain and planning problems than dispersed renewable generation.

The scenarios presented in the report depend on commercialisation of some technologies, removal of planning and connection constraints and development of an appropriate support scheme.

5.3 Impact on wholesale prices

We have not explicitly modelled the effect that enhanced renewable penetration may have on wholesale electricity price formation over time. Higher renewable output may lead to a change in the distribution of wholesale prices, with periods of zero prices (when there is high output of zero marginal cost renewables) and periods of very high prices (when there is low renewable availability and remaining conventional plant must charge higher prices to recover their costs of operation).

This may affect entry and exit decisions. For example, it may influence decisions relating to investment to ensure compliance with Phase 2 of the Large Combustion Plants Directive in 2016, resulting in early plant closures or limited operating capabilities.

---

[25] National Grid plc, '2008 Great Britain Seven Year Statement'

5.4 Treatment of renewables post-2020

Our analysis assumes that renewable capacity plateaus in 2020, largely as a result of falling or constant demand implying there is no need for additional capacity to maintain the set share of generation. However, it is possible that further expansion of renewables support mechanisms could provide further growth in this period.

6. CONCLUSIONS

This study was commissioned to consider how compliance with the EU 2020 renewable energy target affects the likely generation capacity gap.

What is clear, is that, in order for the UK to achieve its 15% renewable energy target, there will need to be a substantial increase in total renewable energy production and the majority of this can be expected to be sourced from the electricity sector due to the UK's higher barriers to deployment of renewable heat.

If we disregard the possibility of meeting the 2020 target through trading mechanisms, then renewable electricity can expect to comprise between 30% and 45% of generation output – a 6- to 9-fold increase over its current contribution – implying a growth in installed renewable capacity from 5 GW in 2007 to between 33 and 52 GW in 2020.[26]

Any generation capacity gap is a consequence of both the demand- and supply-side situation. Additional renewable capacity, for a given electricity demand profile and conventional generation capacity, would be expected to reduce the need for additional capacity. However, the materiality of the reduction depends upon the need to increase overall capacity margins to maintain the same level of generation adequacy (and network stability) as volumes of intermittent generation increase.

This may impact on the delivery of conventional generation to maintain a safe capacity margin due to increased uncertainty in the wholesale price levels due to increased intermittent generation.

Within the limitations of the modelling, this study has shown the following:

- under the demand assumptions employed, a major need for new generation capacity does not emerge until after 2020, even if we assume that peak capacity must fully account for the risk of a no-wind day event;
- if we are to fully mitigate against no-wind days, effective capacity margins may have to rise to between 25% and 35%;
- while higher intermittent penetration does increase the variability of generation output, the no-wind scenario is a very-low probability event and it remains an open question as to what level of supply security (and what types of security event or risk) is worth insuring against within the system;
- not all capacity required is baseload – the pattern of intermittency results in short duration capacity shortfalls best suited to peaking plant or demand-side management. The actual means of meeting this gap is a commercial decision – for example, new baseload plant may enter, forcing current plant to operate in a peaking role;
- Total installed generation capacity is in the order of 10GW to 24GW higher than would be required to meet a 20% capacity margin if only business as usual renewable capacity were to be delivered, reflecting the lower contribution of intermittent generation at the peak;

[26] The range reflects different assumptions on demand, renewable electricity contributions and technology mix.

- additional renewable capacity is likely to incentivise changes in the operating pattern and load factors of conventional generation, with the consequence that we observe lower overall gas demand (and import dependence) and lower carbon emissions; and
- the sustainability of these long-term environmental and security benefits depend upon the technology assumed to meet any incremental capacity requirement. To the extent that any emerging gap can be filled by low-carbon options such as marine renewable technologies, carbon capture and storage (CCS), large-scale industrial CHP schemes, etc, rather than new CCGTs, then further benefits would be observed.

