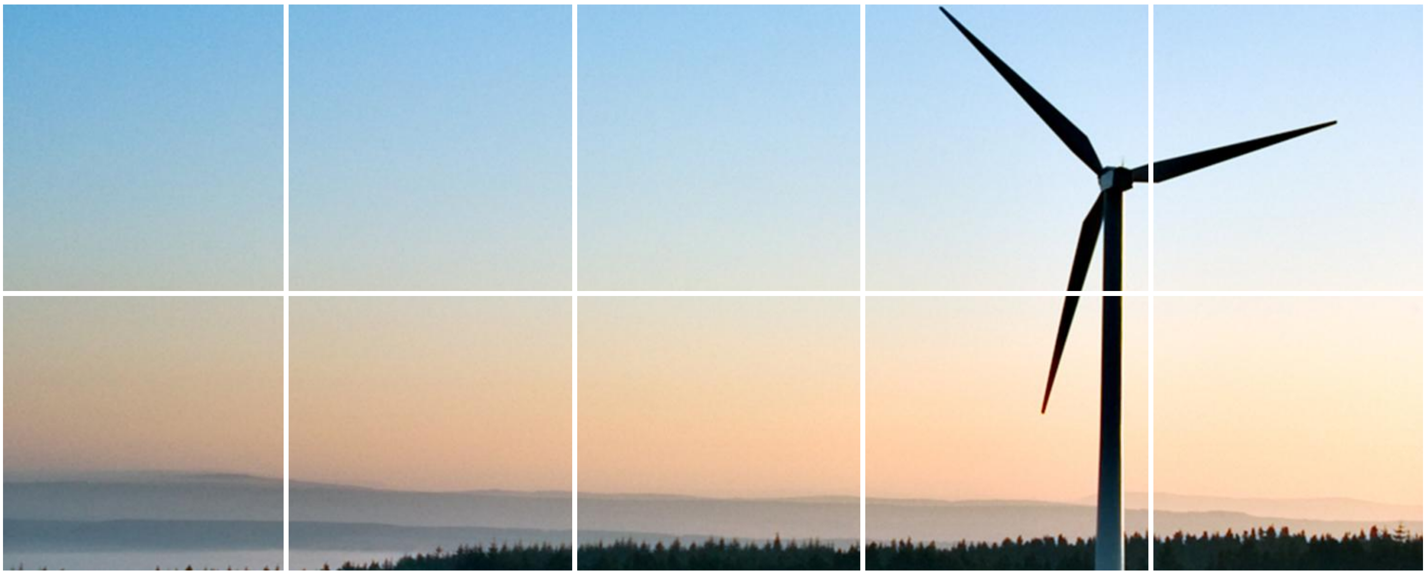

# Analysis of Renewables Growth to 2020

**Report to DECC**

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| | Signature | P.A. Michael |
| | Date | 28 May 2010 |

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# Executive summary

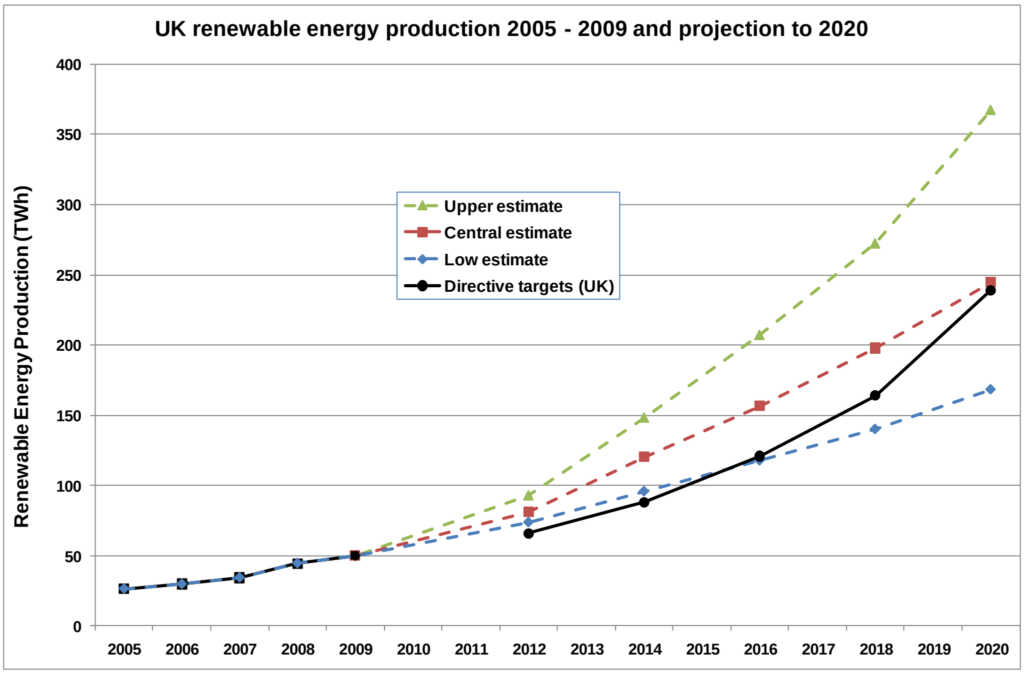
This report provides an analysis undertaken by AEA for DECC in March 2010 of the prospects for renewable energy growth in the UK to 2020. Through the EU's Renewable Energy Directive the UK is now committed to supplying 15% of its energy consumption from renewable sources by 2020, with interim targets of 4% for 2011-12, 5.4% by 2013-14, 7.5% by 2015-16 and 10.2% by 2017-18. The Government outlined its strategy for meeting the 2020 target with the publication of the UK Renewable Energy Strategy (RES) in July 2009. The next step for DECC is to produce a detailed delivery plan for the strategy and the analysis contained in this report provides an initial starting point.

The aim of this work was three-fold:

- Review the deployment that has taken place for relevant technologies from 2005 to the present.
- Review the amount of capacity that is currently in the project development pipeline.
- Assess industry's view of the level of deployment that is likely to take place to 2020, based on the measures presented in the RES.

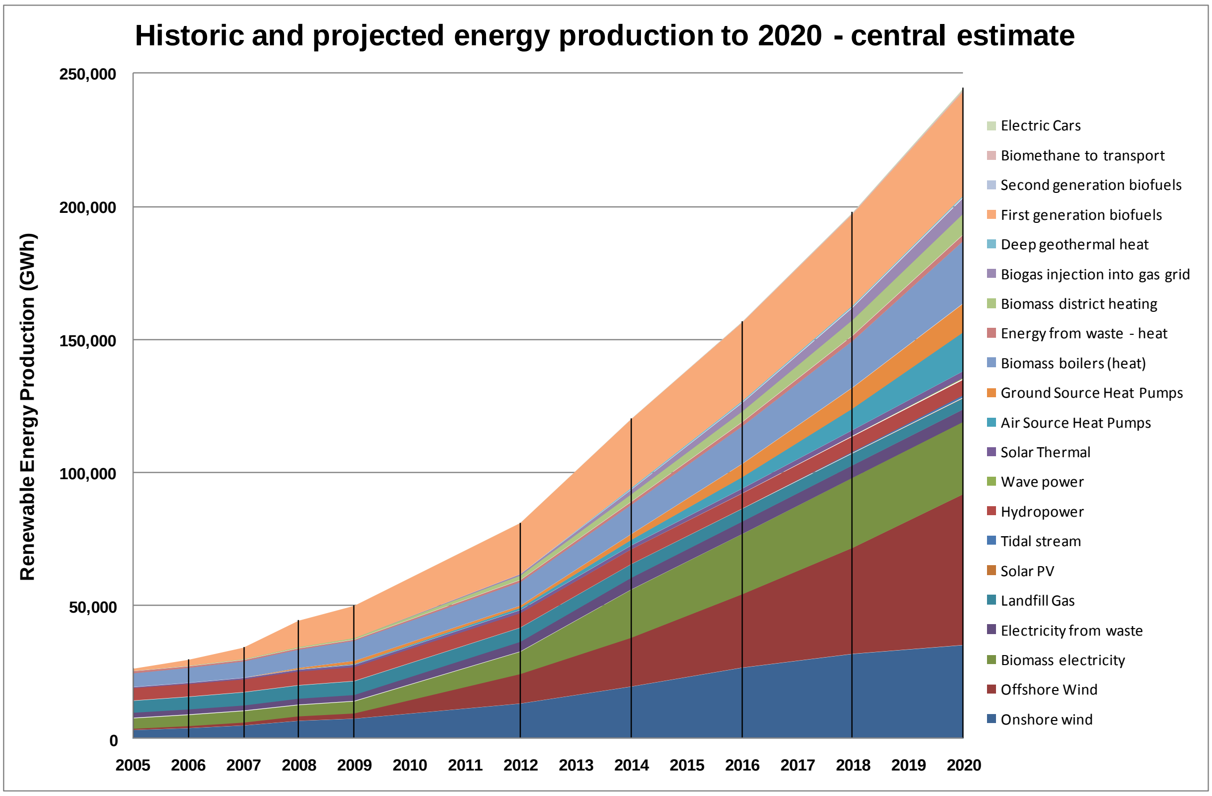
To achieve the first two aims we have drawn on two databases that AEA manages on behalf of DECC: RESTATS, the UK's Renewable Energy STATisticS database, and REPD, the Renewable Energy Planning Database project that meets the need to track the progress of potential new projects from inception, through planning, construction and operational stages. To address the third aim we have consulted industry to gauge what is likely to be achieved on the basis of the current state of the market and the additional deployment likely to be stimulated by the measures already in place or announced in the RES (for example the new RHI). The analysis has covered 22 discrete sectors that represent the likely renewable contributions in the electricity, heat and transport sectors. The forward projections are presented as a range from pessimistic to optimistic, with a central view representing the most likely outcome foreseen. Whilst this has been a very limited exercise, the data presented in this report represent a baseline from which future assessments can build.

The figure below provides an overall summary of the aggregate energy production to 2009 and the three projections forward to 2020. The graph also shows the projected contributions required by the renewable energy directive, based on the UK's projected gross final energy consumption (if the UK is to achieve 15% of overall consumption, renewables will need to deliver around 239 TWh in 2020). These should be seen as preliminary results, requiring confirmation through further consultation with industry and the regulatory authorities.



The projections indicate that, in all but the "pessimistic" low projection, the 2020 target figure of 239 TWh renewables contribution is achieved. However the central projection (245 TWh) is very close to the target figure of 239 TWh, well within the margin of error, so there is no room for complacency. The other notable feature is that the low and central projections result in a fairly steady rate of growth, whereas the targets depict a possibly more realistic scenario of growth that accelerates in the run-up to 2020. This suggests that the projections for the early years may be rather optimistic, though it could also imply that the measures already taken by the Government are providing the required impetus to encourage early deployment. They certainly show that, for all but the low estimate, the UK's interim directive targets can be achieved.

The figure below presents the aggregated historic and projected growth (under the 'central' assumptions) for the 22 sectors assessed. All of the projections show an increase in the overall rate of deployment by 2012, indicating that industry believes the measures in the RES are sufficient to provide the required impetus. From the position at the end of 2009 (50 TWh) the projections for 2012 fall in the range 74 – 93 TWh, indicating an immediate impact from the policies currently being implemented. More generally one can say that the renewables incentives framework that has been put in place appears sufficient to increase deployment rates across the required technologies; in particular the key technologies of onshore wind, biomass heat and power and especially offshore wind demonstrate significant growth over the coming decade. The two heat pump technologies also show significant growth, spurred on by the RHI, but these must be seen as more uncertain, given the major change in heating practice that this implies. A number of technologies make smaller contributions, but these are nevertheless required if the targets are to be achieved.




The basis for the projections and the results are discussed in detail in the individual technology chapters and summarised in Chapter 2. These also assess the key dependencies to achieve the required growth in deployment. Ensuring that investment returns are sufficient to attract developers and consumers must be a primary goal, as the markets will not react in sufficient volume without that. Consenting is not seen as a major barrier but integration of renewables to energy markets could well be due to the significant investment in infrastructure required. There is a need across the board to strengthen renewable energy supply chains, as the UK starts from a low base.

This study provides an initial assessment of where the UK stands with respect to achieving the 15% target in 2020. Further work is required to verify the forward projections but the initial indication is that the target is achievable on the basis of the current strategy so long as all of the available opportunities are progressed.

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**Appendices**

# 1 Introduction

The Renewable Energy Directive[1] has set the UK a target of supplying 15% of its energy consumption from renewable sources by 2020, with interim targets of 4% for 2011-12, 5.4% by 2013-14, 7.5% by 2015-16 and 10.2% by 2017-18. Recognising the challenging nature of these targets, the UK government published its Renewable Energy Strategy (RES) in July 2009[2], covering the full range of factors that will influence deployment over the coming decade. Of primary significance among these is a suite of market incentives that address all sectors of the energy market. These provide the main impetus for individuals, companies and communities to make the required investments. However there are many other factors that influence whether the required growth rate can be achieved. In addition, renewable energy covers a large number of quite different technologies all subject to their own individual considerations and constraints.

DECC is currently preparing a detailed delivery plan for the RES, with the aim of ensuring that the targets mentioned above can be achieved. In order to provide a firm foundation for this, it has asked AEA to undertake the analysis contained in this report, focusing on three areas:

1. The deployment that has actually taken place for relevant technologies from 2005 to the present.

2. The amount of capacity that is currently in the project development pipeline, covering initial project planning, the planning application process and the subsequent period during which projects are financed and built prior to commencing energy production.

3. Industry's view of the level of deployment that is likely to take place to 2020, based on the measures presented in the RES.

To provide the information for the first two areas, AEA has relied primarily on two databases that it manages on behalf of DECC[3]:

**RESTATS**, the UK's Renewable Energy STATisticS database, is a project that has been running for 20 years and over this period has become the primary source of accurate, up-to-date energy statistics of UK renewable energy sources. These cover onshore and offshore wind power; large and small-scale hydropower, biomass and biowastes (including co-firing); solar photovoltaics (PV); wave power; active solar heating; geothermal aquifers. It is thus the most reliable means by which the success of the UK renewables programme can be both measured and monitored.

**REPD**: In parallel and complementing RESTATS, the Renewable Energy Planning Database project meets the need to track the progress of potential new projects from inception, through planning, construction and operational stages. These data help identify where problems may be occurring in policy, incentive mechanisms and in the planning process and provide good quality information to Government to assist in evidence-based policy making.

Note however that these databases do not hold data equally across all technologies. In recent years data from electricity producing technologies has predominated, due to the renewables market focusing on the Renewables Obligation. In the case of heat producing technologies the information sources available are very limited and the data therefore less reliable. Data on biofuel consumption in the transport sector are obtained from HMRC and in future may be available from the RFA through its management of the RTFO.

The third part of the analysis, that of projecting forward to 2020, is undoubtedly the most challenging aspect of the project. The goal here has been, not to mathematically model some hypothetical deployment rate or create a scenario of how the 15% target can be achieved, but to talk to industry and gauge what is likely to be achieved on the basis of the current state of the market and the additional deployment likely to be stimulated by the measures already in place or announced in the

[1] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:140:0016:0062:EN:PDF
[2] http://www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/energy_mix/renewable/res/res.aspx
[3] Appendix 1 (Data sources for estimating future growth rates in the uptake of renewable energy technologies) provides further information on the RESTATS and REPD databases.

RES (for example the new RHI). We must stress that in the very limited time available it has only been possible to provide an initial view of the bottom-up assessment of the future deployment potential.

Given the wide range of factors that can influence the outcome, the forward projections are presented as a range from pessimistic to optimistic, with a central view representing the most likely outcome foreseen. The current exercise presents a rather limited bottom up assessment undertaken during March 2010. Technical experts at AEA have drawn on the published literature and discussions with industry contacts to populate the chapters that follow. With limited resources, some technologies could only be assessed very superficially. Nevertheless the data presented in this report represent a baseline from which future assessments can build.

This report presents the annual renewable energy contributions in terms of GWh for individual technologies, or TWh for the aggregate data, at the end of each of the years or periods in question. The UK has recently submitted to the European Commission its forecast document as required under the terms of the Renewable Energy Directive[4]. This includes estimates of the UK's gross final energy consumption over each of the next ten years and thereby the interim targets that need to be achieved. The data are presented in ktoe in the document and are translated into TWh as follows.

| | UK gross final energy consumption (RES definition) | | | |
|---|---|---|---|---|
| **Period** | **Ktoe** | **TWh** | **UK RE target** | **RES target (TWh)** |
| 2011-12 | 141,811 | 1,649 | 4.0% | 66 |
| 2013-14 | 140,846 | 1,638 | 5.4% | 88 |
| 2015-16 | 139,237 | 1,619 | 7.5% | 121 |
| 2017-18 | 137,938 | 1,604 | 10.2% | 164 |
| 2020 | 136,741 | 1,590 | 15.0% | 239 |

The Renewable Energy Directive gives equal weight to a $kWh_{th}$ as a $kWh_e$ so the energy production or saving data are simply presented as kWh/GWh/TWh. In the case of heat pumps the technology requires a significant amount of electricity to move heat from an external to an internal source, and heating from conventional sources is therefore saved rather than 'produced'. In this case the Directive provides a formula in its Annex VII to calculate the net energy contribution, and this has been used for ASHP and GSHP. In the case of transport technologies, the vast majority of contribution is expected to come from 1$^{st}$ generation biofuels. For transport biofuels the primary units for installed capacity are the appropriate units for annual biofuel consumption (for example millions of litres per annum of bioethanol and biodiesel); these are then converted into GWh for comparison with the other sectors. For electric vehicles the calculation is more complicated, but these are only expected to make a very limited contribution by 2020.

Despite the wide range of renewable energy technologies and their often very different characteristics, the aim of this work was to present their potential contributions on as common a basis as possible. Hence a standard Excel workbook template has been used to present the quantitative data, with slight variations for those technologies to which CHP contributes. The workbooks for individual sectors represent a separate deliverable under this project, as does an over-arching workbook that aggregates the energy production information (key results are summarised in Chapter 2).

In the time available it was not possible to undertake a full bottom-up assessment of the future deployment potential. For example the energy production data are calculated from the installed capacities using a single load factor, representing a weighted average across the whole sector, including for the historic data. This means that the historic energy production figures will not agree exactly with data recorded in RESTATS; however they are probably a more realistic comparator for future production as it's the installed capacity that is the important determinant, whereas annual generation is subject to variations resulting from variable weather conditions and other factors. It has also been necessary to make a range of assumptions and approximations to project future capacities and their splits by country, scale and use. Wherever possible these assumptions are described in this supporting document – it is therefore important to interpret the data in the workbooks in the light of the qualifying text in this report.

[4] Documents for all the EU Member States are at http://ec.europa.eu/energy/renewables/transparency_platform/forecast_documents_en.htm

The bioenergy sector provides particular challenges in this regard, especially important due to the accepted view that bioenergy is likely to contribute around half of the renewable energy production in 2020. The bioenergy sector is a complex one, with a wide range of feedstocks (including the potential to grow energy crops or import biomass or biofuels) and a wide range of technologies at various stages of development. Furthermore these technologies contribute to all three of the energy markets – heat, power and transport. The opportunities for deployment are often inter-related, governed by a range of factors. With the range of new incentives being introduced (in particular the Renewable Heat Incentive) the past is no particular guide to what will happen in the future. In general the market will favour those opportunities that provide the greatest investment return; these are in turn determined by the level of incentive available in each sector.

Hence the Government can itself determine the likely outcome through the levels at which it sets the incentives, though clearly there are also other factors that can have a major influence. Investment behaviour in recent years has been determined largely by the RO and, more recently the RTFO. In the last month we now know the sectors and levels of support for Feed-in Tariffs. More importantly the consultation on the RHI has been launched and this is expected to provide a major boost to heat deployment for bioenergy feedstocks. It is early days and industry views are still evolving, so we have done our best to ensure that a rational approach to the outcomes is taken.

The other feature for bioenergy is the ability to supplement UK arisings with imported feedstocks. This will only apply to certain sectors, but could end up making the major contribution to the bioenergy share. For feedstocks that are unlikely to be imported (e.g. most of the wastes), we have taken the data on UK arisings as the ultimate limiting factor on deployment. Where imports are feasible, the deployment will mainly be limited by our ability to put the required infrastructure in place and the relative economic attractiveness of the option. In these cases we have focused very much on UK consumption rather than UK production. We have aimed to cover these matters in this supporting document. Further information on how this report treats bioenergy is presented in Appendix 2.

**Conclusion**

Given the limited nature of this exercise, the data presented here must be taken as an initial view of the future deployment potential. We strongly recommend that in Phase 2 a more thorough consultation of industry and other key stakeholders be undertaken to provide confidence that the projections truly represent a consensus view. More detailed information also needs to be gathered to provide confidence that the required project pipeline can match the deployment projections.

**Structure of the report**

The bulk of this report is made up of chapters on each of the sectors requested by DECC, set out to a standard format and drawing both data and charts from the relevant sector workbook. In some cases sectors were assigned a low priority and therefore the information presented is limited; this can also apply where the relevant information was simply not available. As previously mentioned Chapter 2 presents some of the information on an aggregate basis in order to provide an overview of the main contributions and key dependencies.

In addition the report contains three appendices:

**Appendix 1: Data Sources for estimating future growth rates in the uptake of renewable energy technologies**. This appendix provides background information on the RESTATS and REPD databases that were used to provide historical information, where available, on the installed capacities, energy production and project development pipeline of a number of renewable energy technologies.

**Appendix 2 Allocating resources to bioenergy categories**.

**Appendix 3 Grid Related issues in Achieving 2020 Targets**. It is accepted that, without major expansion and development of the electricity grid and distribution systems, it will not be possible for a number of renewable energy technologies to reach their full potential. This appendix reviews the issues and presents the current position with respect to their influence on achieving deployment of new capacity over the coming decade.

# 2 Aggregated summary results

## 2.1 Introduction

This study has assessed the contributions to electricity, heat and transport from almost all of the technologies that are likely to make contributions to the UK's renewable energy targets over the next decade. This chapter presents summaries and an aggregate picture of the data that follow in the individual technology chapters and must be viewed within the limitations stated in the previous chapter. In addition the deployment prospects change with time as projects are developed and built and the commercial, regulatory and policy frameworks evolve.

The data in the individual modules are presented in terms of installed capacity and translated into energy production in GWh. The capacity data are mostly in MW but for a few modules that metric is not relevant, so a more appropriate unit is used. In order to present all the data on a common basis this chapter presents the energy production/saving data in GWh or TWh; these after all are what the target will be based on. The Excel workbook that aggregates the data has links to the 22 individual technology workbooks and these links must be preserved if they are to work correctly. Initially the data will be frozen to prevent corruption but in due course the files need to be established in the correct directory structure so that they can operate as 'live' links.

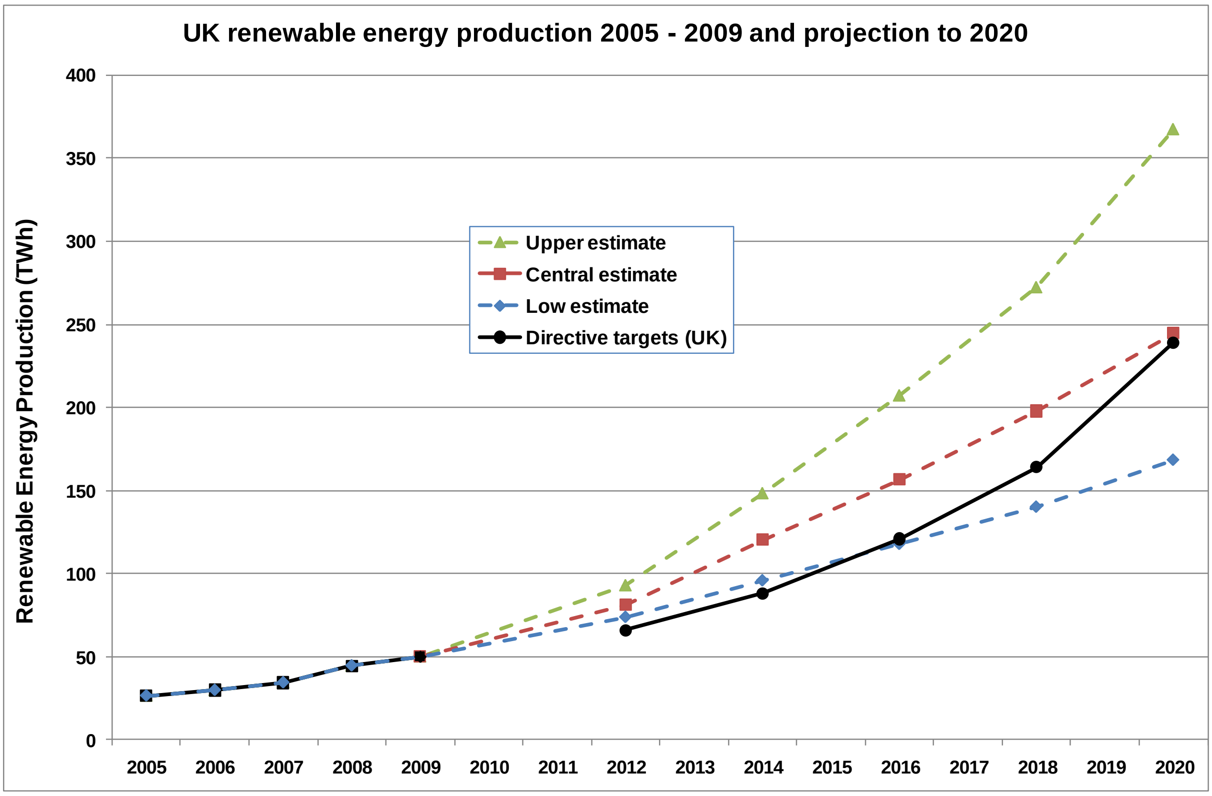
## 2.2 Aggregate data

Figure 2.1 overleaf provides an overall summary of the aggregate energy production to 2009 and the three projections forward to 2020. The graph also shows the projected contributions required by the renewable energy directive, as shown in Chapter 1. It must be emphasised that these should be seen as preliminary results, requiring confirmation through further consultation with industry and the regulatory authorities.

The projections indicate that in all but the "pessimistic" low projection, the 2020 target figure of 239 TWh renewables contribution is achieved. However the central projection (245 TWh) is very close to the target figure of 239 TWh, well within the margin of error, so there is no room for complacency. The other notable feature is that the low and central projections result in a fairly steady rate of growth, whereas the targets depict a possibly more realistic scenario of growth that accelerates in the run-up to 2020. This suggests that the projections for the early years may be rather optimistic, though it could also imply that the measures already taken by the Government are providing the required impetus to encourage early deployment. They certainly show that, for all but the low estimate, the UK's interim directive targets can be achieved.

The graphs that follow demonstrate how the individual technologies contribute to this overall picture.

**Figure 2.1: UK renewable energy production 2005 – 2009 and forward projection to 2020**




## 2.2.1 Energy production under central, low and upper projections

The tables and graphs on the pages that follow provide an aggregate summary of the data presented in the technology chapters, in terms of energy contributions in GWh. The contributions achieved by 2020, in relation to the notional target figure of 239 TWh, are as follows:

Low projection: 168 TWh

Central projection: 245 TWh

Upper projection: 368 TWh

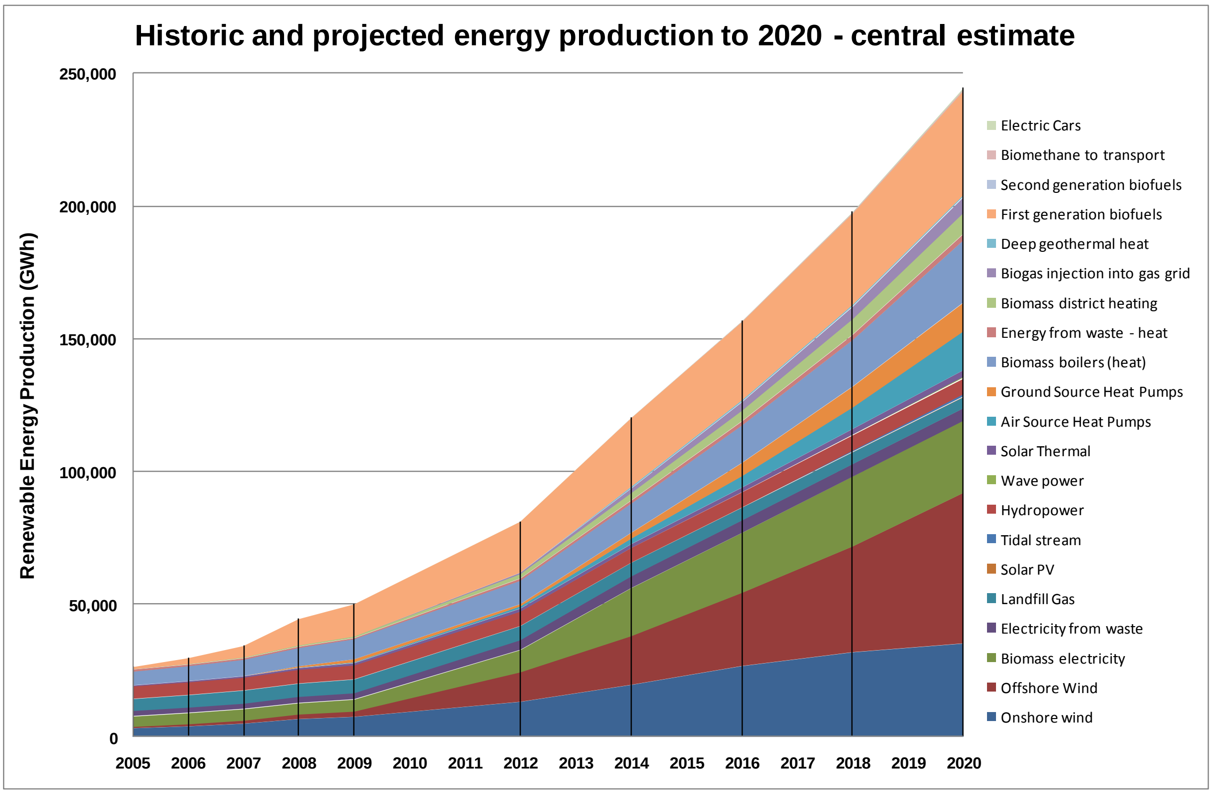
All of the projections show an increase in the overall rate of deployment by 2012, indicating that industry believes the measures in the RES are sufficient to provide the required impetus. From the position at the end of 2009 (50 TWh) the projections for 2012 fall in the range 74 – 93 TWh, indicating an immediate impact from the policies currently being implemented. More generally one can say that the renewables incentives framework that has been put in place appears sufficient to increase deployment rates across the required technologies; in particular the key technologies of onshore wind, biomass heat and power and especially offshore wind demonstrate significant growth over the coming decade. The two heat pump technologies also show significant growth, spurred on by the RHI, but these must be seen as more uncertain, given the major change in heating practice that this implies. A number of technologies make smaller contributions, but these are nevertheless required if the targets are to be achieved. There must be some uncertainty about market uptake under FiTs and the RHI, given the need for customers to invest significant up-front capital outlay, especially as the incentives they follow mitigated this through grant aid. However it is hoped that the financial sector will come up with financing mechanisms that overcome this potential barrier.

## Central estimate

### Table 2.1: Breakdown of UK renewable energy production 2005 – 2009 and forward projection to 2020 - central estimate

| Central projection | Annual output at the end of the stated year/period | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Energy production (GWh)** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010-12** | **2013-14** | **2015-16** | **2017-18** | **2019-20** |
| **Electricity** | | | | | | | | | | |
| Onshore wind | 3,196 | 3,904 | 4,928 | 6,670 | 7,483 | 13,159 | 19,545 | 26,641 | 31,844 | 35,156 |
| Technology: Offshore Wind | 656 | 932 | 1,239 | 1,833 | 2,109 | 11,191 | 18,396 | 27,594 | 39,858 | 56,721 |
| Biomass electricity | 3,891 | 4,157 | 4,301 | 4,211 | 4,487 | 8,354 | 18,049 | 22,577 | 26,353 | 27,245 |
| Electricity from MSW and C&I waste | 2,041 | 2,043 | 2,043 | 2,369 | 2,369 | 3,723 | 4,468 | 4,765 | 4,765 | 4,765 |
| Landfill Gas | 4,477 | 4,688 | 4,931 | 4,973 | 5,170 | 5,311 | 5,147 | 4,818 | 4,490 | 4,205 |
| Solar PV | 8 | 11 | 13 | 17 | 20 | 24 | 29 | 41 | 62 | 107 |
| Tidal stream | 0 | 0 | 0 | 0 | 3 | 6 | 14 | 98 | 603 | 1,079 |
| Hydropower | 4,865 | 4,910 | 4,943 | 5,282 | 5,357 | 5,478 | 5,575 | 5,672 | 5,769 | 5,867 |
| Wave power | 1 | 1 | 1 | 1 | 1 | 2 | 5 | 31 | 189 | 485 |
| Deep Geothermal electricity (CHP) | 0 | 0 | 0 | 0 | 0 | 0 | 74 | 74 | 74 | 74 |
| **Heat** | | | | | | | | | | |
| Solar Thermal | 370 | 457 | 566 | 704 | 880 | 1,171 | 1,417 | 1,715 | 2,075 | 2,510 |
| Air Source Heat Pumps | 0 | 0 | 0 | 111 | 244 | 795 | 2,090 | 4,326 | 8,169 | 14,753 |
| Ground Source Heat Pumps | 0 | 0 | 0 | 489 | 1,162 | 841 | 2,183 | 4,988 | 7,868 | 10,813 |
| Biomass boilers (heat) | 5,178 | 5,629 | 6,181 | 6,914 | 7,607 | 8,827 | 10,985 | 14,082 | 17,498 | 23,387 |
| Energy from waste - heat | 829 | 617 | 574 | 543 | 444 | 839 | 1,144 | 1,543 | 1,958 | 2,349 |
| Biomass district heating | 112 | 225 | 345 | 492 | 619 | 1,728 | 2,908 | 4,133 | 6,056 | 8,126 |
| Biogas injection into gas grid | 0 | 0 | 0 | 0 | 0 | 560 | 1,734 | 3,227 | 4,646 | 5,937 |
| Deep geothermal heat (with CHP) | 9 | 9 | 9 | 9 | 9 | 9 | 596 | 596 | 587 | 587 |
| **Transport** | | | | | | | | | | |
| First generation biofuels | 822 | 2,216 | 4,303 | 9,903 | 12,105 | 19,145 | 25,812 | 29,454 | 34,363 | 39,272 |
| Second generation biofuels | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Biomethane to transport | 0 | 0 | 0 | 0 | 0 | 0 | 96 | 267 | 480 | 676 |
| Electric Cars | 0 | 0 | 0 | 0 | 2 | 31 | 72 | 132 | 245 | 544 |
| **Totals** | **26,456** | **29,798** | **34,377** | **44,522** | **50,072** | **81,192** | **120,339** | **156,774** | **197,953** | **244,658** |

### Figure 2.2: Breakdown of UK renewable energy production 2005 – 2009 and forward projection to 2020 - central estimate

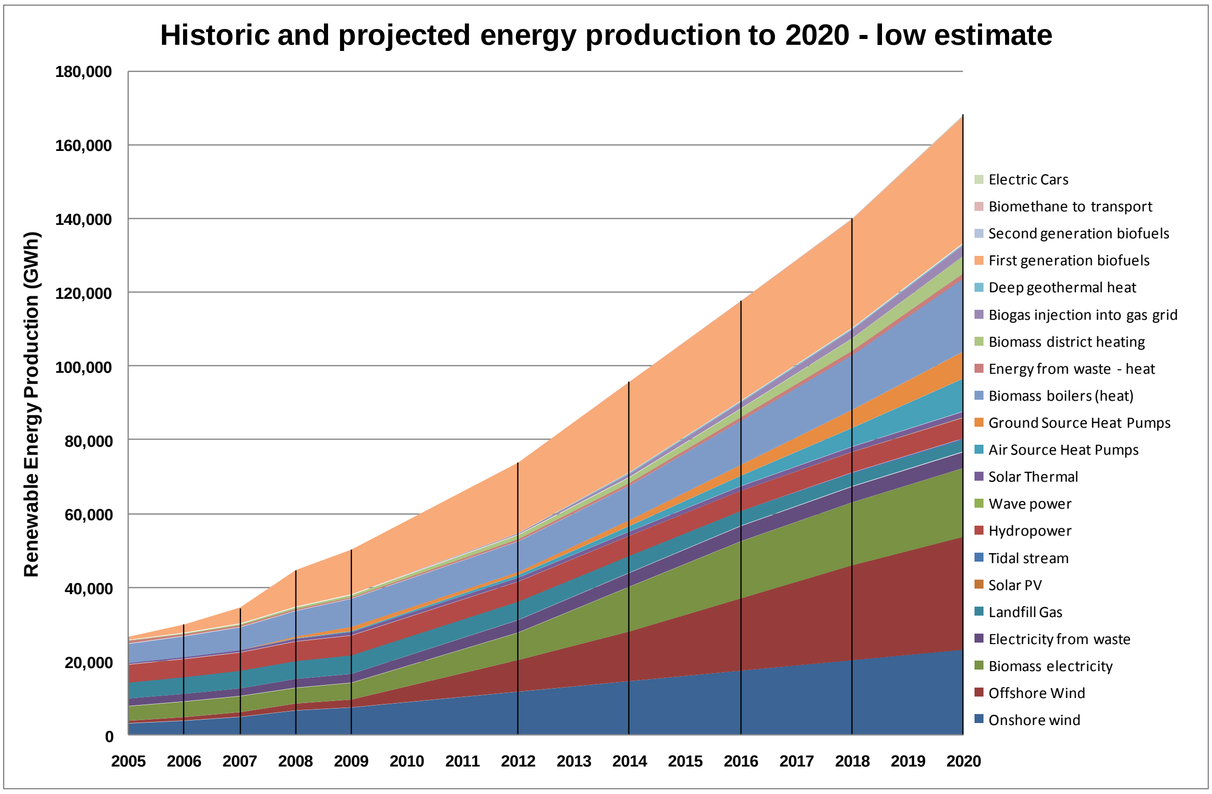


### Low estimate

### Table 2.2: Breakdown of UK renewable energy production 2005 – 2009 and forward projection to 2020 - low estimate

| Low projection | Annual output at the end of the stated year/period | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Energy production (GWh)** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010-12** | **2013-14** | **2015-16** | **2017-18** | **2019-20** |
| **Electricity** | | | | | | | | | | |
| Onshore wind | 3,196 | 3,904 | 4,928 | 6,670 | 7,483 | 11,740 | 14,579 | 17,417 | 20,255 | 23,093 |
| Offshore Wind | 656 | 932 | 1,239 | 1,833 | 2,109 | 8,585 | 13,490 | 19,622 | 25,754 | 30,660 |
| Biomass electricity | 3,891 | 4,157 | 4,301 | 4,211 | 4,487 | 7,407 | 12,135 | 15,498 | 17,095 | 18,689 |
| Electricity from waste | 2,041 | 2,043 | 2,043 | 2,369 | 2,369 | 3,351 | 3,723 | 4,095 | 4,244 | 4,319 |
| Landfill Gas | 4,477 | 4,688 | 4,931 | 4,973 | 5,170 | 5,092 | 4,654 | 4,052 | 3,559 | 3,154 |
| Solar PV | 8 | 11 | 13 | 17 | 20 | 23 | 28 | 38 | 56 | 93 |
| Tidal stream | 0 | 0 | 0 | 0 | 3 | 3 | 6 | 42 | 252 | 449 |
| Hydropower | 4,865 | 4,910 | 4,943 | 5,282 | 5,357 | 5,413 | 5,445 | 5,478 | 5,510 | 5,542 |
| Wave power | 1 | 1 | 1 | 1 | 1 | 9 | 9 | 19 | 104 | 248 |
| Deep Geothermal electricity (CHP) | 0 | 0 | 0 | 0 | 0 | 0 | 40 | 40 | 40 | 40 |
| **Heat** | | | | | | | | | | |
| Solar Thermal | 370 | 457 | 566 | 704 | 880 | 1,019 | 1,123 | 1,238 | 1,365 | 1,505 |
| Air Source Heat Pumps | 0 | 0 | 0 | 111 | 244 | 720 | 1,450 | 2,766 | 5,022 | 8,885 |
| Ground Source Heat Pumps | 0 | 0 | 0 | 489 | 1,162 | 787 | 1,573 | 2,924 | 4,879 | 7,287 |
| Biomass boilers (heat) | 5,178 | 5,629 | 6,181 | 6,914 | 7,607 | 8,278 | 9,339 | 11,970 | 14,870 | 19,880 |
| Energy from waste - heat | 829 | 617 | 574 | 543 | 444 | 683 | 805 | 1,039 | 1,270 | 1,477 |
| Biomass district heating | 112 | 225 | 345 | 492 | 619 | 1,148 | 1,532 | 2,329 | 3,340 | 4,715 |
| Biogas injection into gas grid | 0 | 0 | 0 | 0 | 0 | 280 | 867 | 1,613 | 2,323 | 2,969 |
| Deep geothermal heat | 9 | 9 | 9 | 9 | 9 | 9 | 312 | 312 | 303 | 303 |
| **Transport** | | | | | | | | | | |
| First generation biofuels | 822 | 2,216 | 4,303 | 9,903 | 12,105 | 19,145 | 24,545 | 27,000 | 29,454 | 34,363 |
| Second generation biofuels | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Biomethane to transport | 0 | 0 | 0 | 0 | 0 | 0 | 48 | 133 | 240 | 338 |
| Electric Cars | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 14 | 40 | 205 |
| **Totals** | **26,456** | **29,798** | **34,377** | **44,522** | **50,072** | **73,691** | **95,703** | **117,637** | **139,975** | **168,213** |

### Figure 2.3: Breakdown of UK renewable energy production 2005 – 2009 and forward projection to 2020 - low estimate

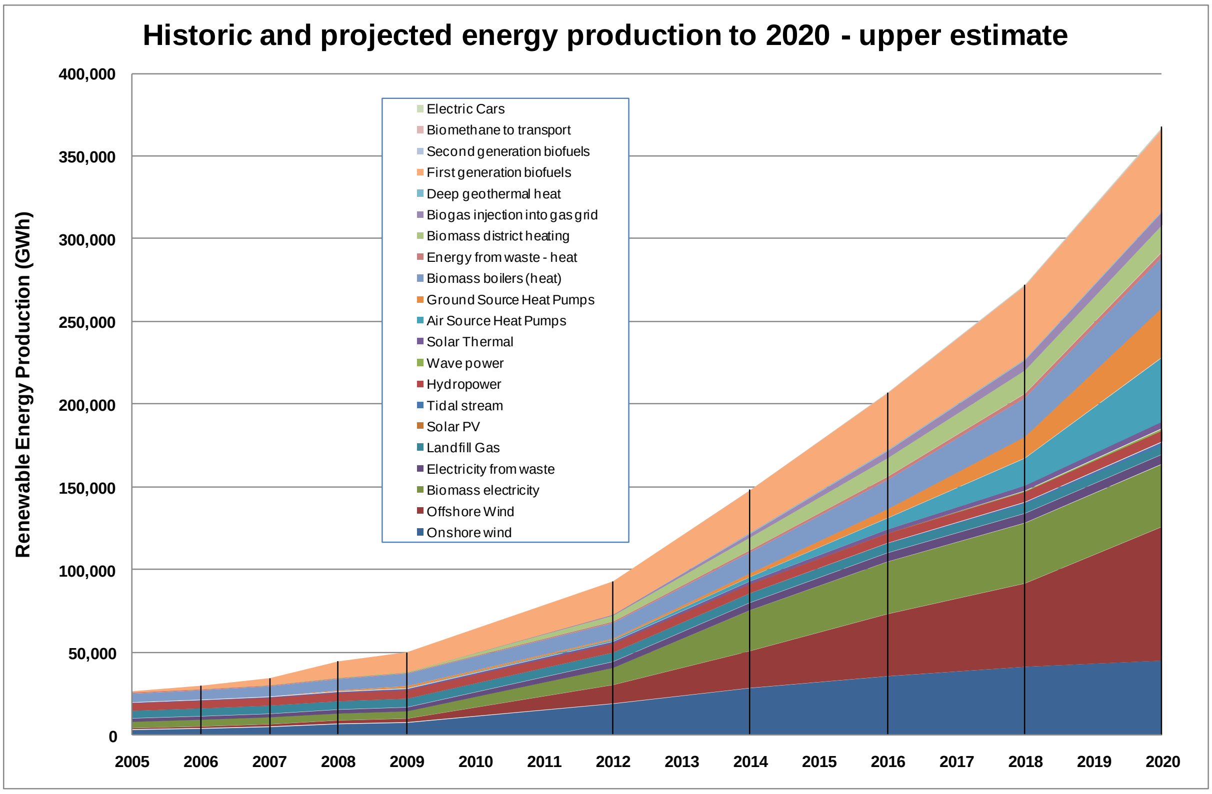


## Upper estimate

### Table 2.3: Breakdown of UK renewable energy production 2005 – 2009 and forward projection to 2020 - upper estimate

| Upper projection | Annual output at the end of the stated year/period | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Energy production (GWh)** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010-12** | **2013-14** | **2015-16** | **2017-18** | **2019-20** |
| **Electricity** | | | | | | | | | | |
| Onshore wind | 3,196 | 3,904 | 4,928 | 6,670 | 7,483 | 18,836 | 28,297 | 35,392 | 41,069 | 44,853 |
| Offshore Wind | 656 | 932 | 1,239 | 1,833 | 2,109 | 11,191 | 22,382 | 37,712 | 50,589 | 81,249 |
| Biomass electricity | 3,891 | 4,157 | 4,301 | 4,211 | 4,487 | 10,276 | 24,661 | 31,600 | 36,541 | 37,807 |
| Electricity from waste | 2,041 | 2,043 | 2,043 | 2,369 | 2,369 | 3,723 | 4,468 | 5,212 | 5,585 | 5,622 |
| Landfill Gas | 4,477 | 4,688 | 4,931 | 4,973 | 5,170 | 5,420 | 5,585 | 5,667 | 5,749 | 5,749 |
| Solar PV | 8 | 11 | 13 | 17 | 20 | 24 | 31 | 45 | 67 | 121 |
| Tidal stream | 0 | 0 | 0 | 0 | 3 | 8 | 28 | 168 | 995 | 1,794 |
| Hydropower | 4,865 | 4,910 | 4,943 | 5,282 | 5,357 | 5,542 | 5,672 | 5,996 | 6,482 | 6,871 |
| Wave power | 1 | 1 | 1 | 1 | 1 | 9 | 14 | 57 | 485 | 1,206 |
| Deep Geothermal electricity (CHP) | 0 | 0 | 0 | 0 | 0 | 0 | 91 | 91 | 91 | 91 |
| **Heat** | | | | | | | | | | |
| Solar Thermal | 370 | 457 | 566 | 704 | 880 | 1,338 | 1,770 | 2,341 | 3,095 | 4,094 |
| Air Source Heat Pumps | 0 | 0 | 0 | 111 | 244 | 795 | 2,479 | 6,767 | 16,571 | 38,928 |
| Ground Source Heat Pumps | 0 | 0 | 0 | 489 | 1,162 | 837 | 2,129 | 5,424 | 12,942 | 30,062 |
| Biomass boilers (heat) | 5,178 | 5,629 | 6,181 | 6,914 | 7,607 | 9,440 | 12,825 | 17,761 | 23,630 | 30,746 |
| Energy from waste - heat | 829 | 617 | 574 | 543 | 444 | 874 | 1,278 | 1,891 | 2,511 | 3,045 |
| Biomass district heating | 112 | 225 | 345 | 492 | 619 | 3,679 | 7,705 | 11,153 | 13,930 | 16,052 |
| Biogas injection into gas grid | 0 | 0 | 0 | 0 | 0 | 672 | 2,254 | 4,357 | 6,272 | 8,015 |
| Deep geothermal heat | 9 | 9 | 9 | 9 | 9 | 9 | 689 | 689 | 680 | 680 |
| **Transport** | | | | | | | | | | |
| First generation biofuels | 822 | 2,216 | 4,303 | 9,903 | 12,105 | 20,225 | 25,812 | 34,363 | 44,181 | 49,090 |
| Second generation biofuels | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Biomethane to transport | 0 | 0 | 0 | 0 | 0 | 0 | 125 | 360 | 648 | 912 |
| Electric Cars | 0 | 0 | 0 | 0 | 2 | 31 | 99 | 248 | 388 | 729 |
| **Totals** | **26,456** | **29,798** | **34,377** | **44,522** | **50,072** | **92,931** | **148,391** | **207,294** | **272,502** | **367,717** |

### Figure 2.4: Breakdown of UK renewable energy production 2005 – 2009 and forward projection to 2020 - upper estimate



### 2.2.2 Summary of constraints and key dependencies

This is the area that is possibly most subjective and therefore care needs to be exercised when interpreting the results[5]. The comments in the individual technology chapters should be viewed together with the green/amber/red classifications shown in the table below. Some of the conclusions that can be drawn follow the table.

**Table 2.4: Summary of the constraints and key dependencies**

| **Constraints on renewable energy deployment** | Returns insufficient to stimulate significant deployment | Planning (local policies, obtaining permissions) | Integration to energy markets | Supply chain issues and constraints | Regulatory constraints | Institutional barriers | Unclear policy (national, regional, local) | Motivating investors to act | Other constraints |
|---|---|---|---|---|---|---|---|---|---|
| **Electricity** | | | | | | | | | |
| 1. Onshore wind | Green | Amber | Green | Amber | Green | Green | Amber | Amber | |
| 2. Offshore wind | Amber | Green | Red | Amber | Green | Green | Green | Amber | Green |
| 3. Bioenergy for electricity | Amber | Amber | Green | Red | Amber | Green | Amber | Amber | Green |
| 4. Electricity from waste incineration | Green | Amber | Green | Green | Green | Amber | Amber | Green | Red |
| 5. Landfill gas | Green | Green | Green | Green | Green | Green | Green | Green | Red |
| 6. Solar PV | Amber | Green | Green | Amber | Amber | Amber | Green | Green | |
| 7. Tidal stream | Red | Amber | Amber | Amber | Green | Green | Green | Amber | Amber |
| 8. Hydropower | Green | Amber | Amber | Amber | Green | Green | Green | Green | |
| 9. Wave power | Red | Amber | Amber | Amber | Green | Green | Green | Amber | Amber |
| 10. Deep geothermal electricity | Amber | Green | Green | Green | Green | Green | Amber | Amber | Amber |
| **Heat** | | | | | | | | | |
| 11. Solar thermal | Amber | Green | Green | Amber | Green | Green | Green | Amber | |
| 12. Air source heat pumps | Amber | Green | Amber | Amber | | Amber | Green | Amber | Red |
| 13. Ground source heat pumps | Amber | Green | Amber | Amber | Green | Amber | Green | Amber | Red |
| 14. Biomass heat | Amber | Green | Amber | Amber | Amber | Green | Amber | Green | |
| 15. Energy from waste - heat | Green | Green | Green | Green | Green | Green | Amber | Green | |
| 16. Biomass district heating | Amber | Amber | Amber | Amber | Green | Green | Amber | Amber | |
| 17. Biogas injection into gas grid | Green | Green | Green | Green | Amber | Green | Green | Amber | Green |
| 18. Deep geothermal heat | Amber | Green | Green | Green | Green | Amber | Amber | Amber | Amber |
| **Transport** | | | | | | | | | |
| 19. First generation biofuels | Amber | Green | Amber | Amber | Amber | Amber | Red | Red | Red |
| 20. Second generation biofuels | Red | Amber | Green | Red | Green | Green | Amber | Red | Red |
| 21. Biogas transport | Red | Green | Red | Green | Green | Amber | Red | Red | |
| 22. Electric cars | Red | Green | Amber | Green | Green | Green | Green | Red | Red |

| | |
|---|---|
| Green | **Unlikely to present a constraint to achieving the central projection.** |
| Amber | **Could constrain achieving the central projection and will certainly constrain achieving the upper projection** |
| Red | **Likely to constrain achieving the central projection; could result in only the low projection being achieved** |

#### Market incentives

Whilst the projections would imply that the incentives available to consumers are sufficient to achieve the UK's targets (except under pessimistic assumptions), this positive message would appear to be contradicted by the number of technologies that get amber or red in terms of 'rates of return' or 'motivating investors to act'. This is especially marked for the transport technologies. As already stated investment in renewables usually requires a significant capital outlay. Whilst larger commercial projects undertaken though balance sheet or project financing may be used to such investments, the new focus on consumer-scale investments creates much greater uncertainty, especially for technologies that may be seen as novel, unusual or risky. The sharing of risk to assure early and sustained uptake is therefore a crucial element in achieving deployment targets.

[5] Whilst the key to the table shows the definitions provided against green/amber/red, these are quite general and not necessarily interpreted in exactly the same way by those producing the individual technology chapters.

**Consenting processes**

The picture here is much more positive, with a majority of technologies classifying the position as green. This is less the case for electricity generating technologies, where over half are classified as amber. It must be said that in many respects it is too early to tell, as the new planning processes recently introduced have yet to be fully implemented. It is also quite difficult to predict, for the new technologies like wave and tidal energy, to what extent planning issues will constrain early deployment. Onshore wind, which is projected to grow five fold over the coming decade and make a 14% contribution towards achieving the 2020 target (under the central projection), is known to often be an emotive subject at local level. As deployment increases, it is difficult to predict whether the technology will gradually become more accepted (as people realise that it is more benign than they had feared) or whether a saturation effect will take place, constraining future deployment. This situation will need to be carefully monitored.