These results are, nevertheless, subject to some caveats:

- the implied generation requirement is largely constrained by the demand assumptions. If significant reductions in end-use consumption can be achieved, the requirement for new conventional generation will be significantly lower, though total capacity on the system is likely to be higher (due to the lower capacity factors of most renewable generation);
- the scenarios presented in the report depend on commercialisation of some emerging renewable technologies, removal of planning and connection constraints and development of an appropriate support scheme for renewables; without these policy changes and a proportionate response from the renewables sector, there is uncertainty over whether the required capacity increments will be delivered.
- the impact on the profile of wholesale prices over the period may exacerbate short-term capacity constraints, either through creating conditions where closure is accelerated, or through affecting investment decisions for coal plant in Phase 2 of the LCPD, thereby imposing tighter restrictions on their operating patterns in the post-2015 period; and
- without greater flexibility on the demand-side, capacity margins immediately post-2015 will be lower as there is little incentive for new conventional entry as it would be unlikely to achieve load factors that would justify entry.

In conclusion, there are several issues for policymakers to consider in more detail:

- the need to establish long-term framework for renewable electricity investment and operation and to ensure that an accelerated deployment of renewables happens as rapidly as possible; this would include government action to address barriers in planning, network access, supply chain and an appropriate support mechanism.
- saving energy will contribute to security and climate change objectives, and will also greatly reduce the need for investment in new conventional generation capacity. Reducing energy consumption will require concerted policies in all sectors, linked to a strong need to facilitate demand-side adjustments in the longer-term as an option to help manage variability in renewable electricity output;
- more focus on developing a coherent and holistic definition of supply security that addresses the spectrum of risks to electricity and energy supply systems, rather than partial analysis of single technologies in isolation; and
- if the above issues are addressed effectively, there is little or no need for large-scale investment in conventional baseload technology in the period up to 2020. Beyond that date, there are a range of options for continued growth in low-carbon capacity. For example, marine renewable energy technologies may have reached full commercialisation and the policy and infrastructure framework for small-scale and industrial CHP could have been brought to an advanced stage of development. By 2020, it should also be clear whether carbon capture and storage technology is a

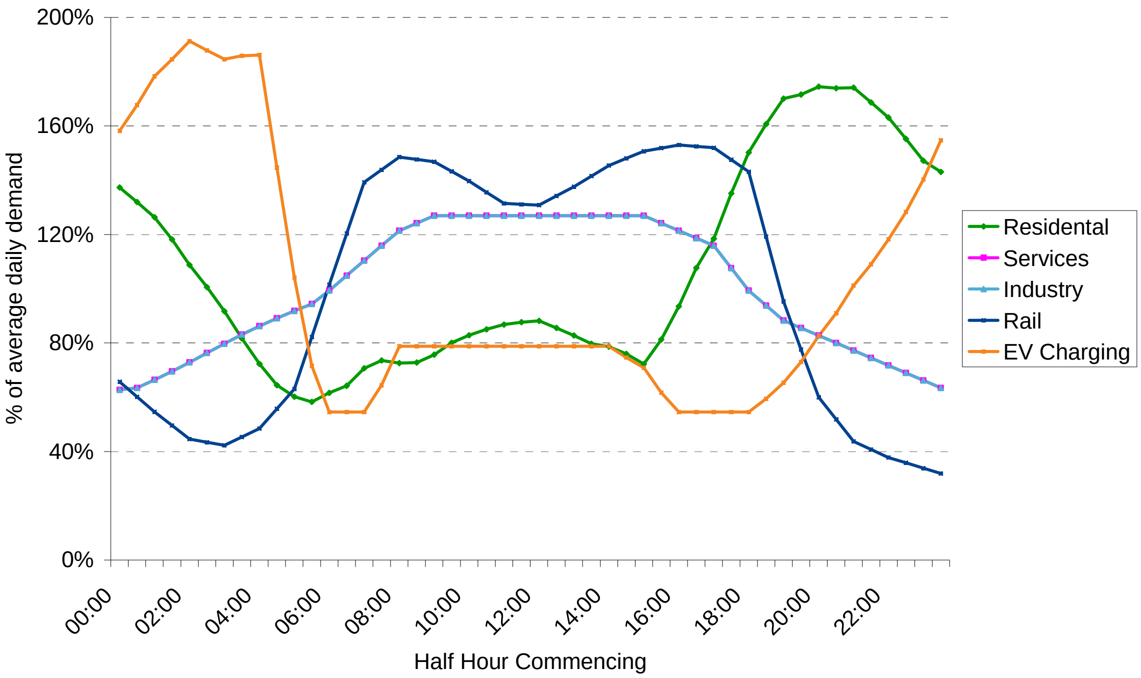
technically and economically viable option which could be applied to new fossil fuel fired power stations..

[This page is intentionally blank]

ANNEX A – BACKGROUND DATA

A.1 Background data

Figure 37 – Assumed sector load profiles



Source: Poyry Energy Consulting

Figure 38 – Comparison of capacity factor by technology

	Peak Capacity Factor used	BERR EMO	Redpoint Consultation Analysis
Onshore Wind	41%	35%	26%
Offshore Wind	41%	35%	37%
Biomass	85%	35%	80%
Biowaste	85%		73%
Biogas	85%		61%
Solar PV	8%		
Solar Thermal	20%		
Large Hydro	60%	60%	
Small Hydro	60%	60%	
Geothermal	20%		
Wave	35%		30%
Tidal Stream	35%		35%
Co-fired biomass	85%		80%
Barrage	35%		
CHP	90%	90%	80%
PS	80%	60%	
CCGT	96%	90%	
OCGT	95%	95%	
Coal	95%	85%	
HFO	95%	95%	
CCS Gas	95%		
CCS Coal	95%		
Nuclear	87%	80%	
Imports	99%	100%	

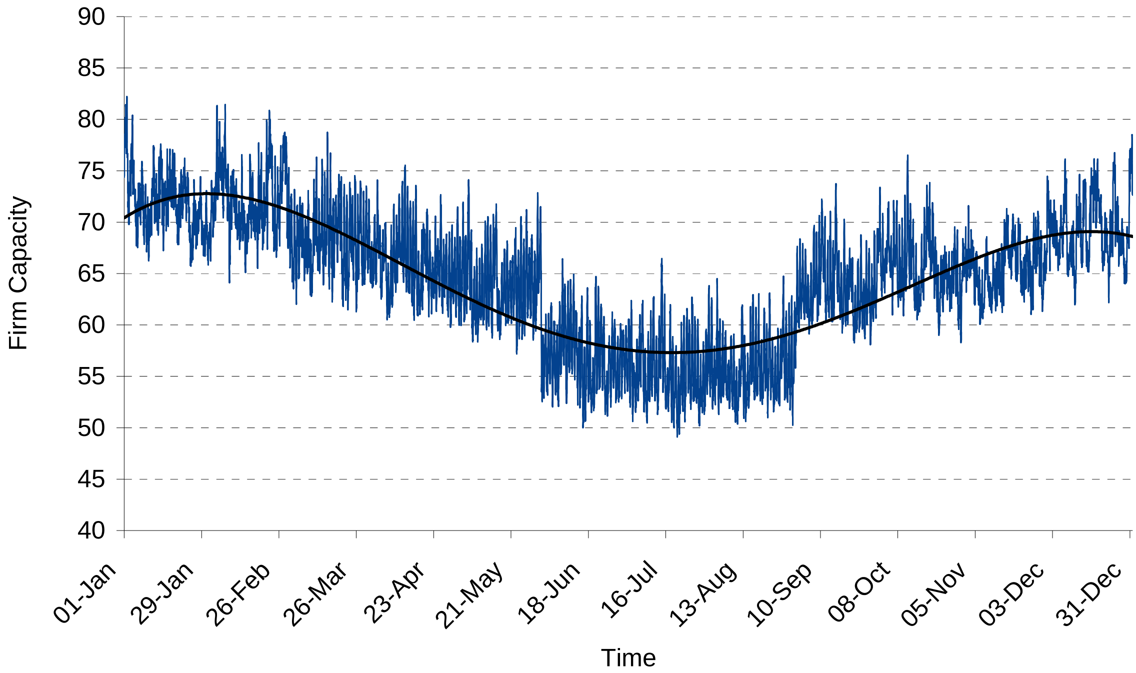
Source: Pöyry Energy Consulting, BERR Energy Markets Outlook October 2007, Implementation of EU 2020 Renewable Target in the UK Electricity Sector: Renewable Support Schemes, Redpoint, 2008