**Integration to energy markets**

This provided a mixed bag of classifications, very dependent on the specific technology. It is clear that, for many of the electricity generating technologies necessarily located remotely to capture the most economic resource, deployment can only take place if the electricity grid can transport the power to where the demand is located (sometimes a good distance away). For offshore wind, which makes 23% of the 2020 renewables contribution under the central projection, this issue is crucial and could greatly affect the outcome. Appendix 3 summarises some of the grid related issues. For the heat producing technologies the position is also mixed – the 2020 position represents a major shift compared with the current one and it is likely that issues will be raised that require addressing. For some technologies, like electric vehicles, major questions still remain concerning their integration into a fossil-dominated marketplace.

District heating could provide a significant market for bioenergy, especially in major urban areas, but the UK has a poor track record compared with many other European countries and future policy in this area is uncertain.

**Supply chain issues**

This area has resulted in a majority of technologies classified amber, and two red. The UK does not have a strong equipment supply tradition in most renewables and achieving the directive target requires major expansion across the full suite of technologies. Thus we will initially be dependent in many cases on equipment imported from abroad, at a time when other countries are facing similarly demanding targets. It is not clear yet whether a strong UK supply base will develop to meet the need; it is certainly desirable but may only happen if concerted measures are taken at national, regional and local level. This situation also applies for the multitude of support industries required to install and maintain the required equipment – technical trades that are often in short supply. For the offshore technologies a whole new infrastructure is required to install and support the required capacity, and transport the power to market.

For bioenergy the position is compounded by the need to import a significant share of the feedstock required to achieve the projected deployment. Whilst it currently appears that there is sufficient resource available from international markets, it is clear that UK users will be competing for this with growing demand elsewhere, making it difficult to guarantee sufficient supply at a predictable price. Supply could be further constrained if tough sustainability standards are imposed – the position here remains fluid, with the European Commission recently unwilling to commit itself to EU-wide standards. The issue of biomass imports also raises questions about energy security, one of the main justifications for renewables deployment. One way of mitigating the need to import would be through the vigorous encouragement of energy crops, however Government policy in this area remains unclear.

**Regulatory and institutional constraints**

The position in these areas is much more positive, with the majority of the technologies classifying them as green. There do remain important issues, such as the classification of waste fuels under environmental regulations and the ways in which emissions will be controlled from small-scale biomass combustion. The shift to a decentralised energy market with significant distributed capacity is a fundamental one that will raise issues in a number of areas, such as quality standards for bioenergy supply, management of electricity and gas grids and regulation of the energy supply industries. The RHI will provide a major challenge if it is to be successful.

**Other potential barriers**

A number of other potential barriers have been highlighted, such as potentially unclear policy. An example of this is the position for biofuels in the transport market, where concerns over sustainability issues and international trade issues have undermined investor confidence. Skills shortages in key areas such as the regulatory regime could delay project implementation. Some of the bioenergy options are in competition with one another and the outcome will often be shaped by policy decisions. Public acceptability is a key issue and it will be very important for the early acceleration of deployment not to create any kind of public backlash through poor project implementation.

**Conclusions**

The term renewables covers a set of very different technologies and it is important for each one to be looked at individually. The brief assessment undertaken for this report suggests that the policies announced under the Renewable Energy Strategy could be sufficient to achieve the UK's 2020 target under the renewables directive, but there is no room for complacency. There was insufficient time or data available to say with certainty whether the projects currently in the project planning pipeline are sufficient to achieve the projected deployment; in some areas this does appear to be the case but further work is required to gain a more complete picture.

### 2.2.3 Distribution of deployed capacity by country and project size

One of the requests was to split the existing and projected capacity by country in the UK and by project size. In the time available this was not achievable for all of the technologies. Where historic data were available (mainly from REPD) these are presented in the technology workbooks. In some cases these have been extrapolated forward to 2020 for distribution by country based on a number of factors, in particular the location of the most economic resource, population distribution and (less likely) other regional factors. For project size the extrapolations are most likely a continuation of historical trends.

Aggregate graphs are presented on the following page, however it must be emphasised that the data are only indicative, in particular the projections beyond 2009 (as the technology coverage is incomplete). Further work is required to confirm the individual splits and fill in blanks where data are currently missing.

**Figure 2.5: Breakdown of UK renewable energy production 2005 – 2009 by country and incomplete forward projection to 2020 – central estimate**

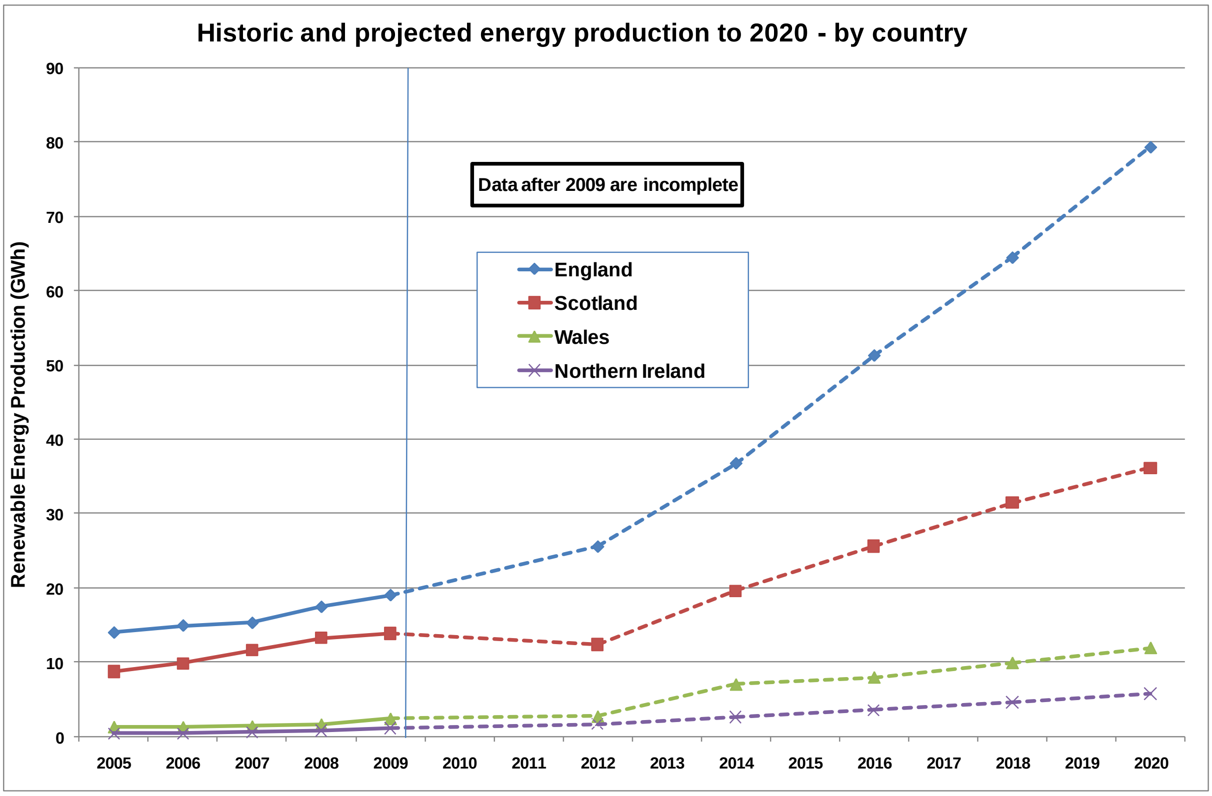
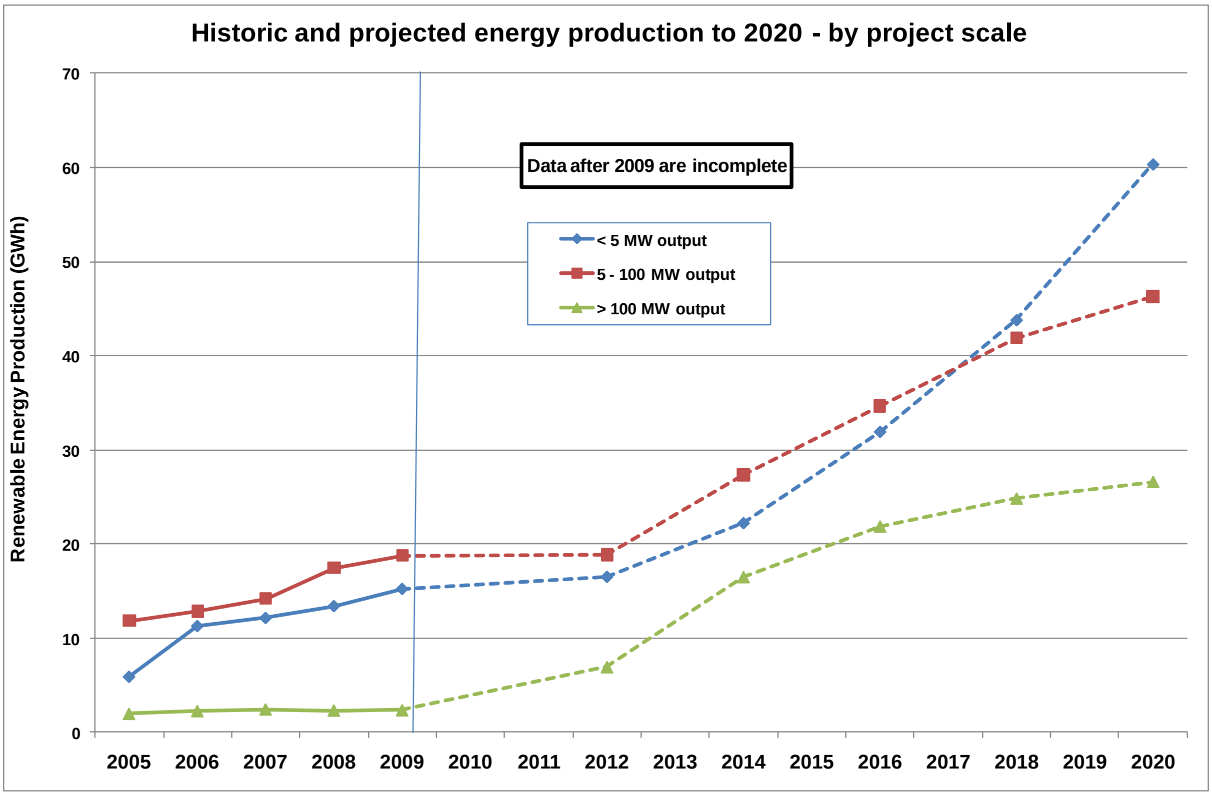



**Figure 2.6: Breakdown of UK renewable energy production 2005 – 2009 by project size and incomplete forward projection to 2020 – central estimate**



# 3 Onshore wind

## 3.1 Introduction

Onshore wind is one of the most mature renewable energy technologies. Wind farms have been operating in the UK since 1991. The UK has an excellent onshore wind resource with wind speeds particularly good in Scotland, Northern Ireland and Wales, (less so in England, particularly the south east). Turbine size has steadily increased over the years and the average new turbine size is around 2.5MW. The increased tower height associated with the increased turbine size has increased wind capture (wind speed generally increases with height above ground level) and turbine design has improved and become more sophisticated – both of these leading to improvements in efficiency. The UK ranks relatively low in installed capacity terms compared with European neighbours with significantly lower wind speeds for a variety of reasons, some of which will be discussed below.

## 3.2 Historical deployment

Onshore wind capacity has increased every year though not in a steady manner (the maximum installed in one year, 2008, was 800MW – but only an estimated 340MW was installed in 2009). The UK now has over 3 GW of installed capacity in over 100 wind farms. The introduction of the Renewables Obligation has proved a more attractive incentive to developers than the NFFO it replaced and the rate of installation of new wind farms has increased since its introduction.

Factors affecting the rate of installation to date include:

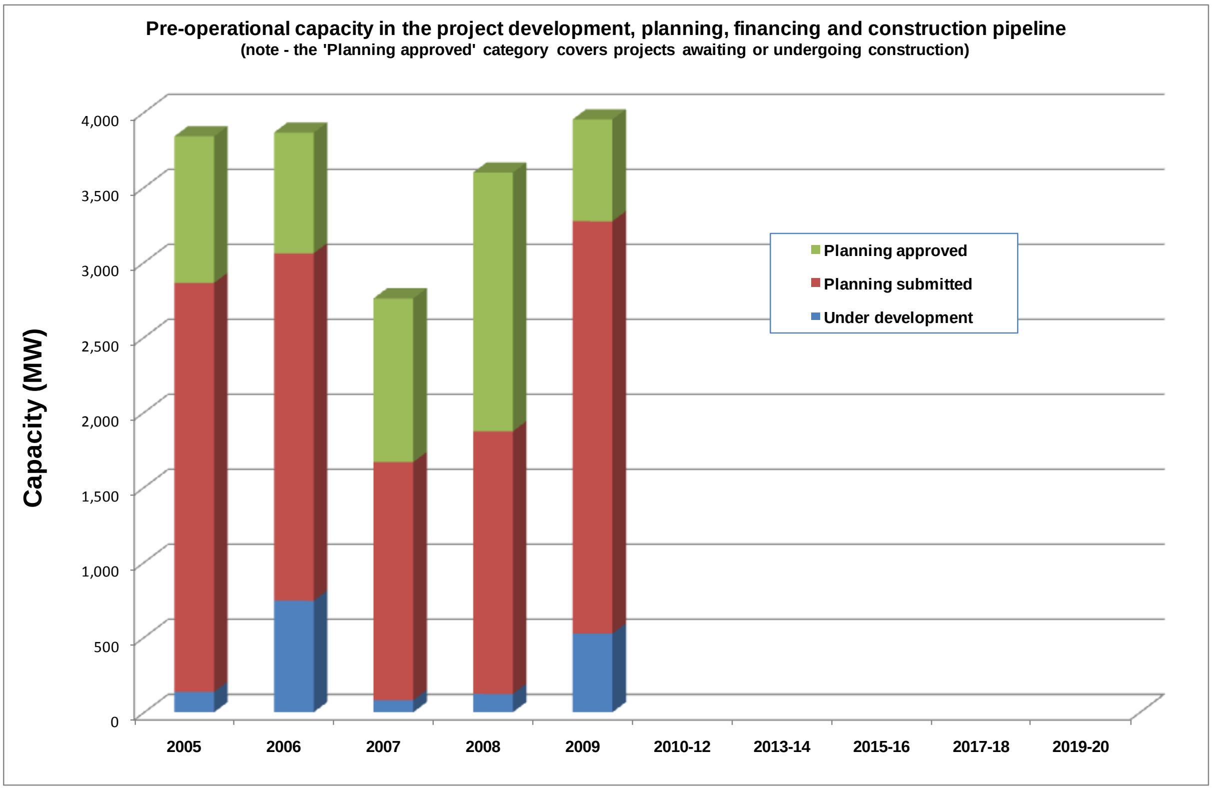
- Uncertain returns/the design of the incentive scheme
- A relatively low planning success rate (data from the Renewable Energy Planning Database, REPD, suggest an average rate from 2005 for onshore wind of 68%)
- A prolonged and expensive planning process
- Difficulty connecting to the electricity network (distribution and transmission, particularly in Scotland)
- Inadequate supply of turbines at an acceptable price
- Skills shortage to install
- Difficulty accessing finance.

All of these are discussed in more detail in section 1.4

The development timescale is quite long – data from the REPD suggests an average time from submission of formal planning application to operation of around three years. The REPD data on scoping is incomplete but industry experience suggests a lead time for scoping for wind resource assessment and environmental assessment of at least two years. REPD data also shows that a significant proportion of capacity which has consent does not become operational – of the order of 10% 5 years after the planning application was submitted. This is thought to be for a variety of reasons including difficulty meeting planning conditions and lack of access to finance.

Figure 1 shows the data from the REPD from 2005 to 2009. The current planning data were used to derive the forward projections of capacity but the individual planning categories were not used so these are not projected beyond 2009. Renewable UK (RUK) noted that the record level of consents application in 2009 reflected the fact that developers' lack of access to finance last year meant that they concentrated their efforts on planning.

**Figure 1: Pre-operation phases: project development, planning, financing and construction**




# 3.3 Projected deployment to 2020

An initial estimate was made of the projected deployment to 2020 and this was then sent to RUK and key industry members for comment. A range of views were expressed and an attempt has been made to reflect the consensus. Where an individual has expressed a significantly different view this is noted.

Input data used for the projections were:

- Capacity with consent but not operational – approx 4,200 MW
- Capacity with planning applications submitted approx 7,000MW
- Average planning success over 2005-2009 of the order of 68%
- Average time from planning submission to operation approximately 3 years (from REPD. RUK feel that a longer figure is more accurate).
- Approximately 10% of capacity with planning not built.
- Maximum capacity installed in on year to date – 800MW

**Low estimate**
A simple assumption of 600MW installed per year was used. One industry member felt that this should be lower – the average installation rate of 450MW from the last few years. However most felt this was reasonable.

**Central estimate**
A couple of industry members felt that this should be lower. One quoted a total range (low to high) for 2020 of 8 -14GW. However most were comfortable with the following:

**2010-2012**
Credit crunch still limiting access to finance and grid connection queue taking time to clear means that installation rate only slowly increasing – from 600 to 800 to 1,000MW per year.

**2013-2016**
Period of fewest constraints. Installation rate increases to 1,500MW per year in 2014 and remains there to 2016. At the end of this period 7.5GW have been installed since end of 2009 – estimated to have largely 'used up' the capacity consented or that already in the planning system as at end 2009.

**2017-2020**

Installation rate gradually falls (to 6,00MW/year in 2020) as the availability of good wind sites decreases and planning becomes more difficult for those which are put forward. A greater proportion of the new capacity is from 'repowering' old sites and small installations supported under the Feed In Tariff (FIT).

### High estimate

**2010-2012**
Installation rate increases and all of consented but not operational (less drop out) built plus some of that currently in planning.

**2013-2014**
Installation rate increases to a maximum of 2,000MW per year. At the end of his period all the consented but not operational plus all currently in planning (taking into account drop out rates) is operational.

**2015-2020**
Installation rate drops year on year from 1,500MW in 2015 to 800MW in 2020 as good site become less available, increases in planning constraints (cumulative impact) and the growing penetration rate of variable generation (onshore and offshore wind) mean that this generation pays a price penalty decreasing the financial incentive.

**Table 1: Historic and projected capacity development and deployment 2005 – 2020**

| | | Total capacties/output in the different categories at the end of the stated year/period | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Unit | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
| | | 31/12/05 | 31/12/06 | 31/12/07 | 31/12/08 | 31/12/09 | 31/12/12 | 31/12/14 | 31/12/16 | 31/12/18 | 31/12/20 |
| Under development | MW | 136 | 743 | 81 | 122 | 525 | | | | | |
| Planning submitted | MW | 2,726 | 2,316 | 1,586 | 1,750 | 2,748 | | | | | |
| Planning approved | MW | 977 | 804 | 1,091 | 1,724 | 679 | | | | | |
| Operational (central) | MW | 1,351 | 1,651 | 2,083 | 2,820 | 3,164 | | | | | |
| Projected operational | MW | | | | | | 5,564 | 8,264 | 11,264 | 13,464 | 14,864 |
| Energy production | GWh | 3,196 | 3,904 | 4,928 | 6,670 | 7,483 | 13,159 | 19,545 | 26,641 | 31,844 | 35,156 |

**Range of projected operational capacity**

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Low estimate | MW | | | | | 3,164 | 4,964 | 6,164 | 7,364 | 8,564 | 9,764 |
| | GWh | | | | | | 11,740 | 14,579 | 17,417 | 20,255 | 23,093 |
| Central estimate | MW | 1,351 | 1,651 | 2,083 | 2,820 | 3,164 | 5,564 | 8,264 | 11,264 | 13,464 | 14,864 |
| | GWh | 3,196 | 3,904 | 4,928 | 6,670 | 7,483 | 13,159 | 19,545 | 26,641 | 31,844 | 35,156 |
| Upper estimate | MW | | | | | 3,164 | 7,964 | 11,964 | 14,964 | 17,364 | 18,964 |
| | GWh | | | | | | 18,836 | 28,297 | 35,392 | 41,069 | 44,853 |

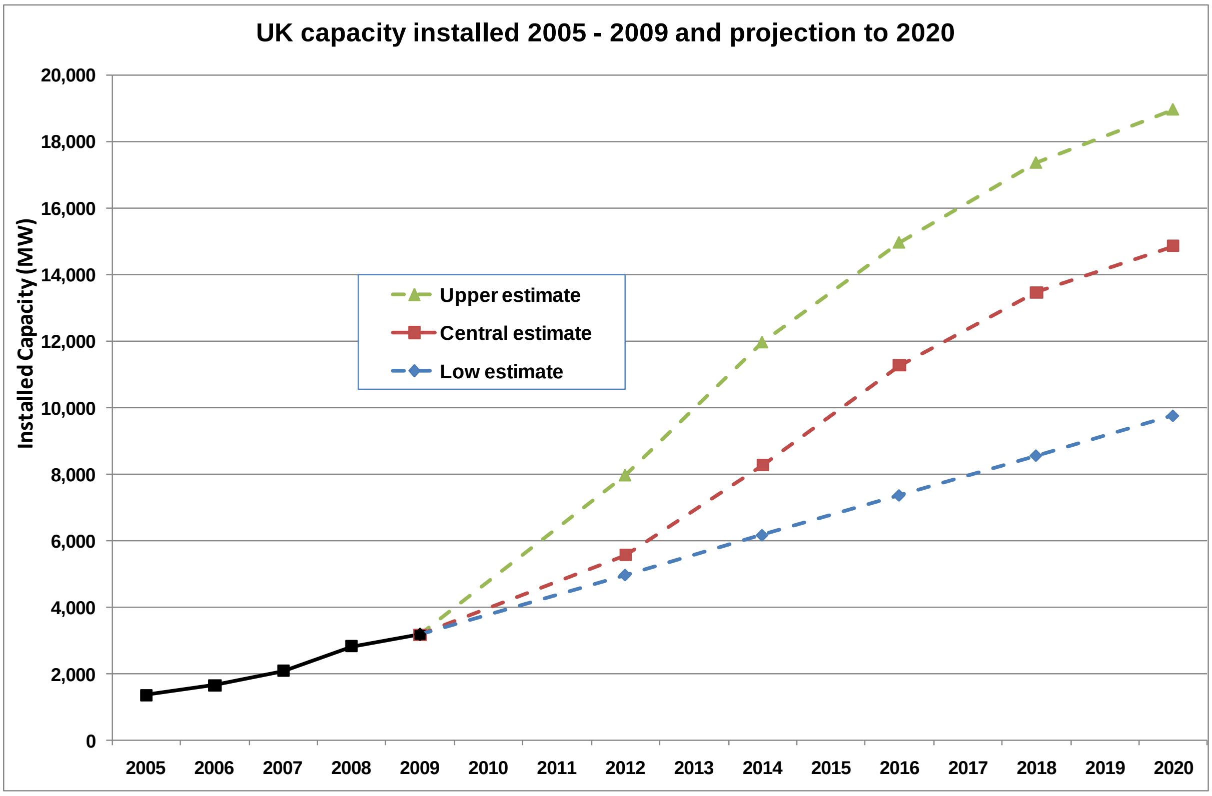
### Load Factors/energy output

The spreadsheet used to present the estimates is a common template across all technologies and has a single load factor across time. This is not likely to be representative for onshore wind. Wind speeds vary from year to year so even for a stable installed capacity load factors vary year to year. This makes is difficult to discern any long term trends but it appears that there has been a trend of increasing load factors reflecting increased turbine size and efficiency.

It is expected that this will continue to rise for a few years but then start to decrease (in the central estimate and more so in the high estimate) as the high wind speed sites are used up. So projected energy outputs are likely to be higher than shown in the short to medium terms and lower in the longer term.

AEA initially proposed a 27% load factor (based on the simple average of the last five years). Some industry members felt that this was too high, some too low so this was left as a central value.

**Figure 2: Historic deployment and range of future projections to 2020**




## 3.4 Achieving future deployment – key dependencies

These are based on industry views. Where there is a significant variation from consensus this is noted.

### 3.4.1 Impact of financial incentives

The combination of the RO and FIT is generally thought to provide adequate incentive in the medium term provided that they remain at the current levels. There is concern that to access the later capacity (post 2015 in the central case) costs will rise (rates, land rentals and community benefit schemes) and lower wind speed sites will need to be exploited resulting in greater incentives being needed (despite possible decreases in turbine costs and some further increases in efficiency)

### 3.4.2 Impact of consenting processes

There is sufficient capacity consented or in the system for the consenting process not to be a restriction in the short to medium term. However planning success rates are still relatively low and variable. Increased build in selected areas with good wind resource may increase cumulative impact and decrease planning success. Aviation impacts show signs that technical solutions should become available but if this proves not to be the case or if the cost is prohibitive then this could reduce the resource significantly. There is also concern that statutory consultees are under-resourced and slow to respond and this lengthens the planning process and makes it more uncertain (ideally a developer will have a provisional view from consultees before formally submitting a planning application but if they are slow in responding this may not be possible). Slow and uncertain planning has indirect effects as well as a direct one – it increases costs and decreases developer appetite. One industry member felt that this was a potential red traffic light.

### 3.4.3 Integration to energy markets

The general consensus is that the 'connect and manage' approach adopted for the electricity transmission and distribution network is working, although the queue is such that it may take some time for the backlog to clear. The consent for the Beauly Denny line upgrade and the prospect of development of other inter-connectors is also encouraging the industry. Two industry members however said that this remained an active constraint.

Industry members did not directly comment on the issue of intermittency but, at the penetration levels of intermittent power (onshore and offshore wind) projected for 2020, certainly in the high estimate and possibly in the central, there may be effects on the operation of the electricity network which may have operational and/or financial effects on wind farms.

### 3.4.4 Supply chain issues and constraints

It is largely felt that the wind turbine supply chain is now less of a constraint as in recent years manufacturing capability has been developed in the two main markets, China and the USA, that in the past have competed with the European market, increasing prices and slowing installation rates. It is thought that the skilled labour to install the turbines will still be a constraint (although this was assumed not to be the case for the high estimate).

### 3.4.5 Regulatory framework

The Infrastructure Planning Commission (if in operation - or alternative) should address issues, for large schemes, of getting planning permission for network reinforcement as part of overall scheme permission.

### 3.4.6 Other potential barriers to deployment

**Unclear policy**
Some concern was expressed that a change of Government or of Government policy could result in major changes to the local planning system in England and that this would cause further delays in planning and possibly a reduced planning success rate.

**Access to capital**
The credit crunch has reduced capital available - EIB funds are helping but it is still expected that limited access to capital will limit development to 2012. Financing is most difficult to access for smaller schemes < 20MW. One industry member felt that this was a potential red traffic light.

### 3.4.7 Summary of constraints

The constraints are summarised in Table 2 overleaf

The central estimate is limited by different constraints at different points in time: network connection and access to finance initially, then skills capacity limits, then obtaining planning permission for sites with reasonable wind speeds.

Overall industry is reasonably optimistic that if things continue on the course we are on, that is:

- adequate support mechanisms,
- electricity network connection blockages removed,
- aviation concerns largely addressed,
- planning no more difficult than at present
- capital becoming more available

there is a reasonable chance of the central estimate being achieved although some were more pessimistic (e.g. total installed capacity by end 2020 of 8-14GW).

The main concerns are that if any of the policies or actions put in place change or fail to address the constraints as expected, this level of deployment may not be possible.

**Table 2: Significance of various potential constraints on deployment**

| Potential constraints | Significance | Comment |
|---|---|---|
| Returns insufficient to stimulate sufficient deployment | Green | ROCs for larger schemes and FIT for <5MW (supported with Pay as you save for households) should provide reasonable returns, provided ROC targets sufficiently stretching and onshore wind retains 1 ROC/GWh. CRC provides additional incentive for businesses to install where appropriate. Concern that in future, 2015 onwards, rising costs and lower wind speed sites may reduce attractiveness. |
| Planning (local policies, obtaining permissions) | Amber | Planning success rates are still relatively low and vary. Increased build in selected areas with good wind resource may increase cumulative impact and decrease planning success. Aviation impacts show signs that technical solutions should become available but if this proves not to be the case or if the cost is prohibitive then this could reduce the resource significantly. Concern that statutory consultees slow to respond and under-resourced. |
| Integration to energy markets | Green | Connect and manage regime should give good access to the electrical distribution and transmission networks at acceptable cost. |
| Supply chain issues and constraints | Amber | Turbine supply becoming less dependent on worldwide markets - more local manufacturing turbines in China and USA mean European market more robust. However skilled staff resource still limited. |
| Regulatory constraints | Green | IPC (if in operation - or alternative) should address issues, for large schemes, of getting planning permission for network reinforcement as part of overall scheme permission. |
| Institutional barriers | Green | |
| Unclear policy (national, regional, local) | Amber | Concern that change of Government may cause further changes in planning system resulting in further delays and more negative decisions. |
| Motivating investors to act | Amber | Credit crunch has reduced capital available - EIB funds are helping but still expect capital to limit development to 2012. Financing most difficult to access for smaller schemes < 20MW. |

| | |
|---|---|
| Green | **Unlikely to present a constraint to achieving the central projection.** |
| Amber | **Could constrain achieving the central projection and will certainly constrain achieving the upper projection** |
| Red | **Likely to constrain achieving the central projection; could result in only the low projection being achieved** |

# 4 Offshore wind

## 4.1 Introduction

There is enormous potential around the UK coastline for offshore wind generation. The first phase (Round 1) of the development of offshore wind projects in the UK was launched in December 2000 when The Crown Estate (TCE) granted a number of twenty-two year leases for developments. This process resulted in fourteen projects, of which eleven are now operational. The rapidly developing UK offshore wind industry is now the largest in the world with around 976MW installed by the end of March 2010.

Late in 2003, Round 2 sites were awarded to 15 projects, with a combined capacity of up to 7.2 GW; this had followed a strategic environmental assessment (SEA) undertaken earlier in 2003. Round 3 was announced in December 2007. Following an SEA process, in January 2010, TCE announced the successful bidders for each of the nine new Round 3 offshore wind zones, potentially totalling 32GW in capacity. This is considered sufficient to ensure that the 25GW that has been enabled by the Government's SEA for offshore renewable energy can be achieved. This is in addition to the 8GW already enabled across Rounds 1 and 2.

In the intervening period, TCE also offered (in February 2009) exclusivity agreements to companies and consortia for 10 sites for development of offshore wind farms in Scottish Territorial Waters (STW), with a total capacity of almost 6.5 GW. Development of these sites will be subject to Scotland's SEA process due for completion this year. In addition, TCE is currently assessing applications to extend Round 1 and Round 2 sites.

The combined total of all Rounds is over 47GW.

Offshore wind is expected to make the single biggest contribution to renewable energy generation in 2020. The Renewable Energy Strategy (RES) 'illustrative' lead scenario projected 14 GW of installed offshore wind in the UK capacity producing 44 TWh in 2020. In 2008, the Renewables Advisory Board (RAB), in the paper[6] '2020 Vision - How the UK can meet its target of 15% renewable energy' put forward, in a central scenario of what was "deliverable with significant but achievable policy changes" a contribution in 2020 from offshore wind of 18GW or 55 TWh.

The capital investment required is in the order of £100 billion, covering a wide range of industries and services. The Government is developing a range of measures to ensure that all elements of the supply chain develop in step and high levels of deployment can be achieved.

## 4.2 Historical deployment

Eight Round 1 projects were operational at the end of 2009. Including the Blyth and Beatrice demonstration projects, the total installed capacity was 688MW. The energy production figures presented in Table 1 are calculated using the weighted average load factor in DUKES. For forward projections a load factor of 35% is used (as used in RAB's '2020 Vision' paper).

For the Round 1 projects the time taken to progress from scoping to operation has ranged from three-four years for the first projects, to ten years for the latter projects. The consenting timeframes for Round 1 have varied between 1 and 3 years from application submission. Construction timeframes have varied from between one and two years, largely influenced by vessel availability, licence conditions (dictating down-time) and weather days. Only a very small number of projects have been abandoned / withdrawn to date. Two on economic grounds, including Cromer, and more recently Scarweather Sands (due to the adverse seabed conditions and "relatively poor" wind conditions in Swansea Bay) and one (Shell Flats) on environmental grounds (issues relating to wintering birds and subsequently MoD objections).

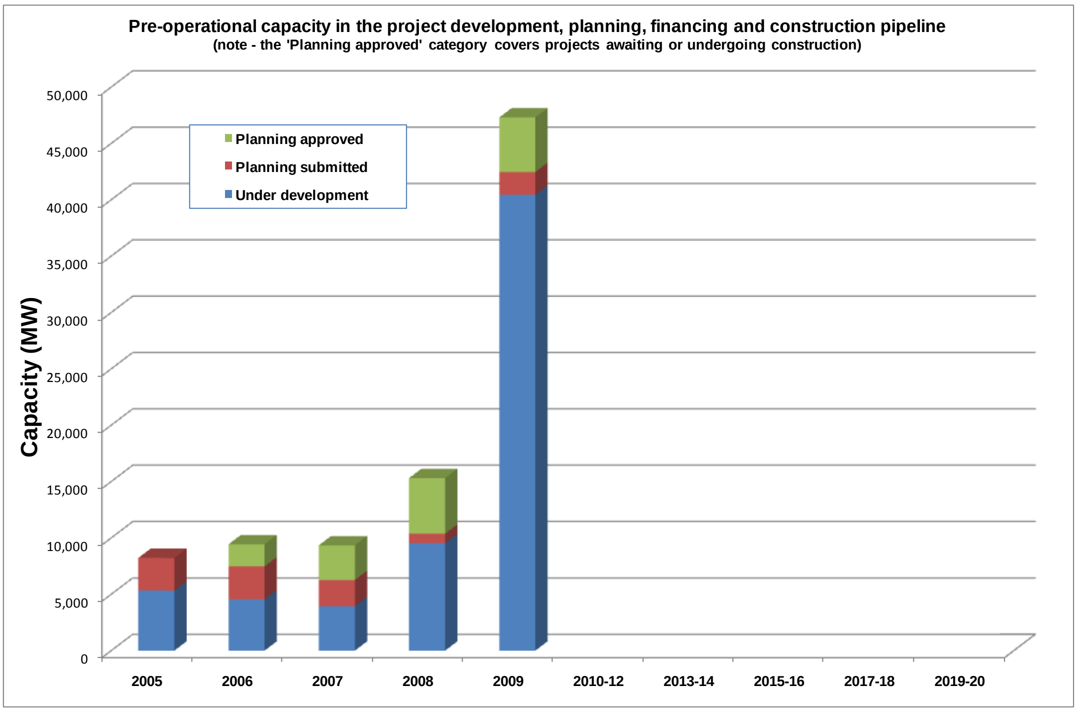
To date, the installation rate has been around 0.2GW/year (compared to a global rate of just under 1GW/yr).

[6] http://www.renewables-advisory-board.org.uk/vBulletin/showthread.php?t=11

Looking at Round 2, the average time taken from projects registering their interest with TCE to develop sites to consent application has been over three years and for determination the timescale is approaching two years. There are still a number of applications submitted in 2008 awaiting determination.

In the 2009 Renewables Obligation Order the Government introduced 'banding' of the number of Renewable Obligation Certificates (ROCs) that could be earned by different technologies. In particular, offshore wind projects were awarded 1.5 ROCs/MWh from 1 April 2009 compared with onshore wind projects which earn 1.0 ROC/MWh. Subsequently, in the Budget 2009 the UK Government announced a proposal to increase the ROC multiples for offshore wind projects reaching financial close in the following two years. This was in reaction to project developers presenting evidence that the cost of generation from new projects had increased since the 1.5 multiple was established in the 2008 RO statutory consultation, making investment unattractive. Nearly 3000MW of already consented capacity was believed to be in this situation. Government has now announced that all offshore wind projects granted full accreditation between 1 April 2010 and 31 March 2014 would receive 2 ROCs/MWh.

**Figure 1: Pre-operation phases: project development, planning, financing and construction**




We have not attempted at this stage to provide a 'pre-operational' breakdown of capacity from 2010 to 2020, however, Figure 1a below shows a project timeline for a first Round 3 project, assuming no delays and first generation in 2015, and comparison with a couple of real previous Round examples:

**Figure 1a: Example post-application timelines**

| | Year1 | Year2 | Year3 | Year4 | Year5 | Year6 | Year7 | Year8 |
|---|---|---|---|---|---|---|---|---|
| **Round 3 (by 2015)** | | | | | | | | |
| - Consent consideration | ■ | | | | | | | |
| - Construction | | ■ | ■ | | | | | |
| **Round 1 example** | | | | | | | | |
| - Consent consideration | ■ | | | | | | | |
| - Construction | | | | | ■ | ■ | | |
| **Round 2 example** | | | | | | | | |
| - Consent consideration | ■ | ■ | ■ | | | | | |
| - Construction | | | | | | ■ | ■ | ■ |

## 4.3 Projected deployment to 2020

As set out in the Introduction, a combined total for Rounds 1, 2, 3 and STW projects could be over 47GW by 2020. However, in reality the level of deployment will depend on a number of factors including three key areas of: economic viability, the availability of the grid to accept projects and building the supply chain capability.

Table 1 and Figure 2 present three scenarios for operational capacity by 2020. A **Central** projection broadly representing the capacity that is expected to be deployed on the basis of the measures presented in the RES and a median expectation of market factors and the effect of constraints, a **Low** projection representing a more pessimistic view of what can be achieved, but representing the minimum likely deployment, and an **Upper** estimate representing a realistic maximum capacity that is likely to be achieved, if all relevant factors come together to encourage deployment.

Round 3 bidders have signed exclusive Zone Development Agreements with TCE to take the proposals through the planning and consenting stage (within agreed timescales). Therefore, for comparison, we have also included TCE's projection (ref[7]: 'UK Offshore Wind Report 2010').

**Table 1: Historic and projected capacity development and deployment 2005 – 2020**

Technology: Offshore Wind

Weighted average load factor: 35%

| | Unit | Total capacties/output in the different categories at the end of the stated year/period | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
| | | 31/12/05 | 31/12/06 | 31/12/07 | 31/12/08 | 31/12/09 | 31/12/12 | 31/12/14 | 31/12/16 | 31/12/18 | 31/12/20 |
| Under development | MW | 5,322 | 4,551 | 3,933 | 9,531 | 40,443 | | | | | |
| Planning submitted | MW | 2,901 | 2,919 | 2,333 | 840 | 2,020 | | | | | |
| Planning approved | MW | 0 | 1,965 | 3,076 | 4,931 | 4,841 | | | | | |
| Operational (central) | MW | 214 | 304 | 404 | 598 | 688 | | | | | |
| Projected operational | MW | | | | | | 3,650 | 6,000 | 9,000 | 13,000 | 18,500 |
| Energy production | GWh | 510 | 764 | 906 | 1,592 | 1,832 | 11,191 | 18,396 | 27,594 | 39,858 | 56,721 |

**Range of projected operational capacity**

| | Unit | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Low estimate | MW | | | | | 688 | 2,800 | 4,400 | 6,400 | 8,400 | 10,000 |
| | GWh | | | | | | 8,585 | 13,490 | 19,622 | 25,754 | 30,660 |
| Central estimate | MW | 214 | 304 | 404 | 598 | 688 | 3,650 | 6,000 | 9,000 | 13,000 | 18,500 |
| | GWh | 656 | 932 | 1,239 | 1,833 | 2,109 | 11,191 | 18,396 | 27,594 | 39,858 | 56,721 |
| Upper estimate | MW | | | | | 688 | 3,650 | 7,300 | 12,300 | 16,500 | 26,500 |
| | GWh | | | | | | 11,191 | 22,382 | 37,712 | 50,589 | 81,249 |

Supportive text for the three estimates is provided below.

### Central estimate

We assume that the remaining Round 1 projects and most of the Round 2 projects get built out to their planned timeframes. This equates to ~1GW installed/yr on average to 2015. We have then assumed a steady ramp up to reach 18.5GW by 2020. This equates to a build rate of 1.5GW/yr from 2015-17, increasing to 2GW/yr 2018/19 and 4GW in 2020.

There are currently three turbine manufacturers with proven capability (Siemens, Vestas, Repower) - however others are investing in offshore models (Clipper, Bard, Mitsubishi, Multibrid etc). Assuming that about half of these turbine manufacturers could base themselves in the UK, an industry view is that each could support an annual installed capacity of between 500MW and 1GW per year.

This central estimate is consistent with the BWEA's 2009 forecast (Ref[8]: 'UK Offshore Wind: Staying on Track –forecasting offshore wind build for the next five years') which shows approaching 6GW of

[7] http://www.thecrownestate.co.uk/uk_offshore_wind_report_2010.pdf
[8] http://www.bwea.com/pdf/publications/CapReport.pdf

capacity installed by 2015, taking account of some reduction in project capacity (~1GW) and project delays (~1.5GW of Round 2 projects still to be built post 2015), and it is also consistent with RAB's '2020 vision' of 18GW by 2020. At the time some in the industry felt that the RAB view was too pessimistic, however, some of the Members consulted still feel it is an appropriate assessment.

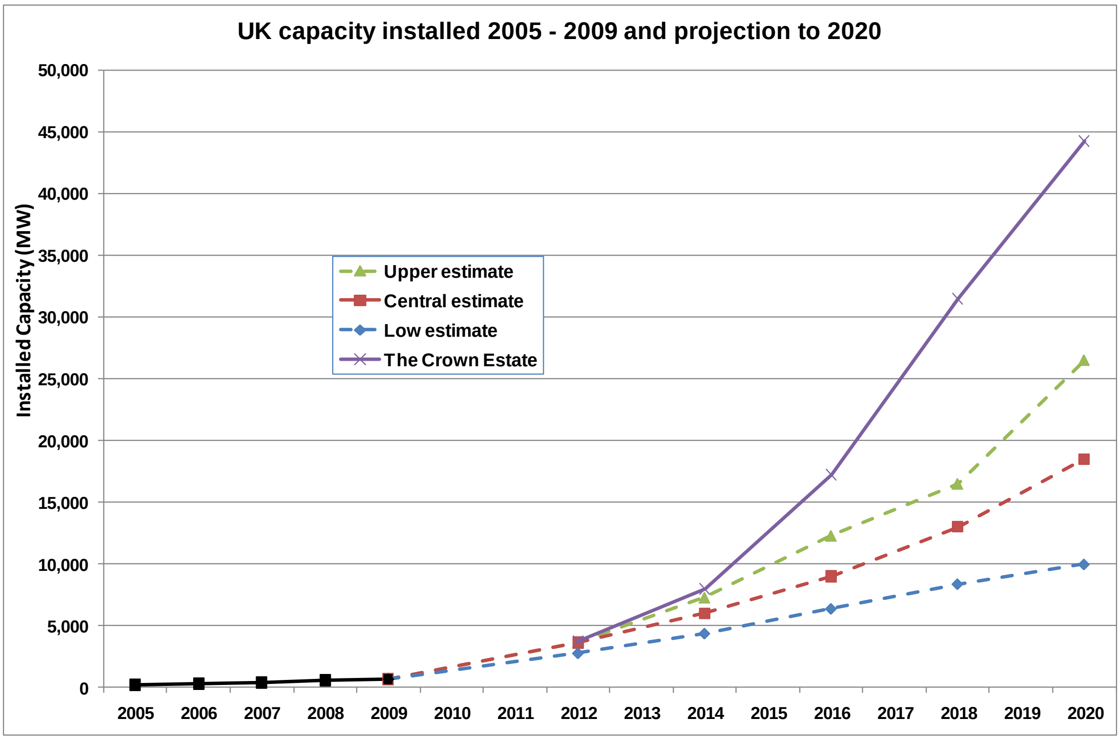
It is also broadly consistent with the results presented in BVG associates report[9] for TCE 'Towards Round 3: Building the Offshore Wind Supply Chain'. This states that before the concerns of industry regarding economic viability were addressed by the RO uplift, industry considered that only around 10GW would be installed by 2020. With the increased support for Round 2 projects, the industry expected that at least 20GW would be delivered in the UK by 2020.

The central estimate also fits well with the likely UK need from offshore wind. This is still a demanding effort but achieveable as long as there are longer-term aspirations, a stable support framework and investment is enabled.

**Upper estimate**
The high estimate is set at 26.5GW. This follows a similar pattern to the central estimate to 2015, but assumes limited delays to all Round 2 projects and the early STW projects. A build rate of 2GW/yr in the period 2015-16, 3GW/year by 2018 and rising to 5GW/year in the 2019-2020 period will be required to reach 26.5GW in 2020. It also assumes that sufficient grid capacity will be available to accept Round 3 projects from 2015. [For comparison, an annual peak build rate of 6GW/yr is presented by TCE for 2018/19, assuming limited constraints].

**Low estimate**
This is set at 10GW and represented a consistently low build rate profile. It assumes that the main constraint will be grid availability. This would in turn impact on investor and supply chain confidence leading to significant delays to deployment.

**Figure 2: Historic deployment and range of future projections to 2020**




[9] http://www.thecrownestate.co.uk/round3_supply_chain_gap_analysis.pdf

# 4.4 Achieving future deployment – key dependencies

## 4.4.1 Impact of financial incentives

A stable, long term, attractive support mechanism is vital. The banded RO is the main mechanism to provide the right level of financial support for offshore wind. It is assumed the RO will remain as the main support mechanism; should there be a change to, for example, a Feed in Tariff mechanism, there will undoubtedly be a hiatus in development to 2015 or later.

In the Budget 2009 a proposal was announced to increase the ROC multiples for offshore wind projects reaching financial close in the next two years. This was welcomed by the industry as a short term pragmatic solution to support Board approval of Round 2 projects, however, developers remain uncertain of a stable RO in the future, which could delay investment decisions with Round 3 projects. Government has provided a market signal of reduced support for later projects, however, the future path of offshore wind costs is uncertain. Competition in the market could reduce costs but this will be balanced by moving into deeper water and more costly solutions for Round 3. If costs do not come down, future discussions around economic viability are likely. More generally, current availability of power purchase prices and European Investment Bank (EIB) funding are positive factors.

For Round 3, moving to deeper water (beyond 15m) further offshore, with larger turbines, new installation methods and practices etc is going to increase costs (of foundations, turbines, cables etc). Also competition issues around foundations, cables etc will influence costs. As most of the Capex is associated with the turbine, greater competition in the turbine market should balance the other cost increases to an extent.

Many studies have shown that costs should fall through R&D, lessons learning, increasing competition in turbine and component supply etc. The ZAP approach by the Crown Estate should also have a bearing on cost control and support development / installation / operational efficiencies. Round 3 economies of scale should see some cost reduction also but history tells us this might not materialise. Early Round 1 project costs were just over £1million/MW but escalated to near £3million/MW for the later projects. Some Round 2 projects are still at the stage of raising finance. .

No immediate actions are required but the availability of sufficient financial support has significant potential to disrupt / delay deployment.

## 4.4.2 Impact of consenting processes

A smooth and effective planning process is essential. Recent planning reforms are designed to achieve this for nationally significant infrastructure projects but how this will work in practice is still to be tested. Under the provisions of the 2008 Planning Act, offshore wind projects (over 100MW in capacity) will be determined by the Infrastructure Planning Commission (IPC) for E&W. The target for decisions is 9-12 months. The National Policy Statements (NPSs) should help with decision making setting policy framework for IPC decisions (and equally important if not more so for grid connection/infrastructure consents than the windfarms themselves).
In the best cases the consenting timetable can be approximated to 3 years (2 years to prepare the application, and one year to make a decision) but as stated above, the new IPC process is untested and a fundamental different approach than previously followed, and so considered a risk by developers. (There are still four Round 2 projects awaiting consent; Triton Knoll should be the first offshore wind application passed through the IPC).

To reach any significant deployment by 2020, a first milestone must be to get all (or as many as possible) of the Round 3 projects consented, as quickly as possible.

## 4.4.3 Integration to energy markets

This is the key issue that is likely to constrain development. Industry needs economic and timely connections. The development of the on- and offshore electricity networks must be well coordinated. Consenting of new grid infrastructure (onshore) is likely to be the main constraint. As seen with

Beauly- Denny, it can take years for planning permission to be granted to allow construction to begin on major transmission infrastructure.

The key question is whether the grid will be available to accept projects. There must be onshore infrastructure in place to support growth offshore and transmission capacity must be made available in quantities that avoid delay or abandonment. Projects won't start construction unless they know they can connect.

The OFTO process (licensing of offshore electricity transmission through competitive tenders) is subject to much debate; some in the industry support the need for a socialised grid with strong Government leadership, moving away from the pure market-led proposals. Developers are also calling for a pseudo-transitional arrangement for Round 3 rather than the enduring approach proposed. TCE timelines currently do not match those of Ofgem. Unaligned project and grid consenting decisions could cause difficulties and potential for stranded assets.

### 4.4.4 Supply chain issues and constraints

The Government is taking an active role in ensuring the development of the supply chain. The (offshore) wind power supply chain can grow at the rate required – it has done so historically in onshore wind. But from a developers viewpoint, they await to see the evidence that supply chain won't be a critical constraint, although hopeful based on recent activity / Government announcements.

There are numerous underlying constraints within the supply chain (e.g. turbine capex, steel and copper prices, exchange rate issues, component supply, vessels, cables, manufacturing facilities etc, etc.) Vessels could be a pinch point in the supply chain in the short term but there is significant interest and commitment amongst developers and vessel operators to invest in the construction and operation of additional and larger dedicated vessels. There are only three turbine manufacturers with proven capability (Siemens, Vestas, Repower), however others are investing in offshore models (Clipper, Bard, Mitsubishi, Multibrid etc) which should lead to increased competition and cost reduction, so the signs are encouraging. There are few suppliers of foundations for offshore wind currently and this is having an impact on cost. A number of players are investing – all coastally located - including in the UK, so this area is unlikely to be the major constraint. There is more concern in the industry about cable supply; especially high voltage AC or DC cables where the supply base is limited currently to four companies and time to establish new production facilities is significant.

More pressing issues around component, local supply chain development and development of port infrastructure. Government is in advanced discussions with a range of wind turbine manufacturers about establishing assembly facilities in the UK. The RDAs with coastline and ports will play a significant role in new infrastructure for windfarm developers and manufacturers.

As long as there is sufficient notice (i.e. 2-3 years) to build up the supply chain (and by association the ports infrastructure), there is confidence from some in the industry that supply chain will not be the key constraint. Others are adopting a more wait and see approach.

### 4.4.5 Regulatory framework

TCE has adopted a specific framework Zonal Appraisal and Planning (ZAP) to help faciliate the complex constraints involved in offshore windfarm developments. This should assist the decision making process. However, it is very unlikely that consenting / construction programmes will be actioned to time and proceed without delays for reasons of bad weather, consent conditions / down time, vessel issues / availability (and knock-on effects between projects), and some of these constraints, for example weather days, are likely to increase as projects move further offshore. Even some Round 1 near shore projects experienced significant (12 month) delays to construction programmes. For the larger Round 3 zones, the construction programmes are likely to be spread over several years.

For far offshore projects (out to 120km offshore) as well as water depth and distance issues, projects could also be influenced by the regulatory processes and conditions of international neighbours, which adds another layer of uncertainty.

The industry is fairly confident that radar solutions will be found to mitigate MoD objections. In October 2009 TCE announced the launch of a £5.15 million research and development project looking at solutions to the problem of radar interference and wind turbines. The project involves a nineteen-month R&D programme to mitigate the effects of wind turbines on the NATS En Route primary radar infrastructure. This project, if successful has the potential for releasing 6GW of existing capacity, and putting in place solutions for Rd3. Aviation mitigation will also have project specific solutions.

Environmental constraints will have a bearing on deployment. As some stage Government will have to make decisions on an 'energy vs environmental' basis. It is not guaranteed that consent will be passed for all projects and there is some risk that developments will not achieve the full zone capacities.

### 4.4.6 Other potential barriers to deployment

**Institutional barriers**
There is a potential resource issue within IPC and statutory bodies and ability to cope with number of applications; this is not considered to be a serious issue and will work itself out, but limited resources may cause delay to development programmes for some. The IPC approach is currently untested (it is a fundamental different approach for projects than previously) and the process could change again with a Conservative Government (resulting in delay, further uncertainty and also impacting on cost, perceived risk (access to finance) etc.).

More important is the skills issue but skills developed in the North Sea oil and gas industry are highly relevant to the installation and maintenance of offshore wind power as well as to parts of the design and fabrication process for key components.

**National Policy**
The policy framework is in place through the Renewable Energy Strategy (and subsequent announcements) but as history shows this is subject to change and uncertainty (e.g. developers cite the history with the RO). Although it could be argued that Government reacted swiftly to calls for intervention relating to economic viability, to ensure momentum / confidence was not lost and Round 2 projects would be built. Therefore Government policy has had / is having a positive influence in this sector and motivating investors to act and has (DECC in particular) an ongoing role to play in facilitating policy interventions necessary to help deliver offshore wind.

**Access to Finance**
The recent recession has seen a slowdown in economic growth but on back of Government policy, there is significant interest from investors in offshore wind, across turbine development, new vessels, ports development etc. Motivating investment is not seen as a significant constraint. Access to capital through, for example EIB, and increased support from the RO has helped near term developments (Round2). But access to finance is related to perception of risk which is influenced by all the constraints discussed here.