Figure 39 – Load factors used in Pöyry's EURENO model

	Load Factor
Onshore Wind	27%
Offshore Wind	37%
Biomass	73%
Biowaste	73%
Biogas	61%
Solar PV	8%
Solar Thermal	0%
Large Hydro	37%
Small Hydro	37%
Geothermal	0%
Wave	30%
Tidal Stream	35%
Barrage	22%

Source: Pöyry Energy Consulting

Figure 40 - Hourly variation of total firm capacity



Source: Poyry Energy Consulting

A.2 Characteristic days

In order to assess the capacity gap over the year, characteristic days were needed for each month, for each scenario.

The starting point for this was the annual load profiles for each scenario. The developments of these are described in section 3.

The characteristic day (only weekdays were used, in order to avoid any reduction in demand, which would have resulted from including weekends) for each month and annual load profile for 2006-7 were calculated from the national grid half hourly demand data.

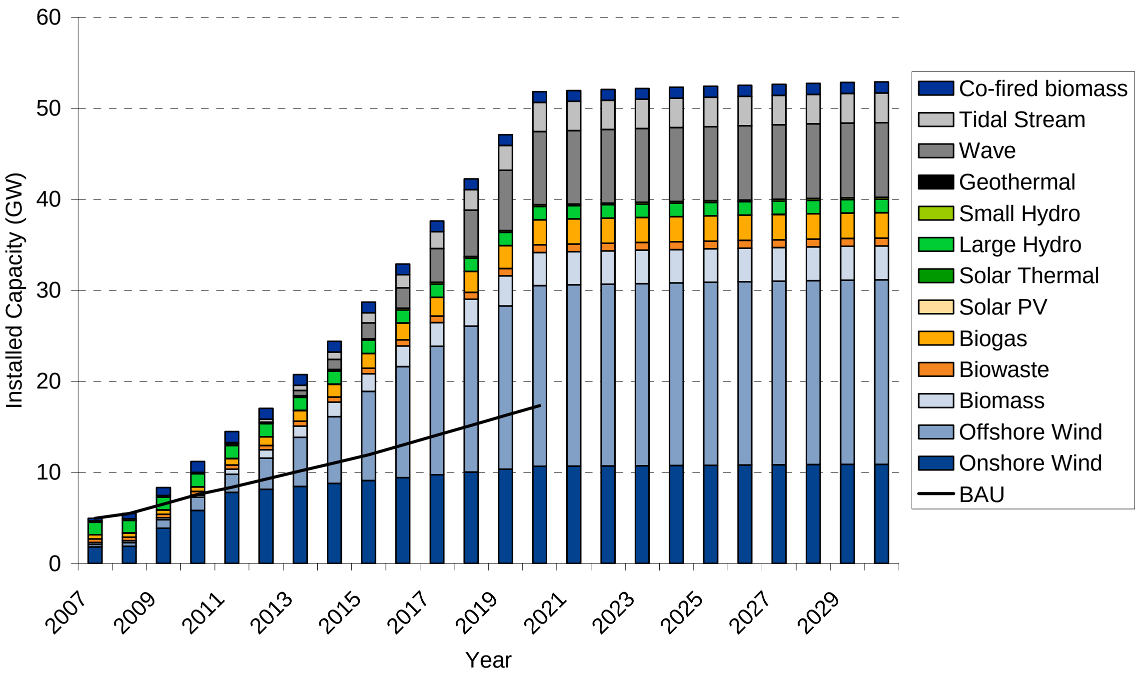
It was assumed that the ratio between demand for each half hour in the characteristic days and in annual load profile would remain unchanged. Therefore, the demand for any half hour can be calculated by:

$$\textit{Demand in scenario characteristic day} = \textit{Demand in 2007 characteristic day} \times \frac{\textit{Demand in scenario annual profile}}{\textit{Demand in 2007 annual profile}}$$

ANNEX B – ADDITIONAL GRAPHS

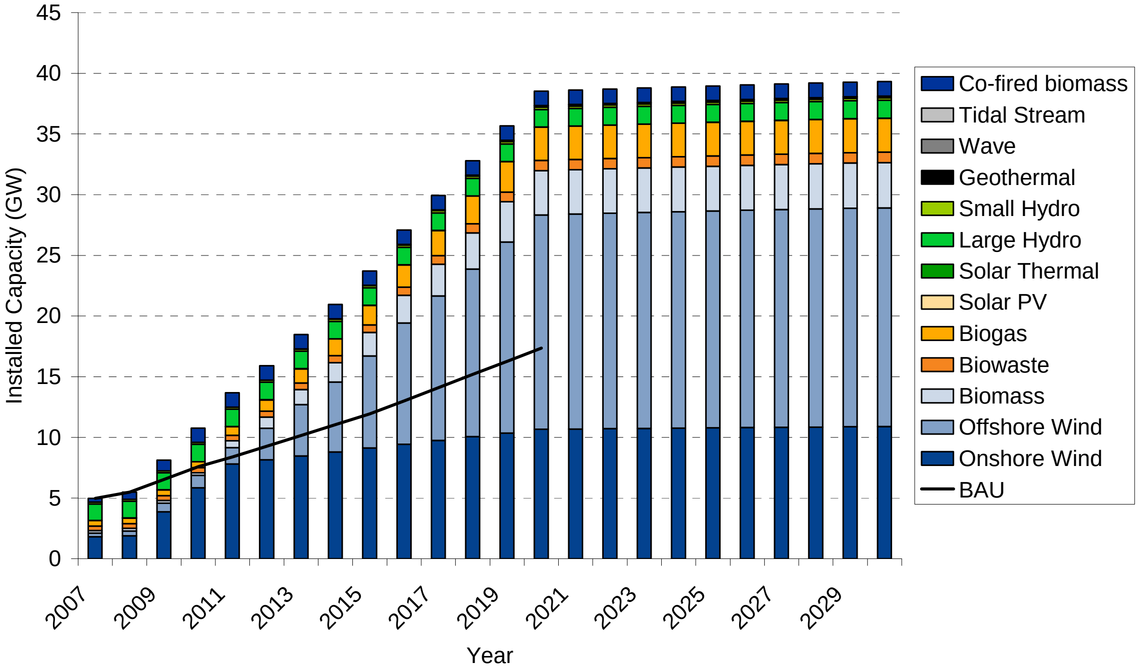
B.1 Renewable build in each scenario

Figure 41 – Renewable build 'Green power'