**Other**
Additional and accelerated RD&D support is needed to reduce costs, progress development of the next generation of technologies, for test rigs, test turbines etc (via DECC's ETF programme, ETI's Offshore Wind programme and Carbon Trust's Offshore Wind Accelerator).

### 4.4.7 Summary of constraints

## Table 2: Significance of various potential constraints on deployment

| Potential constraints | Significance | Comment |
|---|---|---|
| Returns insufficient to stimulate sufficient deployment | Amber | A stable, long term, attractive support mechanism is vital. The banded RO is the main mechanism to provide the right level of financial support for offshore wind. It is assumed the RO will remain as the main support mechanism; should this change to a FiT there will undoubtedly be a hiatus in development. Developers remain uncertain of a stable RO in the future, which could delay Round 3 projects. Economies of scale and competition in the market could reduce costs but will be balanced by moving into deeper water and more costly solutions for Round 3. If costs do not come down, future discussions around economic viability can not be ruled out. History tells us that cost reduction might not materialise. Early Round 1 costs were £1million/MW but escalated to near £3million/MW. No immediate actions required but significant potential to disrupt / delay deployment. |
| Planning (local policies, obtaining permissions) | Green | A smooth and effective planning process is essential. Recent planning reforms are designed to achieve this for nationally significant infrastructure projects but how this will work in practice is still to be tested. In the best cases the consenting timetable can be approximated to 3 years (2 years to prepare the application, and one year to make a decision) but as stated above, the new IPC process is untested and a fundamental different approach than previously followed, and so considered a risk by developers. (There are still four Round 2 projects awaiting consent; Triton Knoll should be the first offshore wind application passed through the IPC). |
| Integration to energy markets | Red | This is the key issue that is likely to constrain development. Industry needs economic and timely connections. The development of the on- and offshore electricity networks must be well coordinated. Consenting of new grid infrastructure (onshore) is likely to be the main constraint. As seen with Beauly- Denny, it can take years for planning permission to be granted to allow construction to begin on major transmission infrastructure.<br><br>The key question is whether the grid will be available to accept projects. There must be onshore infrastructure in place to support growth offshore and transmission capacity must be made available in quantities that avoid delay or abandonment. Projects won't start construction unless they know they can connect.<br><br>The OFTO process (licensing of offshore electricity transmission through competitive tenders) is subject to much debate; some in the industry support the need for a socialised grid with strong Government leadership, moving away from the pure market-led proposals. Developers are also calling for a pseudo-transitional arrangement for Round 3 rather than the enduring approach proposed. TCE timelines currently do not match those of Ofgem. Unaligned project and grid consenting decisions could cause difficulties and potential for stranded assets. |
| Supply chain issues and constraints | Amber | The Government is taking an active role in ensuring the development of the supply chain. The (offshore) wind power supply chain can grow at the rate required – it has done so historically in onshore wind. But from a developers viewpoint, they await to see the evidence that supply chain won't be a critical constraint, although hopeful based on recent activity / Government announcements.<br><br>As long as there is sufficient notice (i.e. 2-3 years) to build up the supply chain (and by association the ports infrastructure), there is confidence from some in the industry that supply chain will not be the key constraint. Others are adopting a more wait and see approach. |
| Regulatory constraints | Green | TCE has adopted a specific framework Zonal Appraisal and Planning (ZAP) to help faciliate the complex constraints involved in offshore windfarm developments. This should assist the decision making process. However, it is very unlikely that consenting / construction programmes will be actioned to time and proceed without delays for reasons of bad weather, consent conditions / down time, vessel issues / availability (and knock-on effects between projects), and some of these constraints, for example weather days, are likely to increase as projects move further offshore. For far offshore projects (out to 120km offshore) as well as water depth and distance issues, projects could also be influenced by the regulatory processes and conditions of international neighbours, which adds another layer of uncertainty.<br><br>The industry is fairly confident that radar solutions will be found to mitigate MoD objections. Environmental constraints will have a bearing on deployment. As some stage Government will have to make decisions on an 'energy vs environmental' basis. It is not guaranteed that consent will be passed for all projects and there is some risk that developments will not achieve the full zone capacities. |
| Institutional barriers | Green | There is a potential resource issue within IPC and statutory bodies and ability to cope with number of applications; this is not considered to be a serious issue and will work itself out, but limited resources may cause delay to development programmes for some. The IPC approach is currently untested (it is a fundamental different approach for projects than previously) and the process could change again with a Conservative Government (resulting in delay, further uncertainty and also impacting on cost, perceived risk (access to finance) etc.).<br><br>More important is the skills issue but skills developed in the North Sea oil and gas industry are highly relevant to the installation and maintenance of offshore wind power as well as to parts of the design and fabrication process for key components. |
| Unclear policy (national, regional, local) | Green | The policy framework is in place through the Renewable Energy Strategy (and subsequent announcements) but as history shows this is subject to change and uncertainty (e.g. developers cite the history with the RO). Although it could be argued that Government reacted swiftly to calls for intervention relating to economic viability, to ensure momentum / confidence was not lost and Round 2 projects would be built. Therefore Government policy has had / is having a positive influence in this sector and motivating investors to act and has (DECC in particular) an ongoing role to play in facilitating policy interventions necessary to help deliver offshore wind. |
| Motivating investors to act | Amber | The recent recession has seen a slowdown in economic growth but on back of Government policy, there is significant interest from investors in offshore wind, across turbine development, new vessels, ports development etc. Motivating investment is not seen as a significant constraint. Access to capital through, for example EIB, and increased support from the RO has helped near term developments (Round2). But access to finance is related to perception of risk which is influenced by all the constraints discussed here. |
| Other constraints (please specify under comments) | Green | Additional and accelerated RD&D support is needed to reduce costs, progress development of the next generation of technologies, for test rigs, test turbines etc (via DECC's ETF programme, ETI's Offshore Wind programme and Carbon Trust's Offshore Wind Accelerator). |

| | |
|---|---|
| Green | **Unlikely to present a constraint to achieving the central projection.** |
| Amber | **Could constrain achieving the central projection and will certainly constrain achieving the upper projection** |
| Red | **Likely to constrain achieving the central projection; could result in only the low projection being achieved** |

# 5 Biomass electricity

## 5.1 Introduction

Electricity generation from biomass covers a range of different renewable energy technologies involving thermal processing (direct combustion and/or gasification) as well as anaerobic digestion (AD), where the resulting biogas is used in gas engines.

Biomass feedstocks include woodchip, waste wood, energy crops (e.g. Short Rotation Coppice or SRC and miscanthus) and other agricultural residues such as cereal straw and poultry litter; for AD a range of wastes are possible including food wastes, livestock wastes, energy crops as well as sewage sludge.

## 5.2 Historical deployment

Based on RESTATS data the installed capacity for biomass electricity is low in comparison to some of the other renewable energy technologies (onshore wind, large hydro) and has increased overall from 635 to 687 MWe in 2005 to 2008; a further estimated 45MWe installed in 2009. Of installed capacity to date 48% is dedicated biomass, 21% is sewage gas and 31% is co-firing.

During the period 2005 to 2008 the amount of dedicated biomass installed capacity increased by circa 75%, whilst co-firing has decreased by circa 27%. Sewage gas installed capacity increased by 37% overall during this period but deployment levelled off from 2007 to 2009; it is notable that circa 93% of sewage gas deployed capacity is located in England.

The development timescale for biomass electricity projects tends to be quite long, although there is some variation from technology to technology and around the size of schemes – for dedicated biomass plant the REPD suggests an average time from submission of formal planning application to operation of around three years (schemes below 5MWe: 20 months; schemes over 5MWe: 43 months).

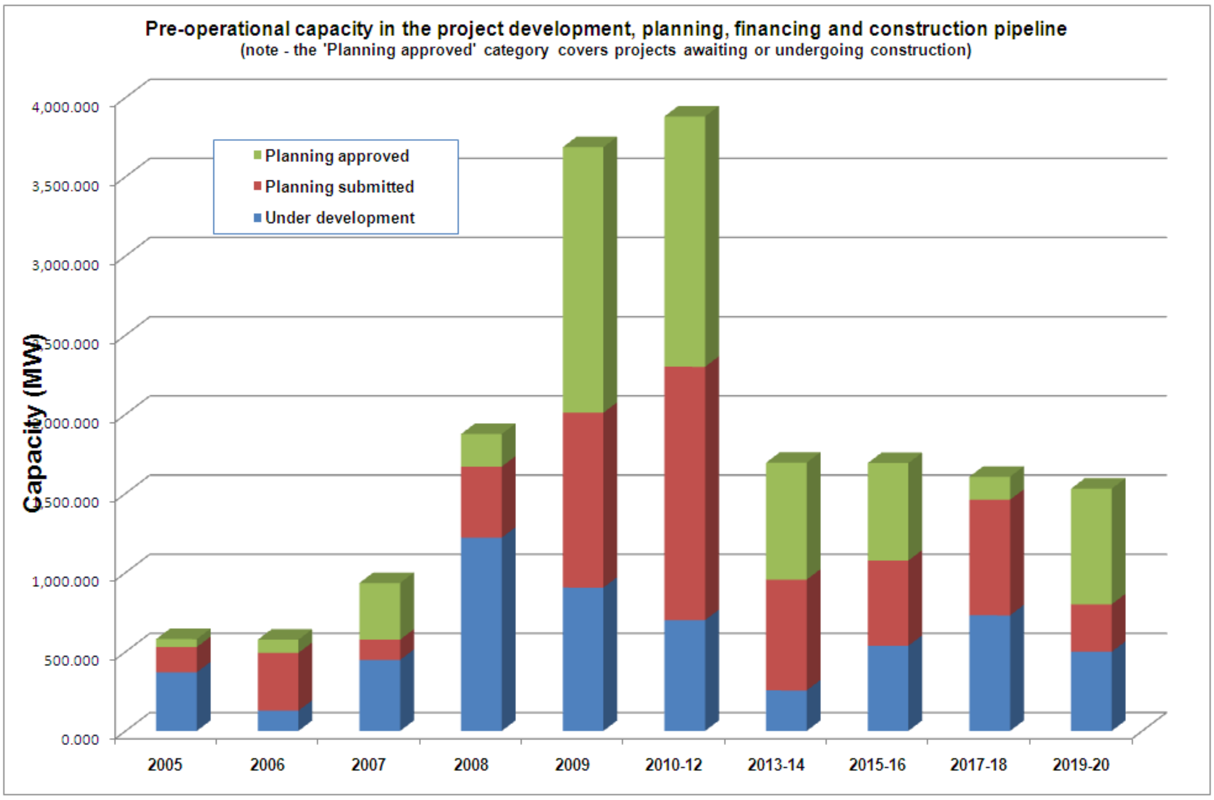
At the scoping stage REPD data is incomplete but it is suggested that a lead time of 1 to 2 years for scoping for biomass power plant is likely.

At the planning stage REPD suggests that the average time to be determined is from 12 to 15 months at Local Planning Authority (LPA) and S36 application levels respectively. Based on historical data in the REPD all S36 applications have been approved to date; the picture for LPA applications is slightly different based on installed capacity of scheme: 100% of schemes of 5MWe or less have been approved and 83% of schemes greater than 5MWe installed capacity (but below 50 MWe).

Current REPD data suggests that there is 1.1 GWe installed capacity in the pre-consent stage (application being considered) and a further 1.2 GWe awaiting construction with 100 MWe installed capacity actually under construction. The delay between consent and construction may be between 1 to 2 years or longer in some cases; for example, the 350 MWe Port Talbot (Prenergy) Renewable Energy Plant was granted consent in November 2007 but it is understood that construction has not yet started, although it is expected to be commissioned by 2014.

Figure 1 following shows the data from the REPD from 2005 to 2009, and the central projection from 2010 to 2020. The current planning data was used in part to derive the forward projections of capacity alongside a bottom up analysis of data identified from developers scoping studies and planning applications and predicted operational capacity. The divisions 2010 to 2020 are bi-annual and there is therefore carry over of schemes between the different categories within each division.

**Figure 1: Pre-operation phases: project development, planning, financing and construction**




## 5.3 Projected deployment to 2020

The introduction of the Renewables Obligation and the further proposals for banding has proved attractive to developers and there are currently in the region of 30 power plant projects of different sizes at various stages of development from project scoping to awaiting or under construction.

Of these at least 11 are expected to operate as base load plants with an installed capacity of over 120 MWe; they are located at or near to port facilities around the UK and are expected to import circa 90 to 100% of their fuel requirements by sea from abroad.

In order to derive the projections, proposed biomass Renewable Energy Plants were identified from a variety of different information sources. Where possible information was obtained from developers' websites or from LPAs, including:

- Annual reports;
- Scoping reports;
- Planning applications; and
- LPA decisions (where available and in the absence of other data).

The reports and applications/decisions were then reviewed to confirm:

- Individual plant power capacities (net);
- Predicted commissioning/operational dates;
- Plant availability where given; and
- Likely feedstock quantities, types and sources.

Where developers have indicated the intention to build additional capacity in the next ten years this was also noted and incorporated into the projections. Where there were doubts about the current position of a particular project the project developer was contacted and where possible the query clarified. However, it has proved difficult to contact developers in the timescales given for this project and a more thorough analysis is recommended.

The biomass feedstocks covered by the above bottom-up analysis of published data includes:

- Recycled and Waste wood: recycled and waste wood diverted from landfill – UK or imported;
- Wood chip: from clearing of forests, sawmill co-product, and energy crops – UK or imported;
- Poultry waste and MBM: Poultry litter from poultry farms and some MBM;
- Cereal straw and some energy crops (miscanthus): baled and used for power generation;
- Other biomass crop and process residues – UK or imported.

The information reviewed to date suggests that six power plants would be commissioned between 2010 to 2012 and a further twenty-six plants between 2013 to 2016. This is likely to be unrealistic, based on experience to date for existing UK biomass power plants.

For sewage gas an estimate was made based on deployment rates over the period 2007 to 2008. The assumption was made that this sector is largely fully exploited and than an additional 15 MWe or 10% on current deployment can be expected to be installed over the period 2010 to 2020. RO data of accredited sewage gas stations indicate the deployment rates in Scotland, Wales and Northern Ireland are low; aside from the lower population reasons for this are not fully understood and there may, therefore, be a greater potential for generation from sewage gas than considered here.

For co-firing of biomass the UK Biomass Strategy (2007) indicated that co-firing had the potential to play a long term role to 2020 and beyond, in the context of continuing electricity generation from coal. However, RESTATS data shows marked inter-annual variability in the contribution from co-firing of as much as 30% between years. It is suggested that this is likely due to:

- Competition for cheap imported biomass feedstocks has gone up and availability gone down;
- The 0.5 ROC banding is not as attractive – there is more interest in dedicated biomass plant.

Industry suggested that given constraints on co-milling and the 0.5 ROC banding the contribution from co-firing is expected to be at 3% of the proportion of fossil-fuelled capacity year on year, excluding Drax; although it was suggested that with higher support for co-firing the potential could be very high with all stations firing at up to 35% - 50% with biomass injectors.

Therefore, it is unlikely there will be an increase in co-firing or investment in technology to fire higher levels of biomass under the present support regime. An assumption was made here that co-firing will continue to supply the equivalent of 230 MWe of installed capacity year on year to 2020. An additional 400 MWe (DRAX) capacity due to be operational by the middle of 2010 was accounted for under dedicated biomass plant.

For Biomass CHP data biogas was included under the different upper, central and lower projections. Since November 2009 projects going through planning have to demonstrate that they have considered the supply of heat to other users. To date circa 53% of power plants > 50 MWe in the pipeline will be enabled to supply heat to the surrounding area, if they can economically do so.

Input data for installed capacities used for the projections were:

- Biomass Renewable Energy Plant: 350.3 MWe (2009) plus a pipeline of 4,473 MWe by 2020, including projects from scoping to pre-construction to date;
- Sewage gas: 152 MWe (2009) plus an additional 15 MWe by 2020;
- Co-firing: 230 MWe (2009) year on year through to 2020;
- Average planning success over 2009 to 2020 of the order of 100% for all large schemes over 50 MWe, as per REPD;
- Construction time: 36 months for large plants (from start of construction to start of operation, as per planning applications and scoping reports reviewed).
- Average load factor of 70% for 2010 to 2020.

**Estimates**

Large biomass plant may achieve planning but it is not clear whether it will go on to construction. To date it has taken 4 to 7 years for power plants to get to commissioning post consent, but this would be likely to fall given the scale of the construction of new plant predicted from the analysis of the scoping and planning applications: six plants from 2010 to 2012, a further 26 power plants from 2010 to 2016;

**Low estimate**
Assumes that circa 2 GWe of installed capacity in various stages in planning does not proceed through to commissioning either due to:

- Planning refused;
- Financial constraints post planning;
- Failure to secure adequate feedstock.

It also assumes that no further large power plant projects come forward subsequent to 2015/16 and that the build of those going through to commissioning is later than predicted from planning applications to date

**Central estimate**
Assumes some additional projects come forward (730 MWe including a further 120 MWe (3) of straw fuelled biomass power plants in Eastern England, given the potential spare resource available). However, some fall out is also predicted to take place, based on assumptions of:

- 10% less through planning
- 10% lost through lack of finance / business case;
- 10% lost through failure to secure adequate feedstock.

By way of comparison the Renewable Energy Association predicted a scenario whereby 15% or projects fall through, giving an installed capacity of circa 5GWe by 2020 (Personal Communication, REA).

**2010-2012**
Based on commissioning Drax co-firing facility in 2010 plus 75 MWe of biomass CHP: Rothes Distillery and Tullis Russell papermill, plus biomass CHP AD.

**2013-2020**
Based on commissioning of Renewable Energy Plant which has been delayed. Some fall out of projects that have not been able to secure feedstock and/or finance.

**High estimate**
Assumes that all projects known about are consented and go forward to construction (no drop out) and some additional projects come forward (730 MWe including a further 120 MWe (3) of straw fuelled biomass power plants in Eastern England, given the potential spare resource available there).

**2010-2012**
Based on commissioning of six power plants between 2010 to 2012 – based on scoping reports and planning applications to date;

**2013-2016**
Based on commissioning of a further twenty-six power plants between 2010 to 2016 – based on scoping reports and planning applications to date;

**2017-2020**
Assuming some delays in the system, the higher estimate still reaches 6.1GWe installed by 2020.

**Table 1: Historic and projected capacity development and deployment 2005 – 2020**

| Biomass electricity | Weighted average load factor: 70% |
|---|---|

| | Unit | Total capacties/output in the different categories at the end of the stated year/period | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
| | | 31/12/05 | 31/12/06 | 31/12/07 | 31/12/08 | 31/12/09 | 31/12/12 | 31/12/14 | 31/12/16 | 31/12/18 | 31/12/20 |
| Under development | MW | 371 | 128 | 449 | 1,221 | 905 | 700 | 256 | 538 | 730 | 500 |
| Planning submitted | MW | 159 | 365 | 128 | 449 | 1,104 | 1,600 | 700 | 538 | 730 | 300 |
| Planning approved | MW | 50 | 83 | 358 | 206 | 1,677 | 1,581 | 738 | 616 | 145 | 730 |
| Operational | MW | 635 | 678 | 701 | 687 | 732 | | | | | |
| Projected operational | MW | | | | | | 1,362 | 2,943 | 3,682 | 4,298 | 4,443 |
| Energy production | GWh | 3,891 | 4,157 | 4,301 | 4,211 | 4,487 | 8,354 | 18,049 | 22,577 | 26,353 | 27,245 |

**Range of projected operational capacity (electrical, total including CHP)**

| | Unit | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Low estimate | MW | | | | | 732 | 1,208 | 1,979 | 2,527 | 2,788 | 3,048 |
| | GWh | | | | | | 7,407 | 12,135 | 15,498 | 17,095 | 18,689 |
| Central estimate | MW | 635 | 678 | 701 | 687 | 732 | 1,362 | 2,943 | 3,682 | 4,298 | 4,443 |
| | GWh | 3,891 | 4,157 | 4,301 | 4,211 | 4,487 | 8,354 | 18,049 | 22,577 | 26,353 | 27,245 |
| Upper estimate | MW | | | | | 732 | 1,676 | 4,022 | 5,153 | 5,959 | 6,166 |
| | GWh | | | | | | 10,276 | 24,661 | 31,600 | 36,541 | 37,807 |

### Load Factors/energy output

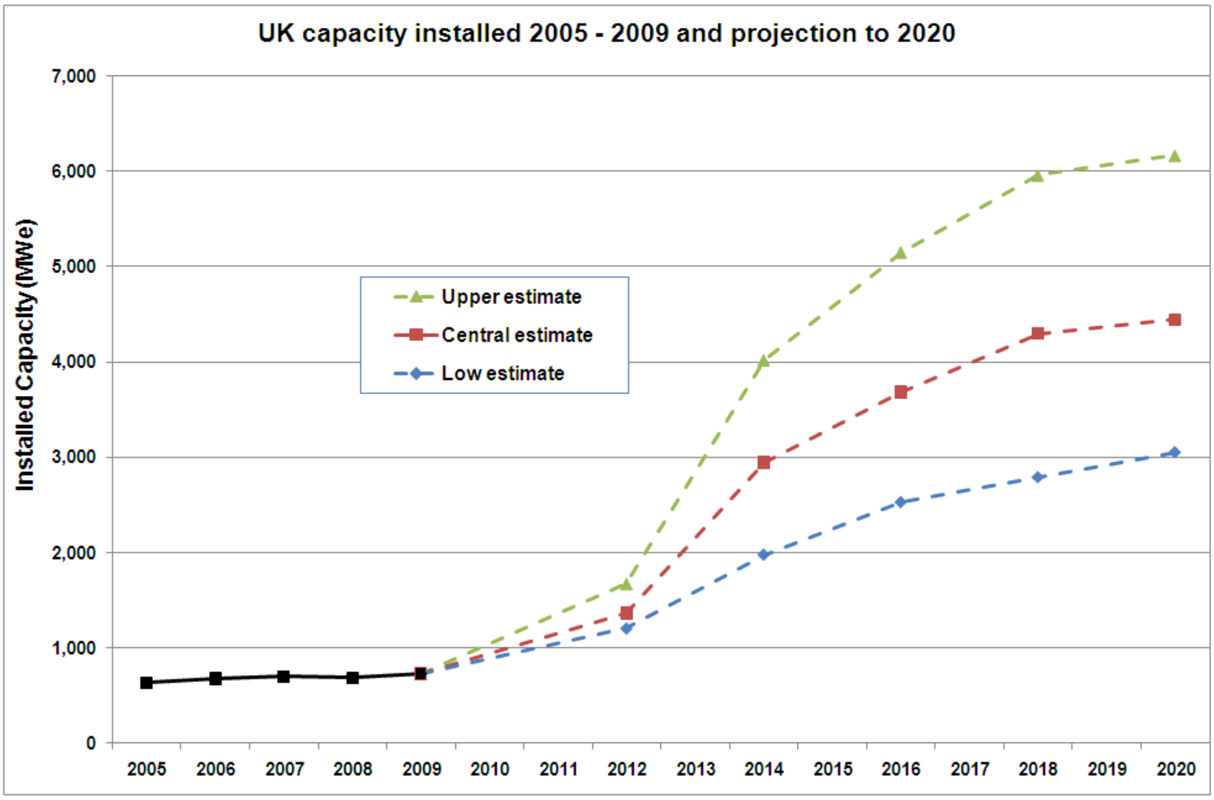
The spreadsheet used to present the estimates is a common template across all technologies and a single load factor of 70% has been attributed to biomass electricity across time.

The load factors supplied by RESTATS are lower than this averaging 60% for dedicated biomass (excluding co-firing) since 1999/00; the load factor for co-firing is separately identified as 60% by the UK Biomass Strategy (2007).

A load factor of 60% is unlikely to accurately represent generation from the large >100 MWe biomass power plants, which are being designed to operate 24 hours per day for base load generation. These large power plants, if built, will make up the majority of installed capacity by 2020 and will have an availability of around 85 to 90% – i.e. plant downtime of 35 to 55 days per year. It is likely that the plants will run as close to their Maximum Continuous Rating as possible, hence load factors will be circa 75% or more.

Therefore, an assumption has been made that a higher load factor of 70% will more fairly represent the mix of generation capacity for 2015 to 2020.

**Figure 2: Historic deployment and range of future projections to 2020**




## 5.4 Achieving future deployment – key dependencies

These are based on industry views where represented and were discussed in brief with the Renewable Energy Association (REA), which contributed its own views.

### 5.4.1 Impact of financial incentives

There is a substantial pipeline of projects due to be constructed by 2015/16; subsequent to this there is interest in bringing forward additional schemes from some developers, but the amount is difficult to quantify. However, there are current concerns around grandfathering fuelled projects.

### 5.4.2 Impact of consenting processes

The REA made the point that too few projects have progressed over recent times to be able to say whether certain aspects of the planning process are not a constraint.

Some industry comments stated that the Infrastructure Planning Commission (IPC) planning application process is more front-loaded than the previous system – in terms of what needs to be done before an application is made – but that this was perfectly manageable.

Large projects (>50 MWe) have progressed well, whilst some smaller projects below 50 MWe have been rejected or delayed by local planning concerns and/or appeals. There are some concerns within the industry around certain types of fuel being proposed (SRF: whether this is considered a fuel or a waste) and the impact this uncertainty can have on planning.

### 5.4.3 Integration to energy markets

Both large and small biomass power plants proposed to date are mostly located at sites with good grid connections (although this is not always the case e.g. Rose Energy Ltd in Northern Ireland).

The large biomass plants planned are intended as base load plants with projected availability as high as 85 to 91%.

Since November 2009 projects going through planning have to demonstrate that they have considered the supply of heat to other users. The analysis of planning applications to date indicates that circa 53% of power plants > 50 MWe in the pipeline will be enabled to supply heat to other surrounding industrial and commercial users, if they can economically do so. A number of these planning applications e.g. by E.ON have gone as far as identifying potential customers for the heat that could be supplied.

### 5.4.4 Supply chain issues and constraints

Fuel supply is seen as crucial by industry to the success of biomass electricity projects: the largest of which are proposed at or near to ports where they will be importing biomass fuel by sea (generally stated to be circa 90 to 100% of their annual fuel requirement).

In terms of the estimated demand for biomass fuel for these projects the aggregate is 29.2 million tonnes by 2020, of which an estimated 81% will be imported. Hence, most of the biomass fuel will be shipped direct to Renewable Energy Plants located at or near to ports. Some developers are proposing to import their fuel from their own forestry activities located around the North Atlantic basin – from as far afield as North and South America.

Projects where developers have their own fuel source available to them would have a greater probability of going ahead, compared to projects that are dependent on buying biomass on the international market, in competition with others. The plants are expected to have a lifetime of 25 years, therefore the ability to contract a long term fuel source is important.

The other ‘market segment’ is for UK sourced biomass, which is typically exploited by smaller schemes. This includes woodchip and energy crops, waste wood, and agricultural wastes such as cereal straw and poultry litter. Projects may potentially be in competition with other users of the biomass, straw for the livestock industry been a good example; sawmills that utilise small round wood have expressed concern about the impact of Renewable Energy Plants on the availability of their feedstock. Therefore, projects are regionally limited in the type of and availability of feedstocks available to them.

### 5.4.5 Regulatory framework

Political risk is seen as being very high at the moment by the industry with respect to grandfathering arrangements for fuelled projects. The proposals on the capital cost element and the fuel element are going out for consultation but the REA is concerned that the proposals could have an adverse effect on the projects going through to construction (liquid biofuels are not going to be grandfathered at all).

### 5.4.6 Other potential barriers to deployment

**Access to capital**
The REA stated that it would be good if the Green Bank could be encouraged to lend to projects: "“A Green Bank, because it is underwritten by Government, would be very reassuring in situations where lenders perceive more political risk.  Where the risks are in Government’s control, if a government-backed bank lends on the strength of its own policy incentives, lenders will perceive far less risk and the costs of capital will fall" Gaynor Hartnell, REA.

### 5.4.7 Summary of constraints

The constraints are summarised in Table 2 overleaf

Overall industry members contacted are reasonably optimistic, with some important provisos:

- Concerns around proposals for grandfathering – seen as high political risk at moment;

- Too early to say on the IPC system as yet but those who are going through it believe it is manageable;
- Securing an adequate fuel supply (and definition of SRF) is a key concern for projects;
- Government support via the recently announced Green Bank would be welcome by the industry as it would reduce the cost of capital to projects/the required rate of return for lenders/investors;
- Most plants are using proven technology (fluidised beds) and so technology is not a major concern.

The main concerns are that if any of the policies or actions put in place change or fail to address the constraints as expected, this level of deployment may not be possible.

**Table 2: Significance of various potential constraints on deployment**

| Potential constraints | Significance | Comment |
|---|---|---|
| Returns insufficient to stimulate sufficient deployment | Amber | There is a substantial pipeline of projects due to be constructed by 2015/16; subsequent to this there is interest in bringing forward additional schemes from some developers, but the amount is difficult to quantify. However, there are current concerns around grandfathering fuelled projects - see Regulatory Constraints. |
| Planning (local policies, obtaining permissions) | Amber | The REA made the point that too few projects have progressed over recent times to be able to say that aspects of the planning process are not a constraint. Comments included that the Infrastrucutre Planning Commission (IPC) planning application process is more front loaded than the previous system in terms of what needs to be done before an application is made but it is manageable. Large projects have progressed well; some smaller projects below 50 MWe have been rejected or delayed by local planning concerns. Some concerns around the type of fuel used (e.g whether SRF is considered a fuel or a waste) and impact on planning. |
| Integration to energy markets | Green | Both large and small biomass power plants are to be located at sites with good grid connections. The large biomass plants planned are baseload plants with projected load factors as high as 85 to 91%. Since November 2009 projects going through planning have to demonstrate that have considered the supply of heat to other users; analysis of planning applications indicates that circa 53% of power plants > 50 MWe in the pipeline will be enabled to supply heat to other surrounding industrial and commercial users, if they can economically do so. |
| Supply chain issues and constraints | Red | Fuel supply is crucial to projects: the largest projects have been sited near to or in ports where they will be importing biomass fuel by sea (circa 90 to 100% of annual fuel required). UK sourced biomass by smaller schemes includes woodchip and energy crops, waste wood, SRF, and agricultural wastes such as cereal straw and poultry litter. (Other users of small roundwood - sawmills - have in the past expressed concern about the impact of co-firing and dedicated biomass power plants of the availability of their feedstock.) |
| Regulatory constraints | Amber | Political risk is seen as being very high at the moment by the industry with respect to grandfathering arrangements for fuelled projects (DECC consultation proposals on the capital cost element and the fuel element; liquid biofuels are not going to be grandfathered at all). |
| Institutional barriers | Green | No comments raised in respect |
| Unclear policy (national, regional, local) | Amber | Concern over the support for biomass. However, the budget 2010 confirmed that the Government intends to grandfather a minimum level of Renewables Obligation support for biomass installations at the point of accreditation, subject to consultation. See Regulatory Constraints above. |
| Motivating investors to act | Amber | The REA stated that it would be good if the Green Bank could be incentivised to lend to projects: ""A Green Bank, because it is underwritten by Government, would be very reassuring in situations where lenders perceive more political risk. Where the risks are in Government's control, if a government-backed bank lends on the strength of its own policy incentives, lenders will perceive far less risk and the costs of capital will fall" Gaynor Hartnell, REA. |
| Other constraints (please specify under comments) | Green | Technology Risk – low; not a big issue even for big schemes of 300 MWe. Construction is predicted to take 36 months for most of the large biomass power plants. |

| | |
|---|---|
| Green | **Unlikely to present a constraint to achieving the central projection.** |
| Amber | **Could constrain achieving the central projection and will certainly constrain achieving the upper projection** |
| Red | **Likely to constrain achieving the central projection; could result in only the low projection being achieved** |

# 6 Electricity from waste combustion

## 6.1 Introduction

The sector module covers energy recovery by means of thermal treatment of waste. The wastes concerned are those produced by households and similar waste produced by commercial premises that are collected by or on behalf of local authorities. These wastes are known as Municipal Solid Waste - MSW. In addition, the sector includes similar wastes collected for treatment and disposal by private sector waste disposal contractors, which is referred to as commercial and industrial waste – C&I waste for short. Energy recovery from specialised industrial wastes, such as solvents, hazardous waste and clinical waste, and biomass or biomass residues, is not addressed in this module. Similarly, energy recovery through the use of anaerobic digestions of biodegradable materials in MSW and C&I waste are addressed in the Landfill Gas and Biogas module, respectively.

The most widespread form of thermal treatment of MSW is mass-burn incineration. Waste is combusted in a plentiful supply of air, the main products of which are a volume-reduced sterile ash, water vapour and carbon dioxide. Energy is recovered from the combustion-off gases via a steam turbine/alternator, to generate electricity. In addition, where suitable end-markets exist, heat can also be provided via a combined heat and power (CHP) installation, with considerable benefits in terms of energy efficiency. Other variations on energy from waste technologies are outlined below.

Mass-burn incineration was developed in the 19$^{th}$ century as an effective way of reducing the bulk and harmfulness of wastes in the rapidly developing urban centres, and as an opportune means of recovering energy. The term “energy from waste” (EfW) is generally used to distinguish between waste incineration where energy is recovered from plants that do not recover energy. Incineration without energy recovery for non-hazardous wastes is no longer permitted under EU rules.

EfW fell from favour in the 1970s when the importance of incinerators as the major source of toxic dioxins in the environment was discovered. Although improvements in emission control largely brought about by the 2000 Waste Incineration Directive have resulted in an enormous improvement in the environmental performance of incinerators[10], a legacy of unpopularity survives to this day that is a significant barrier to the public and political acceptance of energy from waste.

Although widely deployed elsewhere in Europe, EfW has not been widely used in the UK because of the plentiful supply of landfill void space, offering a cheap and low tech solution to waste disposal. The main driver for change in this area has been the 1993 Landfill Directive, which aims to prevent or reduce adverse effects of landfilling on human health and the environment. The directive introduced binding targets on member states to reduce the amount of biodegradable waste going to landfill. The targets for the UK are shown in the following table.

| | 2010 | 2013 | 2020 |
|---|---|---|---|
| **Biodegradable municipal waste to landfill target as a per cent of the 1995 base year** | 75% | 50% | 35% |
| **UK** | 13,700,000 | 9,130,000 | 6,390,000 |
| **England** | 11,200,000 | 7,460,000 | 5,220,000 |
| **Scotland** | 1,320,000 | 880,000 | 620,000 |
| **Wales** | 710,000 | 470,000 | 330,000 |
| **Northern Ireland** | 470,000 | 320,000 | 220,000 |

The principal means by which the landfill directive targets will be achieved is through the Waste and Emissions Trading Act 2003. This sets each waste disposal authority a limit for the maximum amount of biodegradable municipal waste that can be landfilled each year, with fines (currently £150/tonne) for exceedence. Authorities in England that landfill less than their allocation can, however, trade the surplus with authorities that expect to exceed their allocation. In addition, the government introduced the landfill tax (in 1996) as a way of reflecting the environmental damage caused by landfilling that is

[10] Dioxin emissions from waste incineration fell by 83% between 1993 and 2007, despite a large increase in capacity during this period (National Atmospheric Emissions Inventory http://www.naei.org.uk/pollutantdetail.php?poll_id=45&issue_id=5)

not reflected through the disposal fee. The landfill tax rate is currently £48/tonne for biodegradable waste, but this is set to increase to £80/tonne by 2015. These measures have together significantly overturned the cost advantage of landfill compared with other, more sustainable options for waste management.

The government's 2007 Waste Strategy for England sets out a number of key objectives that will also impact on the opportunities for energy recovery from waste. These include an objective to decouple waste production from economic growth; to meet and exceed the landfill directive targets and to increase investment in waste management infrastructure to increase recycling and recovery of energy from waste using a mix of technologies. In addition to measures to increase waste prevention and recycling, the strategy recognises the need to increase recovery of energy from residual waste that can't be reused or recycled, anticipating that by 2020 a quarter of waste collected by local authorities will be used to recover energy, compared with 10 per cent in 2006.

Further incentivisation of energy from waste comes from the Renewables Obligation, which subsidises energy produced from renewable sources through Renewable Obligation Certificates (ROCs) paid to power generators for each MWh of renewable electricity generated. ROCs are payable to conventional energy from waste plants provided they operate as CHP, rather than power-only facilities. The biomass part of the fuel – that derived from paper, cardboard and other contemporary forms of carbon, and not plastics, which are largely fossil-derived – qualifies for 2 ROCs per MWh produced. The aim is to stimulate the development of CHP-based energy recovery that has largely been constrained by lack of access to suitable heat markets. In addition, two ROCs per MWh are also payable to "advanced conversion technologies" (ACT) like AD, gasification and pyrolysis, which are underdeveloped in the UK and are believed to require support to establish a foothold in the market. A further category, designated "standard gasification" is eligible for one ROC per MWh for technologies based on gasification but in which the secondary fuel is burnt in a separate part of the reactor, rather then being isolated as a secondary fuel as is the case for ACT. These options are further outlined below.

Other initiatives that have helped to stimulate the development of energy recovery from waste include the Private Finance Initiative (PFI) that has been instrumental in securing private sector investment in waste management infrastructure and the Waste Implementation Programme (WIP). The latter Defra-sponsored programme has provided £30 million of assistance to set up new waste treatment technology demonstration projects to help reduce the perceived risk from new technologies.

Mass-burn EfW are generally large facilities designed with an annual capacity of between 100 and over 400 ktonnes/year of waste. As the waste is processed with little or no pre-treatment, the combustion system must be large and robust enough to cope with all conceivable contrary items in the waste stream without damaging the plant, and generally mass burn plants below about 100 ktonnes/y capacity have substantially higher overhead costs than larger plants.

An alternative to mass-burn EfW is process and burn technologies, where the waste is first shredded and sorted to produce a fraction enriched in combustible materials such as paper, cardboard and plastics, suitable for use in smaller scale burners. This material is known generically as refuse-derived fuel (RDF) or, when produced to meet defined quality standards, solid recovered fuel (SRF). RDF technologies were developed in the 1980s in response to the increased need for indigenous energy supplies following the oil crises of the 1970s. Initially the focus was on pelletised RDF (dRDF – densified RDF) for use as a distributed fuel in industrial boilers as a coal substitute or supplement. However, with strict new emission limits for waste combustion on the horizon in the Waste Incineration Directive and the decline in coal as an industrial fuel, dRDF never fulfilled its promise beyond a few initial niche outlets.

The focus on RDF has now switched to the use of the shredded combustible fraction, known as floc, or coarse RDF – cRDF. This can then be processed in a plant adjacent to the production facility, or baled for onward transport. The RDF can be treated in either smaller scale (compared with mass-burn EfW) grate-based combustion systems, or in fluidised bed systems. An advantage of RDF combustion compared with mass-burn incineration is that the plant can be considerable smaller in scale, as less non-combustible material and potentially harmful objects are present in the fuel.

There is increasing interest in gasification and pyrolysis[11], in which the waste fuel is heated with a carefully-controlled supply of oxygen to produce a secondary liquid or solid fuel. Whilst such systems that produce an isolated secondary fuel have yet to establish a commercial foothold, interest is increasing in systems where the secondary fuel is burnt without isolation in a staged combustion system, as in the “standard gasification” category for ROCs. These options are usually fuelled by RDF.

AEA estimates that in 2010, there are about 24 mass-burn EfW plants in operation in the UK, with a combined waste capacity of some 4,920 kt/year. There are a further 8 process and burn facilities, where the combustible fraction is either converted to RDF or sent to mass-burn EfW, plus 3 ACT facilities using RDF. The total waste capacity of these other plants is about 1,500 kt/year. Further development to 2020 is expected to result from a significant development of RDF and ACT based solutions for residual waste treatment. The scale of such facilities (at between 20-100 kt/year), smaller than mass-burn EfW, may improve the chances of successful planning applications. In addition, they tend not to suffer the same degree of public and political hostility as mass-burn EfW, although no waste management operation is ever regarded as a welcome neighbour. Against this is the lower operational experience with RDF and ACT based solutions, which adds to investor uncertainty.

Whilst most EfW plant are operated on behalf of waste disposal authorities by private companies, there is expected to be an increase in the number of merchant EfW plant built by waste management companies to deal with C&I waste, as well as taking MSW on short-term contracts. Most EfW plant built primarily for MSW also offer spare capacity to third-party C&I waste producers.

## 6.2 Historical deployment

Energy from waste use has increased steadily since 2005, from 274 MWe to 318 MWe in 2009, nearly all of which is from mass-burn plants. The first of the current generation of wholly new facilities was the SELCHP plant in Lewisham, commissioned in 1994. This was the first EfW plant built in UK since the Edmonton facility was commissioned in 1974.

The main factor for the successful development of EfW is the need to secure a long-term waste management contract from the waste holder, to secure investor support. These contracts are typically amongst the largest let my local authorities and may extend over 25 years with a total value for infrastructure, operation and maintenance often in excess of £1bn. Competition is intense among the bidders.

The WDA will have developed a detailed waste management strategy, which it is obliged to put out to public consultation, to determine the best overall (environmental, deliverable, secure and affordable) outline solution. The reduction in the opportunity for landfilling waste, together with the increasing landfill tax and LATS penalties have eliminated the cost advantage of landfilling compared with recycling and EfW that impeded development in the 1990s and before. Guaranteed access to the grid at a premium price for electricity from EfW, under the NFFO rounds, and now support under ROCs, have also helped improve the cost-competitiveness of EfW.

The developer will also need to submit a successful planning application and application for an environmental permit. Of these barriers, securing planning is often the most challenging.

## 6.3 Projected deployment to 2020

The estimates in Table 1 and Figure 1 overleaf are based on AEA data on proposed and planned new facilities, and currently operational facilities, under the following assumptions:

[11] In gasification, waste is heated in air to provide with a small amount of oxygen. As the organic matter breakdown, it produces a mixture of carbon monoxide, hydrogen and methane which can be used as a fuel in an engine or turbine. In pyrolysis, the waste is heated in the absence of oxygen to produce a tarry liquid that can also be recovered as a secondary fuel.

- **Central estimate** – all proposed and planned mass-burn EfW plants go forward to completion, plus 50% of the capacity in proposed RDF/ACT based facilities.
- **High estimate** - all proposed and planned mass-burn EfW plants and all RDF/ACT plants go forward to completion.
- **Low estimate** – all proposed and planned mass-burn EfW plants go forward to completion, plus 25% of the capacity in proposed RDF/ACT based facilities.

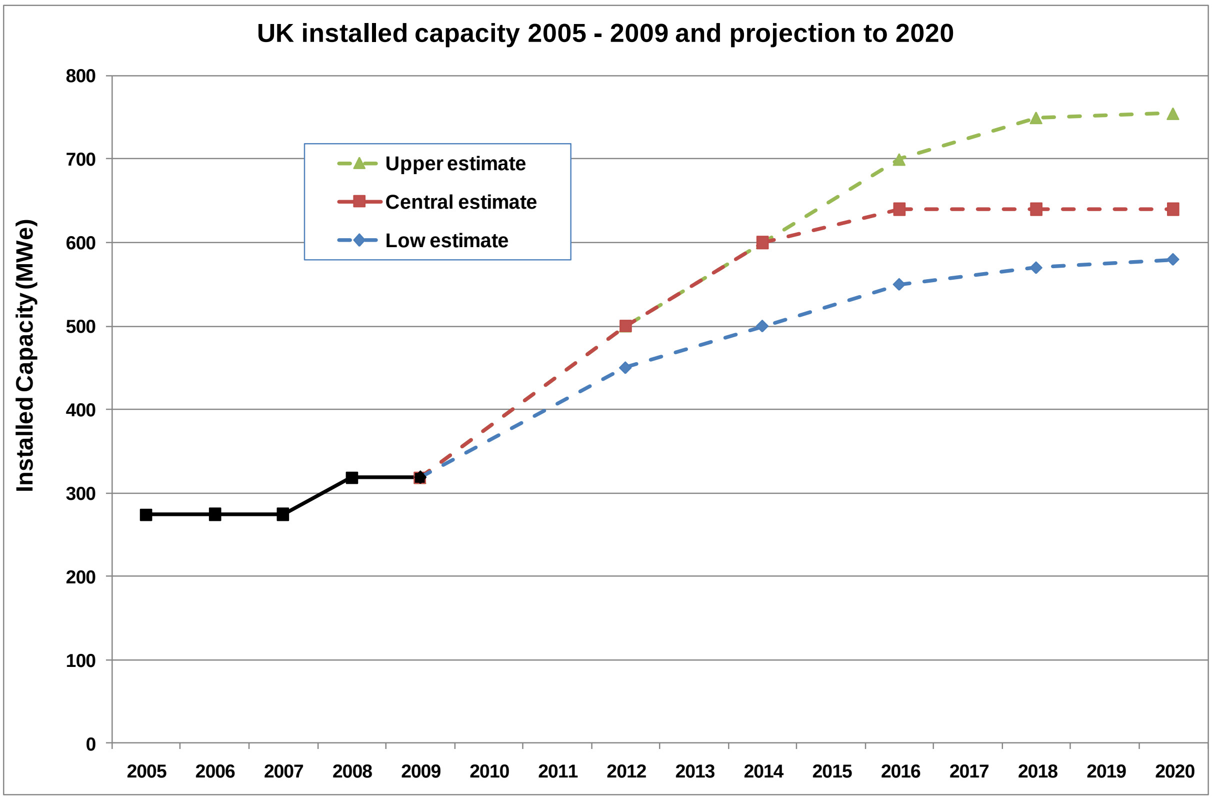
**Table 1.1: Historic and projected capacity development and deployment 2005 – 2020**

| Electricity from MSW and C&I waste | | | | | | | | | Weighted average load factor: | 85% | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Total capacties/output in the different categories at the end of the stated year/period | | | | | | | | | |
| | Unit | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
| | | 31/12/05 | 31/12/06 | 31/12/07 | 31/12/08 | 31/12/09 | 31/12/12 | 31/12/14 | 31/12/16 | 31/12/18 | 31/12/20 |
| Under development | MW | | | | | | | | | | |
| Planning submitted | MW | | | | | | | | | | |
| Planning approved | MW | | | | | | | | | | |
| Operational | MW | 274 | 274 | 274 | 318 | 318 | | | | | |
| Projected operational | MW | | | | | | 500 | 600 | 640 | 640 | 640 |
| Energy production | GWh | 2,041 | 2,043 | 2,043 | 2,369 | 2,369 | 3,723 | 4,468 | 4,765 | 4,765 | 4,765 |

Range of projected operational capacity (electrical, total including CHP)

| | | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Low estimate | MW | | | | | 318 | 450 | 500 | 550 | 570 | 580 |
| | GWh | | | | | | 3,351 | 3,723 | 4,095 | 4,244 | 4,319 |
| Central estimate | MW | 274 | 274 | 274 | 318 | 318 | 500 | 600 | 640 | 640 | 640 |
| | GWh | 2,041 | 2,043 | 2,043 | 2,369 | 2,369 | 3,723 | 4,468 | 4,765 | 4,765 | 4,765 |
| Upper estimate | MW | | | | | 318 | 500 | 600 | 700 | 750 | 755 |
| | GWh | | | | | | 3,723 | 4,468 | 5,212 | 5,585 | 5,622 |

**Figure 1.1: Historic deployment and range of future projections to 2020**



The central and low estimates reflect uncertainty over the success with which the newer and less familiar RDF/ACT technologies succeed in establishing themselves, reflecting the higher degree of technological risk associated with these options.

## 6.4 Achieving future deployment – key dependencies

### 6.4.1 Impact of financial incentives

The availability of support under NFFO played a key role in helping to establish EfW in the 1990s, although this was later restricted to that portion of the energy derived from biomass sources, in line with EU renewables policy. Further support under the RO is expected to increase interest in EfW with CHP, and in RDF-based options of ACT and standard gasification.

### 6.4.2 Impact of consenting processes

Securing planning consent is a major hurdle for EfW and several schemes have suffered extensive delays, or refusal, as a result.

Key success factors are to ensure appropriate public consultation and buy-in, honest treatment of objections and a high level of local political support and ownership.

### 6.4.3 Integration to energy markets

Connection to the local electricity grid is not generally a problem for EfW technologies.

However, access to suitable heat markets, in the absence of an adjacent user of the heat (e.g. industrial user or residential heating, etc) is continuing to be a major barrier to heat-only or CHP development. Most of the existing CHP EfW schemes were developed by municipalities in the 1970s, with access to suitable heat users (such as municipal housing, industrial estates etc) and were not required to meet commercial returns on investment.

### 6.4.4 Supply chain issues and constraints

The supply chain for energy from waste is dominated by European companies such as von Roll Innova, Keppel-Sehgers, Martin Engineering, Energos, Cyclerval, CNIM etc, with few, if any, significant UK players. In addition, North American companies such as Wheelabrator and Covanta are becoming increasing prominent players.

Components of EfW plant, such as grate systems, heat exchange systems and pollution control plant are highly sophisticated pieces of equipment and suppliers require an on-going order stream to maintain capability. The lack of a significant UK manufacturing base in this sector today can be traced to the death of the domestic market in the 1970s and 80s.

### 6.4.5 Regulatory framework

The principal legislation governing EfW is the waste incineration directive (WID) and the waste framework directive (WFD). The WID sets very strict minimum emission standards for EfW plant, that may be further strengthened by the regulator (Environment Agency in England and Wales) in setting emission limits for individual facilities. The revised WFD also sets criteria on energy recovery efficiency, including for CHP applications.

### 6.4.6 Other potential barriers to deployment

Factors that will reduce the deployment of EfW include a reduction in waste growth rate (perhaps as a result of a prolonged economic downturn) and reduced cost of recycling, coupled with the development of effective markets for recycled materials. Conversely, an increase in growth of waste and the failure to find suitable markets for recycled materials may increase reliance on EfW.

### 6.4.7 Summary of constraints

A summary of the constraints is presented in Table 2, with a green/amber/red rating to indicate the impact each constraint may have on projected deployment.

**Table 2: Electricity from waste combustion: summary of constraints and key dependencies**

| Potential constraints | Significance | Comment |
|---|---|---|
| Returns insufficient to stimulate sufficient deployment | Green | Not usually a problem. |
| Planning (local policies, obtaining permissions) | Amber | EfW (especially mass-burn incineration) is deeply unpopular with the public and many local politicians and a number of projects have been delayed or refused. |
| Integration to energy markets | Green | Not usually a problem. |
| Supply chain issues and constraints | Green | Not usually a problem. |
| Regulatory constraints | Green | Modern EfW plant can meet and exceed statutary emission limits without difficulty, so obtaining an environmental permit should not usually present difficulties. |
| Institutional barriers | Amber | EfW deployment is driven primarily by waste management policy and energy recovery is seen as an incidental benefit to the main role of treating and disposing of waste. |
| Unclear policy (national, regional, local) | Amber | EfW is frequently seen as an alternative to recycling and its use as part of an integrated approach to waste management, as seen elsewhere in Western Europe, is often overlooked. |
| Motivating investors to act | Green | The bulk of the capacity is provided by well-proven technology. More novel smaller scale solutions are also building reference capacity, which will reduce perceived technology risk. |
| Other constraints (please specify under comments) | Red | Technological risk associated with some newer technologies based on RDF / ATT is deterring investment and erroding confidence in the deliverability of solutions based on these technolgies. |

| | |
|---|---|
| **Green** | **Unlikely to present a constraint to achieving the central projection.** |
| **Amber** | **Could constrain achieving the central projection and will certainly constrain achieving the upper projection** |
| **Red** | **Likely to constrain achieving the central projection; could result in only the low projection being achieved** |

# 7 Landfill Gas

## 7.1 Introduction

Landfill gas is a combustible mixture of methane and carbon dioxide formed when biodegradable organic wastes decay in the airless (anaerobic) conditions of landfills. The process of methane formation in landfills is the same as that which forms methane when vegetation decays in swamps and marshes. The process is also harnessed for digesting organic wastes in purpose-built vessels to generate methane-rich biogas from organic wastes, by means of anaerobic digestion (AD). Energy recovery from AD of organic wastes is addressed in the Biogas Module.

Landfill gas came to prominence in the 1980s. The local government reorganisations of the previous decade brought waste disposal under the control of county, as opposed to district and borough councils, thus greatly increasing the amounts of waste under the control of the disposal authorities. As a result, a vast number of small town and district dumpsites were closed and larger sites were needed to dispose of the greater concentrations of waste. The UK has an active mineral extraction industry and landfilling offered a convenient way of filling up the large holes left in the ground, prior to site restoration. To capitalise on these opportunities, many mineral extraction companies formed waste management subsidiaries to run the landfill side of their businesses. These businesses are the forerunners of some of the UK's present day waste management companies.

These administrative changes led to a vast increase in the scale of waste disposal operations. Whilst the problems of litter, fires, flies and odours associated with the former dumpsites were immediately apparent, the new landfills also brought serious threats to the environment. Compaction of the waste is needed to reduce the risk of fire (waste masses can catch fire spontaneously if air pockets are left), and also to maximise returns on the void space – the principal asset of a landfill business. This increase in scale and compaction ensured that anaerobic conditions soon became established in landfills accepting organic wastes, so rapidly increasing the amount of landfill gas being formed. The occurrence of a number of serious fires, explosions and odour problems affecting properties adjacent to landfills alerted regulators in the 1980s to the potential local hazards of landfill gas emissions. In addition, as methane is approximately 23 times more powerful as a greenhouse gas than carbon dioxide, there is also a major global perspective to landfill gas emissions. UK landfills are the largest man-made source of methane emissions, accounting for about 3.6% of the country's greenhouse gas emissions, in carbon dioxide equivalents in 2007[12].

Environmental regulators developed statutory guidance in the 1990s on the methods to be used to prevent offsite landfill gas migration through the use of barriers, impermeable liners and actively pumped gas wells. The 1993 Landfill Directive has since played a key role in driving up landfill standards to reduce the threats posed to human health and the local and global environment. Amongst other things, the directive requires the implementation of measures to reduce or eliminate the escape of pollutants, reduces the amount of biodegradable wastes that members states can landfill, setting targets for reduction based on 1995 levels, and bans the co-disposal of hazardous and liquid wastes. The following table shows the maximum tonnages of biodegradable municipal waste that can be landfilled to 2020.

| | 2010 | 2013 | 2020 |
|---|---|---|---|
| **Biodegradable municipal waste to landfill target as a per cent of the 1995 base year** | 75% | 50% | 35% |
| **UK** | 13,700,000 | 9,130,000 | 6,390,000 |
| **England** | 11,200,000 | 7,460,000 | 5,220,000 |
| **Scotland** | 1,320,000 | 880,000 | 620,000 |
| **Wales** | 710,000 | 470,000 | 330,000 |
| **Northern Ireland** | 470,000 | 320,000 | 220,000 |

[12] UK Greenhouse Gas Inventory, 1990 to 2007 - Annual Report for Submission under the Framework Convention on Climate Change. http://www.airquality.co.uk/reports/cat07/0905131425_ukghgi-90-07_main_chapters_Issue2_UNFCCC_CA_v5_Final.pdf

Further details of the measures that have been introduced to achieve the landfill diversion targets are outlined in the Energy from municipal and C&I wastes module.
Landfill gas formation begins within a few months of organic waste being emplaced in the landfill and then increases rapidly over the following 5 to 10 years. Methane concentrations during this stage of waste decomposition are typically around 60% by volume, the rest being carbon dioxide and water vapour, plus a vast number of trace constituents either formed from or present in the waste. Gas formation peaks within about 5-10 years and then gradually tails off, although some methane may be detected after decades. As production falls, the methane content also decreases. Below about 30% by volume methane, energy recovery becomes problematic, and below about 17% the landfill gas cannot be flared without a pilot fuel. Most landfill gas energy schemes have a life of about 5-10 years.

Methane (and carbon dioxide) originates from various biodegradable materials in the waste. Paper and cardboard decay relatively slowly, whilst food and garden waste decay rapidly. Changes in the amount of these materials in landfilled waste therefore exert a major influence over the amount and timescale of methane formation, and hence the potential for energy recovery.

Initial regulatory requirements to prevent off-site migration of landfill gas focused on the use of barriers and peripheral collection of gas, followed either by venting or flaring, which reduced the greenhouse gas impacts and odours. However, some operators recognised the fuel potential of landfill gas and schemes were set up to use the gas in brick works and paper mills. The acceptance of landfill gas as a renewable source of energy and hence eligibility for support for electricity generation in the early 1990s, greatly stimulated the use of landfill gas as a fuel, although arguably diverting resource from some heat-based schemes towards NFFO-eligible power generation projects. In parallel with NFFO, tighter regulations on landfill gas emission control, requiring gas collection from whole sites, rather than just the periphery, brought access to a much larger energy resource, the costs of which could be offset against the requirements of environmental compliance, rather than being borne by the energy recovery project. Landfill operators typically claim that over 85% recovery of landfill gas can be achieved from sites during the phase of maximum gas production, although this declines over the life of the site and a figure of 70% recovery is used to estimate methane emissions for the UK's greenhouse gas emission inventory[12].

Today, electricity generation is the predominant exploitation route of landfill gas. The technology for electricity generation for landfill gas is well-proven and there is now a great deal of industry experience in the field. The gas is drawn from a network of gas wells, which are perforated pipes sunk into the waste, connected to plastic pipes. A blower is used to extract the gas under a small negative pressure. The gas is generally provided to the prime mover following minimal clean-up (usually limited to removal of particulate matter and condensation, although it may sometimes be necessary to use more extensive clean up, depending on the quality). The most common prime movers are multi-cylinder reciprocating engines driving an alternator to generate the electricity. Typical sizes per unit range from 0.25 to over 3 MWe per unit. The engines are often derived from marine or heavy vehicle propulsion units. Most landfill gas engines currently deployed operate on the spark-ignition principle, although some are compression ignition engines which use a few per cent of the energy input as diesel as the pilot fuel. There are also a number of gas turbine based schemes. A typical installation may consist of a group of engine/generator sets, plus a flare stack to dispose of landfill gas safely when engines are down for servicing. The modular approach allows flexibility as when gas production in one site starts to tail off, the superfluous capacity can be moved elsewhere to maximise recovery.

There is an active industry providing landfill gas technology, including gas extraction systems, flares and engines. Most engines originate from international manufactures such a Jenbacher, Caterpillar and Perkins.

As mentioned above, landfill gas formation depends on the input of biodegradable wastes to landfill. This is already declining, and will inevitably decline further in order to meet the landfill directive targets. The impact of this on the future potential of landfill gas energy is recognised by a recent report[13], which concluded *"The potential for generation of electricity from landfill gas is limited by the amount of biodegradable waste going to landfill, which is projected to decline over time. Estimates of the theoretical potential resource range from 62-86 PJ (gross energy content), which could generate 19-29 PJ of electricity or 1.6-2.5% of 2004 UK electricity sales. Much of this resource is likely to be economic, as landfill gas has one of the lowest costs of any renewable energy resource, estimated at*

[13] "Study of UK Renewable Energy Potential (2006), available from the Renewable Energy Association website at http://www.r-e-a.net/info/projects/IPA0606.pdf

*£34-54/MWh (£9-15/GJ) currently and £24-32/MWh (£7-9/GJ) in 2010.”* The analysis presented below reflects the anticipated decline in landfill gas energy resource before 2020.

## 7.2 Historical deployment

Electricity generation from landfill gas has benefited greatly from the availability of NFFO and later RO support at a time when tighter environmental regulation landfill gas emissions, requiring extensive gas collection systems, brought access to a much larger resource of gas. The technology is simple, proven and readily available, requiring little modification to run on landfill gas. As the energy recovery facilities are usually situated on, or adjacent to, a landfill, there have been few problems in securing either planning of environmental consents, and access to the local electricity grid has, overall, been generally unproblematic.

Whilst the industry’s early development was led by waste management companies themselves, the main players today are specialist renewable energy companies which have bought the rights to the gas. There is currently considerable consolidation occurring in the sector, as the main players seek to maximise returns through greater efficiencies on what is widely perceived to be a diminishing resource.

## 7.3 Projected deployment to 2020

Table 1 and Figure 1 present our estimates of both historical and projected capacity and energy production to 2020. The projected figures are electricity only; CHP is not considered to make a contribution.

**Table 1: Historic and projected capacity development and deployment 2005 – 2020**

Landfill Gas | Weighted average load factor: 62.5%

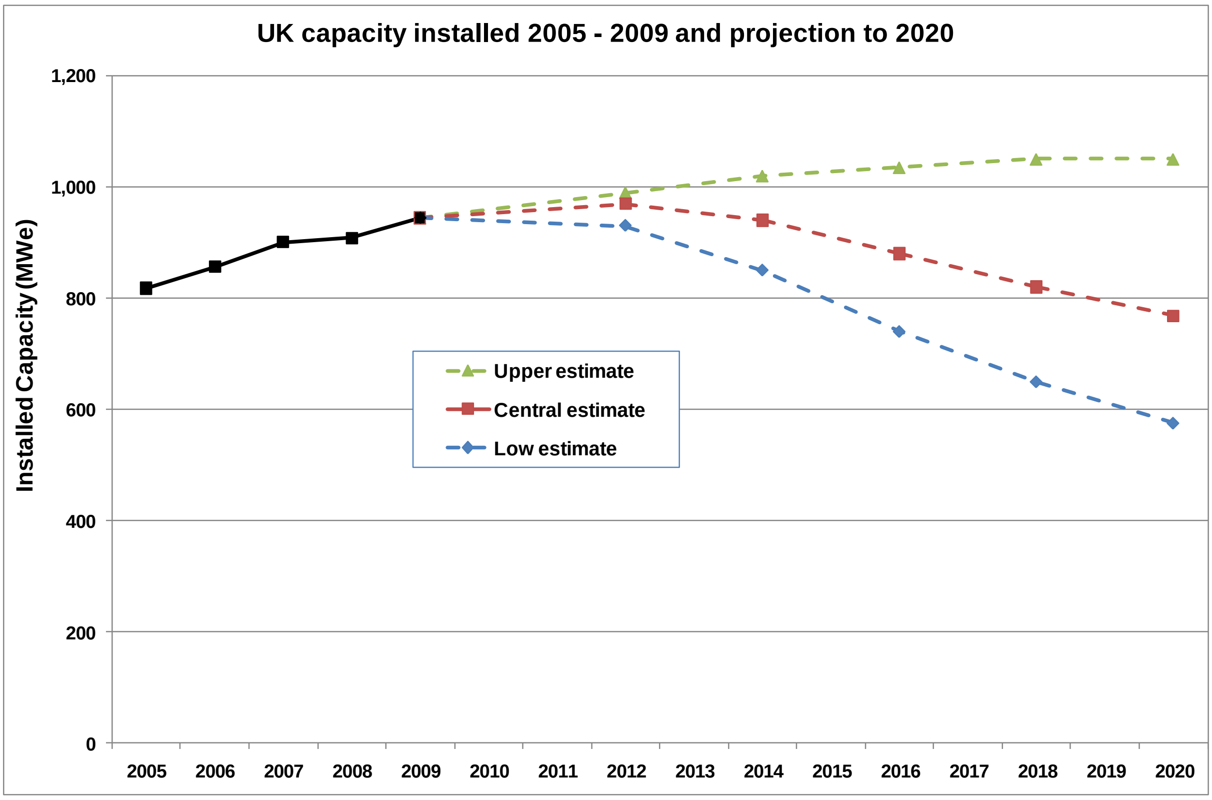
| | | Total capacties/output in the different categories at the end of the stated year/period | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Unit | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
| | | 31/12/05 | 31/12/06 | 31/12/07 | 31/12/08 | 31/12/09 | 31/12/12 | 31/12/14 | 31/12/16 | 31/12/18 | 31/12/20 |
| Under development | MW | | | | | | | | | | |
| Planning submitted | MW | 11 | 0 | 4 | 0 | 2 | | | | | |
| Planning approved | MW | 30 | 5 | 0 | 1 | 1 | | | | | |
| Operational | MW | 818 | 856 | 901 | 908 | 944 | | | | | |
| Projected operational | MW | | | | | | 970 | 940 | 880 | 820 | 768 |
| Energy production | GWh | 4,477 | 4,688 | 4,931 | 4,973 | 5,170 | 5,311 | 5,147 | 4,818 | 4,490 | 4,205 |

**Range of projected operational capacity (electrical, total including CHP)**

| | | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Low estimate | MW | | | | | 944 | 930 | 850 | 740 | 650 | 576 |
| | GWh | | | | | | 5,092 | 4,654 | 4,052 | 3,559 | 3,154 |
| Central estimate | MW | 818 | 856 | 901 | 908 | 944 | 970 | 940 | 880 | 820 | 768 |
| | GWh | 4,477 | 4,688 | 4,931 | 4,973 | 5,170 | 5,311 | 5,147 | 4,818 | 4,490 | 4,205 |
| Upper estimate | MW | | | | | 944 | 990 | 1,020 | 1,035 | 1,050 | 1,050 |
| | GWh | | | | | | 5,420 | 5,585 | 5,667 | 5,749 | 5,749 |

Industry sources predict a decease in landfill gas electricity capacity of between about 20% and 40% of 2010 levels by 2020, which are reflected the above table and graphs as “best” and “low” estimates, respectively. A less pessimistic view is reflected in the “high” estimate, which assumes that operators are able to mitigate to the expected downturn in resource through improvements in site management and operation, resulting in a levelling-off of resource at about 1,050 MWe after 2016.

**Figure 1: Historic deployment and range of future projections to 2020**




# 7.4 Achieving future deployment – key dependencies

## 7.4.1 Impact of financial incentives

NFFO and latterly ROCs have been a major driver in developing landfill gas. However, measures to stimulate exploitation may well have come too late, now that the resource size is declining. Opportunities for heat exploitation are, as is often the case, limited to access to a suitable end market and distribution system.

## 7.4.2 Impact of consenting processes

The consenting process has generally not been problematic for this technology.

## 7.4.3 Integration to energy markets

The size of landfill gas electricity schemes (typically 1-5MWe) has meant that grid connection has not generally been a major difficulty, provided there is reasonable proximity to the local distribution system.

## 7.4.4 Supply chain issues and constraints

No significant barriers. The equipment is well proven and widely available, although overseas engine manufacturers dominate the supply of prime movers.

### 7.4.5 Regulatory framework

Landfill gas exploitation has benefited greatly from tighter regulation of landfill gas collection and control, which has allowed energy recovery to access a greater resource, which has to be controlled as a permit condition.

### 7.4.6 Other potential barriers to deployment

The principal barrier to further growth of electricity from landfill gas is the diminishing resource size as the biodegradable waste required for methane formation is increasingly diverted from landfill.

### 7.4.1 Summary of constraints

A summary of the constraints is presented in the Table 2 below, with a green/amber/red rating to indicate the impact each constraint may have on projected deployment.

**Table 2: Landfill Gas: summary of constraints and key dependencies**

| Potential constraints | Significance | Comment |
|---|---|---|
| Returns insufficient to stimulate sufficient deployment | Green | Established technology, proven performance, good industry experience. |
| Planning (local policies, obtaining permissions) | Green | Planning consents for landfill gas energy projects have generally been unproblematic. |
| Integration to energy markets | Green | Grid access has rarely been a significant constraint on development. |
| Supply chain issues and constraints | Green | No major impacts |
| Regulatory constraints | Green | Regulatory pressures to reduce emissions of LFGs were a major stimulus to the development of the industry in the 1990s and continue to exert a beneficial effect on energy recovery. |
| Institutional barriers | Green | No major impacts |
| Unclear policy (national, regional, local) | Green | No major impacts |
| Motivating investors to act | Green | ROCs income is the major investment stimulus but against background of declining methane resource. Industry consolidations in progress to maximise return on the decreasing asset. |
| Other constraints (please specify under comments) | Red | Methane resource decreasing with reduction in biodegradable wastes sent to landfill, reduction in paper and card in particular reducing gassing life of landfills, increasing site closure rate. |

| | |
|---|---|
| Green | Unlikely to present a constraint to achieving the central projection. |
| Amber | Could constrain achieving the central projection and will certainly constrain achieving the upper projection |
| Red | Likely to constrain achieving the central projection; could result in only the low projection being achieved |

# 8 Solar Photovoltaics

## 8.1 Introduction

In the UK the majority of solar photovoltaic (PV) installations are grid connected distributed systems; installed on the roofs of domestic and non–domestic buildings (DECC 2009). Ground mounted arrays are rare. Building integrated PV (BIPV) is becoming increasing popular with the use of solar tiles which take the place of traditional roof tiles and also the use of PV in facades, louvres and canopies (DECC 2009). Systems are typically small; 1–3 kWp for domestic installations or 5– 30 kWp for non–domestic installations on average (DECC 2009). The largest system in the UK to date is the 391 kWp PV façade on the CIS tower in Manchester.

The off–grid market is small; just over 100 kWp was installed off–grid in 2008 (DECC 2009). Typical applications include PV systems at remote non–grid connected locations to meet both domestic and non–domestic electricity demand (DECC 2009). PV is also used for stand–alone applications such as remote lighting, speed cameras, lighthouses and remote battery charging although these applications are often smaller than 40w (DECC 2009).

### 8.1.1 State of the technology

Solar PV materials and devices convert light energy into electrical energy (USDOE, 2008). Commonly known as solar cells, individual PV cells are electricity–producing devices made of semiconductor materials (silicon, polycrystalline thin film or single–crystalline thin film) and are the basic building block of a PV (or solar electric) system (USDOE, 2008).

Efficiencies of the order of 20–24% have been obtained from silicon cells already in mass production (Wilson 2009). Thin film modules are constructed by depositing extremely thin layers of photosensitive materials onto a low–cost backing such as glass, stainless steel or plastic. This results in lower production costs compared to the more material–intensive crystalline technology and as such offers a price advantage (Wilson, 2009). Three types of thin film modules are currently commercially available. These are manufactured using the semiconductors, amorphous silicon, cadmium telluride or copper indium diselenide. All of these have active layers in the thickness range of less than a few microns. These are the current well established production PV systems (Wilson, 2009).

**Table 1: Solar PV Technology**

| Photovoltaic Materials | | | | |
|---|---|---|---|---|
| Cell Type | | Efficiency % | | State of Development |
| | | Cell | Module | |
| Monocrystalline silicon | m-Si | 24% | 13-17% | Industrial scale production |
| Polycrystalline silicon | p-Si | 18% | 11-15% | Industrial scale production |
| Amorphous silicon | a-Si | 11-12% | 5-8% | Industrial scale production |
| Copper Indium Gallium Diselenide | CIGS | 18% | 10-12% | Industrial scale production |
| Cadmium Telluride | CdTe | 17% | 10-12% | Significant and growing share of the TF market (mostly one company – First Solar) |
| Organic | - | 5-8% | ** | Research Stage |
| Dye Sensitised | DSSC | 5-8% | ** | Pilot Production underway |
| Gallium Arsenide | GaAs | 25% | ** | Mostly aerospace applications |
| Gallium Arsenide /Indium Phosphide etc | GaAs/InP | 25-31% | ** | Research stage |

(Source: Wilson 2009)

Thin–film (TF) PVs are gaining ground in the expanding PV landscape. Currently at 23% of the worldwide production, these TF technologies are predicted as a set, to represent close to 48% of the market by 2015, with crystalline silicon (c–Si) making up the rest (Wilson 2009). Of all the TF PV technologies, amorphous silicon (and other silicon–based TF materials) represents the majority of the market at present, followed by cadmium telluride (CdTe) with copper indium gallium diselenide (CIGS) (Wilson 2009). Other materials are only starting to penetrate the market. A range of other PV technologies are also emerging, including concentrator solar cells, dye sensitised solar cells, organic photovoltaics (efficiencies of 5–8%) and novel active layer cells based on quantum dot solar cell technology (Wilson 2009).

### 8.1.2 The UK PV supply chain

In the UK, Wilson (2009) identified 19 companies engaged in the manufacture and R&D of solar cell/module manufacture. In electricity capacity the total output per annum is 263MW amounting to 4% of global production (Wilson 2009). This is a relatively high figure for a country that has a very small market in terms of PV installation, and Wilson (2009) concluded that the majority of this output is probably exported into Germany and Spain. Two companies are responsible for 97% of this output – Sharp Electronics UK based in Wrexham and Romag based in County Durham.

**Table 2: UK Solar cell and module manufacturers**

| Solar module manufacture | m–Si p–Si | CdTe | a–Si | CIS CIGS | CPV GaAs | DSSC OPV |
|---|---|---|---|---|---|---|
| **Total World** | 671 | 5 | 100 | 25 | 45 | 6 |
| UK | 2 | – | 1 | – | – | 2 |
| Germany | 45 | 1 | 12 | 10 | 2 | 1 |
| China | 372 | – | 33 | 1 | 3 | – |
| USA | 23 | 4 | 10 | 6 | 19 | 4 (17) |

(Source: Wilson 2009)

When a comparison is drawn between the production capabilities of other countries, the lack of PV production capacity within the UK is particularly evident. However, the UK PV supply chain consists of more than the PV cell and module manufacturers and installation and balance of systems (BOS) suppliers (Wilson 2009). The existence, development and growth of the solar PV industry are dependent upon access to the latest technological advances in PV manufacturing processes and equipment and material science (Wilson 2009). It is understood that these factors will prove critical in accelerating the required cost reductions required within the PV industry.

In the UK 63 companies are involved in equipment for PV manufacturing such as sawing machines (Si blocks to form wafers), wafer machines, process cleaning, cell machines, wet chemistry (cleaning , structuring and AR coating), laser technology (contacts, sputtering), vacuum technology (PECVD, sputtering, monocrystalline Si production) and printing machines (contacts) (Wilson 2009). Materials and equipment expertise for PV manufacture is a UK strength with several world class companies involved in thin film and III–V CPV solar cell production.

### 8.1.3 Size of the UK solar resource

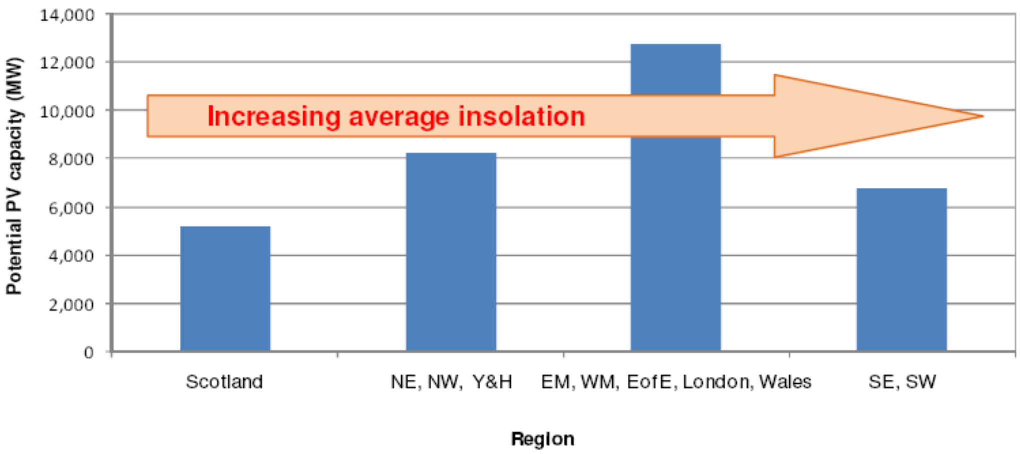
In 1998 ETSU (the former UK Government executive agency for energy technologies (subsequently Future Energy Solutions (FES), now AEA group) estimated the theoretical potential for building–mounted PV in the UK (assuming 1000 kWh/m2/year average insolation on a horizontal surface, use of all available roof space on all domestic and non–domestic buildings in the UK, and improving PV efficiencies over time, reaching 12–15% by 2025) at 266 TWh/year (REA 2006). By comparison, in

2006, the UK Photovoltaic Manufacturers Association (UK–PV) (2008) estimated it at 460 TWh/year (assuming that PV could be mounted on the 4,000 available km$^2$ of roofs and facades on UK buildings) with ground-mounted PV add further potential to this total (UK–PV 2009b).

Yet both identify that in practice the availability of roof space for this purpose will be limited by a wide range of factors, including cost. As such the 'practicable' resource was estimated by ETSU as 140 TWh/year (35% of UK electricity consumption, based on south–facing roofs and facades only) (UK–PV 2009b). This figure approximately correlates with estimates of the maximum reasonably available on buildings by Mackay ('Sustainable Energy – without the hot air', 2008), of 111 TWh, and IEA ('PVPS Annual Report', 2002) of 105 TWh, both based on south facing roofs only. UK-PV estimated it at a much lower 36.9 TWh/year in 2025 (11.4% of 2004 UK electricity sales), with the economic potential in 2025 estimated at only 0.5 TWh (0.2% of 2004 UK electricity sales) (REA 2006).

Element Energy (2008) finds that the opportunity for installation of PV in the non-domestic building stock is enormous, over 30GW based on availability of suitable roof area. The distribution of this potential capacity across the country is shown in the chart below. The economics of PV projects are expected to improve somewhat the further south the location, as the average insolation increases.

**Figure 1: Distribution of potential PV capacity by region**




(Source: Element Energy 2008)

## 8.2 Historical deployment

The annual installed PV capacity in the UK in 2008 was 4420 kWp (DECC 2009). This compares to 3810 KWp in 2007 and 3400 kWp in 2006. The cumulative installed PV generation capacity increased by 24% during 2008 reaching a total of 22.5 MWp (DECC 2009). Government support through the Low Carbon Buildings Programme (LCBP) and other grants supported approximately 72% of total new capacity (DECC 2009).

A summary of the cumulative installed PV power, from 1992–2008, broken down into four sub–markets (off–grid domestic, off–grid non–domestic, grid–connected distributed and grid–connected centralised) is shown below.

**Table 3: Cumulative Installed PV Power in 4 sub–markets in the UK**

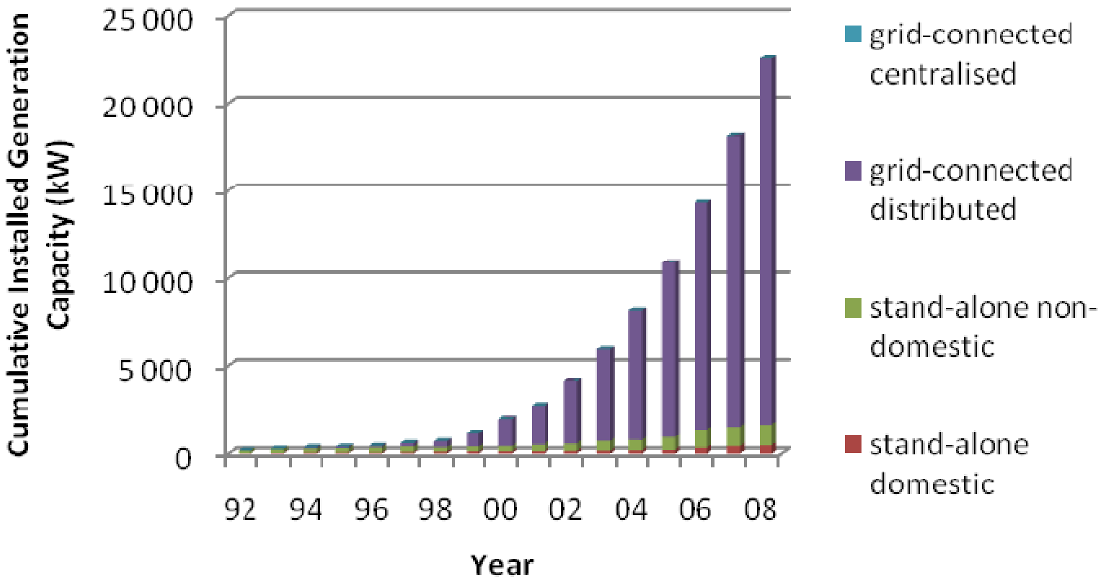
| | Cumulative installed capacity as at 31st December 2008 | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Submarket | | | | | | | | | | | | | | | | | |
| | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 |
| Stand-alone domestic | 7 | 47 | 52 | 57 | 69 | 83 | 108 | 119 | 121 | 135 | 162 | 172 | 193 | 227 | 320 | 420 | 480 |
| Stand-alone non-domestic | 166 | 213 | 232 | 252 | 279 | 316 | 254 | 276 | 302 | 385 | 406 | 542 | 585 | 697 | 980 | 1050 | 1110 |
| Grid-connected distributed | 0 | 6 | 54 | 59 | 75 | 190 | 328 | 736 | 1506 | 2226 | 3586 | 5189 | 7386 | 9953 | 12960 | 16620 | 20920 |
| Grid-connected centralised | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL (kW) | 173 | 266 | 338 | 368 | 423 | 589 | 690 | 1131 | 1929 | 2746 | 4154 | 5903 | 8164 | 10877 | 14260 | 18090 | 22510 |

(Source DECC 2009)

*The cumulative installed power includes power installed before 1992.*
*The stand alone installed capacity in 2006 differs from that published in the International Trends Report 2006 due to one installer submitting information after the Trends report had gone to press.*
*From 2005 onwards figures are reported to the nearest 10 kWp.*

This data has come from DECC (2009) in their report 'National Survey Report of PV Power Applications in the United Kingdom, 2008'.

**Figure 2: Cumulative Installed PV capacity 1992 – 2008**




(Source: DECC 2009)

The development timescale for solar PV is relatively short; the REPD indicates that the submission of a typical PV application takes on average 6 months to be determined, and another 6 months to become operational after approval has been granted. We Support Solar estimate that installing a typical 3kWp system to power a family home takes about one day to install.

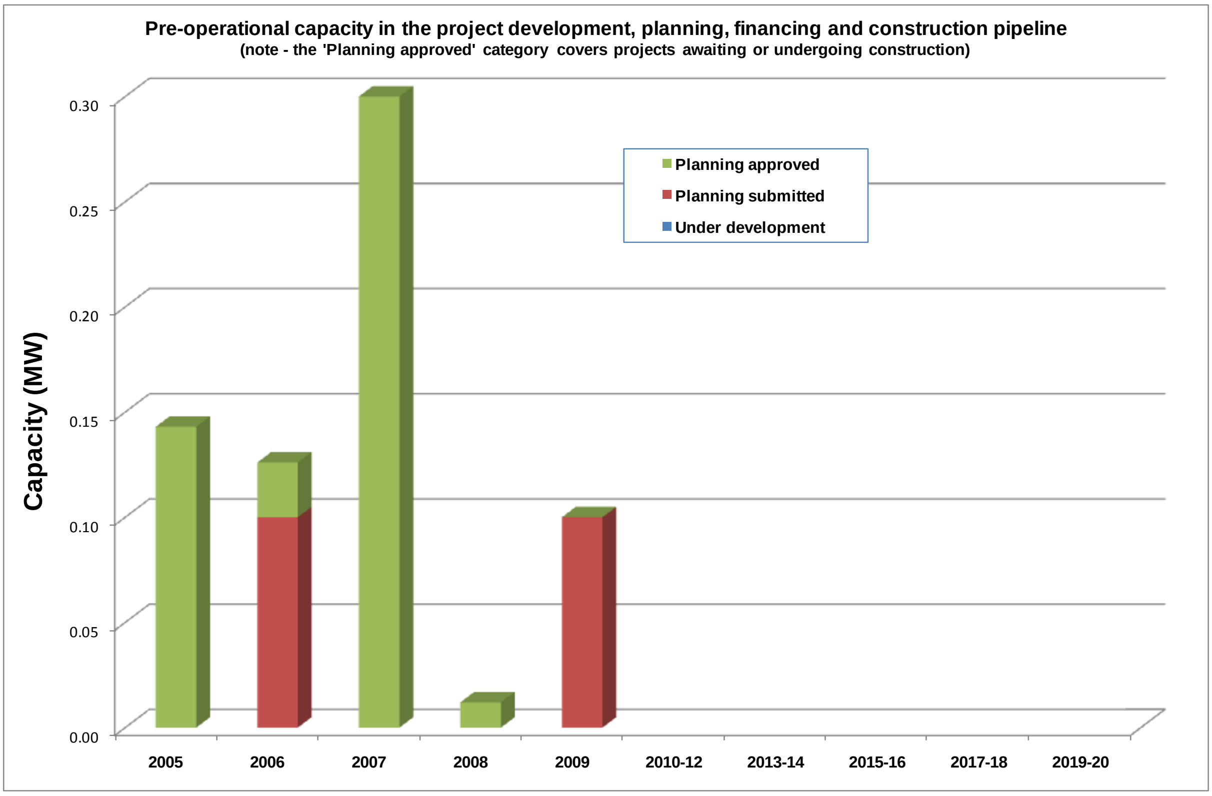
While solar PV is taking off in the UK, factors affecting the rate of installation to date include:

- High cost of solar PV technology compared with conventional energy
- Current implementation of PV systems requires significant consumer knowledge and patience – there needs to be a set of steps for making an intelligent PV purchase decision; also need easily accessible incentives
- Difficulty overcoming established energy systems (includes difficulty introducing innovative energy systems, particularly for distributed generation such as PV, because of technological lock-in, electricity markets designed for centralized power plants, and market control by established generators)
- Inadequate workforce skills and training (e.g. PV installers)
- Inadequate financing options for solar PV projects
- Dominance of PV manufacturing and deployment by other countries
- Lack of adequate codes, standards, and interconnection and net–metering guidelines for solar PV

(taken from Margolis & Zuboy 2006)

Figure 3 shows the data from the REPD from 2005–2009. The current planning data were used to derive the forward projections of capacity but the individual planning categories were not used so these are not projected beyond 2009.

**Figure 3: Pre-operation phases: project development, planning, financing and construction**




## 8.3 Projected deployment to 2020

An initial estimate was made of the projected deployment to 2020 based on the German experience of installed PV capacity after they introduced a feed-in tariff (FIT) in 1990. This projection was then sent to key industry members for comment.

Input data used for the projections were:

- Maximum installed capacity increase of 4.5MW between 2008 and 2009
- Planning success 2005-2009 of the order of 100% (the installation of solar PV systems falls under 'permitted development' and as such does not require planning permission)

**Central**
Assumes that the UK will follow a similar trajectory to Germany after they introduced a FIT in 1990. This uses the figures below and adds them to the 27MW currently installed in the UK.

**Table 4: PV installations by year in Germany (MW)**

| 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0.6 | 1 | 3.1 | 3.5 | 4 | 5.9 | 10.6 | 14.5 | 12.6 | 16.5 | 44 | 80 | 83 |

(Source: Solarbuzz)

Figures are provided by Solarbuzz which conducts its own solar market research (http://www.solarbuzz.com/FastFactsGermany.htm).

**Low estimate**
Assumes 75% of the German experience due to limiting factors around unfamiliarity with the FITs programme, tentative enthusiasm about solar PV, low numbers of UK-based installers and a cautious investment climate.

### High Estimate

Assumes 150% of the German installation experience, considering the numbers of installers to be less of a limiting factor (as the LCBP has already developed a small installation industry), the investment climate will improve and that the UK consumer will be equally enthusiastic about solar PV as their German counterparts.

**Table 5: Historic and projected capacity development and deployment 2005 – 2020**

**Solar PV** | **Weighted average load factor: 8.5%**

| | | Total capacties/output in the different categories during the stated period | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Unit** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010-12** | **2013-14** | **2015-16** | **2017-18** | **2019-20** |
| See definitions below | | 31/12/05 | 31/12/06 | 31/12/07 | 31/12/08 | 31/12/09 | 31/12/12 | 31/12/14 | 31/12/16 | 31/12/18 | 31/12/20 |
| **Under development** | **MW** | 0 | 0 | 0 | 0 | 0 | | | | | |
| **Planning submitted** | **MW** | 0 | 0 | 0 | 0 | 0.1 | | | | | |
| **Planning approved** | **MW** | 0.14 | 0.03 | 0.30 | 0.01 | 0 | | | | | |
| **Operational (central)** | **MW** | 10.88 | 14.26 | 18.09 | 22.51 | 27 | | | | | |
| **Projected operational** | **MW** | | | | | | 32 | 39 | 56 | 83 | 143 |
| **Energy production** | **GWh** | 8 | 11 | 13 | 17 | 20 | 24 | 29 | 41 | 62 | 107 |

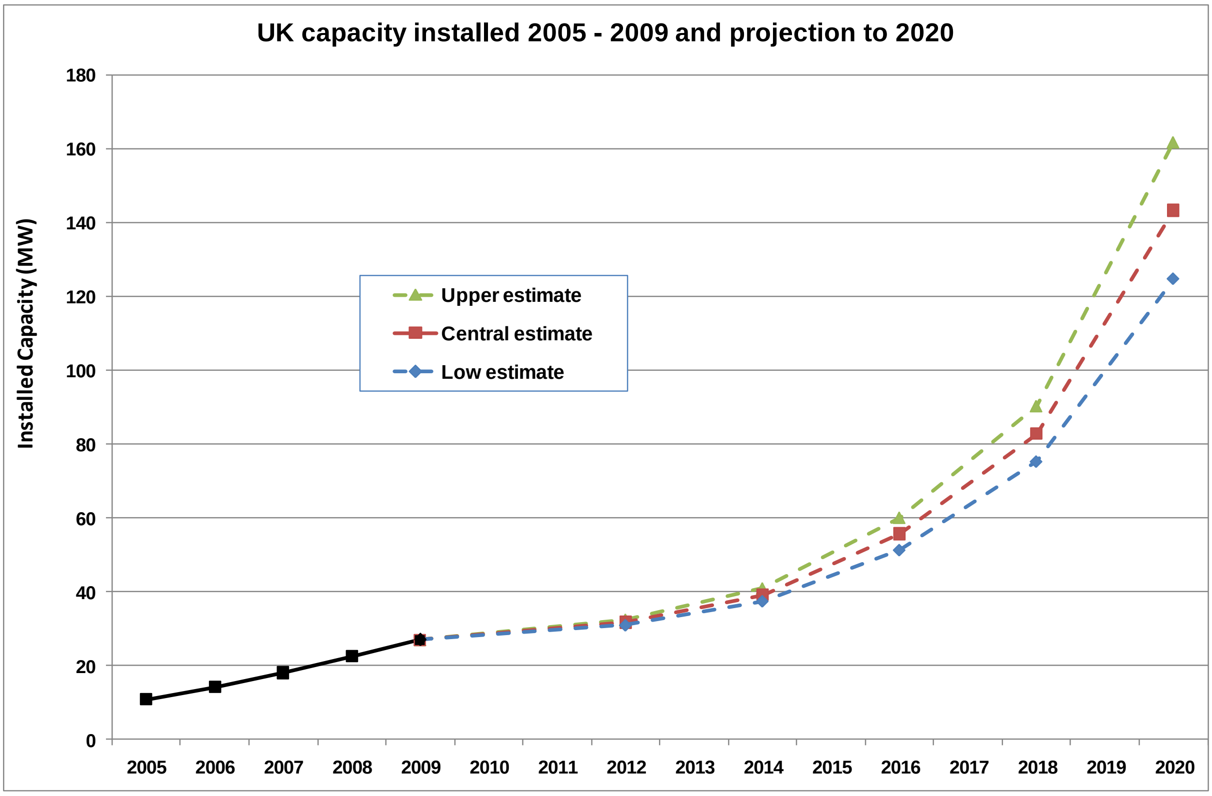
**Range of projected operational capacity**

| | | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Low estimate** | **MW** | | | | | 27 | 31 | 37 | 51 | 75 | 125 |
| | **GWh** | | | | | | 23 | 28 | 38 | 56 | 93 |
| **Central estimate** | **MW** | 11 | 14 | 18 | 23 | 27 | 32 | 39 | 56 | 83 | 143 |
| | **GWh** | 8 | 11 | 13 | 17 | 20 | 24 | 29 | 41 | 62 | 107 |
| **Upper estimate** | **MW** | | | | | 27 | 32 | 41 | 60 | 90 | 162 |
| | **GWh** | | | | | | 24 | 31 | 45 | 67 | 121 |

### Load Factors/energy output

The spreadsheet used to present the estimates is a common template across all technologies and has a single load factor across time. This is not likely to be representative for solar PV. Levels of insolation vary from year to year so even for a stable installed capacity load factors vary year to year. This makes is difficult to discern any long term trends. When reporting electrical output for PV for DUKES, AEA have tended to use a factor of 750kWh per kW installed capacity per year. This equates to a load factor of approximately 8.5%.

**Figure 4: Historic deployment and range of future projections to 2020**




## 8.4 Achieving future deployment – key dependencies

### 8.4.1 Impact of financial incentives

The introduction of the FIT tariff from 1st April 2010, to include solar PV projects of up to 5MW, has given the UK solar industry, which is already growing at 25% per annum, a major boost. For solar PV the FIT tariff levels are as follows:

**Table 6: UK Solar PV FIT rates**

| Technology | Scale | Tariff level for new installations in period (p/kWh) [NB tariffs will be inflated annually | | | | | | | | | | | Tariff lifetime (years) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Scheme Year | 1 1/4/10 – 31/3/11 | 2 to 31/3/12 | 3 to 31/3/13 | 4 to 31/3/14 | 5 to 31/3/15 | 6 to 31/3/16 | 7 to 31/3/17 | 8 to 31/3/18 | 9 to 31/3/19 | 10 to 31/3/20 | 11 to 31/3/21 | |
| PV | ≤4 kW (new build**) | 36.1 | 36.1 | 33 | 30.2 | 27.6 | 25.1 | 22.9 | 20.8 | 19 | 17.2 | 15.7 | 25 |
| PV | ≤4 kW (retrofit**) | 41.3 | 41.3 | 37.8 | 34.6 | 31.6 | 28.8 | 26.2 | 23.8 | 21.7 | 19.7 | 18 | 25 |
| PV | >4-10 kW | 36.1 | 36.1 | 33 | 30.2 | 27.6 | 25.1 | 22.9 | 20.8 | 19 | 17.2 | 15.7 | 25 |
| PV | >10-100 kW | 31.4 | 31.4 | 28.7 | 26.3 | 24 | 21.9 | 19.9 | 18.1 | 16.5 | 15 | 13.6 | 25 |
| PV | >100kW-5MW | 29.3 | 29.3 | 26.8 | 24.5 | 22.4 | 20.4 | 18.6 | 16.9 | 15.4 | 14 | 12.7 | 25 |
| PV | Stand alone system** | 29.3 | 29.3 | 26.8 | 24.5 | 22.4 | 20.4 | 18.6 | 16.9 | 15.4 | 14 | 12.7 | 25 |

(Source: DECC 2009)

For those solar PV projects of 50kW or less, they will have to use Microgeneration Certification Scheme (MCS) eligible products installed by MCS accredited installers to be eligible for FITs support.

In April 2009 banding was introduced under the Renewables Obligation; providing differentiated levels of support to different technologies in order to encourage a larger contribution from emerging renewable technologies. Solar PV will receive two ROCs per MWh generated from this time. During 2008 the RO was extended by 10 years to 2037.

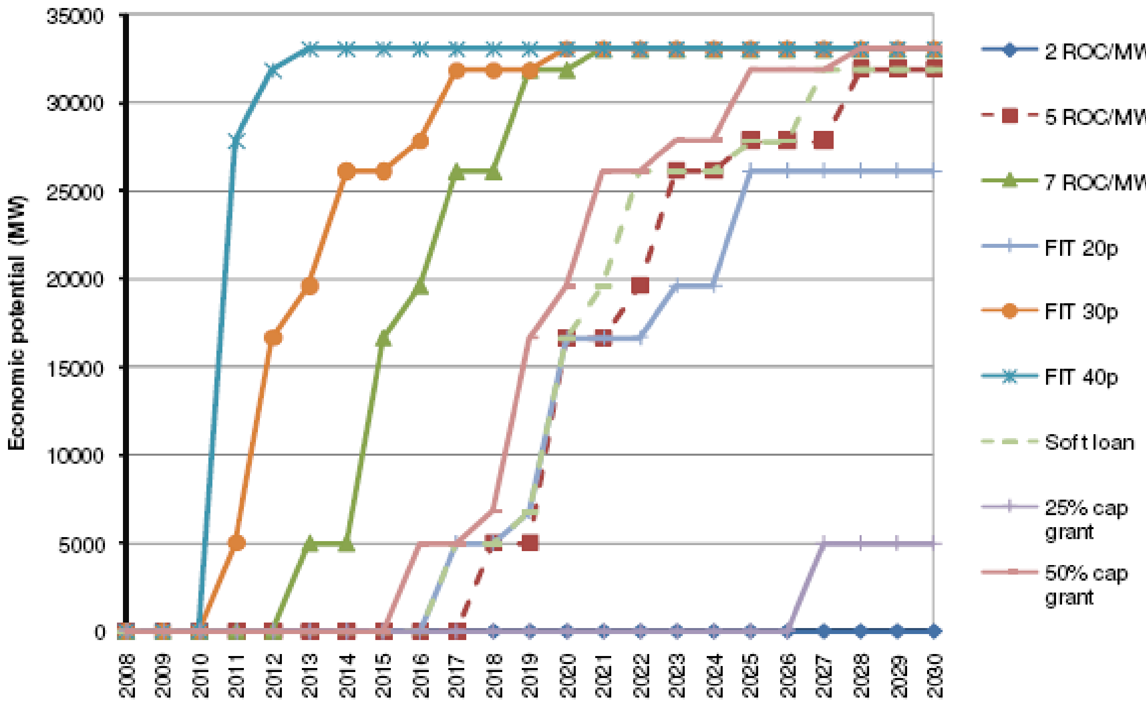
Grant support for the installation of solar PV projects is also important. In 2008, 72% of installed projects received government grant support.

- Low Carbon Buildings Programme (LCBP) – this has been the most significant grant programme. 2008 saw a larger than ten–fold increase in PV capacity installed under Phase 2 from around 150 kWp in 2007 to over 1700 kWp in 2008. The LCBP is now closed to electricity technologies due to the introduction of the FIT.
- Research Institutions – in 2008 nearly £12 million in funding was provided for solar PV research from the EPSRC, TSB, the Carbon Trust and the DTI (now BIS) (DECC 2009). Budgets for demonstrations and field tests came through the grants programmes and amounted to over £12.7 million (DECC 2009). Total funding amounted to £24.7 million, a substantial increase from 2007's total funding of £17.6 million (DECC 2009).

A number of electricity utilities in the UK offer to pay either for exported electricity or total electricity generated from a solar PV system. Most require a separate export meter or generation meter to be installed. In 2008 prices varied from around 10–30p per kWh generated, dependent on the utility, with some paying for total generation whilst others only paid for electricity exported to the grid. The electric utilities such as EDF, Northern Ireland Electricity (NIE), E.ON also provide funding for renewable energy projects. For example, in 2008 NIE provided £222,815 for 76 PV projects, which were mostly used to top up funding from the Reconnect Programme. 15% of the total installed cost or £900 per kWp was available up to a cap of £4,500.

Element Energy (2008) has estimated the impact of each policy measure on the economic potential for PV installations as shown below. This is the capacity of PV that could be economically developed at a particular time, not the capacity that is expected to have been installed.

**<u>Figure 5: Capacity of PV that could be economically developed in the existing non-domestic building stock under various policy scenarios 2008-2030</u>**




(Source: Element Energy 2008)

### 8.4.2 Impact of consenting processes

According to the REPD, 100% of the solar PV projects that were applied for 2005–2008 were approved.

For solar PV, planning permission is not actually required. Local planning authorities do however suggest that building control be informed of installation work being carried out so that it is deemed safe.

### 8.4.3 Integration to energy markets

Solar installation in the UK is dominated by grid–connected PV systems both on commercial buildings and newly built housing. The grid connection allows the 'feed–in' of excess solar energy generation back in to the grid in order to receive the FIT announced by DECC.

There is a need to start a dialogue between the UK PV industry and utilities regarding the integration of PV in the network and how to find a balance between centralised and decentralised generation, keeping in mind grid stability and system control (EPIA 2010). Up until now, utilities have often taken a very critical attitude towards renewable energy sources in general and, as well, towards PV (EPIA 2010). Therefore it is essential to start a constructive dialogue on how the integration of PV into the national grid can be managed, to include the role of solar electricity in marketing campaigns and technical regulations for PV grid-connection, especially the contribution of solar electricity to the peak power supply (EPIA 2010).

### 8.4.4 Supply chain issues and constraints

In 2009 Wilson identified 19 UK companies engaged in the manufacture and R&D of solar cell/module manufacture, with a further 63 companies involved in equipment for PV manufacturing. Materials and equipment expertise for PV manufacture is a UK strength with several world class companies involved in thin film and III–V CPV solar cell production. Furthermore with the German manufacturing market close by, the solar PV supply chain in the UK is unlikely to be significantly constrained.

However it is thought that the skilled labour to install the solar PV panels will still be a constraint (although this was assumed not to be the case for the high estimate).

### 8.4.5 Regulatory framework

The UK government is increasingly looking at regulatory policies which allow integration of the broad spectrum of renewable sources of energy into the national grid in the most efficient and non–discriminatory manner, while maintaining grid reliability. The FIT and the RO working together with government grants should allow installation rates of solar PV to increase relatively significantly by 2020.

### 8.4.6 Other potential barriers to deployment

- High cost of solar PV technology compared with conventional energy
- Current implementation of PV systems requires significant consumer knowledge and patience – there needs to be a set of steps for making an intelligent PV purchase decision; also need easily accessible incentives
- Difficulty overcoming established energy systems (includes difficulty introducing innovative energy systems, particularly for distributed generation such as PV, because of technological lock-in, electricity markets designed for centralized power plants, and market control by established generators)
- Inadequate workforce skills and training (e.g. PV installers)
- Inadequate financing options for solar PV projects
- Dominance of PV manufacturing and deployment by other countries
- Lack of adequate codes, standards, and interconnection and net–metering guidelines for solar PV

### 8.4.7 Summary of constraints

The constraints are summarised in Table 7 below.

Solar PV installation rates will be limited by different constraints at different points in time: network connection and access to finance initially, then skills capacity limits.

It is likely that the UK will be able to follow a similar trajectory to the German model if there are/continue to be:

- adequate support mechanisms,
- capital becoming more available
- electricity network connection blockages removed,

**Table 7: Significance of various potential constraints on deployment**

| Potential constraints | Significance | Comment |
|---|---|---|
| Returns insufficient to stimulate sufficient deployment | Amber | 2 ROCs/MW and FIT for <5MW should provide reasonable returns for solar PV (as in Germany and the USA). However the relative high capital cost of the technology means that payback times are still a constraint for mass deployment. |
| Planning (local policies, obtaining permissions) | Green | Planning success rates are very high according to the REPD. Increased inclusion in new housing developments (e.g. through the Merton rule) may increase cumulative impact. |
| Integration to energy markets | Green | Connect and manage regime should give good access to the electrical distribution and transmission networks at acceptable cost. |
| Supply chain issues and constraints | Amber | Silcone (the predominant raw material for the manufacture of PV panels) supply depends on worldwide markets. A strong surge in demand in one region (eg USA or Germany) can result in reduced supply in the UK - resulting in delays and/or price increases. Also inadequate workforce skills and training (e.g. PV installers). |
| Regulatory constraints | Amber | Lack of adequate codes, standards, and interconnection and net–metering guidelines for solar PV. |
| Institutional barriers | Amber | Difficulty overcoming established energy systems (includes difficulty introducing innovative energy systems, particularly for PV, because of technological lock-in, electricity markets designed for centralized power plants, and market control by established generators). |
| Unclear policy (national, regional, local) | Green | Strong policy statements on RE. Planning policy being strengthened through UK RES and stronger requirements on regional and local government policies. |
| Motivating investors to act | Green | Credit crunch has reduced capital available but with the introduction of the FIT for solar PV (and other renewable technologies), this is likely to stimulate investment in solar PV going forward. Furthermore, there are a growing number of specialist funds being established to invest in clean energy which may offer an alternative source in future. |
| Other constraints (please specify under comments) | | |

| | |
|---|---|
| Green | Unlikely to present a constraint to achieving the central projection. |
| Amber | Could constrain achieving the central projection and will certainly constrain achieving the upper projection |
| Red | Likely to constrain achieving the central projection; could result in only the low projection being achieved |

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# 9 Tidal stream

## 9.1 Introduction

Tidal stream energy is the direct extraction of energy from the motion of water in natural currents in the sea in much the same way as wind turbines extract energy from the wind. Strong tidal currents are found where flow is concentrated through narrow straits, near headlands and around islands.

The UK has some of the best tidal resources in the world, recently estimated as capable of producing 16.3 TWh/year (4.2% of 2008 UK electricity production). The majority of the UK tidal stream resource is located in the north of Scotland, around the Pentalnd Firth, with additional areas around Strangford Lough in Northern Ireland, Anglesey in North Wales, the Bristol Channel and near the Channel Islands.

A number of factors combine to give the UK a strong position with regard to tidal energy: in addition to its tidal resources there are also a number of leading device developers operating in the UK, a leading research base and existing offshore engineering and services industries. Scotland is fortunate to have a first class test centre in the form of EMEC on the Orkney Islands, providing developers the facilities to test, develop and evaluate their technologies. Both UK Government and the Scottish Governments have been very supportive of marine energy, introducing a number of generous support measures.

## 9.2 Historical deployment

Tidal power is at an early stage with respect to commercial scale development.

A wide range of different configurations of tidal current devices are currently being developed. The majority of these are horizontal axis turbines, although other configurations exist such as vertical axis turbines and oscillating hydrofoils. The number of device developers continues to grow worldwide and over 20 tidal device developers are located in the UK[14].

The leading technology developers have progressed closer to fully operational status of their full scale demonstrator devices. Marine Current Turbines Ltd’s 1.2 MW SeaGen tidal turbine was deployed in 2008 in Strangford Narrows, Northern Ireland and has achieved over 1000 hours of operation to date.

The levels of government support have increased in a number of countries. In the UK this has included:

- The UK’s Marine Renewables Deployment Fund, which offers a combination of capital grants and revenue support in addition to the market price of electricity and Renewable Obligation Certificates (ROCs).
- The Scottish Government’s Wave and Tidal Energy Support (WATES) Scheme, supporting projects based at EMEC in Orkney.
- In 2008, the Scottish First Minister announced the Saltire Prize, a £10 million prize to be awarded to the team that can demonstrate in Scottish waters a commercially viable wave or tidal energy technology that achieves a minimum electrical output of 100 GWh over a continuous 2 year period using only the power of the sea.
- In 2009, DECC published the UK Renewable Energy Strategy. This announced that up to £8 million would be allocated to expand the in-sea stage testing facilities at EMEC in Orkney.
- In 2009 the Scottish Government amended the Renewables Obligation Scotland (ROS) to award 3 Renewable Obligation Certificates (ROCs) for tidal electricity.