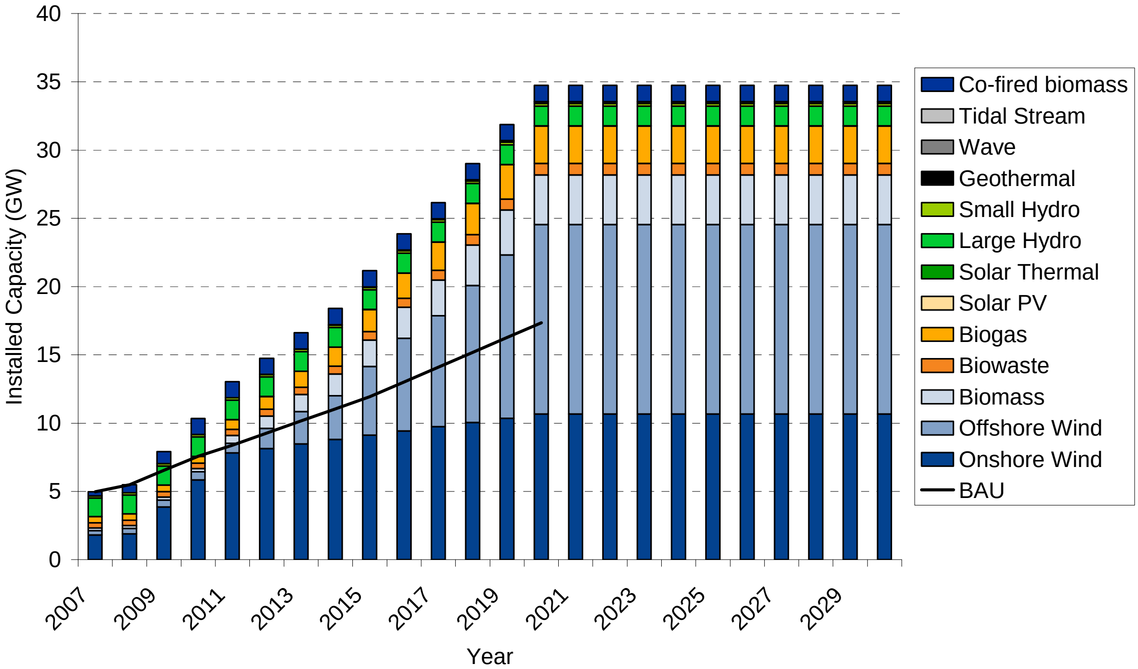
Source: Pöyry Energy Consulting

Figure 42 – Renewable build 'Shared Load'