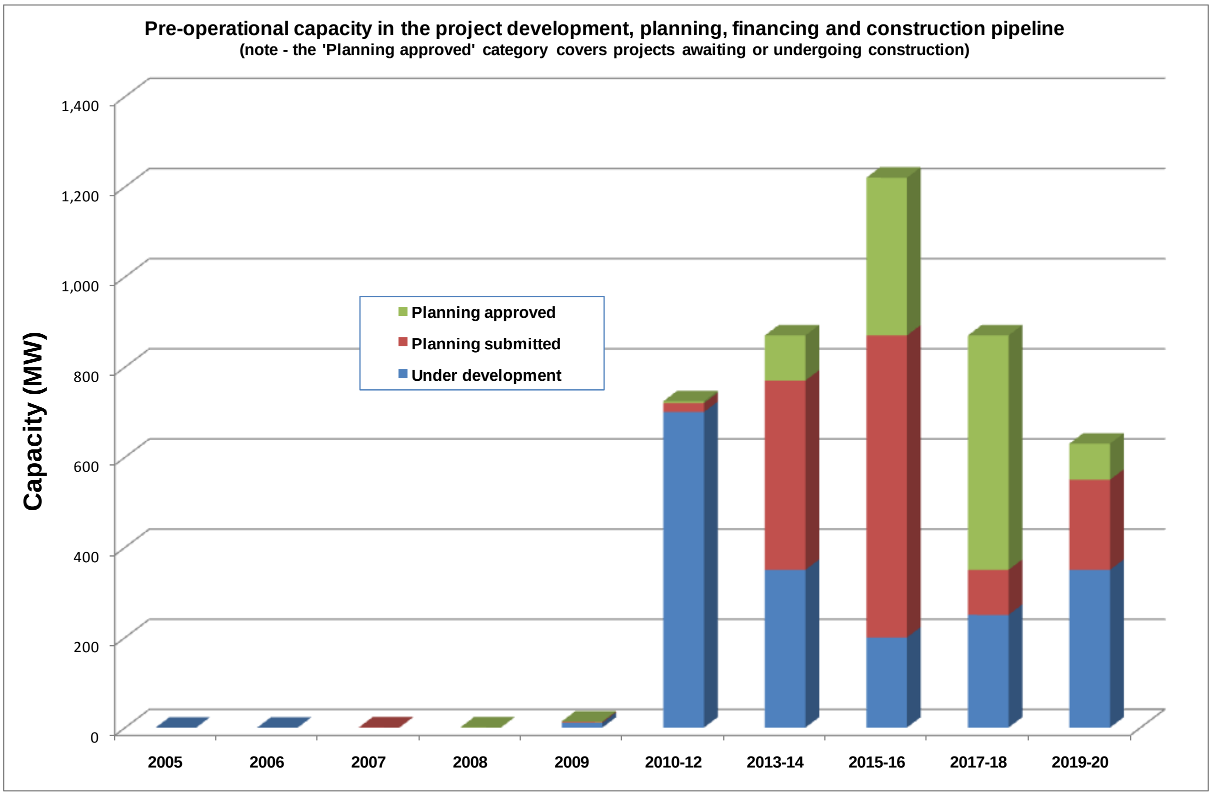
The completion of a Strategic Environmental Assessment ( SEA) for wave and tidal energy in Scotland in 2007 is also significant progress – and there is a strong need for this in England and Wales.

[14] Energy Industry Market Forecasts: The Marine Energy Market 2009 – 2014, Scottish Enterprise.

Grid issues are significant, as is discussed further in Section 9.4. The major Scottish resources in particular are remote from markets and this is exacerbated by limited capacity in the transmission system in the north of Scotland. In January 2010 the Scottish Government announced approval of the Beauly to Denny transmission line, greatly increasing the ability to access tidal and other renewable resources. Grid charging issues (in terms of both securities and use of system costs) remain a risk to deployment of tidal technology.

The Crown Estate has just announced the results of the world's first commercial wave and tidal leasing round, for ten sites in Scotland's Pentland Firth and Orkney waters. 1.2 GW of installed capacity has been proposed by the wave and tidal energy developers for 2020, 600 MW each from wave and tidal.

**Figure 1: Pre-operation phases: project development, planning, financing and construction**




## 9.3 Projected deployment to 2020

A number of market projections have been published in recent years, showing how installed marine energy generating capacity is expected to grow over the next 10 years. An initial estimate was made of the projected deployment to 2010 and this was sent to key industry members for comments. An attempt has been made to reflect the views received.

At the time of writing Marine Current Turbines Ltd's 1.2 MW SeaGen tidal turbine in Strangford Narrows provides the only operational capacity and a further 2 MW has been submitted to planning. It is too early to have reliable data on average % planning success, average time from planning submission to operation or the maximum capacity it will be possible to install in one year.

Following from the Crown Estate's Pentland Firth leasing announcements much activity will focus on the waters there. Four leases have been signed for tidal developments:

- SSE Renewables Developments (UK) Ltd, 200 MW for Westray South site
- SSE Renewables Holdings (UK) Ltd & OpenHydro Site Development Ltd, 200 MW for Cantick Head site

- Marine Current Turbines Ltd, 100 MW for Brough Ness site
- Scottish Power Renewables UK Ltd, 100 MW for Ness of Duncansby site

The vast majority of project delivery is expected to occur from 2016 onwards, a timescale on which the upgrades to the grid in Scotland could be in place. It has been assumed that the results of the early phases of commercial scale activity will be required before further large developments are started, leading to a decline in activity before a subsequent acceleration. Of course it is possible that this assumption is inaccurate, but further progress in demonstrating that devices can work reliably and bring costs down will be key in securing investor confidence.

**Table 1: Historic and projected capacity development and deployment 2005 – 2020**

**Tidal stream** — **Weighted average load factor: 32%**

| | | Total capacties/output in the different categories at the end of the stated year/period | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Unit | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
| | | 31/12/05 | 31/12/06 | 31/12/07 | 31/12/08 | 31/12/09 | 31/12/12 | 31/12/14 | 31/12/16 | 31/12/18 | 31/12/20 |
| Under development | MW | 0 | 0 | 0 | 0 | 11 | 700 | 350 | 200 | 250 | 350 |
| Planning submitted | MW | | | 0 | 0 | 2 | 20 | 420 | 670 | 100 | 200 |
| Planning approved | MW | | | | 0 | 1 | 4 | 100 | 350 | 520 | 80 |
| Operational (central) | MW | 0 | 0 | 0 | 0 | 1 | | | | | |
| Projected operational | MW | | | | | | 2 | 5 | 35 | 215 | 385 |
| Energy production | GWh | 0 | 0 | 0 | 0 | 3 | 6 | 14 | 98 | 603 | 1,079 |

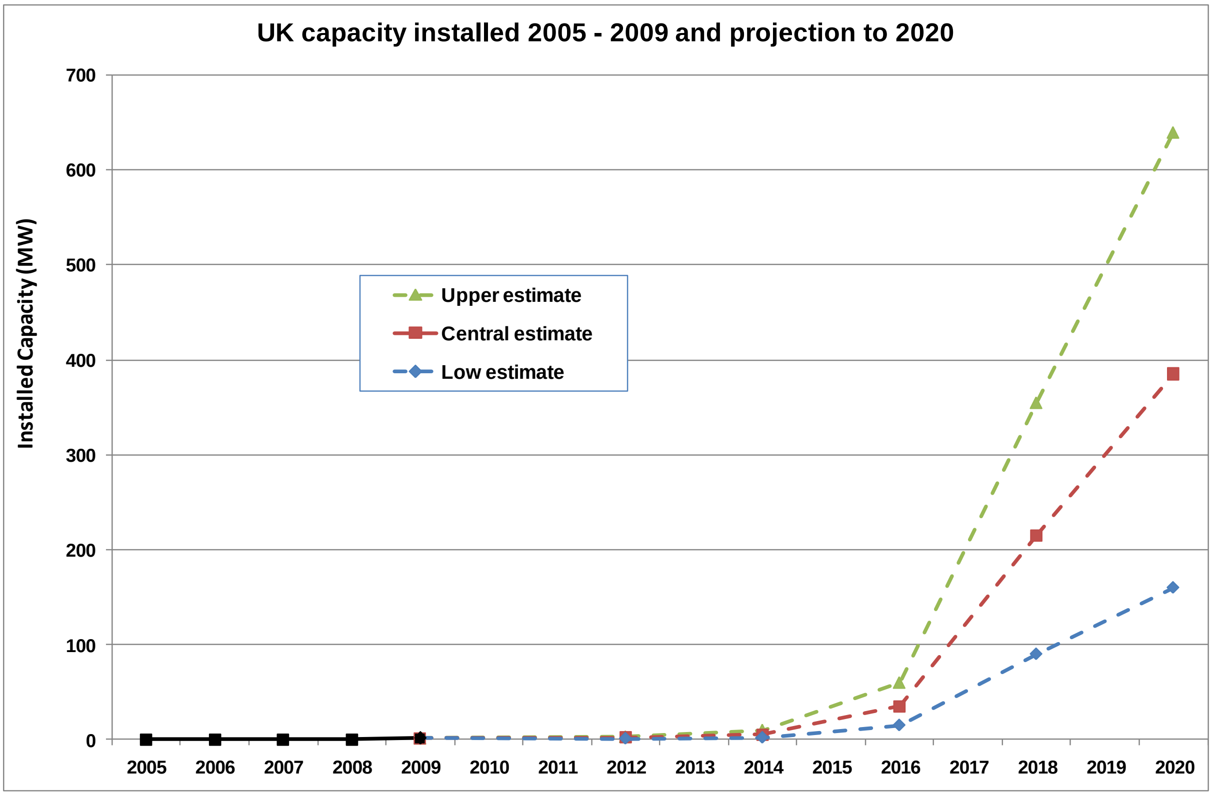
**Range of projected operational capacity**

| | Unit | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Low estimate | MW | | | | | 1 | 1 | 2 | 15 | 90 | 160 |
| | GWh | | | | | | 3 | 6 | 42 | 252 | 449 |
| Central estimate | MW | 0 | 0 | 0 | 0 | 1 | 2 | 5 | 35 | 215 | 385 |
| | GWh | 0 | 0 | 0 | 0 | 3 | 6 | 14 | 98 | 603 | 1,079 |
| Upper estimate | MW | | | | | 1 | 3 | 10 | 60 | 355 | 640 |
| | GWh | | | | | | 8 | 28 | 168 | 995 | 1,794 |

### Load Factors/energy output

The spreadsheet used to present the estimates is a common template across all technologies and has a single load factor for all time. For tidal energy there will be variation of load factor with device and conditions. There is a wide range of estimates of load factor and experience will tell what in practice can be achieved. Marine Current Turbines report achieving load factors over 60% - but the region of 30-35% is more commonly quoted and the figure of 32% has been used in the calculations reported here.

**Figure 2: Historic deployment and range of future projections to 2020**




# 9.4 Achieving future deployment – key dependencies

## 9.4.1 Impact of financial incentives

Capital costs for tidal devices are not yet known and technology risk is a significant concern.

In recent discussions, a number of developers cite insufficient support/ROC banding as the biggest risk associated with commercial deployment, and a potential reason for lack of commitment to locate within the English or Welsh waters. In Scotland, the ROC provision is more generous (3 per MW), although the issue of lack of clarity of true costs remains.

That said, large companies are placing significant resources into technology development which indicates a level of confidence and commitment. It should also be emphasised that there is a very high level of political support at what is a crucial time for the emerging industry.

## 9.4.2 Impact of consenting processes

Development of necessary measures has progressed further in Scotland, where a Strategic Environmental Assessment has been carried out for marine renewables. There is an immediate need for this in England and Wales and there should also be a streamlined planning process.

## 9.4.3 Integration to energy markets

The majority of the UK tidal stream resource is located in the north of Scotland, around the Pentland Firth, with additional areas around Strangford Lough in Northern Ireland, Anglesey in North Wales, the Bristol Channel and near the Channel Islands. The major Scottish resources in particular are remote from markets and this is exacerbated by limited capacity in the transmission system in the north of Scotland.

In January 2010 the Scottish Government announced approval of the Beauly to Denny transmission line, greatly increasing the ability to access tidal and other renewable resources. The consent stated that construction must begin within 4 years and the upgraded line must be in place within 10 years.

Grid charging issues (in terms of both securities and use of system costs) remain a risk to deployment of tidal technology.

### 9.4.4 Supply chain issues and constraints

In discussions with developers the suitability and availability of operation and installation vessels has been identified as a key constraint, and given the dominance of the oil and gas sector, one that can link to the price of oil.

Many developers are not yet at the stage where they have full exposure to supply chain issues and a clearer picture of what these are in practice will emerge as the market develops.

### 9.4.5 Regulatory framework

As owners of the UK seabed, the Crown Estate has recently announced the world's first wave and tidal energy leasing round. Developers have signed leases to take forward installations, enabling them to enter statutory consenting process with security of access to the seabed.

The Scottish Government had just revealed the first stage of its Marine Spatial Plan for use of Pentland Firth and Orkney waters, providing a framework and draft regional locational guidance for wave and tidal energy development. The final plan will highlight how the area's potential in marine energy can be used, managed and protected to balance other commercial interests and environmental challenges.

### 9.4.6 Other potential barriers to deployment

**A very challenging environment**
Areas of the greatest potential resource are in exposed locations, prone to extreme weather. This will require appropriate equipment and skilled crews. In addition, a number of vessels can only install on the neap tide - if bad weather occurs then, this can mean a month long delay.

**Skills**
Some marine technology developers have indicated difficulty in recruiting staff with appropriate skills.

**Access to capital**
There is a significant level of technical risk associated with tidal stream energy – investors are likely to increase in confidence as developers demonstrate reliability and reduce capital costs.

### 9.4.7 Summary of constraints

The constraints are summarised in Table 2 overleaf.

## Table 2: Potential Constraints

| Potential constraints | Significance | Comment |
|---|---|---|
| Returns insufficient to stimulate sufficient deployment | Red | Capital costs for tidal devices are not yet known. In recent discussions, a number of developers cite insufficient support/ROC banding as the biggest risk associated with commercial deployment, and a potential reason for lack of commitment to locate within the English or Welsh waters. In Scotland, more generous ROCs (3 per MW) are proposed, although the issue of lack of clarity of true costs remains.<br>That said, large companies are placing significant resources into technology development which does indicate a level of confidence. |
| Planning (local policies, obtaining permissions) | Amber | This has progressed further in Scotland, where a Strategic Environmental Assessment has been carried out for marine renewables. There is an immediate need for this in England and Wales and there should also be a streamlined planning process.The Crown Estate has just announced the first leasing round results in Scotland. Some areas have constraints due for example to navigation routes, MoD practice and exercise areas, marine conservation zones, or fisheries. |
| Integration to energy markets | Amber | The majority of the UK tidal stream resource is located in the north of Scotland, around the Pentalnd Firth, with additional areas around Strangford Lough in Northern Ireland, Anglesey in North Wales, the Bristol Channel and near the Channel Islands. The major Scottish resources in particular are remote from markets and this is exacerbated by limited capacity in the transmission system in the north of Scotland.<br><br>In January 2010 the Scottish Government announced approval of the Beauly to Denny transmission line, greatly increasing the ability to access tidal and other renewable resources.The consent stated that construction must begin within 4 years and the upgraded line must be in place within 10 years.<br><br>Grid charging issues (in terms of both securities and use of system costs) remain a risk to deployment of tidal technology. |
| Supply chain issues and constraints | Amber | In discussions with developers the suitability and availability of operation and installation vessels has been identified as a key constraint, and given the dominance of the oil and gas sector, one that can link to the price of oil.Connection to the onshore grid is also seen as a significant factor.<br><br>Many developers are not yet at the stage where they have full exposure to supply chain issues and a clearer picture of what these are in practice will emerge as the market develops. |
| Regulatory constraints | Green | As owners of the UK seabed, the Crown Estate has recently announced the world's first wave and tidal energy leasing round. Developers have signed leases to take forward installations, enabling them to enter statutory consenting process with security of access to the seabed. |
| Institutional barriers | Green | There are a wide range of concepts for tidal stream devices, and the main focus facing the developers is to demonstrate that the devices can operate for extended periods and achieve consistent power output, whilst reducing the development cost. A range of universities, commercial research labs and individual companies are working in the field, both generically and for individual companies. |
| Unclear policy (national, regional, local) | Green | There are strong policy steers: The UK Government has stated that it is committed to making large scale deployment of tidal energy a reality and the Scottish Government has stated its aim to generate 50 per cent of Scotland's electricity from renewable sources by 2020. In England organisations such as the East of England Development Agency and One North East are working to develop supply chains. |
| Motivating investors to act | Amber | The Crown Estate in March 2010 announced licencing in the Pentland Firth and surrounding waters - to deliver these alone will require an investment of order £4 billion. The Government recognises the opportunity to take a world lead in the development of marine technologies. Further progress in development, demonstrating that devices can work reliably and bringing costs down will be key in securing investor confidence. |
| Other constraints (please specify under comments) | Amber | Devices still at an early stage of development and have yet to undergo the challenging transition from lab scale to real locations. It is therefore at this stage not possible to know what the capital cost of many devices will be.<br><br>Areas of the greatest potential resource are in exposed locations, prone to extreme weather. This will require appropriate equipment and skilled crews. In addition, a number of vessels can only install on the neap tide - if bad weather occurs then, this can mean a month long delay. |

| | |
|---|---|
| Green | **Unlikely to present a constraint to achieving the central projection.** |
| Amber | **Could constrain achieving the central projection and will certainly constrain achieving the upper projection** |
| Red | **Likely to constrain achieving the central projection; could result in only the low projection being achieved** |

# 10 Hydroelectricity

## 10.1 Introduction

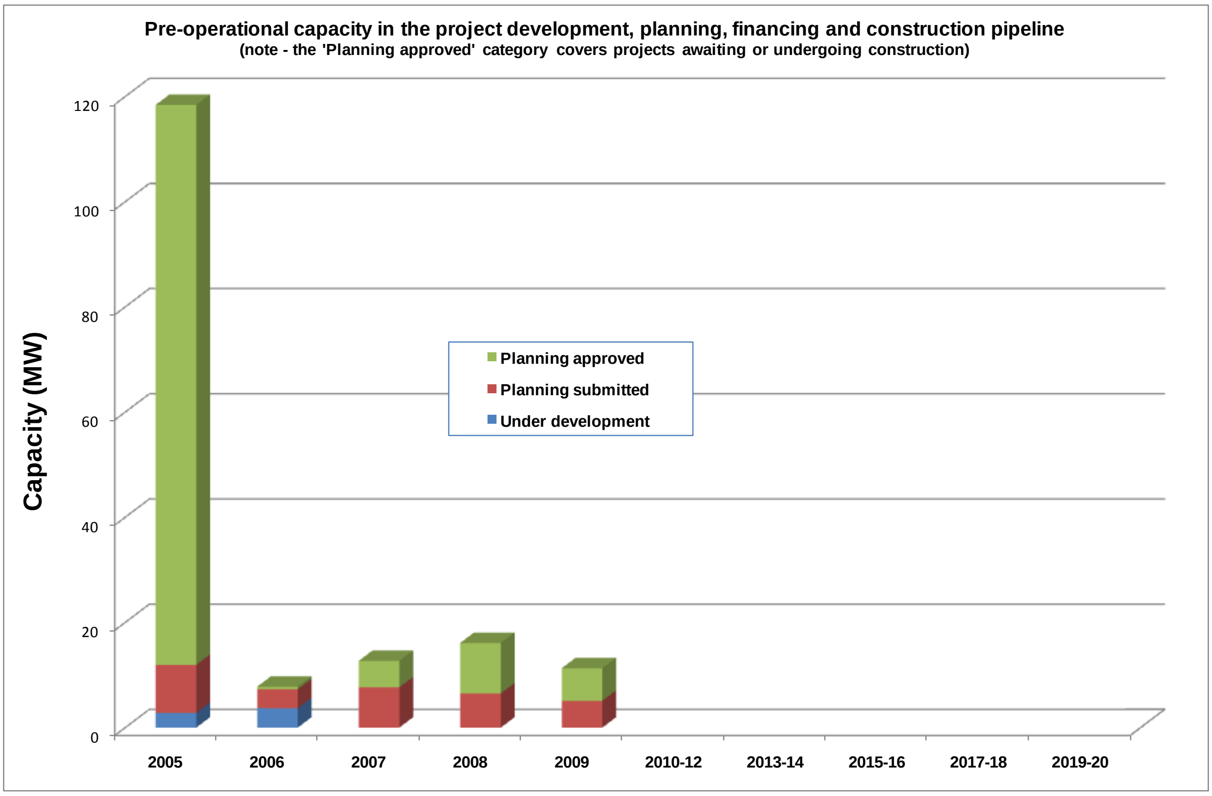
Hydro electricity generation is derived from the force or energy of moving water. It is a well established and proven technology.

## 10.2 Historical deployment

Although the earliest hydro power plant in the UK dates from 1882, the majority of the capacity was added in a concentrated initiative from 1943 to 1965. The recent, 100 MW, Glendoe power station, opened in 2009 was the first of this size in over 50 years.

UK currently has an operational capacity of 1.65 GW, of which 88% is in larger scale plant.

**Figure 1: Pre-operation phases: project development, planning, financing and construction**




## 10.3 Projected deployment to 2020

A number of assessments have been made of potential hydro capacity in the UK. Like other renewable resources it is not a constant source of output and is dependent on the level of water resource[15].

The Environment Agency has mapped the opportunities for small scale hydropower in England and Wales[16]. They concluded that although opportunity hotspots exist, small scale hydro power has some

[15] Although not a focus of this assessment via pumped storage[15], hydro can also provide balancing services to manage intermittency associated with a higher penetration of renewables.
[16] Opportunity and environmental sensitivity mapping for hydropower in England and Wales.

potential throughout England and Wales, with the exception of in East Anglia. Particular concentrations occur along rivers such as the Severn, Thames, Aire and Neath.

The study identified a maximum power potential of 1178 MW, arising from 25,935 barriers. Like all technologies, hydro can have an adverse environmental impact and ensuring it is employed in suitable sites can restrict the opportunities. Only 7% of these sites could be considered “high output – low environmental sensitivity”. The study also identified significant potential for win-win schemes that deliver hydropower and improvements in fish passage. Of these 4190, were win-wins, representing about half the power potential.

In Scotland, a recent study[17] concluded that Scotland's hydro potential is nearly double the amount previously estimated. This update on a 2008 study on Scotland's hydro resources estimates there could be 1.2 GW of potential new hydro capacity in 7,043 schemes. This compares to 657 MW according to the previous 2008 study. The increase in site numbers compared to the 2008 study is largely in the sub-100 kW range, driven by the favourable feed in tariff for micro-hydro generation.

### Table 1: Historic capacity development and deployment 2005 – 2009

**Hydropower** — **Weighted average load factor: 37%**

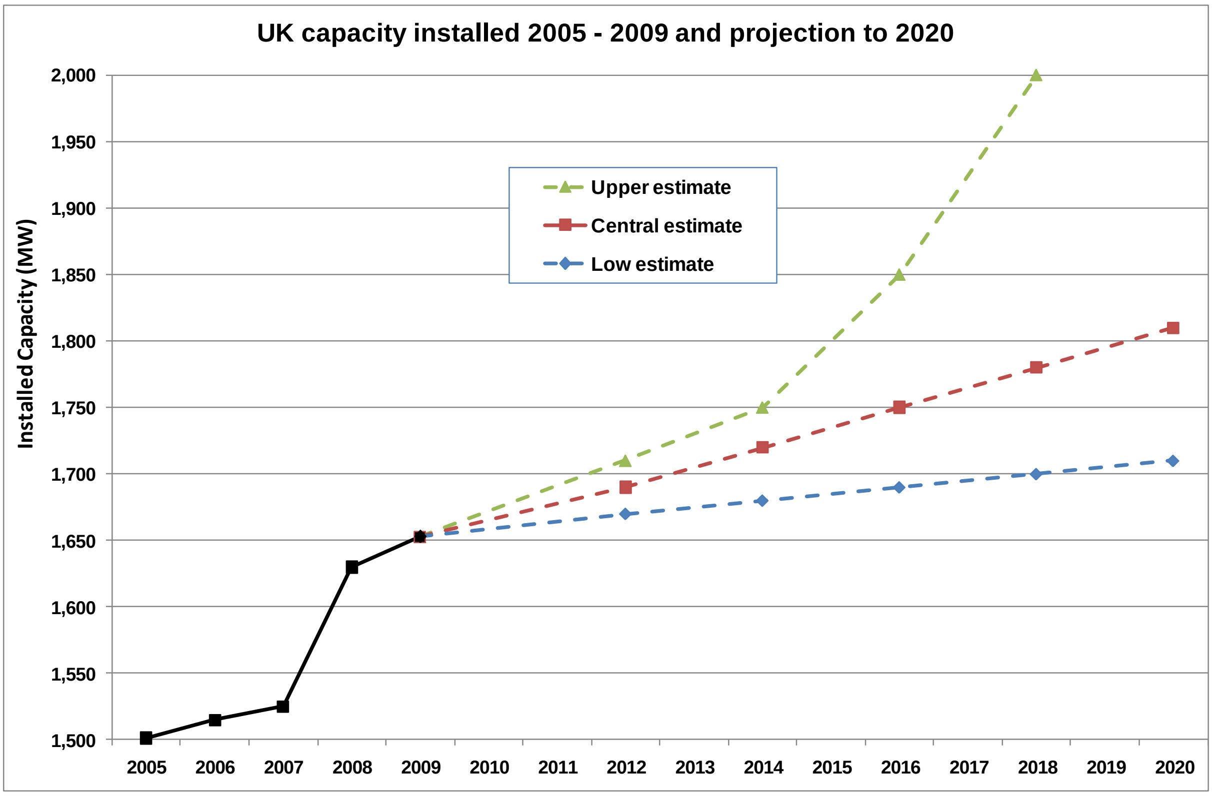
| | Unit | Total capacties/output in the different categories at the end of the stated year/period | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
| | | 31/12/05 | 31/12/06 | 31/12/07 | 31/12/08 | 31/12/09 | 31/12/12 | 31/12/14 | 31/12/16 | 31/12/18 | 31/12/20 |
| Under development | MW | 3 | 4 | | | | | | | | |
| Planning submitted | MW | 9 | 4 | 8 | 7 | 5 | | | | | |
| Planning approved | MW | 106 | 0 | 5 | 10 | 6 | | | | | |
| Operational (central) | MW | 1,501 | 1,515 | 1,525 | 1,630 | 1,653 | | | | | |
| Projected operational | MW | | | | | | 1,690 | 1,720 | 1,750 | 1,780 | 1,810 |
| Energy production | GWh | 4,865 | 4,910 | 4,943 | 5,282 | 5,357 | 5,478 | 5,575 | 5,672 | 5,769 | 5,867 |

**Range of projected operational capacity**

| | Unit | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Low estimate | MW | | | | | 1,653 | 1,670 | 1,680 | 1,690 | 1,700 | 1,710 |
| | GWh | | | | | | 5,413 | 5,445 | 5,478 | 5,510 | 5,542 |
| Central estimate | MW | 1,501 | 1,515 | 1,525 | 1,630 | 1,653 | 1,690 | 1,720 | 1,750 | 1,780 | 1,810 |
| | GWh | 4,865 | 4,910 | 4,943 | 5,282 | 5,357 | 5,478 | 5,575 | 5,672 | 5,769 | 5,867 |
| Upper estimate | MW | | | | | 1,653 | 1,710 | 1,750 | 1,850 | 2,000 | 2,120 |
| | GWh | | | | | | 5,542 | 5,672 | 5,996 | 6,482 | 6,871 |

[17] http://www.scotland.gov.uk/News/Releases/2010/01/21113034

**Figure 2: Historic deployment and range of future projections to 2020**




## 10.4 Achieving future deployment – key dependencies

The Government has stated its commitment to renewable energy generation and the Scottish Government set ambitious targets. The Scottish Government's Renewables Action Plan[18] which was published in June 2009 includes a specific Route-Map for Hydro which sets out key steps to realise its potential, including the abolition of the Fisheries Committee and the establishment of a new industry group on Microhydro to galvanise action and consider barriers.

### 10.4.1 Impact of financial incentives

The introduction of Feed In Tariffs in 2010 will present a significant incentive for generation by micro hydro.

### 10.4.2 Impact of consenting processes

Many areas of hydro resource occur in areas with high levels of environmental sensitivity, including designated sites of special scientific interest, national parks, local nature reserves etc. The impact of planning restrictions has in general an effect of favouring small schemes, while decreasing the number of large schemes.

Recently[19] the Scottish Government issued a policy statement recognising that larger schemes (100 kW or more) make an important contribution to renewables targets, and Ministers accept that in supporting such schemes some deterioration of the water environment may be necessary if it is justifiable. Smaller schemes will be welcomed where they can be shown to have no adverse impact on

[18] http://www.scotland.gov.uk/Resource/Doc/278424/0083663.pdf
[19] Scottish Government Policy Statement, January 2010, www.scotland.gov.uk/Topics/Business-Industry/Energy/Energy-sources/19185/17851-1/HydroPolicy

the water environment. SEPA will be developing guidance to facilitate the appropriate siting and authorisation of sub 100 kW schemes which will be available in Spring 2010.

In its Renewable Energy Action plan the Scottish Government flagged that through Forum for Renewable Energy Development in Scotland (FREDS) Hydro Group, to agree on best level for S36 threshold and implementation of change if required, by June 2010.

### 10.4.3 Integration to energy markets

Grid capacity has been identified as a significant constraint. It has been estimated[20] that 33% of new Scottish hydropower generation could not be accommodated on the grid.

The Scottish Government stated in its Renewable Energy Action Plan that it would continue to engage with Ofgem, National Grid and the electricity transmission companies to ensure continuing progress in obtaining grid connections such as through derogation and Registered Power Zones;

The Scottish Government has announced approval of the Beauly to Denny transmission line, greatly increasing the ability to access renewable resources. However constraints may still arise at a local level - detailed modelling for each scheme would be required.

### 10.4.4 Supply chain issues and constraints

Although the majority of jobs required would be in construction, a recent study[21] has identified potential skills bottlenecks in hydro engineering and electrical network engineering if there was to be rapid growth in hydro development. Many hydro engineers are employed by developers with a focus on schemes above 200 kW, but there is a relative shortage of skilled, independent engineers to work on smaller systems. To this end the Scottish Government has stated an aim to ensure that skills needs are covered in work being taken forward by the Scottish Renewable Energy Skills Group.

### 10.4.5 Other potential barriers to deployment

**Environmental Considerations**
Many potential sites would be considered as highly environmentally sensitive due for example to the presence of particular fish species such as migratory salmon and eel. Good design of schemes (fish passes) can mitigate impacts but do cost considerably more.

### 10.4.6 Summary of constraints

Constraints are summarised in Table 2.

[20] Scottish Hydropower Resource Study, Nick Forrest Associates Ltd, SISTech, Black & Veatch Ltd, 2008, http://www.scotland.gov.uk/Resource/Doc/917/0064958.pdf
[21] The Employment Potential of Scotland's Hydro Resource, Nick Forrest and Jamie Wallace, 2009, http://www.scotland.gov.uk/Resource/Doc/299322/0093327.pdf

## Table 2: Potential Constraints

| Potential constraints | Significance | Comment |
|---|---|---|
| Returns insufficient to stimulate sufficient deployment | Green | The introduction of Feed In Tariffs in 2010 will present a significant incentive for generation by micro hydro. |
| Planning (local policies, obtaining permissions) | Amber | Many areas of hydro resource occur in areas with high levels of environmental sensitivity, including designated sites of special scientific interest, national parks, local nature reserves etc. The impact of planning restrictions has in general an effect of favouring small schemes, while decreasing the number of large schemes.<br><br>Recently (ref 3) the Scottish Government issued a policy statement recognising that larger schemes (100 kW or more) make an important contribution to renewables targets, and Ministers accept that in supporting such schemes some deterioration of the water environment may be necessary if it is justifiable. Smaller schemes will be welcomed where they can be shown to have no adverse impact on the water environment. SEPA will be developing guidance to facilitate the appropriate siting and authorisation of sub 100 kW schemes which will be available in Spring 2010.<br><br>In its Renewable Energy Action plan the Scottish Government flagged that through Forum for Renewable Energy Development in Scotland (FREDS) Hydro Group, to agree on best level for S36 threshold and implementation of change if required, by June 2010. |
| Integration to energy markets | Amber | Grid capacity has been identified as a significant constraint. It has been estimated (ref 1) that 33% of new Scottish hydropower generation could not be accomodated on the grid.<br>The Scottish Government has announced approval of the Beauly to Denny transmission line, greatly increasing the ability to access renewable resources. However constraints may still arise at a local level - detailed modelling for each scheme would be required. |
| Supply chain issues and constraints | Amber | Although the majority of jobs required would be in construction, a recent study (ref 2) has identified potential skills bottlenecks in hydro engineering and electrical network engineering if there was to be rapid growth in hydro development. Many hydro engineers are employed by developers with a focus on schemes above 200 kW, but there is a relative shortage of skilled, independent engineers to work on smaller systems. |
| Regulatory constraints | Green | No obvious regulatory constraints. |
| Institutional barriers | Green | No obvious institutional barriers. |
| Unclear policy (national, regional, local) | Green | The Government has stated its commitment to renewable energy generation and the Scottish Government set ambitious targets. The Scottish Government's Renewables Action Plan (ref5) which was published in June 2009 includes a specific Route-Map for Hydro which sets out key steps to realise its potential, including the abolishion of the Fisheries Committee and Establish a the establishment of a new industry group on Microhydro to galvanise action and consider barriers and report to FREDS. |
| Motivating investors to act | Green | The Feed in tariff will provide a considerable incentive for small scale developments. The technology is well established. |

| | |
|---|---|
| Green | **Unlikely to present a constraint to achieving the central projection.** |
| Amber | **Could constrain achieving the central projection and will certainly constrain achieving the upper projection** |
| Red | **Likely to constrain achieving the central projection; could result in only the low projection being achieved** |

# 11 Wave power

## 11.1 Introduction

Wave energy is the extraction of energy from the motion of water in surface waves on the sea, created by the wind. The UK has some of the best wave resources in the world, recently estimated as capable of producing 52 TWh/year (14% of 2008 UK electricity production). The majority of the UK wave resource is located in the north west of Scotland, with additional areas around the Scottish coasts and to the South West of England.

A number of factors combine to give the UK a strong position with regard to wave energy: in addition to its resources there are also a number of leading device developers operating in the UK, a leading research base and existing offshore engineering and services industries. Scotland is fortunate to have a first class test centre in the form of EMEC on the Orkney Islands, providing developers the facilities to test, develop and evaluate their technologies. Both UK Government and the Scottish Governments have been very supportive of marine energy, introducing a number of generous support measures.

## 11.2 Historical deployment

Wave power is at an early stage with respect to commercial scale development.

A wide range of different configurations of wave devices are currently being developed. A 2009 study listed 17 UK wave power developers out of a worldwide total of 71 known developers. Most industry observers think the number of devices will reduce dramatically as the industry matures – but at the moment the opposite is happening.

The leading technology developers have progressed closer to fully operational status of their full scale demonstrator devices. Currently there is 0.6 MW of operational capacity at the Islay Wave Energy Plant.

The levels of government support have increased in a number of countries. In the UK this has included:

- The UK's Marine Renewables Deployment Fund, which offers a combination of capital grants and revenue support in addition to the market price of electricity and Renewable Obligation Certificates (ROCs).
- The Scottish Government's Wave and Tidal Energy Support (WATES) Scheme, supporting projects based at EMEC in Orkney.
- In 2008, the Scottish First Minister announced the Saltire Prize, a £10 million prize to be awarded to the team that can demonstrate in Scottish waters a commercially viable wave or tidal energy technology that achieves a minimum electrical output of 100 GWh over a continuous 2 year period using only the power of the sea.
- In 2009, DECC published the UK Renewable Energy Strategy. This announced that up to £8 million would be allocated to expand the in-sea stage testing facilities at EMEC in Orkney.
- In 2009 the Scottish Government amended the Renewables Obligation Scotland (ROS) to award 5 Renewable Obligation Certificates (ROCs) for wave electricity.

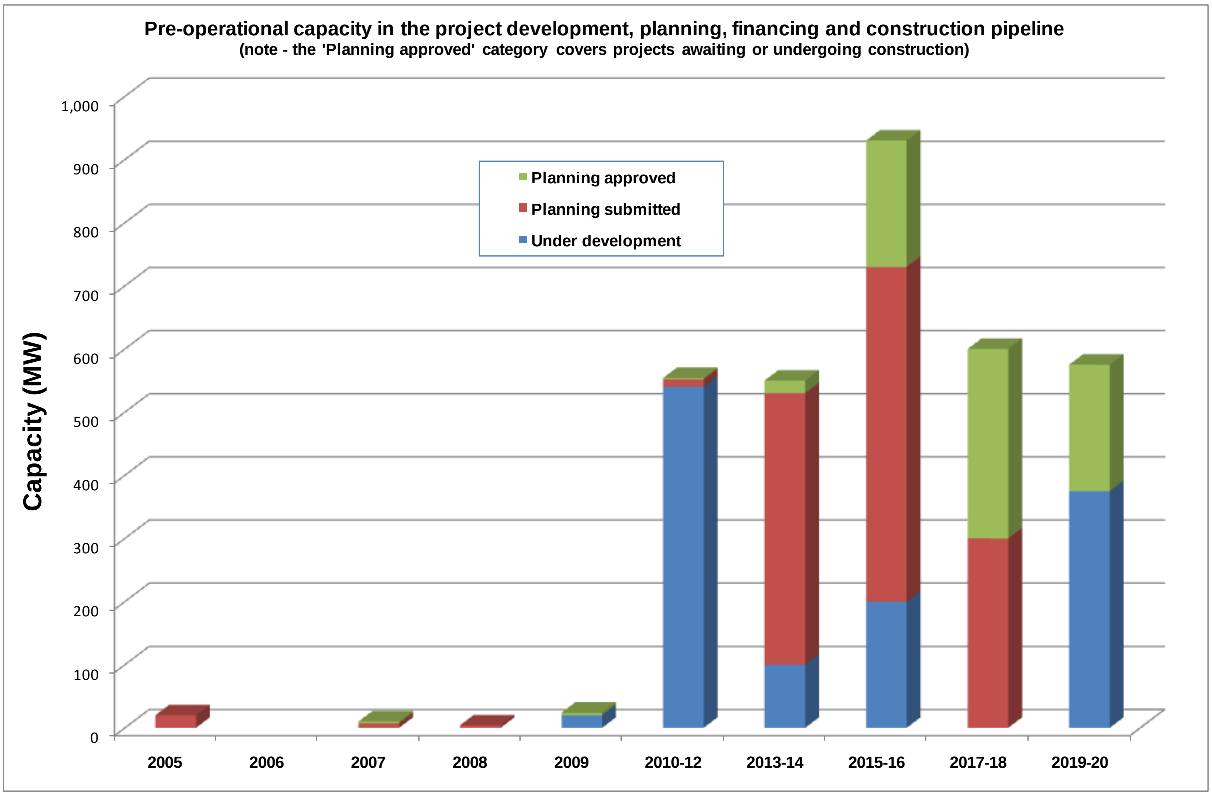
The completion of a Strategic Environmental Assessment ( SEA) for wave and tidal energy in Scotland in 2007 is also significant progress – and there is a strong need for this in England and Wales.
Grid issues are significant, as is discussed further in Section 9.4. The major Scottish resources in particular are remote from markets and this is exacerbated by limited capacity in the transmission system in the north of Scotland. In January 2010 the Scottish Government announced approval of the Beauly to Denny transmission line, greatly increasing the ability to access tidal and other renewable

resources. Grid charging issues (in terms of both securities and use of system costs) remain a risk to deployment of tidal technology.

The Crown Estate has just announced the results of the world's first commercial wave and tidal leasing round, for ten sites in Scotland's Pentland Firth and Orkney waters. The 1.2 GW of installed capacity proposed by the wave and tidal energy developers for 2020, 600 MW each from wave and tidal.

The Scottish Government had just revealed the first stage of its Marine Spatial Plan for use of Pentland Firth and Orkney waters, providing a framework and draft regional locational guidance for wave and tidal energy development. The final plan will highlight how the area's potential in marine energy can be used, managed and protected to balance other commercial interests and environmental challenges.

**Figure 1: Pre-operation phases: project development, planning, financing and construction**




## 11.3 Projected deployment to 2020

A number of market projections have been published in recent years, showing how installed marine energy generating capacity is expected to grow over the next 10 years. An initial estimate was made of the projected deployment to 2010 and this was sent to key industry members for comments. An attempt has been made to reflect the views received.

At the time of writing there is 0.6 MW of installed capacity at the Islay Wave Energy Plant.

It is too early to have reliable data on average % planning success, average time from planning submission to operation or the maximum capacity it will be possible to install in one year.

Following from the Crown Estate's Pentland Firth leasing announcements much activity will focus on the waters there. Several leases have been signed for wave developments:

- SE Renewables Developments Ltd, 200 MW for Costa Head site

- Aquamarine Power Ltd & SSE Renewables Developments Ltd, 200 MW for Brough Head site
- Scottish Power Renewables UK Ltd, 50 MW for Marwick Head site
- E.ON, 50 MW for West Orkney South site
- E.ON, 50 MW for West Orkney Middle South site
- Pelamis Wave Power Ltd, 50 MW for Armadale site.

The vast majority of project delivery is expected to occur from 2016 onwards, a timescale on which the upgrades to the grid in Scotland could be in place. It has been assumed that the results of the early phases of commercial scale activity will be required before further large developments are started, leading to a decline in activity before a subsequent acceleration. Of course it is possible that this assumption is inaccurate, but further progress in demonstrating that devices can work reliably and bringing costs down will be key in securing investor confidence. Some of those consulted in industry have expressed the view that the technological position of wave may lag that of tidal stream in terms of delivery of commercially viable technologies, although there was greater confidence that near-shore wave technology will be commercially viable in the medium term.

**Table 1: Historic and projected capacity development and deployment 2005 – 2020**

Wave power

Weighted average load factor: 27%

| | | Total capacties/output in the different categories at the end of the stated year/period | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Unit | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
| | | 31/12/05 | 31/12/06 | 31/12/07 | 31/12/08 | 31/12/09 | 31/12/12 | 31/12/14 | 31/12/16 | 31/12/18 | 31/12/20 |
| Under development | MW | | | | | 20 | 540 | 100 | 200 | 0 | 375 |
| Planning submitted | MW | 20 | | 7 | 4 | | 12 | 430 | 530 | 300 | 0 |
| Planning approved | MW | | | 3 | | 4 | 2 | 20 | 200 | 300 | 200 |
| Operational (central) | MW | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | | | | | |
| Projected operational | MW | | | | | | 1 | 2 | 13 | 80 | 205 |
| Energy production | GWh | 1 | 1 | 1 | 1 | 1 | 2 | 5 | 31 | 189 | 485 |

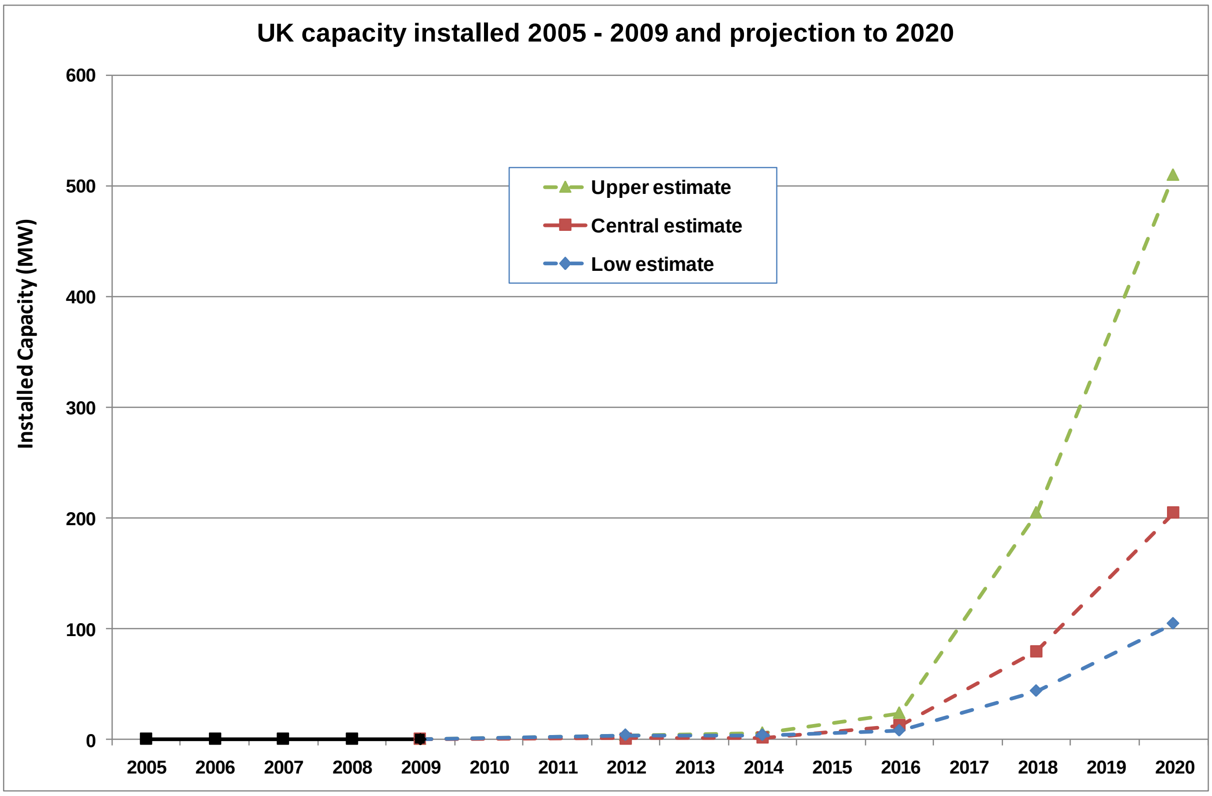
Range of projected operational capacity

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Low estimate | MW | | | | | 1 | 4 | 4 | 8 | 44 | 105 |
| | GWh | | | | | | 9 | 9 | 19 | 104 | 248 |
| Central estimate | MW | 1 | 1 | 1 | 1 | 1 | 1 | 2 | 13 | 80 | 205 |
| | GWh | 1 | 1 | 1 | 1 | 1 | 2 | 5 | 31 | 189 | 485 |
| Upper estimate | MW | | | | | 1 | 4 | 6 | 24 | 205 | 510 |
| | GWh | | | | | | 9 | 14 | 57 | 485 | 1,206 |

## Load Factors

The spreadsheet used to present the estimates is a common template across all technologies and has a single load factor for all time. For wave energy there will be variation of load factor with device and conditions. There is a wide range of estimates of load factor and experience will tell what in practice can be achieved. A figure of 27% has been used in the calculations reported here.

**Figure 2: Historic deployment and range of future projections to 2020**




## 11.4 Achieving future deployment – key dependencies

### 11.4.1 Impact of financial incentives

Capital costs for wave devices are not yet known and technology risk is a significant concern.

In recent discussions, a number of developers cite insufficient support/ROC banding as the biggest risk associated with commercial deployment, and a potential reason for lack of commitment to locate within the English or Welsh waters. In Scotland, the ROC provision is more generous (5 per MW), although the issue of lack of clarity of true costs remains.

That said, large companies are placing significant resources into technology development which indicates a level of confidence and commitment. It should also be emphasised that there is a very high level of political support at what is a crucial time for the emerging industry.

### 11.4.2 Impact of consenting processes

Development of necessary measures has progressed further in Scotland, where a Strategic Environmental Assessment has been carried out for marine renewables. There is an immediate need for this in England and Wales and there should also be a streamlined planning process.

### 11.4.3 Integration to energy markets

The majority of the UK wave resource is located in the north west of Scotland, with additional areas around the Scottish coasts and to the South West of England.. The major Scottish resources in particular are remote from markets and this is exacerbated by limited capacity in the transmission system in the north of Scotland.

In January 2010 the Scottish Government announced approval of the Beauly to Denny transmission line, greatly increasing the ability to access tidal and other renewable resources. The consent stated that construction must begin within 4 years and the upgraded line must be in place within 10 years.

Grid charging issues (in terms of both securities and use of system costs) remain a risk to deployment of tidal technology.

### 11.4.4 Supply chain issues and constraints

In discussions with developers the suitability and availability of operation and installation vessels has been identified as a key constraint, and given the dominance of the oil and gas sector, one that can link to the price of oil.

Many developers are not yet at the stage where they have full exposure to supply chain issues and a clearer picture of what these are in practice will emerge as the market develops.

### 11.4.5 Regulatory framework

As owners of the UK seabed, the Crown Estate has recently announced the world's first wave and tidal energy leasing round. Developers have signed leases to take forward installations, enabling them to enter statutory consenting process with security of access to the seabed.

The Scottish Government had just revealed the first stage of its Marine Spatial Plan for use of Pentland Firth and Orkney waters, providing a framework and draft regional locational guidance for wave and tidal energy development. The final plan will highlight how the area's potential in marine energy can be used, managed and protected to balance other commercial interests and environmental challenges.

### 11.4.6 Other potential barriers to deployment

**A very challenging environment**
Areas of the greatest potential resource are in exposed locations, prone to extreme weather. This will require appropriate equipment and skilled crews. In addition, a number of vessels can only install on the neap tide - if bad weather occurs then, this can mean a month long delay.

**Skills**
Some marine technology developers have indicated difficulty in recruiting staff with appropriate skills.

**Access to capital**
There is a significant level of technical risk associated with wave energy – investors are likely to increase in confidence as developers demonstrate reliability and reduce capital costs.

### 11.4.7 Summary of constraints

These are summarised in Table 2.

### Table 2: Potential Constraints

| Potential constraints | Significance | Comment |
|---|---|---|
| Returns insufficient to stimulate sufficient deployment | Red | Capital costs for wave devices are not yet known. In recent discussions, a number of developers cite insufficient support/ROC banding as the biggest risk associated with commercial deployment, and a potential reason for lack of commitment to locate within the English or Welsh waters. In Scotland, more generous ROCs (5 per MW) are proposed, although the issue of lack of clarity of true costs remains. |
| Planning (local policies, obtaining permissions) | Amber | This has progressed further in Scotland, where a Strategic Environmental Assessment has been carried out for marine renewables. There is an immediate need for this in England and Wales and there should also be a streamlined planning process.The Crown Estate has just announced the first leasing round results in Scotland. Some areas have constraints due for example to navigation routes, MoD practice and exercise areas, marine conservation zones, or fisheries. |
| Integration to energy markets | Amber | The majority of the UK wave resource is located in the north west of Scotland, with additional areas around the Scottish coasts and to the South West of England. The resources are remote from markets and this is exacerbated by limited capacity in the transmission system in the north of Scotland. In January 2010 the Scottish Government announced approval of the Beauly to Denny transmission line, greatly increasing the ability to access marine renewable resources.The consent stated that construction must begin within 4 years and the upgraded line must be in place within 10 years. |
| Supply chain issues and constraints | Amber | In discussions with developers the suitability and availability of operation and installation vessels has been identified as a key constraint, and given the dominance of the oil and gas sector, one that can link to the price of oil.Connection to the onshore grid is also seen as a significant factor. Many developers are not yet at the stage where they have full exposure to supply chain issues and a clearer picture of what these are in practice will emerge as the market develops. |
| Regulatory constraints | Green | As owners of the UK seabed, the Crown Estate has recently announced the world's first wave and tidal energy leasing round. Developers have signed leases to take forward installations, enabling them to enter statutory consenting process with security of access to the seabed. |
| Institutional barriers | Green | There are a wide range of concepts for wave devices, and the main focus facing the developers is to demonstrate that the devices can operate for extended periods and achieve consistent power output, whilst reducing the development cost. A range of universities, commercial research labs and individual companies are working in the field, both generically and for individual companies. |
| Unclear policy (national, regional, local) | Green | There are strong policy steers: The UK Government has stated that it is committed to marine renewables and the Scottish Government has stated its aim to generate 50 per cent of Scotland's electricity from renewable sources by 2020. |
| Motivating investors to act | Amber | The Crown Estate in March 2010 announced licencing in the Pentland Firth and surrounding waters - to deliver these alone will require an investment of order £4 billion. The Government recognises the opportunity to take a world lead in the development of marine technologies. Further progress in development, demonstrating that devices can work reliably and bringing costs down will be key in securing investor confidence. |
| Other constraints (please specify under comments) | Amber | Devices still at an early stage of development and have yet to undergo the challenging transition from lab scale to real locations. It is therefore at this stage not possible to know what the capital cost of many devices will be.<br><br>Areas of the greatest potential resource are in exposed locations, prone to extreme weather. This will require appropriate equipment and skilled crews. In addition, a number of vessels can only install on the neap tide - if bad weather occurs then, this can mean a month long delay. |

| | |
|---|---|
| Green | Unlikely to present a constraint to achieving the central projection. |
| Amber | Could constrain achieving the central projection and will certainly constrain achieving the upper projection |
| Red | Likely to constrain achieving the central projection; could result in only the low projection being achieved |

# 12 Deep geothermal electricity

## 12.1 Introduction

Conventional geothermal energy exploits naturally occurring hydrothermal systems by extracting heated fluids either from permeable aquifers or fracture systems. In some areas of the world the heat resource can be used for electricity generation where it is sufficiently close to the surface. Until the 1970s the UK was not regarded as a region with geothermal potential. During that decade the UK evaluated the deep geothermal resource from both conventional aquifers and granites. At the time the results from aquifers were not sufficiently encouraging to develop the resource.