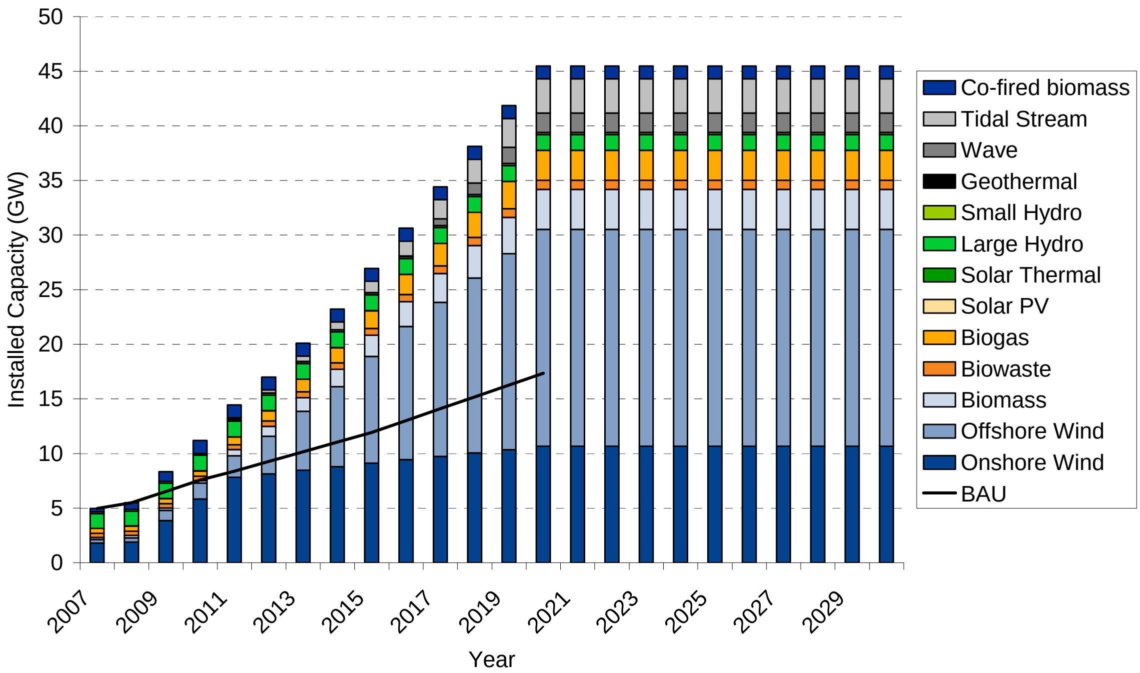
Source: Pöyry Energy Consulting

Figure 43 – Renewable build 'Energy Revolution'



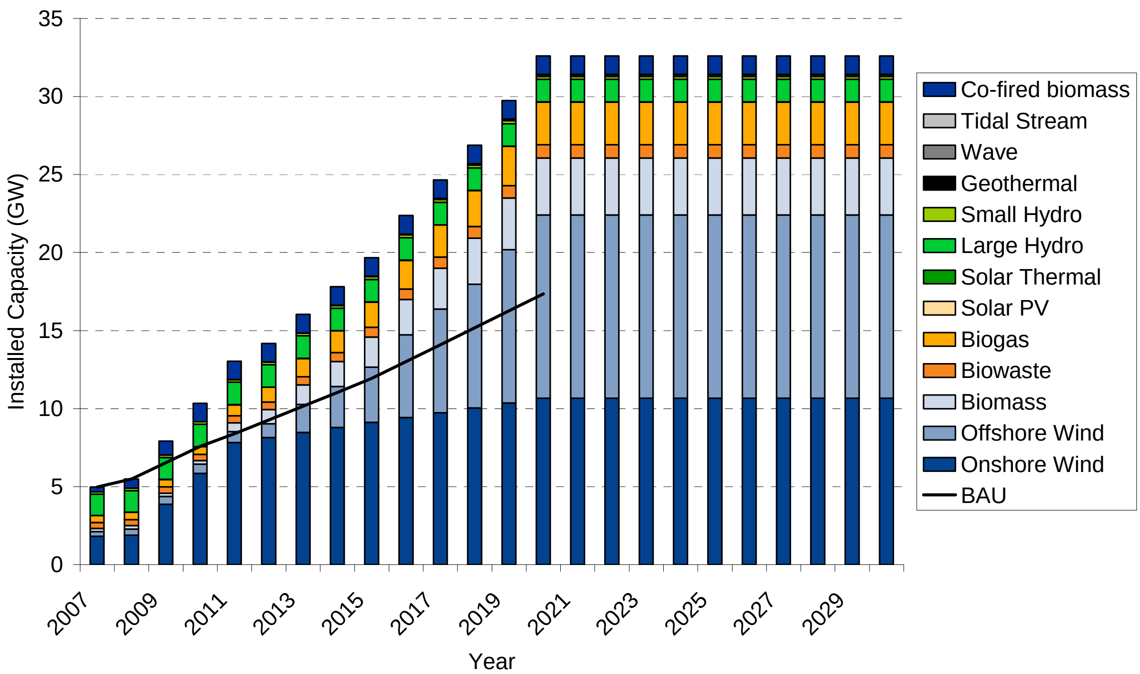
Source: Pöyry Energy Consulting

Figure 44 – Renewable build 'Energy revolution non-bio'