The UK also pioneered Hot Dry Rock (HDR) technology which was designed to extract heat from granites and generate electricity. A series of drilling and circulation experiments were carried at a disused granite quarry at Rosemanowes, near Falmouth in Cornwall. Work started in 1977 with a demonstration of the feasibility. In 1990 a major Programme review concluded that the technology was technically problematic and uneconomic. In 1993 the programme was closed although some UK expertise was transferred to the European HDR programme.

Despite the closure of the UK HDR programme several countries have continued with its development including France, Germany, Japan and Australia. The concept is now referred to as Enhanced or Engineered Geothermal Systems (EGS). It works on the same principle as HDR but targets large fault systems which have known naturally occurring fluid flow. Experimental development at the European site near Soultz and elsewhere has been encouraging. Confidence in EGS technology has led to the development of a 3.8 MW electrical plant near the German town of Landau. These advances have reactivated interest in the UK. There are now two prospective projects which are being developed for electricity generation.

## 12.2 Historical deployment

The development of EGS technology in the UK is comparatively new. The two Cornish projects are still at an early development stage although one has applied for drilling.

## 12.3 Projected deployment to 2020

The two geothermal schemes which are being developed for electricity generation are:

- EGS Energy, Eden Project, Cornwall (3MW)[22]
- Geothermal Engineering, Redruth, Cornwall (10MW)[23]

**Table 1: Historic and projected capacity development and deployment 2005 – 2020**

**Deep Geothermal electricity (CHP)** — **Weighted average load factor: 65%**

| | Unit | Total capacties/output in the different categories at the end of the stated year/period | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
| | | 31/12/05 | 31/12/06 | 31/12/07 | 31/12/08 | 31/12/09 | 31/12/12 | 31/12/14 | 31/12/16 | 31/12/18 | 31/12/20 |
| Under development | MW | | | | | | | | | | |
| Planning submitted | MW | | | | | | | 13 | | | |
| Planning approved | MW | | | | | | | 13 | | | |
| Operational | MW | 0 | 0 | 0 | 0 | 0 | | | | | |
| Projected operational | MW | | | | | | 0 | 13 | 13 | 13 | 13 |
| Energy production | GWh | 0 | 0 | 0 | 0 | 0 | 0 | 74 | 74 | 74 | 74 |

[22] EGS Energy website 26/03/2010 http://www.egs-energy.com/

[23] Geothermal Engineering website 26/03/2010 http://www.geothermalengineering.co.uk/page/projects-and-developments.html

**Range of projected operational capacity (electrical, total including CHP)**

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Low estimate | MW | | | | | 0 | 0 | 7 | 7 | 7 | 7 |
| | GWh | | | | | | 0 | 40 | 40 | 40 | 40 |
| Central estimate | MW | 0 | 0 | 0 | 0 | 0 | 0 | 13 | 13 | 13 | 13 |
| | GWh | 0 | 0 | 0 | 0 | 0 | 0 | 74 | 74 | 74 | 74 |
| Upper estimate | MW | | | | | 0 | 0 | 16 | 16 | 16 | 16 |
| | GWh | | | | | | 0 | 91 | 91 | 91 | 91 |

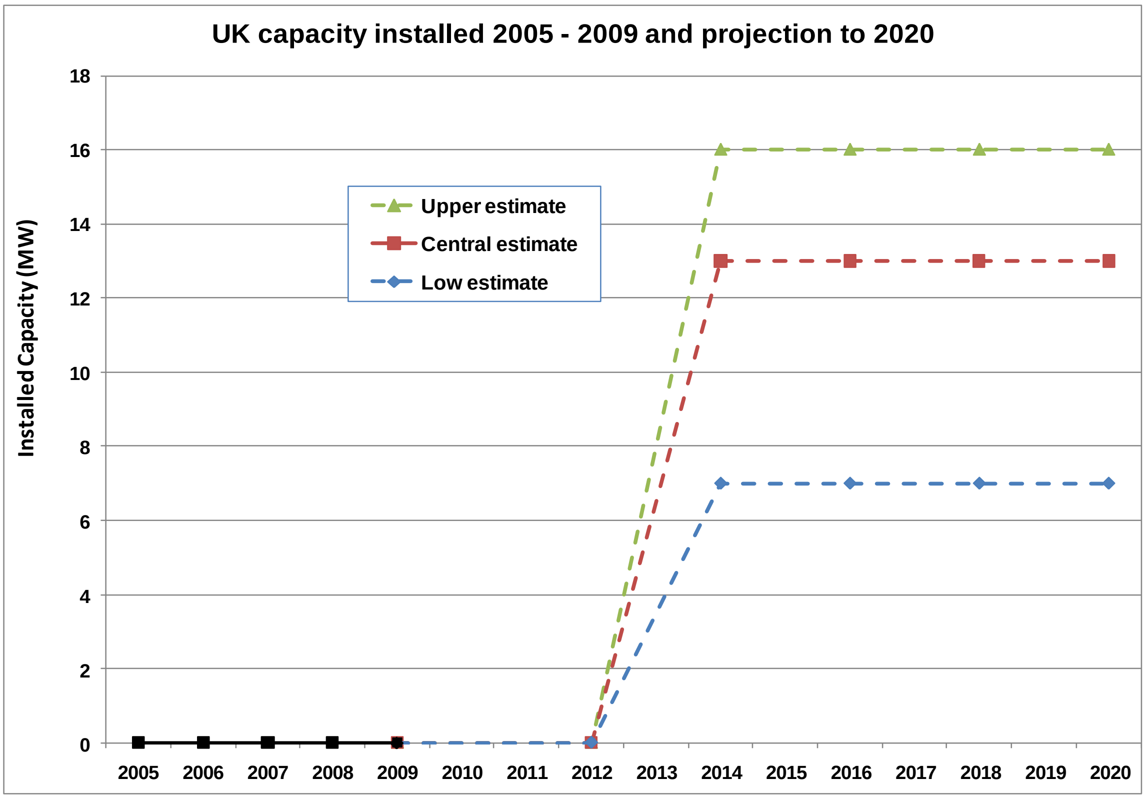
The EGS energy site has reached a pre-planning stage. It is being developed to supply the Eden project with a renewable heat source. It is also being designed to generate 3 MW of electricity.

The Geothermal Engineering project, located near Redruth is designed to have a thermal output of 55 MW and an electrical output of 10 MW.

According to Cornwall County Council Natural Resources Department, the Redruth project was submitted for planning approval in early March. The application is only for drilling and testing the resource not power station or infrastructure development. EGS Energy has yet to submit a formal planning application. [24], [25]

In both cases the resource will need to be evaluated before any surface energy conversion plant can be considered. It has therefore been assumed that planning for power plants will be submitted and approved at least two years from 2010.

**Figure 2: Historic deployment and range of future projections to 2020**




The central estimate assumes that the two schemes under development will operate at a 65% load at a uniform rate until 2019-20,

[24] Article which mentions projects in Cornwall at pre-planning stage, http://www.cornwall.gov.uk/default.aspx?page=22652
[25] Telecom with Cornwall County Council Natural Resources planning department (01872 322611) on 26/03/2010

The low estimate assumes that the electricity generation capacity heat capacity from the two Cornish projects is approximately half the current estimates (i.e. EGS 2 MWe and Geothermal Engineering 10MWe). The high estimate assumes that the Geothermal Engineering scheme manages to achieve a rated output of 12MWe and the EGS project produces 4MWe. Until the two projects are fully proven estimates are conjectural in the absence of technical data. Geothermal energy is difficult to predict with certainty until exploratory boreholes have been drilled and flow rate and temperature data confirmed. The lower estimate is conservative. The upper estimate assumes that a single site is unlikely to yield substantially greater energy than the central estimate.

If these projects can be successfully developed there is the prospect of further development in Cornwall. However, this will be influenced by the successful technical and commercial demonstration of these projects. There will also need to be more detailed resource assessment. For these reasons it has been assumed that only these two new projects will be generating electricity by 2020.

## 12.4 Achieving future deployment – key dependencies

### 12.4.1 Impact of financial incentives

The introduction of ROCs has influenced the revival of commercial interest in deep geothermal energy. For this reason both companies aim to target deep geothermal resources with sufficient surface energy to generate electricity.

### 12.4.2 Impact of consenting processes

The two Cornish projects will only apply for consent to carry out exploratory drilling in the first instance. There will need to be a second stage planning application for the power plant development. Cornwall County Council has offered positive support to these projects which have a high local profile. Provided they meet planning requirements it is likely that they could proceed to full-scale development.

### 12.4.3 Integration to energy markets

The two projects that generate electricity will need to rely on ROCs or FITs. The sale of heat could be harder to integrate. EGS Energy plan to supply heat to the Eden project where there is an obvious and co-incident demand.

### 12.4.4 Supply chain issues and constraints

The deep geothermal resource is limited at present and therefore significant supply chain issues are unlikely to occur. It is possible that there may be shortages of specific technical skills such as drilling, hydraulic stimulation and evaluation. Energy conversion to electricity from a low enthalpy resource will need to rely on imported equipment.

### 12.4.5 Regulatory framework

The regulatory framework should be able to accommodate the limited development of the technology within the UK.

### 12.4.6 Other potential barriers to deployment

One of the potential areas of concern is the potential for induced seismicity. EGS technology relies on hydraulic fracturing of hard crystalline rocks such as granite. Water is injected under high pressure to widen existing joints and fractures in the rock. This can induce movement and the release of seismic energy causing shock waves. The development of EGS projects has created shock waves that have been felt at the surface. Public concern has even caused schemes to close. There is some dispute as to whether this phenomenon will occur in the UK's projects. It is likely that localised monitoring will be necessary to discriminate between induced seismicity and naturally occurring earthquakes.

### 12.4.7 Summary of constraints

- Planning approval likely to be positive, especially as there are only three projects under development or proposed.
- Induced seismicity is potentially capable of stopping or closing projects.

| Potential constraints | Significance | Comment |
|---|---|---|
| Returns insufficient to stimulate sufficient deployment | Amber | Projects which have the potential to generate electricity would received 2 ROCs. Until drilling and appraisal has been completed developers will not know if they can generate sufficient electricity to justify a return on investment. Heat supply will depend on the viability of electricity generation. |
| Planning (local policies, obtaining permissions) | Green | Planning for the two projects is likely to be positive. There is regional support for the development of these projects to meet renewable energy targets and stimulate regeneration. |
| Integration to energy markets | Green | Electricity generation for geothermal sources is eligible to receive ROCs. It also has the advantage of being able to produce firm power if successful. |
| Supply chain issues and constraints | Green | Deep geothermal energy is limited at present. Development may require some expertise outside the UK. Electricity generation equipment will need to be imported. |
| Regulatory constraints | Green | Geothermal schemes can generate saline fluids which will need to be reinjected into the heat exchange reservoir. Provided this is carried these schemes should be compliant with environmental regulations. |
| Institutional barriers | Green | For electricity generation the are unlikely to be significant institutional barriers as thses schems should be capable of producing firm power. |
| Unclear policy (national, regional, local) | Amber | There is no clear policy on the development of geothermal energy or active funding for it (other than the recent geothermal challenge). Regional / national resource assessment could be substantial. |
| Motivating investors to act | Amber | Although there are poetnatilly large geothermal resources and the prospect of firm generation, deep geothermal remains a relatively high risk technology to develop. |
| Other constraints (please specify under comments) | Amber | Induced seismicity has created negative preceptions of EGS schemes. |

| | |
|---|---|
| Green | Unlikely to present a constraint to achieving the central projection. |
| Amber | Could constrain achieving the central projection and will certainly constrain achieving the upper projection |
| Red | Likely to constrain achieving the central projection; could result in only the low projection being achieved |

# 13 Solar Thermal

## 13.1 Introduction

In the UK, the domestic sector is a major consumer of energy, accounting for approximately 30% of energy consumption. Space heating is the greatest energy demand in the domestic sector, and this is generally provided by hot water, therefore solar thermal systems offer an ideal way to reduce domestic energy bills as well as CO2 emissions. Solar water heating is also used for domestic under–floor heating, heating of indoor and outdoor swimming pools and commercial water heating.

A solar (thermal) water heating system uses solar collectors (panels), normally mounted on a roof, to capture the energy released by the sun to heat water (STA 2010). These collectors contain liquid, which once heated travels to a coil in the hot water cylinder and transfers heat to the water store. So over a period of time a full tank of hot water is created; the time period depending on the intensity of the sun, the size and efficiency of the collectors and the size of the hot water tank (Regenesys UK 2010). There are many variations in design of the system, but they all make use of the same principles. The two main systems found in the UK are either drainback systems or fully filled systems. Both these systems can be direct or indirect, with a direct system being one where the water used at the taps is circulated through the system, and an indirect system is one where a heat transfer fluid is used instead (STA 2010).

A properly sized solar thermal installation will provide 60% to 70% of annual domestic hot water needs which generally equates to 100% of the demand in summer months and around 20% of demand in winter (Regenesys UK 2010). This is because the daylight hours are shorter in winter and the weather is poorer i.e. not as much sunlight. A typical 4 person family home in the UK would require 3–5m$^2$ of collectors at a cost of £3,000–£4,500 for a new system, with retrofit usually more expensive due to possible difficulties of access, the potential need to remove and replace existing coverings and fittings, replace existing hot water provision with a twin coil tank and integrate with existing systems (Regenesys UK 2010).

### 13.1.1 State of the technology

Based on generally available information for all collectors, NERA & AEA (2009), in their study for DECC which sought to create a “UK Supply Curve for Renewable Heat” have estimated the capital cost, operational expenditure (opex), typical installation sizes, efficiency, system lifetime, load factor and total installation cost for domestic, commercial and industrial solar water heating systems in the UK. See Tables 2a and 2b.

### 13.1.2 UK solar thermal supply chain

There are two types of solar water heating collectors; evacuated tubes and flat plate collectors, both of which are manufactured in the UK. In addition selective surfaces for use in solar collectors are produced within the UK.

According to the Energy Technology List and the Microgeneration Certification Scheme there are 24 manufacturers of flat plate collectors in the UK; AES Ltd, Baxi Group UK, Buderus, Earth Wind Fire Solar Ltd, Filsol Ltd, Genersys plc, Hoval Ltd, M H S Boilers Ltd, Natural Sustainable Energy Resources Ltd, Organic Energy (UK) Ltd, Oxford Solar, Potterton UK, Rotex Environmental Management Ltd, Roth UK Ltd, Schuco International KG, Solfex Ltd, Sonnenkraft UK Ltd, Sundwel Solar Ltd, Vaillant Ltd, Viessmann Ltd, Viridian Solar, Vokera Ltd, Windhager UK and Worcester, Bosch Group. Evacuated tube collectors are manufactured by 2020 Solar Ltd, All Eco Energy Ltd, Barilla Solar Ltd, Hoval Ltd, Kloben, Logical Energy Ltd, M H S Boilers Ltd, Rayotec Ltd, Renewable Energy Solutions Ltd, Riomay Ltd, Roth UK Ltd, Solar Shop Europe Ltd, SolarUK, Solfex Ltd, Strebel Ltd, Thermomax Ltd, Vaillant Ltd, Viessmann Ltd and Vokera Ltd, totalling 19 manufacturers.

Solar selective surfaces have been developed in the UK as a result of the research efforts of Inco Ltd. Unglazed and un-insulated swimming pool collectors are also produced in the UK by CPV Ltd. Compared to other European markets e.g. Germany, the UK's manufacturing base is fairly small.

The Energy Saving Trust is currently undertaking a field study of 100 installed solar thermal systems across the UK, the findings of which should be published in 2010. This should give a clearer indication of the realistic outputs of installed systems (STA, 2010).

### 13.1.3 Size of the UK resource

Given that the UK has relatively low levels of insolation, long periods of low radiation levels, and levels of insolation that are intermittent and difficult to predict, ETSU the former UK Government executive agency for energy technologies (subsequently Future Energy Solutions (FES), now AEA Energy & Environment) suggested that solar thermal electricity generation is unlikely to be viable on any significant scale (REA 2006). The main viable applications are domestic hot water heating and swimming pool heating. ETSU (1998) estimated the theoretical potential for domestic solar hot water heating in 2025 at 12TWhth/year, of which perhaps 3TWh/year would be economic at a cost of less than £100/MWhth (REA 2006). The theoretical potential for solar heating of swimming pools they estimated at 0.78TWh based on an assumed doubling by 2025 of the current 100,000 domestic swimming pools in the UK. All of this is thought to be economic at £100/MWhth (REA 2006). ETSU (1998) also identified theoretical potential for solar–aided district heating of 18TWh/year and for non–domestic water heating of 1.8TWh/year, although these areas face other constraints, such as the limited investment in district heating (REA 2006). The economic potential in these sectors was estimated at 0.284TWh/year. The total theoretical potential identified by ETSU (1998) is therefore 32.58TWh/year, of which 4TWh/year was thought to be economic at £100/MWhth (REA 2006).

In 2005, FES provided an update of this assessment, estimating that the theoretical potential in the residential sector is up to 33.2TWh/year in 2020, assuming application to 100% of the housing stock, including new build, and average demand of 1,250kWh/year (REA 2006). They estimated the practicable potential at 50% of this (16.6TWh/year) and the realistic contribution by 2020 at 5.5TWh/year (REA 2006). The theoretical potential in the commercial and industrial sectors they estimated at 1.85TWh/year in 2020, the practicable potential at 0.46TWh/year and the realistic contribution at 0.34TWh/year (REA 2006). Therefore the total theoretical contribution in the residential, commercial and industrial sectors is estimated at 35TWh/year, the practicable potential at 17TWh/year and the realistic contribution at 5.8TWh/year (REA 2006).

## 13.2 Historical deployment

In their 2008 study looking at the growth potential for microgeneration in England, Wales and Scotland, Element Energy found that the vast majority of the 95,000–98,000 microgeneration units installed in the UK by the end of 2007 were solar thermal units, which continue to have the highest levels of sales (at least 5,000–6,000 units/year). At the end of 2008, ESTIF estimated that the UK had an installed domestic solar thermal capacity of 270$MW_{th}$, with 132$MW_{th}$ of that capacity added 2006–2008, representing a growth rate of 50% 2007-2008 (ESTIF 2009).

According to the UK Solar Thermal Association (STA), installations of domestic hot water systems and swimming pool heating systems have shown 5% growth per year from 1996–2000 and 30% growth per year since 2000.

As planning permission is not required (although building control need to inspect the system), the development timescale for domestic solar thermal heating systems is relatively short. Planning, configuring, and doing any custom ordering for the system can take up to a few weeks, although the installation process itself can typically be completed in only a few days, in many cases even less.

A summary of the cumulative installed solar thermal energy 1990–2009, broken down into domestic water heating and swimming pool heating systems is shown below.

**Table 1: Cumulative Installed solar thermal in 2 sub–markets in the UK**

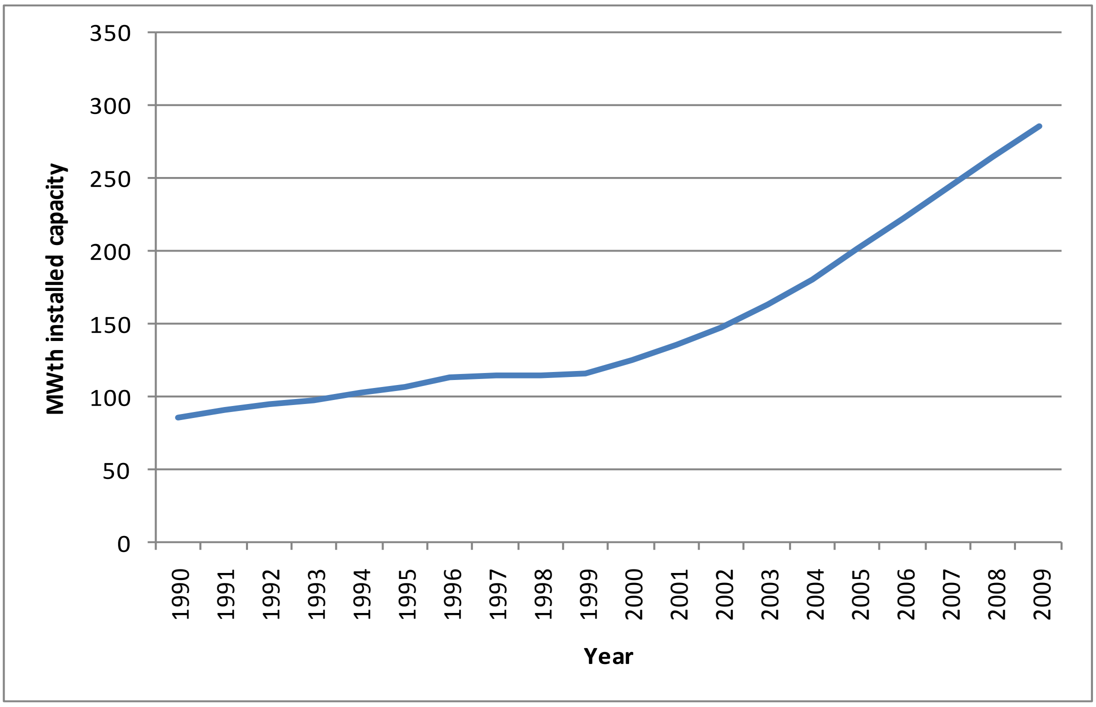
| Sub-market | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **1990** | **1991** | **1992** | **1993** | **1994** | **1995** | **1996** | **1997** | **1998** | **1999** | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** |
| Swimming pools | 58 | 60 | 62 | 65 | 66 | 69 | 72 | 76 | 79 | 83 | 108 | 141 | 183 | 238 | 310 | 402 | 523 | 680 | 884 | 1149 |
| Domestic hot water | 85 | 91 | 95 | 98 | 102 | 106 | 113 | 114 | 115 | 116 | 125 | 136 | 148 | 163 | 181 | 202 | 223 | 244 | 265 | 286 |
| Total (MWth) | 143 | 151 | 157 | 163 | 169 | 175 | 185 | 190 | 195 | 200 | 233 | 276 | 331 | 401 | 490 | 604 | 746 | 924 | 1149 | 1435 |

(Source: Active Solar Estimate for 2006 Digest of United Kingdom Energy Statistics, courtesy of the STA)

RESTATS 2003 update based on:

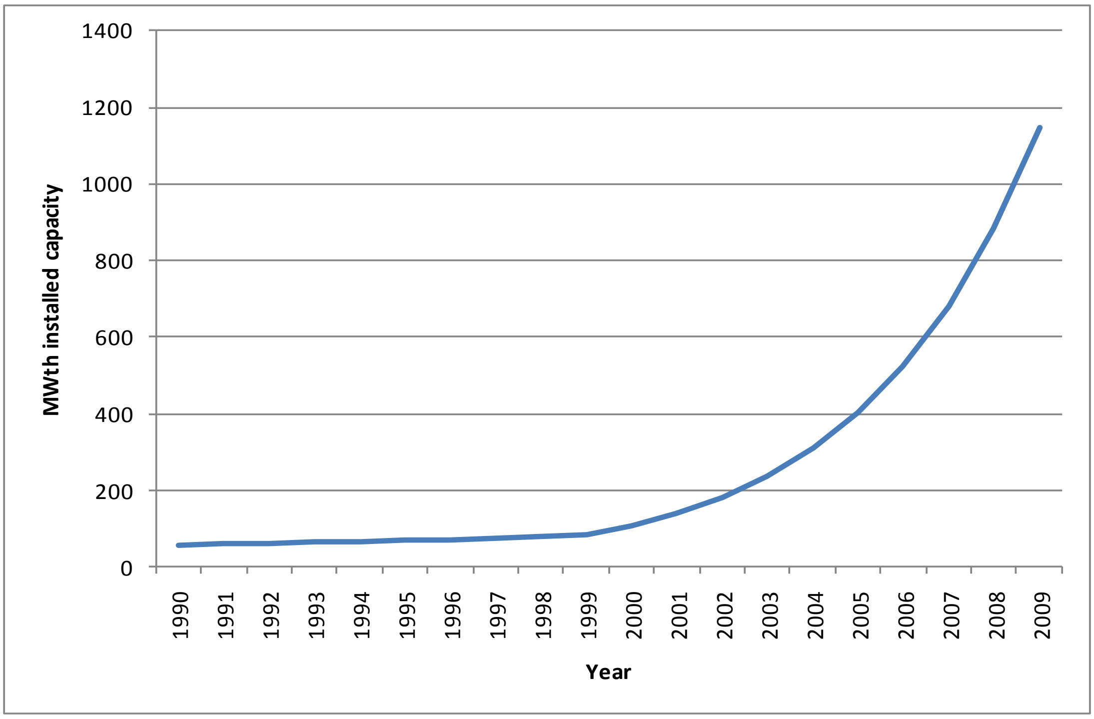
- Add 5% growth per year from 1996, then 30% growth per year from 2000 onwards (information obtained verbally from Gareth Ellis of the STA)
- Sales figures of ETSU S/P3/00173/REP
- Installed numbers of working systems of ETSU S/P3/00238/REP (85% installed ever working)
- Written communication from Roy Swayne for installations up to 1996
- Written communication from James Marsh for installations in 1999
- Assumptions for 1997 and 1998
- Swimming pools assumed steady installation rate

**Figure 1: Installed capacity of UK domestic hot water systems (MWth) 1990–2009[26]**




(Source: derived from STA figures)

**Figure 2: Installed capacity of UK swimming pool heating systems (MWth) 1990–2009**




(Source: derived from STA figures)

[26] In the past, the installed base of solar thermal systems was measured in terms of collector area (square meters or square feet) rather than in terms of installed capacity (MW) to produce heat. As a consequence, solar thermal was not easily comparable with other (renewable) energy sources and thus was often left out of relevant statistics (IEA 2004).

In September 2004, representatives of the International Energy Agency's Solar Heating and Cooling Programme (IEA SHC) and several major solar thermal trade associations agreed on an official recommendation for how to convert solar thermal collector area into installed capacity (IEA 2004). For the purpose of solar thermal statistics, the installed capacity ([kWth] – Kilowatt thermal) shall be calculated by multiplying the aperture area of the solar collector area [$m^2$] by the conversion factor 0.7 [$kWth/m^2$]. This factor shall be used uniformly for unglazed collectors, flat plate collectors and evacuated tubular collectors (IEA 2004).

While the use of solar thermal heating is on an upwards trajectory in the UK, factors affecting the rate of installations to date include (NERA & AEA 2009; Element Energy 2008):

- Unfamiliarity – solar collectors are becoming commonplace but are still regarded as a specialist installation. Information and awareness raising could tackle this.
- High capital cost – the installed cost of a solar collector is much higher than the additional cost for hot water from oil or LPG. However, incentives (e.g. Renewable Heat Incentive (RHI) from 2011/LCBP grants) acknowledge the high up-front cost.
- Lack of trained installers, heating engineers and plumbers – the installation and maintenance of new solar thermal installations requires skilled personnel. If there are insufficient numbers of trained installers, heating engineers and plumbers (or they are otherwise too busy) which can be quickly trained in solar thermal installation this will delay solar thermal uptake. Training up engineers would enable companies to grow faster and cover a larger geographical area.
- Space constraints – solar collectors need a south or south west facing roof. This is not always available. However, there is the opportunity to promote guidelines to ensure optimum placing and incentives that take performance into account.
- Difficulty fitting solar to existing roofs – the range of roof types, collector fittings and health and safety requirements create problems for quick and cost effective installation.
- Difficulty fitting solar to existing heating systems – retro fitting to existing heating systems can be complex and costly.
- Compatibility with combi boilers – some combi boilers are compatible with solar while others are not.
- Availability of low cost high quality collectors manufactured in the UK – there is only a small manufacturing base for solar collectors in the UK. A vibrant home manufacturing base would invest in R&D appropriate to UK market.
- Geographic coverage: travel requirements – existing companies do not cover the whole of the UK which poses difficulties in terms of travel requirements. Local availability of supply and installation skills will help reduce costs of installation.

## 13.3 Projected deployment to 2020

In the UK renewable heat starts from a very low supply base and market share. The ramp–up is likely to be gradual, requiring several years to achieve mass–market adoption (NERA & AEA 2009). Achieving the significant uptake of 61TWh (a ten-fold increase from the current baseline of around 6TWh) envisaged for 2020, will therefore require the significant expansion of supply capacity, including increased capacity for equipment supply, growth or creation of installer companies, training of skilled personnel, and the development of required infrastructure (NERA & AEA 2009).

For this exercise, projected deployment for solar thermal is based on the 2009 NERA & AEA study for DECC which created a UK Supply Curve for Renewable Heat, and the subsequent 2010 NERA report on the Design of the Renewable Heat Incentive.

### 13.3.1 Solar thermal technology assumptions

**Table 2a: Technology Assumptions for Solar Thermal**

| Customer Segment | Variable | Unit | Values |
|---|---|---|---|
| Domestic | Capital Cost | £/kW | 1,806 |
| Domestic | Opex | £/kW/year | 18 |
| Domestic | Size of installation | kW | 2.5 |
| Domestic | Efficiency | % | 50% |
| Domestic | Lifetime | years | 20 |
| Domestic | Load factor | % | 5% |
| Domestic | Total install cost | £'000s | 4 |
| Commercial / Public -- Small | Capital Cost | £/kW | 1,600 |
| Commercial / Public -- Small | Opex | £/kW/year | 18 |
| Commercial / Public -- Small | Size of installation | kW | 12 |
| Commercial / Public -- Small | Efficiency | % | 50% |
| Commercial / Public -- Small | Lifetime | years | 20 |
| Commercial / Public -- Small | Load factor | % | 5% |
| Commercial / Public -- Small | Total install cost | £'000s | 20 |
| Commercial / Public -- Large | Capital Cost | £/kW | 1,600 |
| Commercial / Public -- Large | Opex | £/kW/year | 18 |
| Commercial / Public -- Large | Size of installation | kW | 12 |
| Commercial / Public -- Large | Efficiency | % | 50% |
| Commercial / Public -- Large | Lifetime | years | 20 |
| Commercial / Public -- Large | Load factor | % | 5% |
| Commercial / Public -- Large | Total install cost | £'000s | 20 |
| Industrial -- Small | Capital Cost | £/kW | 1,600 |
| Industrial -- Small | Opex | £/kW/year | 18 |
| Industrial -- Small | Size of installation | kW | 12 |
| Industrial -- Small | Efficiency | % | 50% |
| Industrial -- Small | Lifetime | years | 20 |
| Industrial -- Small | Load factor | % | 5% |
| Industrial -- Small | Total install cost | £'000s | 20 |
| Industrial -- Large | Capital Cost | £/kW | 1,600 |
| Industrial -- Large | Opex | £/kW/year | 18 |
| Industrial -- Large | Size of installation | kW | 12 |
| Industrial -- Large | Efficiency | % | 50% |
| Industrial -- Large | Lifetime | years | 20 |
| Industrial -- Large | Load factor | % | 5% |
| Industrial -- Large | Total install cost | £'000s | 20 |

(Source NERA & AEA 2009)

**Table 2b: NERA revisions to technology assumptions**

| Technology | Sub-segment | Parameter | Units | New value | Previous value |
|---|---|---|---|---|---|
| Solar thermal[2] | Non-domestic | Size | kW | 32 | 12 |
| Solar thermal | Non-domestic | Capex | £/kW | 1,300 | 1,600 |
| Solar thermal | Non-domestic | Opex | £/kW/year | 7 | 18 |
| Solar thermal | Non-domestic | Load factor | % | 7% | 5% |
| Solar thermal | Non-domestic | Implied output | MWh/year | 19 | 6 |
| Solar thermal | Domestic | Size | kW | 2.6 | 2.5 |
| Solar thermal | Domestic | Capex | £/kW | 1,600 | 1,800 |
| Solar thermal | Domestic | Opex | £/kW/year | 17 | 18 |
| Solar thermal | Domestic | Load factor | % | 8% | 5% |
| Solar thermal | Domestic | Implied output | MWh/year | 1.8 | 1.2 |

(Source: NERA 2010)

In NERA & AEA's 2009 modelling exercise to create a UK supply curve for renewable heat, they considered data characterising technology options and heat demand, data on fuel prices, emissions allowance prices, and other quantities relevant to the heat market. It also embodied assumptions about discount rates, and estimates of the cost of overcoming various barriers to renewable heat (NERA & AEA 2009). Given the various input data, the modelling found the composition of renewable heat that would result in the lowest cost to serve a given heat load (thus reflecting the choice of consumers), while also delivering a specified share of renewables in overall heat generation (NERA & AEA 2009).

For solar thermal, their central supply side growth scenario was based on data on initial deployment from published sources, the rates of growth achieved in other EU Member States, and an analysis of the number of installers required to reach the implied capacity. The pattern is one of an initial boost followed by a more sustainable rate of growth, with an implied annual growth rate in installed capacity of around 45% in the period 2010-15, and 20% in 2015-20.

Yet, of all the renewable heat technologies, NERA & AEA found that solar thermal and biomass district heating showed the least potential contribution to 61TWh by 2020. For solar thermal this is driven by a reduction in the technology's assumed load factor (5%), which limits its renewable output contribution (and therefore raises its per unit costs). They estimated that by 2010, solar thermal (domestic and non-domestic) could potentially contribute 5.6TWh (NERA & AEA 2009) but at significant cost.

**Table 3: Solar thermal central estimate**

| Technology | Sector | Potential (TWh) | | | Growth rate (% per year) | |
|---|---|---|---|---|---|---|
| | | 2010 | 2015 | 2020 | 2010-2015 | 2015-2020 |
| Solar Thermal | Non-domestic | 0.1 | 0.3 | 0.8 | 25% | 18% |
| Solar Thermal | Domestic | 0.2 | 1.9 | 4.6 | 51% | 20% |

In NERA's 2010 update to the Renewable Supply Curve, they altered the discount rate used to evaluate uptake of solar thermal, and the demand-side barriers applying to this technology. These inputs were proposed by DECC, and were intended to reflect behavioural parameters applicable to a subset of possible solar thermal installations (NERA 2010). On the basis of historical uptake of solar thermal technologies in the UK when these technologies were supported by grant schemes, DECC believes that required internal rates of return for solar thermal will be lower than those for other technologies (NERA 2010). The discount rate for solar thermal was therefore set at 6% in the central growth scenario. DECC does not expect this lower discount rate to apply to all potential consumers. It is highly uncertain what proportion of the population might evaluate solar thermal using a discount rate at this level, and NERA are not aware of any empirical evidence that could be used to inform this issue (NERA 2010). The uptake of solar thermal associated with this scenario was adjusted by this study to 2.5TWh by 2010.

For the purposes of this study, we have used NERA's central growth scenario to 2.5TWh by 2010 as the central estimate for deployment. The low estimate uses an annual growth rate of 5%, central 10% and high 15%. The central projection results in an installed capacity of 4,094 MW in 2020, which translates to an energy contribution of 2.51 TWh.

**Low estimate**
This assumes that with the termination of the capital grants from the Low Carbon Buildings Programme, and the 6% rate of return on investment for solar thermal technology under the new RHI that annual growth will be around 5% in the UK solar water heating sector.

**Central estimate**
This assumes that with the termination of the capital grants from the Low Carbon Buildings Programme, and the 6% rate of return on investment for solar thermal technology under the new RHI that annual growth will be around 10% in the UK solar water heating sector.

**High estimate**
This assumes that with the termination of the capital grants from the Low Carbon Buildings Programme, and the 6% rate of return on investment for solar thermal technology under the new RHI that annual growth will be around 15% in the UK solar water heating sector.

NERA & AEA did not consider additional potential output from solar thermal heating under their high estimate, as the technology face limitations which restrict its contribution to a least-cost technology mix for overall renewable heat output under the modelling assumptions of the project, namely its high cost (it is above the subsidy level of £100/MWh heat output). However for this study, the figure of 15% above the current base level was used to create a high estimate for solar thermal deployment to 2020.

**Table 4: Historic and projected capacity development and deployment 2005 – 2020**

Solar Thermal

Weighted average load factor: 7%

| | | Total capacties/output in the different categories at the end of the stated year/period | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Unit | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
| | | 31/12/05 | 31/12/06 | 31/12/07 | 31/12/08 | 31/12/09 | 31/12/12 | 31/12/14 | 31/12/16 | 31/12/18 | 31/12/20 |
| Under development | MWth | | | | | | | | | | |
| Planning submitted | MWth | | | | | | | | | | |
| Planning approved | MWth | | | | | | | | | | |
| Operational (central) | MWth | 604 | 746 | 924 | 1,149 | 1,435 | | | | | |
| Projected operational | MWth | | | | | | 1,910 | 2,311 | 2,796 | 3,384 | 4,094 |
| Energy production | GWh | 370 | 457 | 566 | 704 | 880 | 1,171 | 1,417 | 1,715 | 2,075 | 2,510 |

Range of projected operational capacity

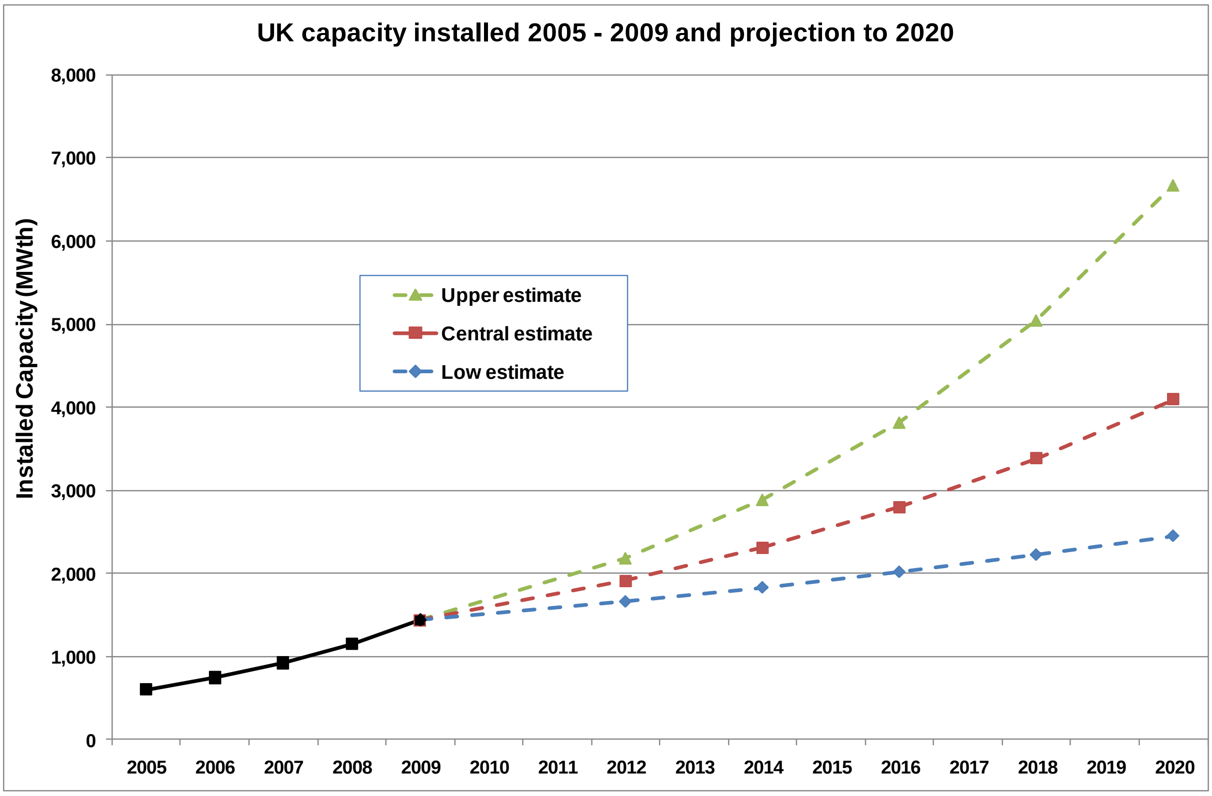
| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Low estimate | MWth | | | | | 1,435 | 1,661 | 1,831 | 2,019 | 2,226 | 2,454 |
| | GWh | | | | | 880 | 1,019 | 1,123 | 1,238 | 1,365 | 1,505 |
| Central estimate | MWth | 604 | 746 | 924 | 1,149 | 1,435 | 1,910 | 2,311 | 2,796 | 3,384 | 4,094 |
| | GWh | 370 | 457 | 566 | 704 | 880 | 1,171 | 1,417 | 1,715 | 2,075 | 2,510 |
| Upper estimate | MWth | | | | | 1,435 | 2,182 | 2,886 | 3,817 | 5,048 | 6,676 |
| | GWh | | | | | 880 | 1,338 | 1,770 | 2,341 | 3,095 | 4,094 |

**Load factor (NERA & AEA 2009)**
The load factor is quoted as 7-8% in the 2010 NERA report “Design of the Renewable Heat Incentive”.

### 13.3.1 Reaching the renewable heat targets

If low-cost options (larger biomass boilers, commercial air-source heat pumps) can be taken up on a large scale the need for other technologies and domestic sector installations decreases. However, if growth is more constrained, need to use higher-cost technologies such as solar thermal to reach the share of renewable heat envisaged under the UK Renewable Energy Strategy (Klevnas & Barker 2009).

**Figure 3: Historic deployment and range of future projections to 2020**




# 13.4 Achieving future deployment – key dependencies

## 13.4.1 Impact of financial incentives

The RHI is due to be implemented in 2011 and will guarantee payments for those who install air, water and ground-source heat pumps (and other geothermal energy), solar thermal, biomass boilers, renewable combined heat and power, use of biogas and bioliquids and the injection of biomethane into the natural gas grid (DECC 2010). Under the proposed tariffs the installation of a solar thermal system up to 20kW will provide an income of 17.5p per kWh of heat produced and 16.4p/kWh for systems 20-100kW (NERA 2010). The installation of solar thermal panels in an average semi–detached house with adequate insulation levels could be rewarded with £250 a year plus an additional saving on fuel. Tariff levels are proposed to provide a rate of return of 12% on the additional capital cost of renewables, with a lower rate of return of 6% given to solar thermal (DECC 2010). This is because their cost is significantly higher than those of other renewable technologies, and DECC (2010) believe that this approach is also a proportionate means of keeping the overall costs of the scheme manageable.

The Low Carbon Buildings Programme (LCBP) householder grant scheme provides funding for solar thermal technology (this will cease once the RHI is introduced), with a maximum amount of grant available of £400 or 30% of the relevant eligible costs, whichever is the lower (Regensys UK 2010). To qualify the homeowner must have compliant levels of insulation, have installed low–energy light bulbs and have a minimum level of central heating and boiler control (e.g. timers and thermostats) (Regensys UK 2010).

## 13.4.2 Impact of consenting processes

For solar domestic hot water systems and swimming pool heating systems, planning permission is not actually required. Local planning authorities do however suggest that building control be informed of installation work being carried out so that it is deemed safe.

### 13.4.3 Integration to energy markets

Under the RHI, operators of solar thermal water heating systems will receive a clean energy cashback payment (16.4-17.5p/kWh depending on the size of the installation) for generating on-site renewable heat for their own consumption. It will not be possible for them to provide surplus heat back to any national heat grid, and the UK government does not want to pay for any excess heat generated. As such, integration into energy market is not an issue for solar thermal, as Ofgem will only provide the subsidy up to the level of "deemed heat" appropriate for a consumer’s building.

### 13.4.4 Supply chain issues and constraints

While there is a solar thermal manufacturing base in the UK, it is relatively small compared to other European countries where solar thermal has really taken off. A vibrant home manufacturing base would invest in R&D appropriate to UK market.

With regards to supply of systems, there is a definite lack of trained installers, heating engineers and plumbers at present which is delaying solar thermal uptake. Training up engineers would enable companies to grow faster and cover a larger geographical area.

### 13.4.5 Regulatory framework

The UK government is increasingly looking at regulatory policies which allow integration of the broad spectrum of renewable sources of energy into the national grid in the most efficient and non–discriminatory manner, while maintaining grid reliability. The introduction of the RHI should allow installation rates of solar thermal systems to steadily increase to 2020, although perhaps not by as much year-on-year as currently due to the loss of the LCBP and the capital grants it provides.

### 13.4.6 Other potential barriers to deployment

Going forward, in order to achieve the large scale deployment of renewable heat technologies it is necessary to increase capacity for equipment supply, grow or create installer companies, train skilled personnel, and develop the required infrastructure (NERA & AEA 2009).

### 13.4.7 Summary of constraints

| Potential constraints | Significance | Comment |
|---|---|---|
| Returns insufficient to stimulate sufficient deployment | Amber | The RHI (from April 2011) should provide good returns for solar thermal to 2010. However the relative high capital cost of the technology means that payback times are still a constraint for mass deployment, particularly as biomass, followed by groundsource and air-source heat pumps offer a lower cost solution to meeting the government's renewable energy targets. |
| Planning (local policies, obtaining permissions) | Green | |
| Integration to energy markets | Green | |
| Supply chain issues and constraints | Amber | Lack of trained installers, heating engineers and plumbers and training. Few low cost high quality collectors manufactured in the UK; a vibrant home manufacturing base would invest in R&D appropriate to UK market. Existing companies do not cover the whole of the UK which poses difficulties in terms of travel requirements. |
| Regulatory constraints | Green | |
| Institutional barriers | Green | |
| Unclear policy (national, regional, local) | Green | Strong policy statements on RE. Planning policy being strengthened through UK RES and stronger requirements on regional and local government policies. |
| Motivating investors to act | Amber | Credit crunch has reduced capital available but with the introduction of the RHI for solar thermal (and other renewable heat technologies), this is likely to stimulate investment in solar thermal going forward. |
| Other constraints (please specify under comments) | | |

| | |
|---|---|
| Green | Unlikely to present a constraint to achieving the central projection. |
| Amber | Could constrain achieving the central projection and will certainly constrain achieving the upper projection |
| Red | Likely to constrain achieving the central projection; could result in only the low projection being achieved |

References

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Klevnas & Barker (2009) – 'Scenarios for Renewable Heat Supply Capacity Growth to 2020'. BIS Conference Centre, 17th July 2009. Available at: http://www.decc.gov.uk/Media/viewfile.ashx?FilePath=What we do\UK energy supply\Energy mix\Renewable energy\policy\renewableheat\1_20090724115050_e_@@_renewableheatscenarios.pdf&filetype=4

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# 14 Air and ground source heat pumps

## 14.1 Introduction

Heat pumps absorb heat in one place where it is plentiful, then transport and release it in another location where it can be used for space or water heating. They operate by evaporating and condensing a working fluid in much the same way as domestic refrigerators. Whilst the heat absorbed and released is renewable, considerable amounts of auxiliary power are needed to operate the cycle. An allowance for this auxiliary power must be subtracted from the heat produced to gain an accurate measure of the carbon saving and renewable energy contribution.

To date, one of the most common applications is in chillers used to provide cool air to office buildings. In recent years, heat pump technology has developed to provide heating for buildings. In this case, heat is extracted from outside the building either from the air or the ground/water source.

The performance of heat pumps is affected by a large number of factors. For heat pumps in buildings these include:

- the climate - annual heating and cooling demand and maximum peak loads;
- the temperatures of the heat source and heat distribution system;
- the auxiliary energy consumption (pumps, fans, supplementary heat for bivalent system etc.);
- the technical standard of the heat pump;
- the sizing of the heat pump in relation to the heat demand and the operating characteristics of the heat pump;
- the heat pump control system.

The efficiency of heat pumps is measured as a ratio of the energy output (heat) to energy input (electricity used to drive the compressor, evaporator and pumps etc.) and is referred to as the Coefficient of Performance (COP). The greater the temperature differential between the source (ground or air) and the 'sink' (building's heating system), the more work must be done by the compressor and hence the efficiency falls. The efficiency for an ideal system can be presented as:

$$COP = \frac{T_{hot}}{T_{hot} - T_{cold}} = \frac{T_{hot}}{\Delta T}$$

The operating performance of an electric heat pump over the season is called the seasonal performance factor (SPF). It is defined as the ratio of the heat delivered and the total energy supplied over the season. It takes into account the variable heating and/or cooling demands, the variable heat source and sink temperatures over the year, and includes the energy demand, for example, for defrosting. SPF is the metric used in Directive 2009/28/EC 'Promotion of the use of energy from renewable sources' to set a minimum performance standard for heat pumps. Only heat pumps achieving an SPF > 1.15*1/ $\eta$ will be accepted as contributing renewable heat, where $\eta$ is the ratio between total gross production of electricity and the primary energy consumption for electricity production. The intention is to base $\eta$ on the EU average, derived from Eurostat data, however, the value is not yet agreed and published. Using UK statistics from DUKES, $\eta$ is ~ 0.401, and hence the minimum SPF is ~ 2.87.

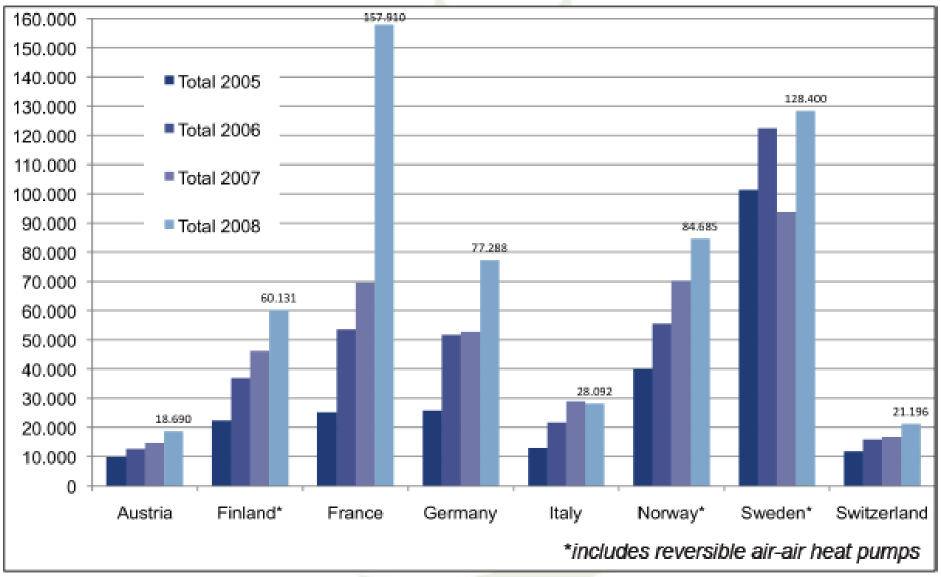
Estimates for heat in this paper are based on COPs and it should be noted that COPs are generally higher than SPFs. (It has not been possible to estimate typical SPFs as monitored operational data for air source heat pumps from field trials are not yet available.)

Air source heat pumps (ASHPs) are relatively easy and inexpensive to install and have therefore historically been the most widely used heat pump type. However, they suffer limitations due to their use of the outside air as a heat source or sink. The higher temperature differential during periods of extreme cold or heat leads to declining efficiency, as explained above.

Ground source heat pumps (GSHPs), typically have higher efficiencies than air source heat pumps. This is because they draw heat from the ground or groundwater which is at a relatively constant temperature all year round below a depth of about 2.5 m. Consequently, the temperature differential is lower, leading to higher efficiency. Ground source heat pumps typically have COPs of 3.5-4.0. The trade-off for this improved performance is that a ground-source heat pump is more expensive to install due to the heat collector 'closed pipe loops' buried horizontally in trenches or in vertical boreholes that are connected back to the GSHP. When compared versus each other, groundwater heat pumps are generally more efficient than heat pumps using heat from the soil.

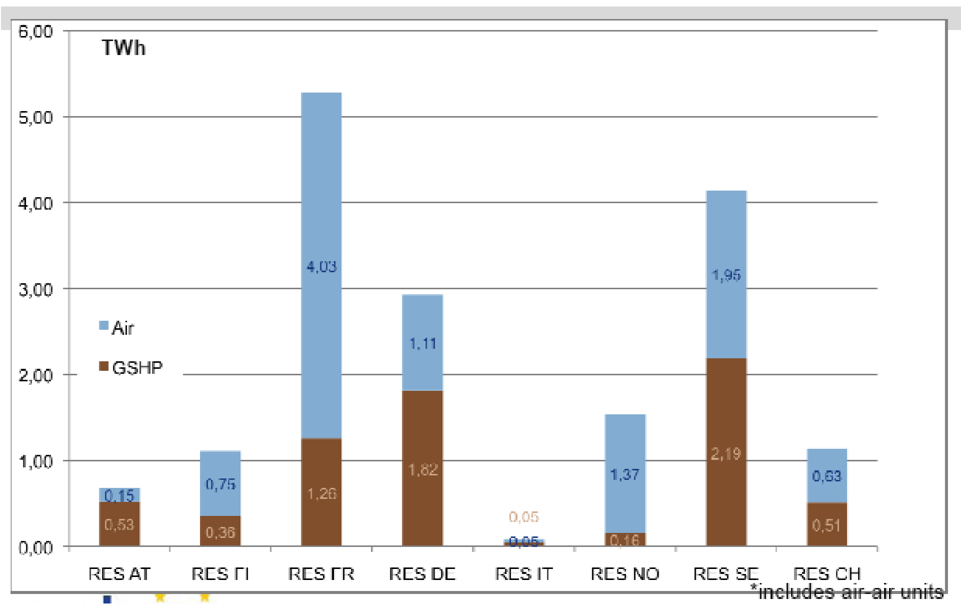
The application of heat pumps for heating is rapidly growing in mainland Europe, stimulated by a range of government policies and financial instruments, including grants, loans and tax breaks, and preferential tariffs for electricity. Overall, this development has the effect of transferring heat demand from combustion of fossil fuels (coal, oil, gas) to electricity. The European Heat Pump Association (EPHA) produces sales statistics for the main EU markets and these are shown below, however, the primary data are only available in the form of a commercial market research report.