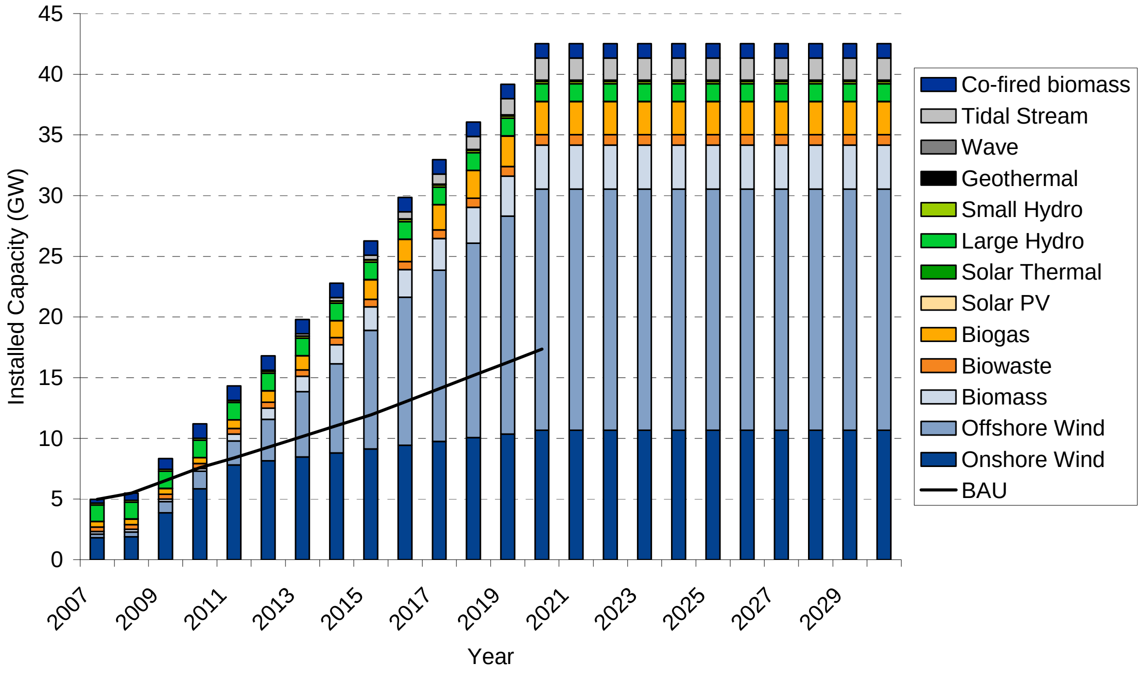
Source: Pöyry Energy Consulting

Figure 45 – Renewable build 'Power Down'



Source: Pöyry Energy Consulting

Figure 46 – Renewable build 'Power down non-bio'



Source: Pöyry Energy Consulting

QUALITY AND DOCUMENT CONTROL

Quality control		Report's unique identifier: 2008/230	
Role	Name	Signature	Date
Author(s):	Gareth Davies		1 August 08
	Brendan Cronin		
Approved by:	Andrew Nind		1 August 08
QC review by:	Louise Carlisle		1 August 08

Document control			
Version no.	Unique id.	Principal changes	Date
v1_0		Final Report	1 August 08

Pöyry is a global consulting and engineering firm.

Focusing on the energy, forest industry, infrastructure and environment sectors, Pöyry employs 7200 experts globally and has annual net sales of €718million.

Pöyry Energy Consulting is the leading advisor to Europe's energy markets, formed from the merger of ILEX Energy Consulting, ECON, Convergence Utility Consultants and the management consulting arms of Electrowatt-Ekono and Verbundplan.

Pöyry Energy Consulting

King Charles House
Park End Street
Oxford, OX1 1JD
UK

Tel: +44 (0)1865 722660
Fax: +44 (0)1865 722988
www.ilexenergy.com
E-mail: consulting.energy.uk@poyry.com

Pöyry Energy (Oxford) Ltd, Registered in England No. 2573801
King Charles House, Park End Street, Oxford OX1 1JD, UK

www.poyry.com