**European heat pump market statistics 2005-2008 – sales per annum**




source: EHPA European Heat Pump Statistics – outlook 2009

**Renewable energy produced based on accumulated sales 2005-2008**



**UK Air source heat pump market**

From figures provided by the UK Heat Pump Association (HPA), the UK market for air source heat pumps is well established in the commercial sector, with sales currently averaging ~ 200,000 systems per annum, including reversible room air conditioners (RACs), including variable refrigerant flow (VRF) air conditioning systems. The domestic market for heating, however, is far less well developed. The Heat Pump Association estimates that, currently, some 5% of sales are attributable to the domestic sector.

Understanding the state of market development can, however, be difficult to interpret as there is no publicly available source of independently verified data. For example, the HPA's data are provided by BSRIA, yet in an article dated December 2008, BSRIA states:

"The UK's small heat pump market grew sharply, with sales of around 3,000 units in 2007. Rising energy prices are said to be the main reason of this growth. Ground/water source heat pumps continue to be the global market leader as they are supported by government grants, whereas air to water heat pumps have for the first time been approved for £900 subsidy for the last quarter of 2008."

From discussion with BSRIA, the difference in sales rate is due to how variable refrigerant flow air conditioning (VRFs) and mini-split air conditioning systems, which are used mainly for cooling, are treated. When these are excluded, the market is judged to be small, particularly from the perspective of domestic heating. Currently, BSRIA's data for annual sales indicate the heat pump market, both air source (mainly air-water) and ground source at ~ 15,000 systems. Compared with the boiler replacement market of ~ 1,560,000/year, and a new-build rate of 17,1700 homes[27] in 2008/09, this indicates a very low level of market penetration.

The emerging market for heat pumps, other than RACs and VRFs, has largely been driven by various incentives aimed at stimulating carbon reduction, including the Clear Skies programme and its successor the Low Carbon Buildings Programme, and energy utilities fulfilling their Carbon Emissions Reduction Target (CERT) obligations.

The supply market is comprised of manufacturers from both the boiler and air-conditioning markets and installers. The Microgeneration Certification Scheme (MCS), covering heat pumps up to 300kWth, lists 14 manufactures with accredited air source heat pump products:

- Bosch Thermotechnology Ltd (Worcester Bosch Group)
- Calorex Heat Pumps Limited
- Climaveneta Home Systems S.r.l.
- Daikin Europe N. V.
- Danfoss Heat Pumps UK Limited
- GDC Group Ltd (Dimplex)
- Global Energy Systems and Technology Ltd
- Ideal Boilers
- Keston Boilers
- Mitsubishi Electric Europe B.V. trading as Mitsubishi Electric Europe UK
- NIBE Energy Systems Limited
- Stiebel Eltron UK ltd
- TEV Limited
- Vaillant Group Ltd trading as Glow-worm

Some 220 installers are MCS accredited, including many small heating and plumbing businesses, alongside larger specialist companies, often allied to the manufacturers.

**UK Ground source heat pump market**

Similar comments regarding availability of statistics apply, however, by ~ 2007/08, the number of GSHP installations appeared to be greater than ASHP once RAC, including VRF data is excluded.

[27] DCLG Housing Statistics: Table 209 'Permanent dwellings completed, by tenure and country'

This thought to be due to support for GSHP through the Low Carbon Buildings Programme (LCB) and from utilities as part of their CERT obligations. Air source pump sales are now overtaking GSHPs due to the influence of large air conditioning manufacturers and the cost advantages described previously.

The supply market for GSHPs comprises specialist suppliers and installers, boiler and air conditioning manufacturers. In the last 5 years several prominent manufacturers have entered the market from Japan and Europe. Currently, the MCS, covering heat pumps up to 300kWth, lists 11 manufactures with accredited ground source heat pump products:

- Bosch Thermotechnology Ltd (Worcester Bosch Group)
- Calorex Heat Pumps Limited
- Climaveneta Home Systems S.r.l.
- Danfoss Heat Pumps UK Limited
- GDC Group Ltd (Dimplex)
- IDM Energie Systems
- Kensa Engineering Ltd
- Lampoassa
- NIBE Energy Systems
- Transen Sustainable Energy Systems Limited
- Vaillant Ltd.

Similar to ASHPs, some 220 installers are MCS accredited, including many small heating and plumbing businesses, alongside larger specialist companies, often allied to the manufacturers. Specialists considered to be dominant in the market include:

- Cool Planet
- Danfoss
- Earth Energy
- Econoc
- Ecovision
- Geothermal International
- Geowarmth
- ICE Energy
- Mitie Energy
- TCS

Energy retailers are active and in many cases have formed alliances with installers, for example ICE Energy works with N Power and EON with Earth Energy.

## 14.2 Historical deployment

Reliable figures for deployment of heat pumps are not available and this is particularly problematic for air source heat pumps where data often includes and is dominated by RACs and VRFs. The data used for the purposes of this report are drawn from the following reports, which in turn are based on a range of sources including, the European Heat Pump Association (EHPA), the UK Heat Pump Association (HPA), which is part of the Federation of Environmental Trade Associations (FETA), BSRIA, the National Energy Foundation (NEF), the Ground Source Heat Pump Association (GSHPA) and managing agencies for support programmes the support programmes mentioned earlier (LCB and CERT):

- Renewable Heat Technologies for Carbon Abatement: Characteristics and Potential, NERA, Entec, Element Energy, July 2008
- The UK Supply Curve for Renewable Heat, NERA, AEA, July 2009
- Design of the Renewable Heat Incentive, NERA, February 2010
- Ground source heating and cooling pumps – state of play and future trends, AEA, November 2008

**Air source heat pumps**

The best estimate for 2008, indicated an installed stock of ~ 2,500 systems and annual sales ~ 3,000 systems/year.

Some figures for UK sales are available, though inconsistent and difficult to reconcile, whereas quantitative information about the characteristics of systems sold and their deployment by end-use market is usually of a more anecdotal nature. Evaluating the renewable heat contribution of air source heat pumps is based therefore on assumptions about:

- System size (kWth) and load factor;
- Distribution by market, usually expressed as domestic and non-domestic markets.

Detailed assumptions are available in the papers listed above and for the purposes of this report the following assumptions have been adopted:

- Approximate market share (numbers of systems): Domestic 95%, non-domestic 5%
- Average domestic system characteristics: 9 kWth, running at a load factor of 22% i.e. annual thermal heat supply of ~ 17.3 MWh, equivalent to the heat and hot water demand for a 4 bed semi-detached house[28]
- Average Non-domestic system characteristics: 300 kWth, running at a load factor of 35% i.e. annual heat supply of ~ 920 kWth

**Ground source heat pumps**

The best estimates for historic deployment suggest:

European Observer Barometer Oct. 2009:
2008 installed stock ~ 5,400 systems and annual sales ~ 3,000 systems

Ground source heating and cooling pumps – state of play and future trends, AEA:
2009 installed stock of ~ 8,500 systems and annual sales ~ 4,000 systems.

The absence of an organisation with an obligation to collect information about the size and characteristics of the heat pump market means there is very little reliable information about the installed capacity of GSHPs. Some insights can be found through the limited sales data that is provided by organisations such as BSRIA and the EHPA, however, primary data from manufacturers and installers is only available in their commercial market research reports.

Sparse information is recorded about the characteristics of systems sold and their deployment by end-use market is usually of a more anecdotal nature. Evaluating the renewable heat contribution of air source heat pumps is therefore based on assumptions about:

- System size (kWth) and load factor;
- Distribution by market, usually expressed as domestic and non-domestic markets.

Detailed assumptions are available in the papers listed above and for the purposes of this report the following assumptions have been adopted:

- Approximate market share (numbers of systems): Domestic 90%, non-domestic 10%, of which ~ 0.5% is of industrial scale up to 1 MWth
- Average domestic system characteristics: 9 kWth, running at a load factor of 22% i.e. annual thermal heat supply of ~ 17.3 MWh, equivalent to the heat and hot water demand for a 4 bed semi-detached house[29]
- Average Non-domestic system characteristics: 55kWth and 600kWth units, each running at a load factor of 35% i.e. annual heat supply of ~ 169 kWth and 1,840 kWth respectively.

[28] Renewable Heat Incentive Consultation on the proposed RHI financial support scheme, Annex 2

**Microgeneration Certification Scheme (MCS)**

In February 2008, the combined MCS for both installers and products started operating with the purpose of strengthening the supply chain and improving consumer confidence in the quality of unfamiliar of renewable microgeneration technologies, including heat pumps. MCS evaluates microgeneration products and installers against strict criteria using European and ISO technical standards before awarding the MCS certification “mark”. The scheme underpins the Low Carbon Buildings Programme which offers UK government grants for installation of microgeneration and will be used as the main criteria for eligibility under the RHI and may also be linked to a proposed stamp duty land tax relief for new zero carbon homes.

## 14.3 Projected deployment to 2020

Combining the above assumptions and a range of estimates for the rate of growth (low-, mid- and high) of the supply market suggests the following ranges for renewable heat supply from air source heat pumps.

**Table 1: ASHP - Historic and projected capacity development and deployment 2005 – 2020**

**Air Source Heat Pumps** — **Average load factor: 22% to 35%**

| | | Total capacties/output in the different categories at the end of the stated year/period | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Unit** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010-12** | **2013-14** | **2015-16** | **2017-18** | **2019-20** |
| | | 31/12/05 | 31/12/06 | 31/12/07 | 31/12/08 | 31/12/09 | 31/12/12 | 31/12/14 | 31/12/16 | 31/12/18 | 31/12/20 |
| **Under development** | **MW** | | | | | | | | | | |
| **Planning submitted** | **MW** | | | | | | | | | | |
| **Planning approved** | **MW** | | | | | | | | | | |
| **Operational (central)** | **MW** | | | | 59 | 130 | | | | | |
| **Projected operational** | **MW** | | | | | | 412 | 1,062 | 2,161 | 4,017 | 7,154 |
| **Energy production** | **GWh** | 0 | 0 | 0 | 111 | 244 | 795 | 2,090 | 4,326 | 8,169 | 14,753 |

**Range of projected operational capacity**

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Low estimate** | **MW** | | | | | 130 | 373 | 737 | 1,381 | 2,470 | 4,309 |
| | **GWh** | | | | | | 720 | 1,450 | 2,766 | 5,022 | 8,885 |
| **Central estimate** | **MW** | 0 | 0 | 0 | 59 | 130 | 412 | 1,062 | 2,161 | 4,017 | 7,154 |
| | **GWh** | 0 | 0 | 0 | 111 | 244 | 795 | 2,090 | 4,326 | 8,169 | 14,753 |
| **Upper estimate** | **MW** | | | | | 130 | 412 | 1,260 | 3,379 | 8,148 | 18,878 |
| | **GWh** | | | | | | 795 | 2,479 | 6,767 | 16,571 | 38,928 |

**Figure 1: ASHP - Historic deployment and range of future projections to 2020**

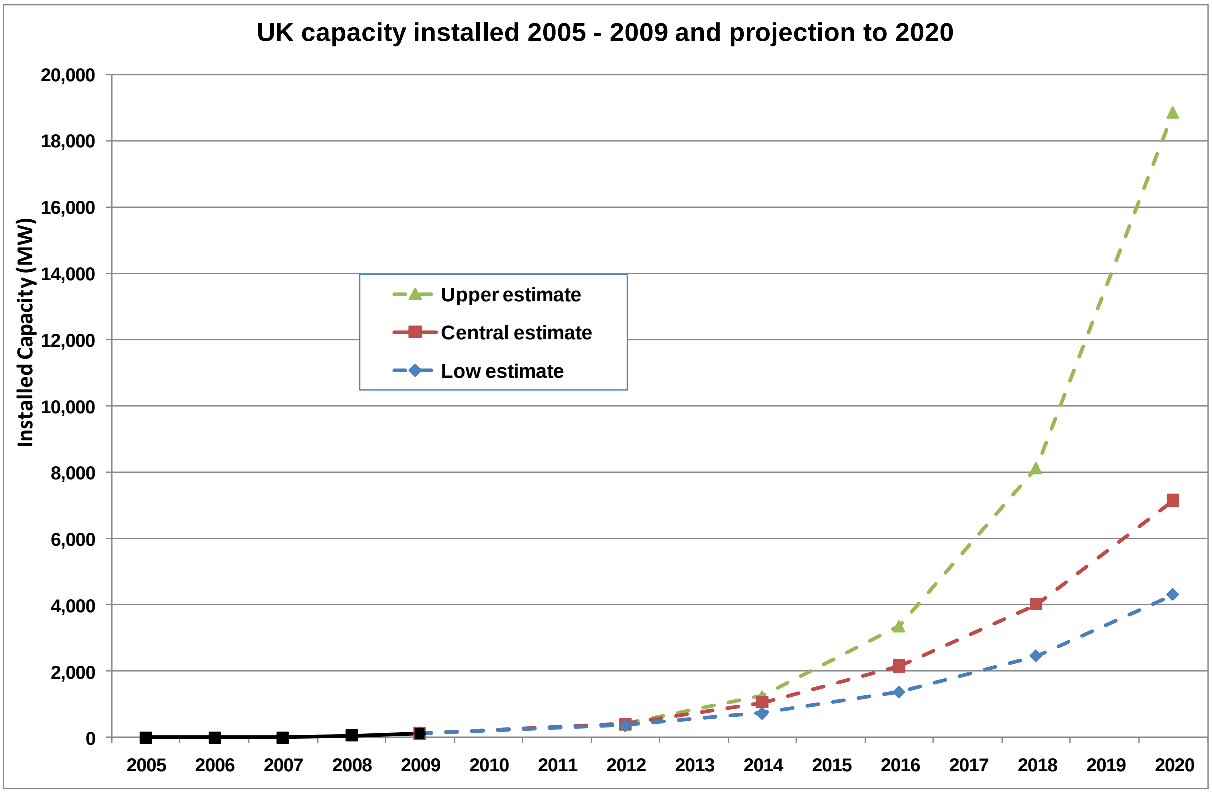


**Table 2: GSHP - Historic and projected capacity development and deployment 2005 – 2020**

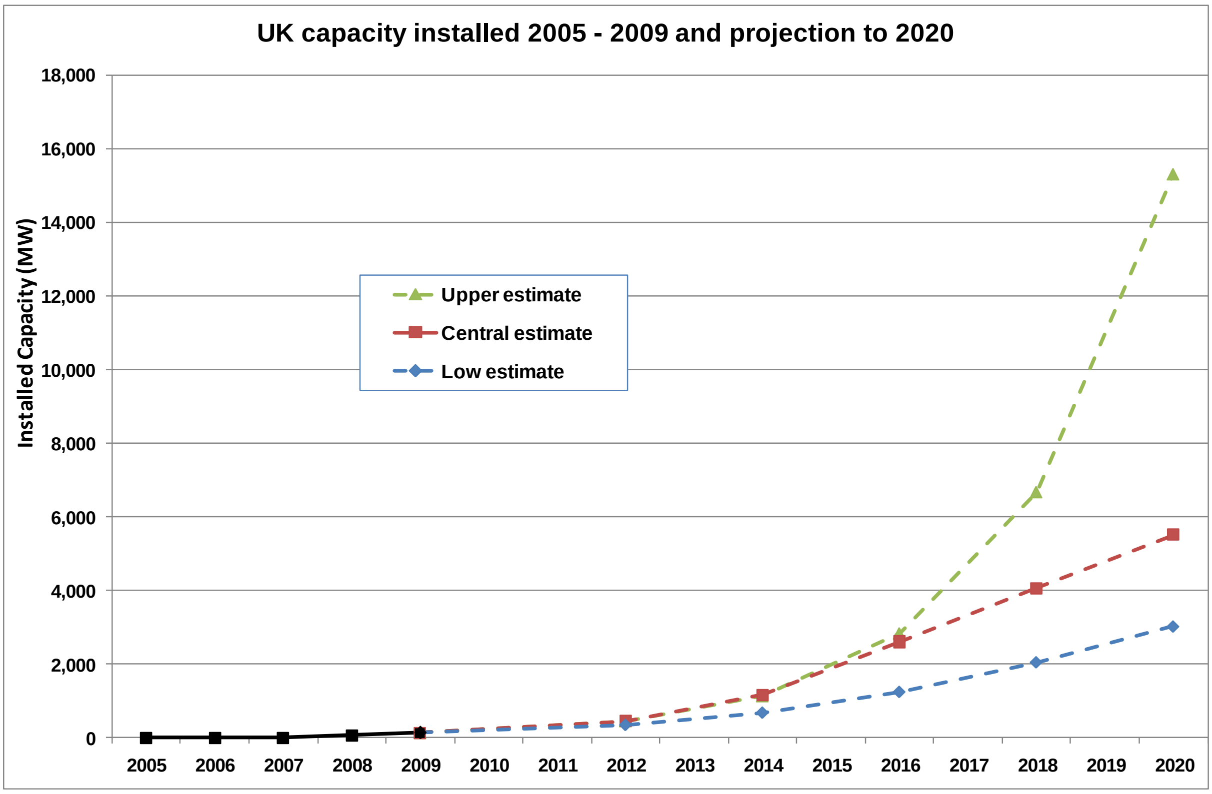
| Ground Source Heat Pumps | Average load factor: 22% to 35% |
|---|---|

| | | Total capacities/output in the different categories at the end of the stated year/period | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Unit | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
| | | 31/12/05 | 31/12/06 | 31/12/07 | 31/12/08 | 31/12/09 | 31/12/12 | 31/12/14 | 31/12/16 | 31/12/18 | 31/12/20 |
| Under development | MW | | | | | | | | | | |
| Planning submitted | MW | | | | | | | | | | |
| Planning approved | MW | | | | | | | | | | |
| Operational (central) | MW | | | | 70 | 131 | | | | | |
| Projected operational | MW | | | | | | 455 | 1,162 | 2,614 | 4,066 | 5,518 |
| Energy production | GWh | 0 | 0 | 0 | 154 | 236 | 841 | 2,183 | 4,988 | 7,868 | 10,813 |

**Range of projected operational capacity**

| | Unit | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Low estimate | MW | | | | | 131 | 348 | 683 | 1,249 | 2,056 | 3,032 |
| | GWh | | | | | 236 | 787 | 1,573 | 2,924 | 4,879 | 7,287 |
| Central estimate | MW | 0 | 0 | 0 | 70 | 131 | 455 | 1,162 | 2,614 | 4,066 | 5,518 |
| | GWh | 0 | 0 | 0 | 489 | 1,162 | 841 | 2,183 | 4,988 | 7,868 | 10,813 |
| Upper estimate | MW | | | | | 131 | 453 | 1,132 | 2,839 | 6,681 | 15,325 |
| | GWh | | | | | 236 | 837 | 2,129 | 5,424 | 12,942 | 30,062 |

**Figure 1: GSHP - Historic deployment and range of future projections to 2020**




The projections are based on applying different rates of growth to the supply market, moderated by the following factors:

- Ability of the emerging and relatively small installer market to respond to rapid growth in demand, though recent entry into the market of large air-conditioning manufacturers and energy suppliers may well overcome this constraint. Concern has been raised by some actors in the supply market about rapid expansion leading to poor quality installations with consequent damage to reputation of both the industry and the technology. This has caused some of the EU markets to stagnate or collapse in their early stages of development and is, perhaps, part of the reasoning for inclusion of specific training requirements for installers in Directive 2009/28/EC 'Promotion of the use of energy from renewable sources' Annex IV. Consultation with industry suggests that at the early stages of growth, when sales volume is low, large % growth between 50 to 100% is possible and has been demonstrated in mainland Europe, however, rapid increases cannot be sustained and a growth rate closer to 35% is considered more sustainable as the market matures, eventually reaching steady state as the market tends towards saturation. For the domestic heating market, this is considered to be when installations become the default choice for boiler replacement i.e. ~ 1.56 million / year.

- Ability to penetrate existing housing stock and the boiler replacement market. Heat pumps are most economically attractive when installed in well insulated new housing and when replacing electric or oil fired heating systems. To extend beyond these markets will require a combination of supply "push" to create economies of scale and expansion of the installer market, alongside technical improvements to improve COP and water 'flow' temperatures, minimising any requirements for upgrading the existing heating system radiators.
- Ability to stimulate consumer demand through, not least the Renewable Heat Incentive (RHI), combined with awareness campaigns to increase understanding and acceptance of the technology by a fairly conservative market.

It should be noted that the HPA considers the above projections to be significant under-estimates as they do not account for the significant RACs, including VRFs market in commercial buildings. These systems are demanded in the commercial sector as cooling is increasingly necessary due to peripheral heat gains from higher levels of occupancy and use of IT, hence RACs, including VRFs are in widespread use and installation of additional, dedicated heat pumps is not financially attractive. HPA estimates indicate a market at 2020 of ~ 4.3 million systems installed (discounting pre-2005 stock for which data was not supplied), representing an installed capacity of ~ 40.5 GW estimated to generate 54 TWh renewable heat. This is far above the central estimate shown above, which is broadly in-line with forecasts published in the papers Published by NERA, Entec, Element Energy and AEA. Indeed, HPA's forecast would account for ~ 75% of the Renewable Energy Strategy (RES) 72TWh target set for heat.

| **HPA Estimates - All Heat Pumps (excluding pre 2005 stock)** | **2006** | **2007** | **2008** | **2009** | **2012** | **2014** | **2016** | **2018** | **2020** |
|---|---|---|---|---|---|---|---|---|---|
| Cumulative installed capacity ('000 units) | 211 | 425 | 624 | 833 | 1,522 | 2,049 | 2,655 | 3,371 | 4,249 |
| Thermal capacity all heat pump units sold in year (MW) | 2,262 | 2,296 | 1,999 | 2,099 | 2,338 | 2,600 | 2,875 | 3,234 | 3,725 |
| Cumulative thermal capacity (MW) | 2,262 | 4,558 | 6,557 | 8,656 | 15,669 | 20,869 | 26,619 | 33,086 | 40,536 |
| Est. thermal output based on 2,000 hours/yr (GWh) | 4,524 | 9,116 | 13,114 | 17,312 | 31,338 | 41,738 | 53,238 | 66,172 | 81,072 |
| Estimated Renewable heat at COP 3 (GWh/yr) | 3,016 | 6,077 | 8,743 | 11,541 | 20,892 | 27,825 | 35,492 | 44,115 | 54,048 |
| | | | | | | | | | |
| **ASHPs - estimated by the HPA (excluding pre 2005 stock)** | **2006** | **2007** | **2008** | **2009** | **2012** | **2014** | **2016** | **2018** | **2020** |
| Domestic plus Non-domestic | | | | | | | | | |
| Number of units '000 | 203 | 408 | 599 | 800 | 1,451 | 1,932 | 2,467 | 3,079 | 3,805 |
| Installed thermal capacity MW | 2,172 | 4,376 | 6,295 | 8,310 | 15,022 | 19,938 | 25,300 | 31,232 | 37,936 |
| Useable thermal output (GWh) | 4,343 | 8,751 | 12,589 | 16,620 | 30,043 | 39,877 | 50,600 | 62,464 | 75,871 |
| Renewable thermal output (GWh) | 2,895 | 5,834 | 8,393 | 11,080 | 20,029 | 26,585 | 33,734 | 41,642 | 50,581 |
| | | | | | | | | | |
| **GSHP - estimated by the HPA (excluding pre 2005 stock)** | **2006** | **2007** | **2008** | **2009** | **2012** | **2014** | **2016** | **2018** | **2020** |
| Domestic plus non-domestic | | | | | | | | | |
| Number of units '000 | 8 | 17 | 25 | 33 | 71 | 117 | 188 | 292 | 444 |
| Installed thermal capacity MW | 90 | 182 | 262 | 346 | 647 | 931 | 1,319 | 1,854 | 2,600 |
| Useable thermal output (GWh) | 181 | 365 | 525 | 692 | 1,295 | 1,861 | 2,638 | 3,708 | 5,201 |
| Renewable thermal output (GWh) | 121 | 243 | 350 | 462 | 863 | 1,241 | 1,758 | 2,472 | 3,467 |

In this estimation, it is not clear what assumption has been applied to calculate the heating contribution of RACs, including VRFs, which in commercial applications will mostly operate in cooling mode.

A similarly ambitious view of the market to 2020 is taken by energy retailers such as EDF, who have analysed the domestic heat market as having a realistic potential for up to 2 million high temperature ASHPs to be installed by 2020, if "appropriate financial support and delivery channels are developed."

# 14.4 Achieving future deployment – key dependencies

## 14.4.1 Impact of financial incentives

In combination with existing measures supporting low carbon technologies, the RHI is likely to provide a significant stimulus to the market, similar to that observed in mainland Europe. However, it is unlikely to stimulate the levels achieved in France as these are thought to have been significantly augmented by EDF's activity to stimulate take-up. Other financial support measures include the:

- Low Carbon Buildings programme (LCB);
- Enhanced Capital Allowance (ECA) scheme for energy saving technologies (only applicable to the non-domestic market);
- Community Energy Saving Programme.

Though the Renewable Heat Incentive (RHI) will make renewable heating technologies more cost competitive with fossil-fuel alternatives, however, the relatively high initial purchase costs (~ £3,000 more expensive than conventional gas boilers) could constrain take up unless innovative methods of financing are developed. Proposed methods include:

- establishment of energy service companies ;
- provision of low-interest 'green' loans from banks;
- Pay As You Save (PAYS) schemes;
- billing for heating via council tax.

Energy service companies (ESCOs) may be made up of members from the local authority, energy suppliers, equipment manufacturers, the community, and energy experts. They are capable of raising finance for renewable heating technologies at a lower cost than individual consumers. This business model is sometimes used for renewable district heating and CHP.

## 14.4.2 Impact of consenting processes

The consenting process does not apply to what is essentially a small scale generation technology.

## 14.4.3 Integration to energy markets

Issues affecting the take-up of electric heat pumps and integration with the national and local supply network are:

- Larger heat pumps > 12 kWth often require a 3 phase electricity supply, which can require the local grid to be reinforced, adding to the costs of installation.
- Heat demand coincides with peak demands on the national grid, should the domestic market grow to the levels where heat pumps become the default replacement for boilers, this will place a significant additional load on the grid. Estimates indicate that 1 million domestic scale systems would result in an extra peak load on the grid of ~ 3GW, equivalent to 4% of total UK grid capacity. Additionally, safeguards will need to be taken to avoid grid instability caused by large spikes in demand at peak heating times.

## 14.4.4 Supply chain issues and constraints

The current installer market, gauged by registrations on the MCS, appears too limited to mange the rate of installation envisaged by 2020. However, industry does not appear to consider this an insurmountable barrier.

Clearly, significant resource will be required to gear-up the installation market through recruitment and training. Large international manufactures are likely to respond, drawing on experience gained in

Europe, alongside energy retailers with ambition to gain and/or retain market share. Indeed, EoN, EDF and Centrica are all known to be developing strategies for market growth.

### 14.4.5 Regulatory framework

As described in the report ‘Renewable Heat Technologies for Carbon Abatement: Characteristics and Potential’:

“Many domestic air-to-water heat pumps have a maximum flow temperature of around 55°C (with an auxiliary electrical heater to achieve higher temperatures for e.g. legionella disinfection in hot water tanks), in order to minimise the temperature difference between inside and outside and hence maximise the COP. This means that heat emitters (under-floor loops, radiators, etc) cannot be run at very high temperatures.

This is not a problem in new-build, well insulated homes, where low temperature under-floor loops or low temperature radiators can be installed. In most existing UK buildings however, high temperature radiators are the main type of emitter in use and currently run at considerably higher temperatures, up to a maximum of around 90°C.

The reason for this is that older homes are less well insulated and hence experience significant heat loss through the walls and roof. In order to maintain a constant inside temperature, a large amount of heat must be delivered by the heating system. Radiators have a limited area through which to emit this heat and as a result tend to be run at high temperatures.”

In light of this, and noting that the effect also applies to GSHPs, regulation and policies controlling the energy efficiency of buildings will influence the technical potential for widespread deployment of heat pumps. These include:

- Building Regulations Part L, which are planned to set increasingly high standards for energy / carbon performance:
    - 2010 - 25% improvement
    - 2013 - 44% improvement
- The Government’s Zero Carbon Homes initiative
- The EU Building Services directive
- The Merton Rule applied by some Local Authorities, which stipulating that for new-build commercial buildings, 10% of their energy needs must be met by renewable supply
- The Code for Sustainable Homes (launched in 2006) which is a voluntary standard developed from the BRE Ecohomes system

The market for heat pumps installed in the commercial sector will also be influenced by regulation designed to reduce carbon emissions, in particular the Carbon Reduction Commitment (CRC) applying to large non-energy intensive organisations that have half-hourly metered electricity consumption greater than 6,000 MWh per year, typically hotel chains, supermarkets, banks, central government and large Local Authorities.

Industrial applications, where heat pumps are most often used for heat recovery, may be influenced by a combination of the Climate Change Agreements, which set emissions reduction targets for over 52 industrial sectors and the EU Emissions Trading Scheme (ETS).

### 14.4.6 Other potential barriers to deployment

To achieve significant take-up, particularly in the domestic sector, considerable consumer resistance may be encountered, arising from lack of awareness and understanding of the technology and confidence in its reliability. These issues may be further exacerbated by low levels of confidence in the technical capabilities and the long-term stability of the installer market.

Prospects for surmounting these barriers are very positive, however, given the size and capabilities of the international scale of many air source heat pump manufacturers combined with energy retailers should they enter the market. However, as mentioned earlier, rapid and uncontrolled expansion of the domestic heating market may cause problems with quality control, with potential to stall market growth through negative PR.

### 14.4.7 Summary of constraints

**Air Source Heat Pumps**

| Potential constraints | Significance | Comment |
|---|---|---|
| Returns insufficient to stimulate sufficient deployment | Amber | ASHP are expected to become increasingly attractive with the advent of the RHI and the technology is well developed via the mass air conditioning market resulting in lower costs systems compared with GSHPs. However, in the residential market, typical domestic units are ~ £3,000 more expensive than an equivalent gas boiler, which the RHI is likely to overcome as a barrier to deployment |
| Planning (local policies, obtaining permissions) | Green | Planning regulations do not apply to ASHPs, though there is some concern that noise may be an issue. The MCS regulates noise emission, but this is a subjective issue and it may emerge as an issue at local planning level as the technology becomes more widespread. |
| Integration to energy markets | Amber | By switching heating form the gas to the electricity grid, widespread take-up (and some within the industry envisage ASHPs as the default replacement for domestic boilers ~ 1.56 million/year) will place a significant additional peak load on the grid e.g. 1 million 8kWth (~ 3kWe) units would result in 3 GW i.e. 4% of total UK capacity. Larger units require 3 phase supply and local grid reinforcement. |
| Supply chain issues and constraints | Amber | Initially, mass deployment in the domestic sector is likely to be constrained by the relatively small installer market. Currently ~ 220 suppliers are registered through the MCS. However, entry of large scale manufacturers from Japan and Europe, alongside utilities, including Centrica, EON and EDF will bring resources to bear that may quickly overcome this constraint. |
| Regulatory constraints | | |
| Institutional barriers | Amber | Switching the heating load to the electricity grid will require long-term planning of how to manage the substantial additional peak loads that could occur, alongside local grid reinforcement to mange instability of the local network caused by large spikes in demand at peak times and allow 3 phase supply required by larger heat pumps.<br><br>To operate effectively (i.e. at sufficiently high COPs), heat pumps require most pre-2000 residential building stock's insulation and heat distribution systems (usually radiators) to be upgraded. This may slow the rate of market penetration in existing houses, affecting the speed at which heat pumps may become the default heating system for boiler replacement. However, technology advances, through use of variable speed compressors is improving COPs, however, a switch to use of CO2 as the refrigerant offers the prospect of large improvements to COP - manufacturers claim up to ~ 7 |
| Unclear policy (national, regional, local) | Green | The current concern expressed by the air source heat pump supply industry is that uncertainty over the present LCB programme and the outcome of the RHI consultation is causing a temporary disruption to demand from consumers. No long-term issues have been identified. |
| Motivating investors to act | Amber | The RHI may stimulate a keen interest and take-up of heat pumps in the domestic sector, however, significant upfront installation costs compared with conventional boilers may countervail the driver provided by the RHI. Novel financing methods may develop in response to the opportunity, including loans from energy retailers should they regard the potential as significant.<br><br>In the commercial and public sector, the guaranteed revenue from the RHI may stimulate entry development of ESCOs and access to long-term, preferential interest rate finance. |
| Other constraints (please specify under comments) | Red | ASHP technology is relatively unknown in the domestic market and consumer acceptance may take time to develop, despite the economic attractiveness following the advent of the RHI. The UK heating market is regarded by many as inherently conservative, for example, 25 years was required to achieve a 90% market penetration for central heating. This may be less of a barrier for the non-domestic commercial and public sector markets where the technology is widespread (in the form of air conditioning), where the market capacity is less in terms of volume of units, but higher in terms of thermal capacity. |

| | |
|---|---|
| Green | Unlikely to present a constraint to achieving the central projection. |
| Amber | Could constrain achieving the central projection and will certainly constrain achieving the upper projection |
| Red | Likely to constrain achieving the central projection; could result in only the low projection being achieved |

**Ground Source Heat Pumps**

| Potential constraints | Significance | Comment |
|---|---|---|
| Returns insufficient to stimulate sufficient deployment | Amber | GSHP are most economically attractive in new build & off-gas grid properties, with an income stream from the RHI, investment will be more attractive, though in the domestic market up-front investment may still be a significant deterrent, despite a one-off payment for the 'inconvenience' of installing ground loops ( sub-surface coils, or boreholes). The initially higher upfront costs associated with GSHPs makes their use less attractive than ASHPs and is a contributory factor in ASHP sales overtaking GSHPs. |
| Planning (local policies, obtaining permissions) | Green | Planning affects open-loop systems where the Environment Agency must issue permits for water abstraction more than closed-loop. Open loop systems are most common in large high density cities and there are a several demonstration schemes in London. The Environmet Agency is actively considering the impact on aquifers (thermal and potential water depletion) should these systems become more widespread.<br><br>The majority of systems are likely to be closed loop and planning is unlikely to be a significant constraint. Nonetheless, where boreholes are required, drilling permits will need to be obtained. |
| Integration to energy markets | Amber | Heat pumps switch the heating load from the gas to the electricity grid & should deployment be widespread, this could cause a significant additional load & at peak times of day. Larger systems > 5kW require 3 phase supply not available to most UK residential properties, requiring local grid reinforcement and hence additional installation cost.<br><br>Switching the heating load to the electricity grid will require long-term planning of how to manage the substantial additional peak demand on capacity that could occur. |
| Supply chain issues and constraints | Amber | The UK market is could be regarded as relatively small and highly fragmented, so there may be significant constraints on supply should demand increase rapidly. Experience in mainland Europe suggests that rapid growth may cause problems with quality control and damage the technolgy's and industry's reputation, hence, many manufacturers are concerned to control growth as the market emerges.<br><br>These obsticles may be mitigated if significant support for developing the installer market is made available through the energy retailers and the larger international manufacturing companies applying their experience and resources to gear-up and trai installers. This is a particularly important aspect of market development if the potential available in the residential market is to be unlocked. |
| Regulatory constraints | Green | None identified. |
| Institutional barriers | Amber | Switching the heating load to the electricity grid will require long-term planning of how to manage the substantial additional peak loads that could occur, alongside local grid reinforcement to mange instability of the local network caused by large spikes in demand at peak times and allow 3 phase supply required by larger heat pumps.<br><br>To operate effectively (i.e. at sufficiently high COPs), heat pumps require most pre-2000 residential building stock's insulation and heat distribution systems (usually radiators) to be upgraded. This may slow the rate of market penetration in existing houses, affecting the speed at which heat pumps may become the default heating system for boiler replacement. However, technology advances, through use of variable speed compressors is improving COPs. |
| Unclear policy (national, regional, local) | Green | The current concern expressed by the air source heat pump supply industry is that uncertainty over the present LCB programme and the outcome of the RHI consultation is causing a temporary disruption to demand from consumers. No long-term issues have been identified. |
| Motivating investors to act | Amber | The RHI may stimulate a keen interest and take-up of heat pumps in the domestic sector, however, significant upfront installation costs compared with conventional boilers may countervail the driver provided by the RHI. Novel financing methods may develop in response to the opportunity, including loans from energy retailers should they regard the potential as significant.<br><br>In the commercial and public sector, the guaranteed revenue from the RHI may stimulate entry development of ESCOs and access to long-term, preferential interest rate finance |
| Other constraints (please specify under comments) | Red | GSHP s are relatively unknown technology in the UK, particularly in the residential sector. Consumer acceptance is likely to create a significant barrier to take-up, slowing market development. As a point of reference, the market for central heating took about 25 years before 95% market penetration was achieved. Further, the space required for sub-surface heat collector coils may moderate the take-up of GSHPs, particularly if competing with less expensive (though generally less efficient) ASHPs. These reasons, in part, explain why in mainland Europe the ASHP market now takes a more significant share of the heat market.<br><br>Coordinated marketing effort from Trade bodies, energy agencies (EST and CT), and the entry of energy retailers and international manufacturing companies may overcome resistance, but the constraints concerning space will persist. |

| | |
|---|---|
| Green | **Unlikely to present a constraint to achieving the central projection.** |
| Amber | **Could constrain achieving the central projection and will certainly constrain achieving the upper projection** |
| Red | **Likely to constrain achieving the central projection; could result in only the low projection being achieved** |

# 15 Bioenergy boilers (heat)

## 15.1 Introduction

Bioenergy boilers burn fuels such as wood and wood wastes from forestry, woodlands and energy crops, agricultural residues (straw etc), clean wood wastes from industrial processes (sawdust, off-cuts, shavings), miscanthus (elephant grass) etc to produce hot water (steam for some applications) for industrial, commercial and domestic heating and/or hot water supply. They can also use biogas produced from organic wastes. Bioenergy boilers are well established in many countries in Europe e.g. Austria, Germany, Sweden, Denmark for heating. The technology is well developed and the market is growing in recent years as it offers virtually zero carbon emissions and sustainable fuel at competitive costs.

Heat, in all its forms, accounts for nearly 49% UK total final energy demands and nearly 47% of total carbon emissions. Potential bioenergy resources in the UK, if properly developed and exploited, can meet a significant proportion of this heating demand.

## 15.2 Historical deployment

The use of bioenergy boilers in the UK is however is still in its infancy as gas and oil have been the dominant fuels for industrial, commercial and domestic heating/hot water applications. However, in recent years the increase in prices of gas and oil for heating applications, and the need for reduction of carbon emissions have drawn UK attention to bioenergy.

Various incentives e.g. Bioenergy Capital Grant Scheme (BECGS), Low Carbon Building Programme, Biomass Heat Accelerator Project, etc have helped the development of bioenergy boilers market for heating applications in the UK. To the end of 2009 around 2480MW of total installed capacity of bioenergy boilers are operating in the UK. The major part of this capacity is with casual users of agricultural wastes (e.g. straws) and wood available locally (e.g. logs, wood pieces). The BECGS has supported 75 MW of this capacity. About 40% of this total capacity is in Scotland and the rest is mainly in England, as Northern Ireland and Wales have only small capacities.

The availability and ease of use of gas and oil, and a lack of familiarity and understanding of bioenergy boilers combined with their higher capital of operating costs have restricted their market in the UK. However, this has started to change as interest is growing due to various reasons e.g. environmental concerns, higher prices of oil and gas, government policy and measures to reduce carbon emissions, public awareness of climate change from fossil fuels combustion etc.

The timescale of bioenergy boiler projects from conception to operation depends on type and size of installation and other site specific conditions e.g. access to fuel deliver and storage. For a small installation (<250kW) replacing a gas/oil boiler with a bioenergy unit can take 3 to 6 months. However, for a large and/or a new installation this can take 12 to 24 months as various stages of the project e.g. feasibility study, planning and other consents, construction, installation etc have to undergo rigorous processes.

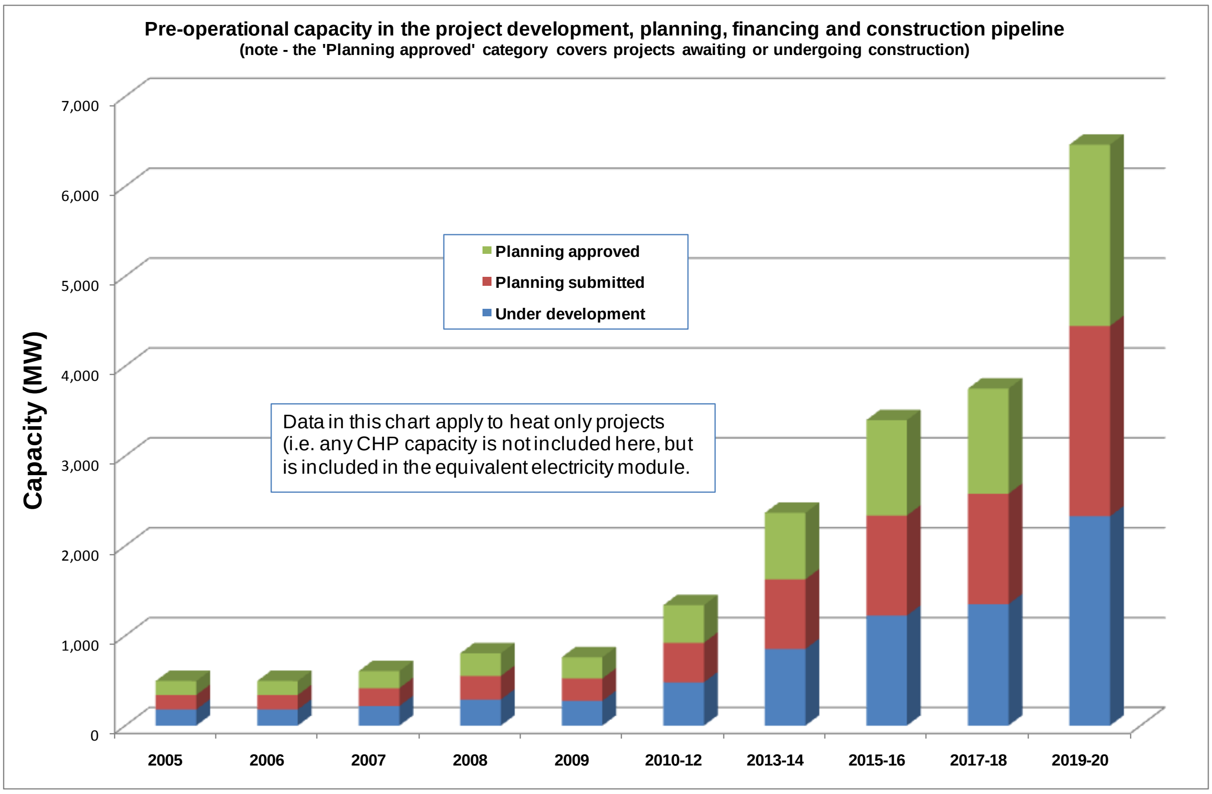
## 15.3 Projected deployment to 2020

Under the central growth scenario the deployment of bioenergy boilers by 2020 is predicted to be around 7600MW. The central growth assumes a plausible expansion in renewable heat supply from current state, assuming that incentives to be offered are financially no worse than relevant gas, oil or electric heating options.

Higher growth scenario will raise this to around 10000MW. The higher growth assumes a more optimistic development than the central growth.

The lower growth scenario assumes a pessimistic development with 15% less growth each year than central growth with a total capacity by 2020 to around 6500MW.

**Figure 1: Pre-operation phases: project development, planning, financing and construction**




In the absence of any other financial incentives, the proposed Renewable Heat Incentive will play an important role to stimulate the growth under each scenario and the level of the RHI offered will have a considerable effect on the growth.

**Table 1: Historic and projected capacity development and deployment 2005 – 2020**

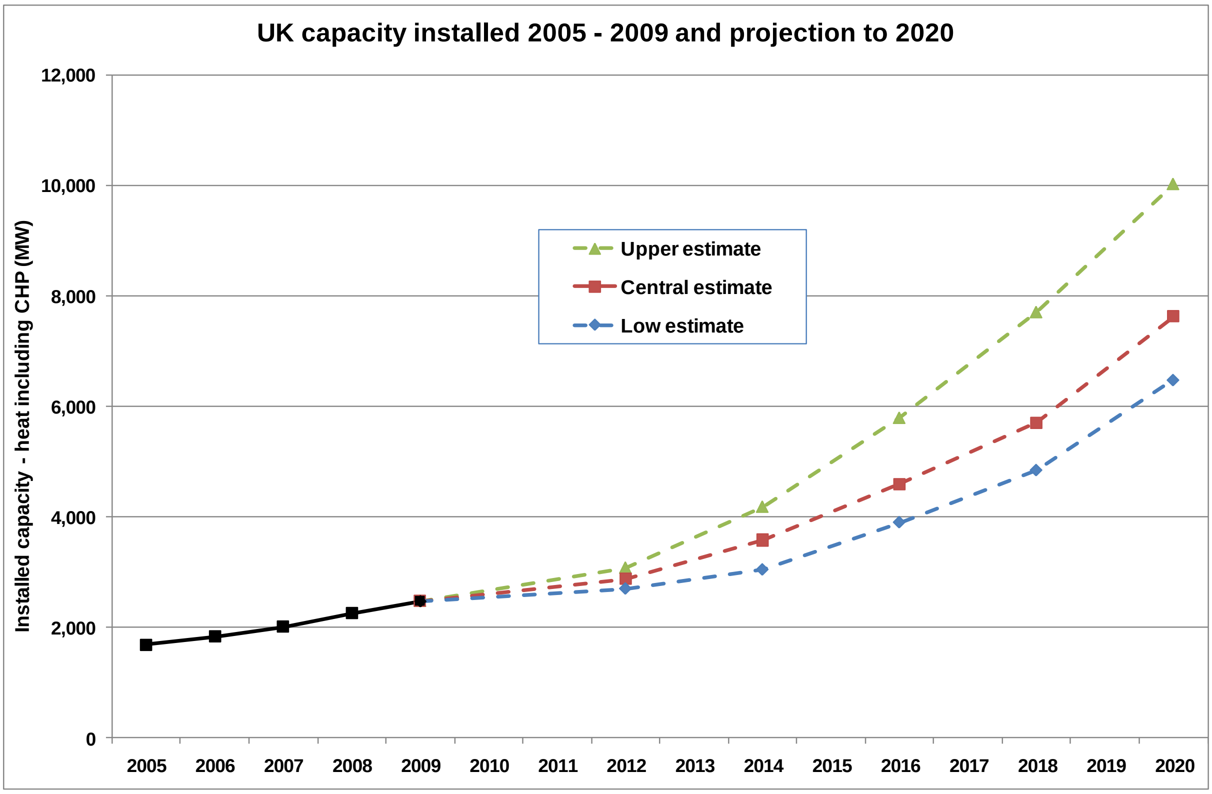
| Biomass boilers (heat) | Weighted average load factor: 35% |
|---|---|

| | Unit | Total capacties/output in the different categories at the end of the stated year/period | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
| | | 31/12/05 | 31/12/06 | 31/12/07 | 31/12/08 | 31/12/09 | 31/12/12 | 31/12/14 | 31/12/16 | 31/12/18 | 31/12/20 |
| Under development | MW | 179 | 179 | 218 | 290 | 275 | 482 | 853 | 1,225 | 1,351 | 2,329 |
| Planning submitted | MW | 162 | 162 | 199 | 263 | 249 | 440 | 775 | 1,113 | 1,229 | 2,118 |
| Planning approved | MW | 155 | 155 | 189 | 251 | 237 | 418 | 739 | 1,061 | 1,169 | 2,017 |
| Operational (central) | MW | 1,689 | 1,836 | 2,016 | 2,255 | 2,481 | | | | | |
| Projected operational | MW | | | | | | 2,879 | 3,583 | 4,593 | 5,707 | 7,628 |
| Energy production | GWh | 5,178 | 5,629 | 6,181 | 6,914 | 7,607 | 8,827 | 10,985 | 14,082 | 17,498 | 23,387 |

**Range of projected operational capacity (excluding CHP)**

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Low estimate | MW | | | | | 2,481 | 2,700 | 3,046 | 3,904 | 4,850 | 6,484 |
| | GWh | | | | | | 8,278 | 9,339 | 11,970 | 14,870 | 19,880 |
| Central estimate | MW | 1,689 | 1,836 | 2,016 | 2,255 | 2,481 | 2,879 | 3,583 | 4,593 | 5,707 | 7,628 |
| | GWh | 5,178 | 5,629 | 6,181 | 6,914 | 7,607 | 8,827 | 10,985 | 14,082 | 17,498 | 23,387 |
| Upper estimate | MW | | | | | 2,481 | 3,079 | 4,183 | 5,793 | 7,707 | 10,028 |
| | GWh | | | | | | 9,440 | 12,825 | 17,761 | 23,630 | 30,746 |

**Figure 2: Historic deployment and range of future projections to 2020**




# 15.4 Achieving future deployment – key dependencies

## 15.4.1 Impact of financial incentives

The capital costs (equipment and its installation costs) of a bioenergy boiler are three to four times that of an equivalent gas- or oil-fired boiler. Its operating and maintenance costs (not including fuel) are also significantly higher. As a result, financial incentives will play a crucial role in the deployment of bioenergy boilers. The Bioenergy Capital Grant Scheme offering up to 40% of capital costs has helped the growth in installation of bioenergy boilers in the UK. Other incentives have also played an important role. These incentives have helped to develop the supply chains for equipment and fuels to its current level.

The proposed Renewable Heating Incentive Scheme will help the increase in deployment, provided it is high enough to make bioenergy boilers more attractive than other competing systems. A higher level of RHI is expected to lead to higher level of deployment.

## 15.4.2 Impact of consenting processes

The consenting process for bioenergy boilers, particularly for new installations and for larger boilers (>500 kW) often takes a long time and delays the project implementation. Unfamiliarity and lack of understanding of bioenergy boilers often results in queries, delaying the process and increasing the costs of projects. The process needs to take into account the special features e.g. fuel delivery and storage issues of bioenergy systems, and be made simple and clear so that it operates more swiftly in order to facilitate renewable deployment.

## 15.4.3 Integration to energy markets

The relative cost of bioenergy compared to other competing fuels, and reliability of supply of the right quality fuel for the particular applications will be important to integrate it in the energy market. Due to higher capital and operating costs of bioenergy boilers, the fuel has to be significantly cheaper to make it attractive in the market. Unfamiliarity and lack of understanding of bioenergy discourages its application.

### 15.4.4 Supply chain issues and constraints

The supply chains of bioenergy boilers and fuels are still evolving in the UK. Most of the equipment available in the UK market is imported. Wood pellets produced in the UK are also not sufficient to meet current needs and a major proportion of it is imported. Although a handful of equipment and fuel suppliers are now reasonably well established in the market, they mainly cover selected areas of the country. As a result, supply chains for both equipment and fuel need to be expanded considerably covering new areas where there is big potential for growth under any of the growth scenarios.

Incentives are needed e.g. training engineers in carrying out feasibility studies and installing bioenergy equipment. Incentives are also needed to produce fuels domestically e.g. growing energy crops and wood in forests and woodland, producing woodchips and pellets from wood and wastes, delivery of fuel to meet increasing demand.

### 15.4.5 Regulatory framework

Regulations will help the growth of the bioenergy heating markets significantly e.g. renewable heat obligation to produce a certain amount heat from renewable sources, energy tax on other competing fuels for heating application to make bioenergy financially more attractive, increasing landfill tax on bioenergy wastes to make it attractive for use as fuel, planning policy and building regulations to favour bioenergy use for heating, carbon reduction commitment for private and public sector to encourage use of bioenergy for heating.

However, some regulations will adversely affect the growth of bioenergy boiler market for heating. For example, stricter emissions limits of particulates and NOX from bioenergy boilers will increase the cost of equipment and discourage its use; stricter air quality objectives will deter the use of bioenergy boilers in urban areas.

### 15.4.6 Other potential barriers to deployment

As higher investment is needed at the front end for bioenergy boilers, the overall economic/investment climate will have a considerable effect on the growth of the market. A tendency to stay with familiar fuels for heating rather than going for an unfamiliar fuel i.e. bioenergy will also act as a barrier in some cases. Unclear policy on planning and other consents for bioenergy boilers will discourage some potential users.

### 15.4.7 Summary of constraints

There are several barriers that need to be addressed to help the growth of bioenergy boiler market in the UK. However, favourable Government regulatory policies and financial incentives, in combination with close collaboration among the various parties that are key to the market e.g. relevant Government agencies, potential users of bioenergy boilers, equipment and fuel suppliers will be able to overcome most of these issues.

**Table 2: Significance of various potential constraints on deployment**

| Potential constraints | Significance | Comment |
|---|---|---|
| Returns insufficient to stimulate sufficient deployment | Amber | The higher capital and operating costs of bioenergy boilers will have a significant effect on deployment without sufficient financial incentive to overcome these. |
| Planning (local policies, obtaining permissions) | Green | Bioenergy heating boilers which are usually small in size (under 5MW thermal output) will not be affected sigbnificantly. |
| Integration to energy markets | Amber | The cost of other competing fuels will have a significant influence. |
| Supply chain issues and constraints | Amber | With the current market of bioenergy boilers at low level, lack of sufficient qualified equipment suppliers and fuel suppliers will adversely affect the rate of uptake. |
| Regulatory constraints | Amber | Constraints of emissions of particulates and NOX will restrict application in urban areas. The higher cost of equipment to meet emisssion will also have on affect. |
| Institutional barriers | Green | As the renewable energy is getting wide attention in the media this is likely to be a significant problem. |
| Unclear policy (national, regional, local) | Amber | This will discourage potential users to use bioenergy boilers. |
| Motivating investors to act | Green | Widespread media and public interest in renewable energy will have a positive affect on investers. |
| Other constraints (please specify under comments) | | |

| | |
|---|---|
| Green | **Unlikely to present a constraint to achieving the central projection.** |
| Amber | **Could constrain achieving the central projection and will certainly constrain achieving the upper projection** |
| Red | **Likely to constrain achieving the central projection; could result in only the low projection being achieved** |

# 16 Energy from waste - heat

## 16.1 Introduction

Various waste streams that would fall into the general classification of special industrial waste (such as meat and bone meal, poultry waste and clinical waste) have at times been used on industrial sites to provide heat. However, due to environmental concerns of thermal combustion plants and the implementation of Waste Incineration Directive into the UK regulatory regime, these applications have tended to cease in favour of the waste being collected for off-site treatment. Therefore many of the specialised industrial waste have been drawn to off-site electricity generation schemes. As a result the only area covered here is that of biogas to heat. The capacity and energy projections also include CHP heat from the energy from waste electricity sector.

This section should be read in conjunction with the section on 'Biogas injection into gas grid', where the basis of the total biogas resource projection is explained. In addition, the total biogas resource for 2020 was divided among four separate modules as follows:

| Installed capacities of biogas use (MW biogas) | Low | Central | High | Section of the report dealing with the resource |
|---|---|---|---|---|
| Biomethane to gas grid | 480 | 970 | 1310 | In Biogas injection into gas grid |
| Biomethane to transport fuel | 60 | 110 | 150 | In this section |
| Biogas to CHP | 230 | 460 | 620 | In Bioenergy for electricity** |
| **Biogas to heat only** | **100** | **210** | **280** | **In Energy from waste – heat** |
| Total resource as predicted | 870 | 1750 | 2360 | |

** The scope for large CHP plants is expected to diminish due to the RHI and any AD plants installing CHP will tend to use much of the waste heat on site based requirements; thereby creating little or export heat.

The UK ranks relatively low in installed capacity of AD plants generally, but the spate of recent announcements (FIT and the impending RHI) in addition to the ROC mechanism is increasing the activities in this area greatly.

If AD plants could be located at or near industrial sites, which have high temperature heat demand, then use of biogas to provide heat will generally be attractive. We estimate heat schemes may be limited to a selection of the potential large industrial process heat users. They would be quite suitable as they are usually situated on brown field sites and could host AD plants nearby. As part of our wider work in this area we have estimated some 17 cement works; 30 steel processors using reheat furnaces; 12 lime kilns and 73 brick works could be potential sites. This would give 142 sites that could accommodate a digester, each would be say 1MW minimum 5MW max so between 142MW and 710MW potential.

## 16.2 Historical deployment

In the last 3-4 years there has been a rise in the AD plants installed in the UK, but the level of deployment is still small. The capacity presented below includes heat from EFW CHP plant.

## 16.3 Projected deployment to 2020

As mentioned earlier, an initial estimate was made of the projected biogas deployment to 2020 and this was used to reconcile industry's response in a number of different areas covered in this report. Of the total biogas resource we project some 15% being dedicated towards heat, mainly driven by large industrial heat users.

**Low estimate**
This is based on a much lower number of industrial sites taking up the biogas to heat opportunity.

**Central estimate**
The central estimate assumes about one third of the industrial sites taking up the biogas heat opportunity.

**High estimate**
This is based on around two thirds of the sites with high heat loads taking up the biogas heat opportunity.

### Table 1: Historic and projected capacity development and deployment 2005 – 2020

**Energy from waste - heat** — **Weighted average load factor: 70%**

| | Unit | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Total capacties/output in the different categories at the end of the stated year/period | | | | | | | | | |
| | | 31/12/05 | 31/12/06 | 31/12/07 | 31/12/08 | 31/12/09 | 31/12/12 | 31/12/14 | 31/12/16 | 31/12/18 | 31/12/20 |
| Under development | MW | | | | | | | | | | |
| Planning submitted | MW | | | | | | | | | | |
| Planning approved | MW | | | | | | | | | | |
| Operational (central) | MW | 0 | 0 | 0 | 0 | 0 | | | | | |
| Projected operational | MW | | | | | | 29 | 73 | 130 | 198 | 262 |
| Energy production | GWh | 0 | 0 | 0 | 0 | 0 | 180 | 446 | 798 | 1,214 | 1,605 |

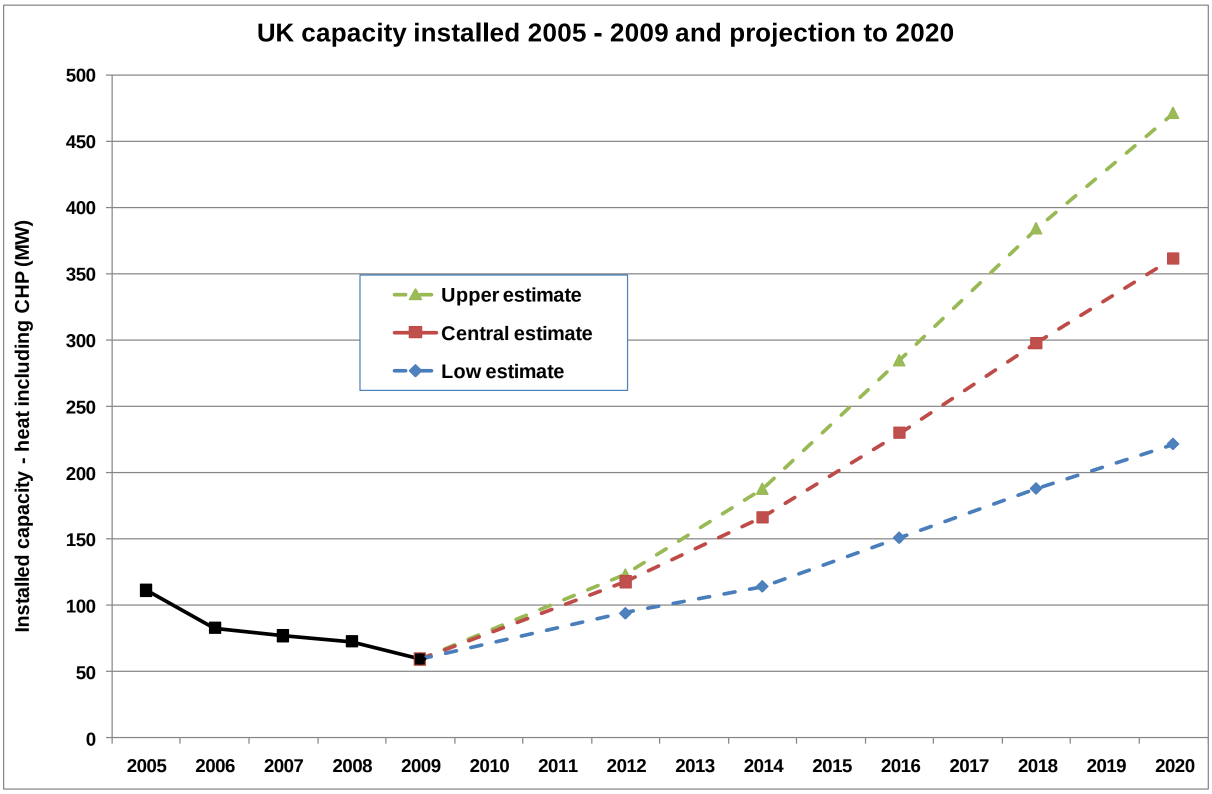
**Range of projected operational capacity including CHP**

| | Unit | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Low estimate | MW | | | | | 60 | 94 | 114 | 151 | 188 | 221 |
| | GWh | | | | | | 683 | 805 | 1,039 | 1,270 | 1,477 |
| Central estimate | MW | 111 | 83 | 77 | 73 | 60 | 118 | 166 | 230 | 298 | 362 |
| | GWh | 829 | 617 | 574 | 543 | 444 | 839 | 1,144 | 1,543 | 1,958 | 2,349 |
| Upper estimate | MW | | | | | 60 | 124 | 188 | 285 | 384 | 471 |
| | GWh | | | | | | 874 | 1,278 | 1,891 | 2,511 | 3,045 |

**Load Factors/energy output**

A load factor of 70% is used and generally accepted by the industry, due to seasonal variation of practically all feedstock, except food waste from households. It is expected that this will rise with the use of energy crops.

**Figure 2: Historic deployment and range of future projections to 2020**




## 16.4 Achieving future deployment – key dependencies

These comments are based on limited industry views and are as summarised in the table below.

**Table 2: Significance of various potential constraints on deployment**

| Potential constraints | Significance | Comment |
|---|---|---|
| Returns insufficient to stimulate sufficient deployment | Green | The heat incentive proposed under RHI is attractive. |
| Planning (local policies, obtaining permissions) | Green | Planning policy is generally supportive of AD development, provided that site-specific environmental issues can be dealt with satisfactorily. The most important issues for AD plants are transport, odour and noise. No major obstacles are foreseen. |
| Integration to energy markets | Green | This option will be taken up by those with sufficient heat loads and therefore no major integration issues are foreseen at site level. |
| Supply chain issues and constraints | Green | Some infrastructure will be required but this is well within the capability of the potential heat using industry. |
| Regulatory constraints | Green | AD plants are generally favoured as long as they are to be built to the required standards. Planning consent, Environmental Permit by the Environment Agency or PAS110 accreditation for the disposal digestate are no longer seen as constraints. |
| Institutional barriers | Green | None. |
| Unclear policy (national, regional, local) | Amber | Although the policy is clear its communication to the potential hosts (that can use heat effectively) would help to indentify and accelerate the take up. |
| Motivating investors to act | Green | Returns on investment are sufficient. |
| Other constraints (please specify under comments) | | |

| | |
|---|---|
| Green | Unlikely to present a constraint to achieving the central projection. |
| Amber | Could constrain achieving the central projection and will certainly constrain achieving the upper projection |
| Red | Likely to constrain achieving the central projection; could result in only the low projection being achieved |

# 17 Biomass District Heating

## 17.1 Introduction

Biomass district heating uses fuels such as wood and wood wastes from forestry, woodlands, and energy crops, agricultural residues (straws etc), clean wood wastes from industrial processes (sawdust, off-cuts, shavings), miscanthus (elephant grass) in a relatively large boiler (1MW or above) to produce hot water or steam for heating a cluster of industrial, commercial or domestic properties or their combination in a close vicinity. Biogas produced from organic wastes can also be used for this purpose. Biomass district heating is well established in many countries in Europe e.g. Austria, Germany, Sweden, Denmark. The technology is well developed and the market is growing in recent years as it offers virtually zero carbon emissions and sustainable fuel at competitive costs. This chapter also includes the heat from biomass CHP plant.

Heat, in all its forms, accounts for nearly 49% UK total final energy demands and nearly 47% of total carbon emissions. Potential biomass resources in the UK, if properly developed and exploited, can meet a significant proportion of this heating demand via district heating.

## 17.2 Historical deployment

In the UK District Heating has got very limited application at the moment and most of the current systems use fossil fuels e.g. coal, oil or gas. However, more recently a handful of District Heating systems have started to use wastes/waste derived fuels or biomass. The increase in prices of gas and oil for heating applications, and the need for reduction of carbon emissions are now drawing attention to biomass district heating in the UK which offers the potential to provide around 20% of all bioenergy heating capacity.

Various incentives e.g. Bioenergy Capital Grant Scheme, Low Carbon Building Programme, Biomass Heat Accelerator Project, etc have helped the development of bioenergy for heating applications in the UK. Currently around 500MW of total installed capacity of bioenergy heating systems are operating in the UK about 75 MW of this has been supported by the BECGS. About 20% of bioenergy heating capacity is in the form of District Heating. Most of these are in Scotland and England with Northern Ireland and Wales having only small capacities.

The availability and ease of use of gas and oil, and unfamiliarity and lack of understanding of biomass district heating systems combined with their higher capital of operating costs have not favoured their application in the UK. However, this has started to change as interest is growing due to various reasons e.g. environmental concerns, higher prices of oil and gas, Government policy and measures to reduce carbon emissions, public awareness of climate change from fossil fuels combustion etc.

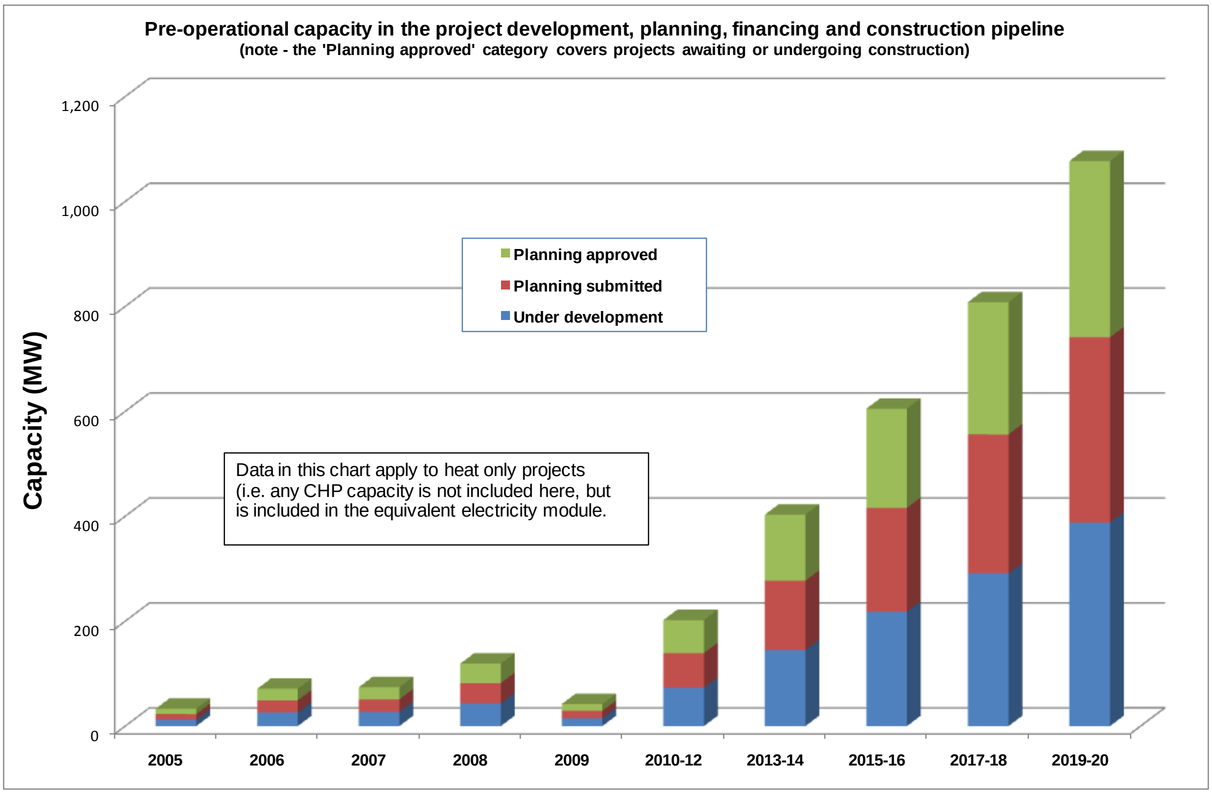
The timescale of biomass district heating from conception to operation depends on the size of installation and other site specific conditions e.g. access to fuel deliver and storage. District heating systems use relatively large boilers (1MW and above) and can take 18 to 36 months as various stages of the project e.g. feasibility study, planning and other consents, construction of building and fuel storage, district heating pipe work laying (in most cases under the ground), installation of boiler and associated equipment have to undergo rigorous processes.

## 17.3 Projected deployment to 2020

Under the central growth scenario the deployment of district heating system is predicted to be 1020MW. The central growth assumes a plausible expansion in renewable heat supply from current state, assuming that incentives to be offered are financially no worse than relevant gas, oil or electric heating options.

Higher growth scenario will raise this to 1500MW. The higher growth assumes a more optimistic development than the central growth.

**Figure 1: Pre-operation phases: project development, planning, financing and construction**




The lower growth scenario assumes a more pessimistic development than the central scenario i.e. 15% less growth each year with a total capacity by 2020 to around 882MW.

In the absence of any other financial incentives, the proposed Renewable Heat Incentive will play an important role to stimulate the growth under each scenario and the level of the RHI offered will have a considerable affect on the growth.

**Table 1: Historic and projected capacity development and deployment 2005 – 2020**

**Biomass district heating** — **Weighted average load factor: 35%**

| | | Total capacties/output in the different categories at the end of the stated year/period | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Unit | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
| | | 31/12/05 | 31/12/06 | 31/12/07 | 31/12/08 | 31/12/09 | 31/12/12 | 31/12/14 | 31/12/16 | 31/12/18 | 31/12/20 |
| Under development | MW | 12 | 26 | 27 | 43 | 15 | 73 | 145 | 218 | 291 | 388 |
| Planning submitted | MW | 11 | 23 | 24 | 39 | 14 | 66 | 132 | 198 | 265 | 353 |
| Planning approved | MW | 10 | 22 | 23 | 37 | 13 | 63 | 126 | 189 | 252 | 336 |
| Operational (central) | MW | 10 | 31 | 54 | 89 | 100 | | | | | |
| Projected operational | MW | | | | | | 160 | 280 | 460 | 700 | 1,020 |
| Energy production | GWh | 31 | 95 | 166 | 273 | 307 | 491 | 858 | 1,410 | 2,146 | 3,127 |

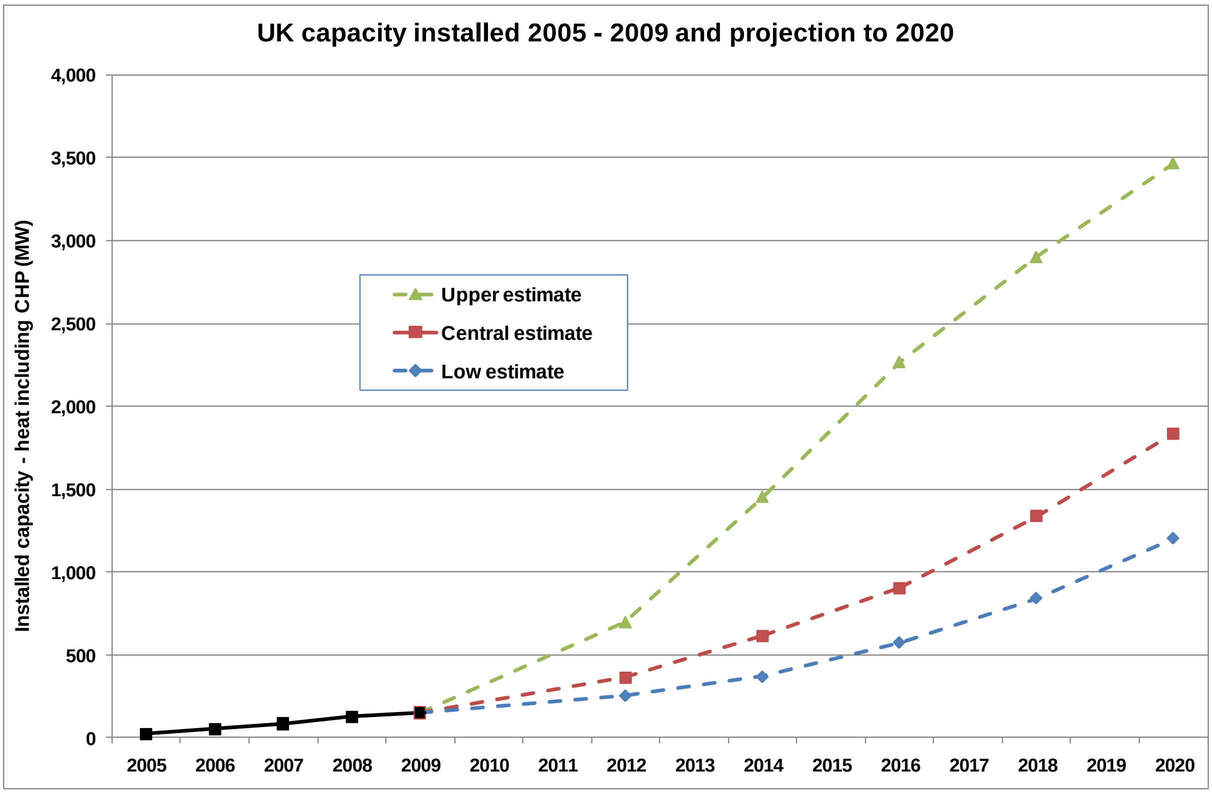
**Range of projected operational capacity (excluding CHP)**

| | | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Low estimate | MW | | | | | 100 | 136 | 238 | 391 | 595 | 867 |
| | GWh | | | | | | 417 | 730 | 1,199 | 1,824 | 2,658 |
| Central estimate | MW | 10 | 31 | 54 | 89 | 100 | 160 | 280 | 460 | 700 | 1,020 |
| | GWh | 31 | 95 | 166 | 273 | 307 | 491 | 858 | 1,410 | 2,146 | 3,127 |
| Upper estimate | MW | | | | | 100 | 200 | 400 | 900 | 1,260 | 1,700 |
| | GWh | | | | | | 613 | 1,226 | 2,759 | 3,863 | 5,212 |

**Range of projected operational capacity including CHP**

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Low estimate | MW | | | | | 151 | 255 | 369 | 575 | 842 | 1,202 |
| | GWh | | | | | | 1,148 | 1,532 | 2,329 | 3,340 | 4,715 |
| Central estimate | MW | 23 | 52 | 83 | 125 | 151 | 362 | 614 | 904 | 1,338 | 1,835 |
| | GWh | 112 | 225 | 345 | 492 | 619 | 1,728 | 2,908 | 4,133 | 6,056 | 8,126 |
| Upper estimate | MW | | | | | 151 | 700 | 1,457 | 2,269 | 2,902 | 3,468 |
| | GWh | | | | | | 3,679 | 7,705 | 11,153 | 13,930 | 16,052 |

**Figure 2: Historic deployment and range of future projections to 2020**




# 17.4 Achieving future deployment – key dependencies

## 17.4.1 Impact of financial incentives

The capital costs (equipment and its installation, district heating distribution pipe work costs) of a biomass district heating system is about three times that of an equivalent gas or oil-fired stand-alone system. Its operating and maintenance costs are also significantly higher. As a result, financial incentives will play a crucial role in its deployment. The Bioenergy Capital Grant Scheme offering up to 40% of capital costs has helped the installation of a limited number of biomass district heating systems in the UK. Other incentives have also played an important role. These incentives have helped to develop the supply chains for equipment and fuels to its current level.

The proposed Renewable Heat Incentive scheme will help the increase in deployment, provided it is high enough to make biomass district heating more attractive than other competing systems. A higher level of RHI is expected to lead to a higher level of deployment.

## 17.4.2 Impact of consenting processes

Consenting processes for biomass district heating, which involve the installation of a large biomass boiler (usually 1MW and above) and district heating distribution network which is mostly under the ground) is complex and takes long time and delays the process. Unfamiliarity and lack of understanding of district heating systems in general and biomass system in particular often results in queries, delaying the process and increasing the costs of projects. The process needs to take into account the special features of biomass district heating e.g. fuel delivery and storage issues, and be made simple and clear so that it operates more swiftly in order to facilitate deployment;

### 17.4.3 Integration to energy markets

The relative cost of biomass compared to other competing fuels, and reliability of supply of right quality fuel for the particular applications will be important to integrate it in the energy market. Due to higher capital and operating costs of a biomass district heating system, the fuel has to be significantly cheaper to make it attractive in the market. Unfamiliarity and lack of understanding of the system discourages its application.

### 17.4.4 Supply chain issues and constraints

The supply chains of biomass boilers for district heating application and fuels are still evolving in the UK. Most of the equipment available in the UK market is imported. Wood chips, which are usually used for biomass district heating, are not available in many parts of the UK with right quality and in sufficient quantity to meet the needs of such systems. Although a handful of equipment and fuel suppliers are now reasonably well established in the market, they mainly cover selected areas of the country. As a result, supply chains for both equipment and fuel need to be expanded considerably covering new areas where there is big potential for growth under any of the growth scenarios.

Incentives are needed e.g. training engineers in carrying out feasibility studies and installing biomass district heating systems. Incentives are also needed to produce fuels domestically e.g. growing energy crops and wood in forests and woodland, producing woodchips from wood and wastes, delivery of fuel to meet increasing demand.

### 17.4.5 Regulatory framework

Regulations will help the growth of biomass district heating systems significantly e.g. renewable heat obligation to produce a certain amount heat from renewable sources, energy tax on other competing fuels for heating application to make the system financially more attractive, increasing landfill tax on bioenergy wastes to make it attractive for use as fuel, planning policy and building regulations to favour biomass use for heating, carbon reduction commitment for private and public sector to encourage use of biomass for district heating.

However, some regulations will adversely affect the growth of biomass district heating. For example, stricter emissions limits of particulates and NOx from biomass boilers will increase the cost of equipment and discourage its use; stricter air quality objectives will deter the use of the system in urban areas.

### 17.4.6 Other potential barriers to deployment

As large investment is needed at the front end for biomass district heating, the overall economic/investment climate will have a considerable affect on the growth of the market. A tendency to stay with familiar fuels for heating rather than going for an unfamiliar fuel i.e. biomass will also act as a barrier in some cases. Unclear policy on planning and other consents will discourage potential developers of biomass district heating projects.

### 17.4.7 Summary of constraints

There are many difficult issues that need to be addressed to help the growth of biomass district heating market in the UK. However, favourable government regulatory policies and financial incentives, in combination with close collaboration among the various parties that are key to the market e.g. relevant Government agencies, potential users of bioenergy boilers, equipment and fuel suppliers will be able to overcome most of these issues.

## Table 2: Significance of various potential constraints on deployment

| Potential constraints | Significance | Comment |
|---|---|---|
| Returns insufficient to stimulate sufficient deployment | Amber | The higher capital and operating costs of bioenergy boilers will have a significant effect on deployment without sufficient financial incentive to overcome these. |
| Planning (local policies, obtaining permissions) | Amber | District heating boilers will need planning permission which will have a significant effect on deployment. |
| Integration to energy markets | Amber | The cost of other competing fuels will have a significant influence. |
| Supply chain issues and constraints | Amber | With the current market of bioenergy boilers at low level, lack of sufficient qualified equipment suppliers and fuel suppliers will adversely affect the rate of uptake. |
| Regulatory constraints | Green | As district heating boilers will be large in size they will be designed appropriately to meet emissions constraints and will not be affected significantly. |
| Institutional barriers | Green | As the renewable energy is getting wide attention in the media this is likely to be a significant problem. |
| Unclear policy (national, regional, local) | Amber | This will discourage potential users to use bioenergy boilers. |
| Motivating investors to act | Amber | As district heating schemes will need higher investment, investors will be careful to get involved in such schemes without sufficient financial incentives. |
| Other constraints (please specify under comments) | | |

| | |
|---|---|
| Green | Unlikely to present a constraint to achieving the central projection. |
| Amber | Could constrain achieving the central projection and will certainly constrain achieving the upper projection |
| Red | Likely to constrain achieving the central projection; could result in only the low projection being achieved |

# 18 Biogas injection into the gas grid

## 18.1 Introduction

This section first outlines the basis of the total biogas resource projection (for all biogas use options - CHP, heat and biomethane to grid and transport fuel) from the likely anaerobic digestion plants based on all feedstock types in the UK. Then it provides estimates the scope for biogas injection into the gas grid in the UK, based on selective discussions with industrial contacts.

There is a general lack of consistent data on wastes and biomass resources that could act as feedstock for biogas production. We have interpolated between different sets of numbers or made the best guesses based on the information available. WRAP (2008) reports food waste amounting to around 18 million tonnes each year, of which 6.7 million tonnes is from UK households. According to Defra (Jan, 2009[30]) the UK produces over 100 million tonnes of organic material per year that could be used to produce biogas; comprising:

- 12-20 million tonnes of food waste (approximately half of which is municipal waste collected by local authorities, the rest being hotel or food manufacturing waste);
- 90 million tonnes of agricultural material such as manure and slurry;
- 1.73 million tonnes of sewage sludge.

A recent report by NNFCC (July 2009[31]) gives the commercial and industrial sector waste as 1.6 million tonnes from retailers, 4.1 million tonnes from food manufacturers and 3 million tonnes from food service and restaurants. Biogas can also be produced from grass silage and energy crops.

The quantitative estimates within different categories are uncertain, but the overall quantity of biodegradable food waste is reported to be around 18 million tonnes per year. This is what we have assumed in this analysis, but divided among four different categories (household, commercial, PPC returns and other), but only around 35% of this is taken as available for AD by 2020. Livestock waste has been taken from the Defra report[4] based on 2004 Livestock Census data. For the purpose this analysis it is assumed that the livestock numbers have not changed significantly.

The UK ranks relatively low in installed capacity of AD plants generally, but the spate of recent announcements (FIT and the impending RHI) in addition to the ROC mechanism is increasing the activities in this area greatly. Most of the plants at the design or construction phases have been considering CHP schemes based on biogas, however, the situation seems to be changing.

Extensive use of the gas grid in the UK to supply natural gas and the Government's proposal under the RHI, to encourage biomethane injection to the national gas grid, have made this an attractive area for the investors to explore. We have come across a great deal of activity from the suppliers of large AD plants.

## 18.2 Historical deployment

Over the last 20 years interest in AD technology (apart from that for traditional sewage sludge plants, which is dealt with under bioenergy to electricity) for livestock and food waste has fluctuated considerably. In practice this led to a very small uptake. The key reason for this was the poor economic returns due to high capital costs of the installation, compared to alterative treatment and disposal options. Since the introduction of the Renewable Obligation Order there has been a rise in the installed electricity generation from around 3 MWe in 2005 to some 6 MWe installed capacity of AD plants in 2009. Most of this capacity is presently in England.

[30] Defra (January 2009); Anaerobic Digestion - Shared Goals; Defra document setting out AD goals for businesses, regulators, and other stakeholders; http://www.defra.gov.uk/environment/waste/ad/pdf/ad-sharedgoals-090217.pdf

[31] NNFCC (2009); Evaluation of Opportunities for Converting Indigenous UK Wastes to Fuels and Energy; Report to the National Non-Food Crops Centre; This project was managed by the NNFCC and funded by DECC; ED45551; July 2009.

It seems that three distinct models for anaerobic digestion will emerge in the UK:

1. On-farm AD plants based on livestock slurry and producing around 50 - 200kW biogas. These will be slow to be implemented as the returns are still poor.

2. Merchant AD plants based on mixed farm and food waste with a proportion of energy crop and producing between 1500 and 5000 kW biogas, but typically 2000kW. These will often be rural or farm enterprises built by local consortia to manage local waste streams.

3. Dedicated food and green waste treatment installations operated by local authority or waste management contractor, based on the regulatory pressures and influenced by local authorities' waste strategies and plans.

## 18.3 Projected deployment to 2020

An initial estimate was made of the projected deployment to 2020 and this was used to compare industry's response. A range of views were expressed and an attempt has been made to reflect the consensus. Where an individual has expressed a significantly different view this is noted. Our projection of the total biogas energy available by 2020 is 11 TWh; of this over 80% will be derived from food wastes and the remainder would be made of livestock wastes and energy crops which will be used to balance the seasonal variations in the availability of wastes. Beyond 2020, the scope for livestock wastes and energy crops could be much higher.

The total biogas resource is divided among four separate modules in this report. Our estimates for the 2020 resources are as follows:

| Installed capacities of biogas use (MW biogas) | Low | Central | High | Section of the report dealing with the resource |
|---|---|---|---|---|
| Biomethane to gas grid | 480 | 970 | 1310 | In this section (Biogas injection into gas grid) |
| Biomethane to transport fuel | 60 | 110 | 150 | In Biomethane to transport fuel |
| Biogas to CHP | 230 | 460 | 620 | In Bioenergy for electricity** |
| Biogas to heat only | 100 | 210 | 280 | In Energy from waste – heat |
| Total resource as predicted | 870 | 1750 | 2360 | |

** The scope for large CHP plants is expected to diminish due to the RHI and any AD plants installing CHP will tend to use much of the waste heat on site based requirements; thereby creating little or export heat.

There are no known schemes of biogas to gas grid but many are now being considered, largely brought about by the National Grid's drive in search for new gas supplies. British Gas recently announced[32] the prospect of five demonstration projects to develop the technology to upgrade biogas for injection into the gas grid. The first project is currently under way at Thames Water's Didcot sewage works and is expected to be operational by mid 2010. This is likely to become a test bed for British Gas implementing the biogas upgrading technology at other sites which will include large AD plants based on food waste, livestock manures and industrial waste such as brewery effluent.

**Low estimate**

The low estimate is based on pessimism expressed by those looking at the scope for AD plants based on livestock waste and energy crops. Philip Lukas of Cosigas Ltd felt that UK agricultural base is similar in size to Germany with large amounts of agricultural slurries, wastes (apple pomace, carrot tops, etc) and large areas of grassland. This is in addition to significant amount of land available for annual biomass crops such as maize and whole crop silage. To achieve 1000MW of plants fed only with maize one would use 300,000 hectares[33] of rotational land; but this would require FIT around 15-17 p/kWH and RHI around 7-9 p/kWh.

[32] http://www.tcetoday.com/tcetoday/NewsDetail.aspx?nid=12484
[33] Compared to arable land base of 5m hectares and 6m hectares of grassland in the UK.

### Central estimate

This is based on our recent projections for CCC, which falls between the low and high estimates expressed by industry.

### High estimate

We are uncertain of the specific issues that will give rise to the high growth rate. However, we are coming across directly, and seeing reports, of a lot of interest from farming and other rural sector where there is the scope of co-digesting livestock slurry with selected by-products and/or energy crops.

Biomethane to gas grid is considered the most convenient and generally cost-effective for schemes producing greater than around 1000 m3/h biogas. As a result a greater proportion (55% overall) of the 2020 biogas resource has been allocated to this option.

### Table 1: Historic and projected capacity development and deployment 2005 – 2020

**Biogas injection into gas grid** | **Weighted average load factor: 70%**

| | | Total capacties/output in the different categories at the end of the stated year/period | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Unit | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
| | | 31/12/05 | 31/12/06 | 31/12/07 | 31/12/08 | 31/12/09 | 31/12/12 | 31/12/14 | 31/12/16 | 31/12/18 | 31/12/20 |
| Under development | MW | | | | | 0 | | | | | |
| Planning submitted | MW | | | | | | | | | | |
| Planning approved | MW | | | | | | | | | | |
| Operational (central) | MW | 0 | 0 | 0 | 0 | 0 | | | | | |
| Projected operational | MW | | | | | | 91 | 283 | 526 | 758 | 968 |
| Energy production | GWh | 0 | 0 | 0 | 0 | 0 | 560 | 1,734 | 3,227 | 4,646 | 5,937 |

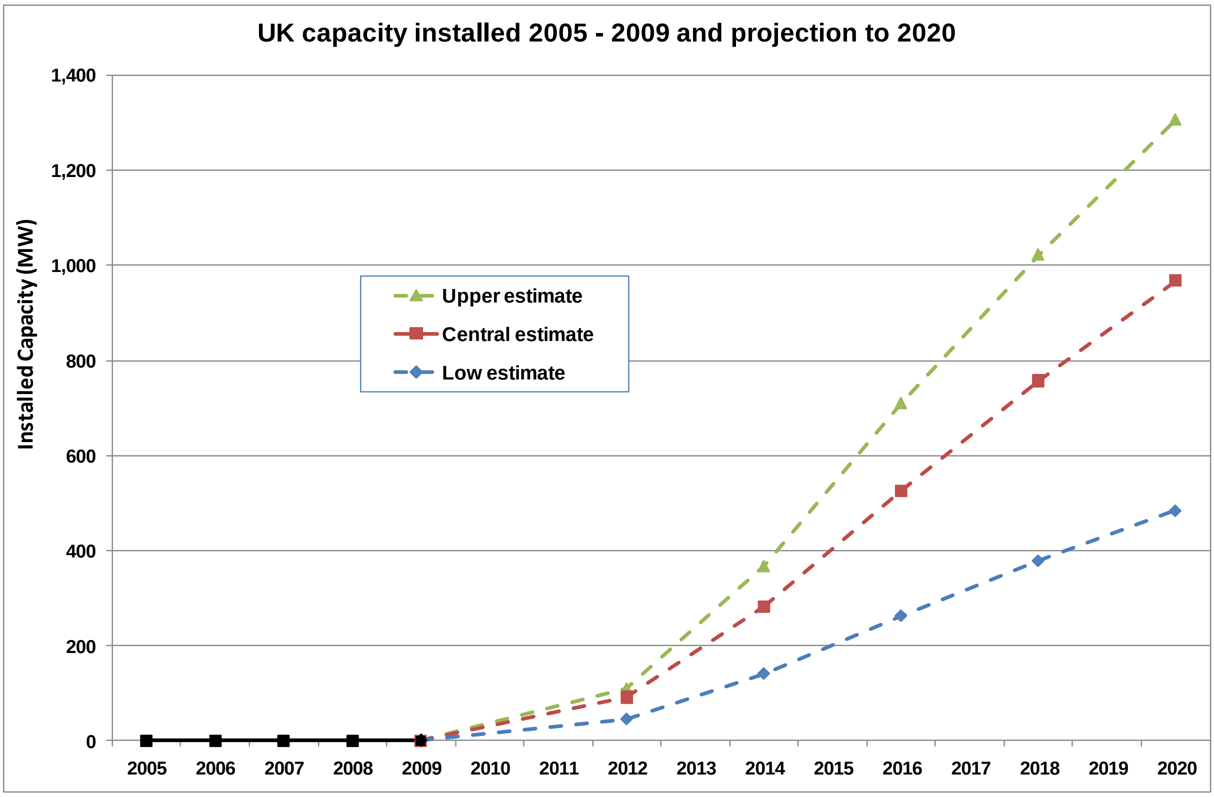
**Range of projected operational capacity**

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Low estimate | MW | | | | | 0 | 46 | 141 | 263 | 379 | 484 |
| | GWh | | | | | | 280 | 867 | 1,613 | 2,323 | 2,969 |
| Central estimate | MW | 0 | 0 | 0 | 0 | 0 | 91 | 283 | 526 | 758 | 968 |
| | GWh | 0 | 0 | 0 | 0 | 0 | 560 | 1,734 | 3,227 | 4,646 | 5,937 |
| Upper estimate | MW | | | | | 0 | 110 | 368 | 710 | 1,023 | 1,307 |
| | GWh | | | | | | 672 | 2,254 | 4,357 | 6,272 | 8,015 |

### Load Factors/energy output

A load factor of 70% is used and generally accepted by the industry, due to seasonal variation of practically all feedstock, except food waste from households. It is expected that this will rise with the use of energy crops and the introduction of RHI.

**Figure 2: Historic deployment and range of future projections to 2020**




# 18.4 Achieving future deployment – key dependencies

These comments are based on industry views. There is a noted variation in views between those focussed on large merchant AD plants (based on food waste) and those dealing with rural or agro-industrial AD plants. This is because the former category avoids the high landfill gate fees for the disposal of food waste; whereas those in the latter category are dealing with wastes that have not traditionally attracted such disposal fees and will therefore provide lower returns on investment.

## 18.4.1 Returns insufficient to stimulate sufficient deployment

The suite of incentives is welcomed by the industry and some regard them as key building blocks that will stimulate the biogas market. There is much focus on the standards of gas cleaning for injection into the gas grid and because of the uncertainties over the standards required (see below). Some have suggested raising the level of support for biomethane to grid for a period of two-three years, to allow testing and demonstration phase to bring about greater confidence and reduce uncertainties in the economics. For agricultural or livestock waste plants the tariff is definitely considered low.

For biomethane from gasification the scope is limited unless RHI provides support above 5.5 p/kWh. This will also stimulate market for Bio Syngas, which is almost stagnant. With the announcement of the RHI, CHP is relatively less attractive and therefore will have lower share of the market going forward.

## 18.4.2 Planning (local policies, obtaining permissions)

Planning policy is generally supportive of AD development, provided that site-specific environmental issues can be dealt with satisfactorily. The most important issues for AD plants are transport, odour and noise. No major obstacles are foreseen and it is worth noting that a greater proportion of applications are being passed due to greater awareness of AD technology among planning personnel.

### 18.4.3 Integration to energy markets

There is a good set of options to supply biogas to market – prominent and most active of these is the biomethane grid injection. Access to the gas grid provides the most convenient energy market (issues with gas standards and measurement being the issue of concern). There are potential heat users but the progress will be limited to large industrial process heat users from here on. It will be difficult to link to the heat market for any AD plants in rural areas.

### 18.4.4 Supply chain issues and constraints

No major supply chain issues are foreseen. Lots of AD plant suppliers are available in the UK. Wide scale provision of training of AD plant operators will help to expedite the uptake.

### 18.4.5 Regulatory constraints

AD plants are generally favoured as long as they are proposed to be built to the required standards. Planning consent, EPC (Environmental Performance Consent by the Environment Agency) or PAS110 accreditation for the disposal digestate are not seen as constraints.

At present the biggest issue concerns biomethane gas specification that requires less than 0.2% oxygen. This is a safety issue (for which the HSE is the responsible body) in the transmission of the gas supply; this issue also has implications on the measurement for charging. It is seen by the industry as a major risk and a barrier in accessing the gas grid to inject biomethane.

There is also an issue relating to the method of making Bio-SNG from biomass. In Section 100 of the Energy Act 2008, biogas is limited to gas produced by 'the anaerobic conversion of organic matter' and the biomethane definition depends on the biogas definition. The problem highlighted by a representative of the UK industry (John Baldwin, Chair of the UK Biogas Group, part of REA) is that Bio-SNG cannot therefore be regarded as biogas or biomethane despite its origin being biomass. This would almost certainly make it ineligible for the biomethane injection tariff. The suggestion offered was to modify the definition of ‘biogas’ to include gas made from thermal processes. This does not require a change to the primary legislation, as Section 100(5)(b) allows for the definition of biogas (but not biomethane) to be modified by an RHI Order.

### 18.4.6 Institutional barriers

Administratively RHI seems simple and is appreciated. However, there is no incentive at present for the gas distribution companies to join in this drive towards increasing the use of biomethane in their managed grid (other than through CSR and wider responsibility) and this could prevent the full potential to be realised in the near future. Positive encouragement to the gas distribution companies will allow several local tweaks to accommodate the new plants to inject into the grid.

### 18.4.7 Unclear policy (national, regional, local)

There is generally a positive move towards AD and biomethane to gas grid, but clear policies in favour of AD will help. Scotland’s Zero Waste policy by 2025 and Welsh Assembly Government’s positive encouragement of AD for all food waste from the local authorities is helpful.

An EU Legislation that is likely to be passed in 2010 is the EU Biowaste Directive. The definition of biowaste is given as biodegradable garden and park waste, food and kitchen waste from households, restaurants, caterers and retail premises, and comparable waste from food processing plants. As part of its preparation, the EU launched a consultation on biowaste management in June 2009. The stated aims are to encourage recycling of food waste to agricultural land and improve soil and its nutrients – through standards for composted products.

### 18.4.8 Motivating investors to act

No major problem is foreseen. Some investors would like to see the question over gas quality for biomethane addressed. Those dealing with livestock wastes, agro-industrial waste and energy crops would like the incentives in RHI to be raised.

### 18.4.9 Other constraints to deployment

The credit crunch has not affected the market or the enthusiasm for investment in AD technology. The suite of market instruments are generally seen to be very positive.

**Table 2: Significance of various potential constraints on deployment**

| Potential constraints | Significance | Comment |
|---|---|---|
| Returns insufficient to stimulate sufficient deployment | Green | The suite of incentives is welcomed by the industry and some regard them as key building blocks that will stimulate the biogas market. Some have suggested to raise the level of support for two-three years, to allow testing and demonstration phase to bring about greater confidence and reduce uncertainties in the economics. For agricultural or livestock waste plants the tariff is definitely considered low. Biomethane from gasification will have limited scope as the incentive is seen as inadequate. |
| Planning (local policies, obtaining permissions) | Green | Planning policy is generally supportive of AD development, provided that site-specific environmental issues can be dealt with satisfactorily. The most important issues for AD plants are transport, odour and noise. No major obstacles are foreseen. |
| Integration to energy markets | Green | There is a good set of options to supply biogas to market – prominent and most active of these is the biomethane grid injection. Access to the gas grid provides the most convenient energy market. |
| Supply chain issues and constraints | Green | None of significance. Lots of AD plant suppliers are available in the UK. Wide scale provision of training of AD plant operators will help to expedite the uptake. |
| Regulatory constraints | Amber | AD plants are generally favoured as long as they are to be built to the required standards. Planning consent, Environmental Permit by the Environment Agency or PAS110 accreditation for the disposal digestate are no longer seen as constraints.<br>At present the biggest issue concerns biomethane gas specification that requires less than 0.2% Oxygen. This is a safety issue (for which the HSE is the responsible body) in the transmission of the gas supply; this issue also has implications on the measurement for charging. At present the scope for injecting biomethane derived from the gasification of biomass is limited (Bio Syngas) and unlikely to impact on the 2020 tagets. |
| Institutional barriers | Green | Administratively RHI seems simple and is appreciated. Some incentives to bring gas distribution companies to join will be helpful (other than through CSR and wider responsibility). |
| Unclear policy (national, regional, local) | Green | There is generally a positive move towards AD and biomethane to gas grid, but clear policies in favour of AD will help. Scotland's Zero Waste policy by 2025 and Welsh Assembly Government's positive encouragement of AD for all food waste from the local authorities is helpful.<br>An EU Legislation that is likely to be passed in 2010 is EU Biowaste Directive, will add further emphasis on AD technology and thereby biomethane to gas grid. |
| Motivating investors to act | Amber | Some investors would like to see the question over gas quality for biomethane addressed. Those dealing with livestock wastes, agro-industrial waste and energy crops would like the incentives in RHI to be raised. |
| Other constraints (please specify under comments) | Green | The credit crunch has not affected the market or the enthusiasm for investment in AD technology. The suite of market instruments are generally seen to be very positive. |

| | |
|---|---|
| Green | Unlikely to present a constraint to achieving the central projection. |
| Amber | Could constrain achieving the central projection and will certainly constrain achieving the upper projection |
| Red | Likely to constrain achieving the central projection; could result in only the low projection being achieved |

# 19 Deep geothermal heat

## 19.1 Introduction

Conventional geothermal energy exploits naturally occurring hydrothermal systems by extracting heated fluids either from permeable aquifers or fracture systems. In some areas of the world the heat resource can be used for electricity generation where it is sufficiently close to the surface. Until the 1970s the UK was not regarded as a region with geothermal potential. During that decade the UK evaluated the deep geothermal resource from both conventional aquifers and granites. At the time the results from aquifers were not sufficiently encouraging to develop the resource.

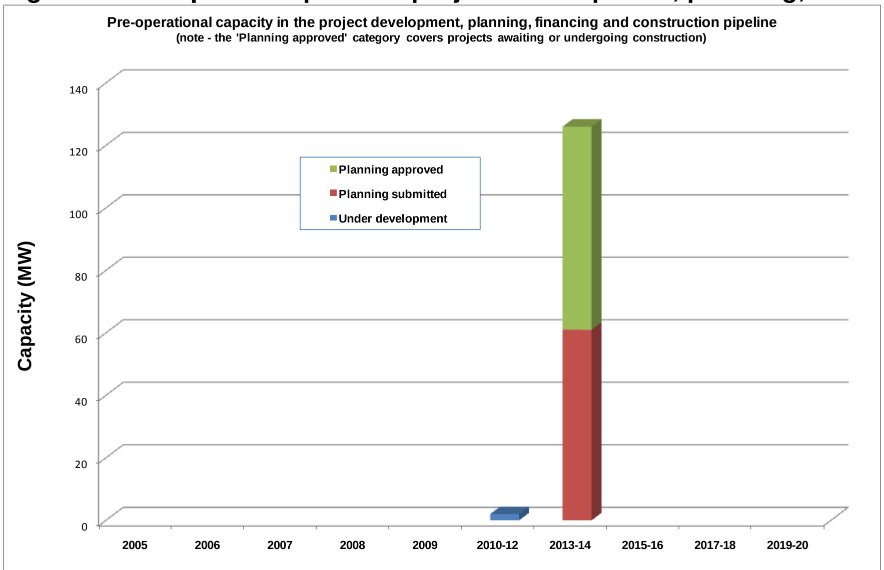
The UK also pioneered Hot Dry Rock (HDR) technology which was designed to extract heat from granites. A series of drilling and circulation experiments were carried at a disused granite quarry at Rosemanowes, near Falmouth in Cornwall. Work started in 1977 with a demonstration of the feasibility. In 1990 a major Programme review concluded that the technology was technically problematic and uneconomic. In 1993 the programme was closed although some UK expertise was transferred to the European HDR programme.

Despite the closure of the UK HDR programme several countries have continued with its development including France, Germany, Japan and Australia. The concept is now referred to as Enhanced or Engineered Geothermal Systems (EGS). It works on the same principle as HDR but targets large fault systems which have known naturally occurring fluid flow. Experimental development at the European site near Soultz and elsewhere has been encouraging. Confidence in EGS technology has led to the development of a 3.8 MW electrical plant near the German town of Landau These advances have reactivate interest in the UK. There are now two prospective projects in Cornwall and a scheme in at Eastgate in Weardale. The Eastgate scheme is now under development. All three schemes could provide heat. The two Cornish sites are also being developed for electricity generation[34].

## 19.2 Historical deployment

The UK's aquifer programme did lead to a single demonstration scheme was developed under the city of Southampton. It supplies approximately 2MW heat load into a district heating scheme. The flow rate has halved since in began operating over 20 years ago. Eventually the flow rate and temperature will drop to a point where it will be no longer economic to continue. Pumping will need to be curtailed for several years until heat and flow within the aquifer regenerates.

**Figure 1: Pre-operation phases: project development, planning, financing and construction**




[34] http://www.cornwall.gov.uk/default.aspx?page=22652

## 19.3 Projected deployment to 2020

The only deep geothermal source currently operation in the UK is the Southampton district heating scheme. Its rated heat output is ~2MW. It has been operating since the mid 1980s and it is likely that the borehole will need to be shut down by 2017. It is for this reason that the projected capacity in 2017 is predicted to decline by 2 MW.

There are three other geothermal schemes either under development or in planning.

- Eastgate in Weardale (~2MW)[35]
- EGS Energy, Eden Project, Cornwall (~6MW)[36]
- Geothermal Engineering, Redruth, Cornwall (55MW)[37]

Eastgate is currently underdevelopment. One borehole has been drilled and established a profile flow rate of 60$m^3$/hr but formation waters are only 26$^{\circ}$C[38]. A second borehole is currently being drilled and it is possible that formation waters at greater depth could be recovered. The heat output has been calculated based on the published figures for temperature and flow rate. A 50% load factor has been assumed. There is an intention to develop the Eastgate site into a spa resort. It has been assumed that it may take until 2013 – 14 to attract and develop the heat source.

**Table 1: Historic and projected capacity development and deployment 2005 – 2020***

**Deep geothermal heat (with CHP)** — **Weighted average load factor: 50%**

| | Unit | Total capacties/output in the different categories at the end of the stated year/period | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
| | | 31/12/05 | 31/12/06 | 31/12/07 | 31/12/08 | 31/12/09 | 31/12/12 | 31/12/14 | 31/12/16 | 31/12/18 | 31/12/20 |
| Under development | MW | | | | | | 2 | | | | |
| Planning submitted | MW | | | | | | | 61 | | | |
| Planning approved | MW | | | | | | | 65 | | | |
| Operational (central) | MW | 2 | 2 | 2 | 2 | 2 | | | | | |
| Projected operational | MW | | | | | | 2 | 65 | 65 | 63 | 63 |
| Energy production | GWh | 9 | 9 | 9 | 9 | 9 | 9 | 285 | 285 | 276 | 276 |

**Range of projected operational capacity including CHP**

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Low estimate | MW | | | | | 2 | 2 | 62 | 62 | 60 | 60 |
| | GWh | | | | | | 9 | 312 | 312 | 303 | 303 |
| Central estimate | MW | 2 | 2 | 2 | 2 | 2 | 2 | 120 | 120 | 118 | 118 |
| | GWh | 9 | 9 | 9 | 9 | 9 | 9 | 596 | 596 | 587 | 587 |
| Upper estimate | MW | | | | | 2 | 2 | 137 | 137 | 135 | 135 |
| | GWh | | | | | | 9 | 689 | 689 | 680 | 680 |

* The top table includes only the 'heat-only' plant whilst the bottom incorporates heat from electricity generating plant, all of which are projected to be CHP.

The EGS energy site has reached a pre-planning stage. It is being developed to supply the Eden project with a renewable heat source. It is also being designed to generate 3 MW of electricity. The heat capacity has been estimated by comparison with the Landau project in Germany which has a thermal output of between 3 – 6 MWth.

The Geothermal Engineering project, located near Redruth is designed to have a thermal output of 55 MW and an electrical output of 10 MW.

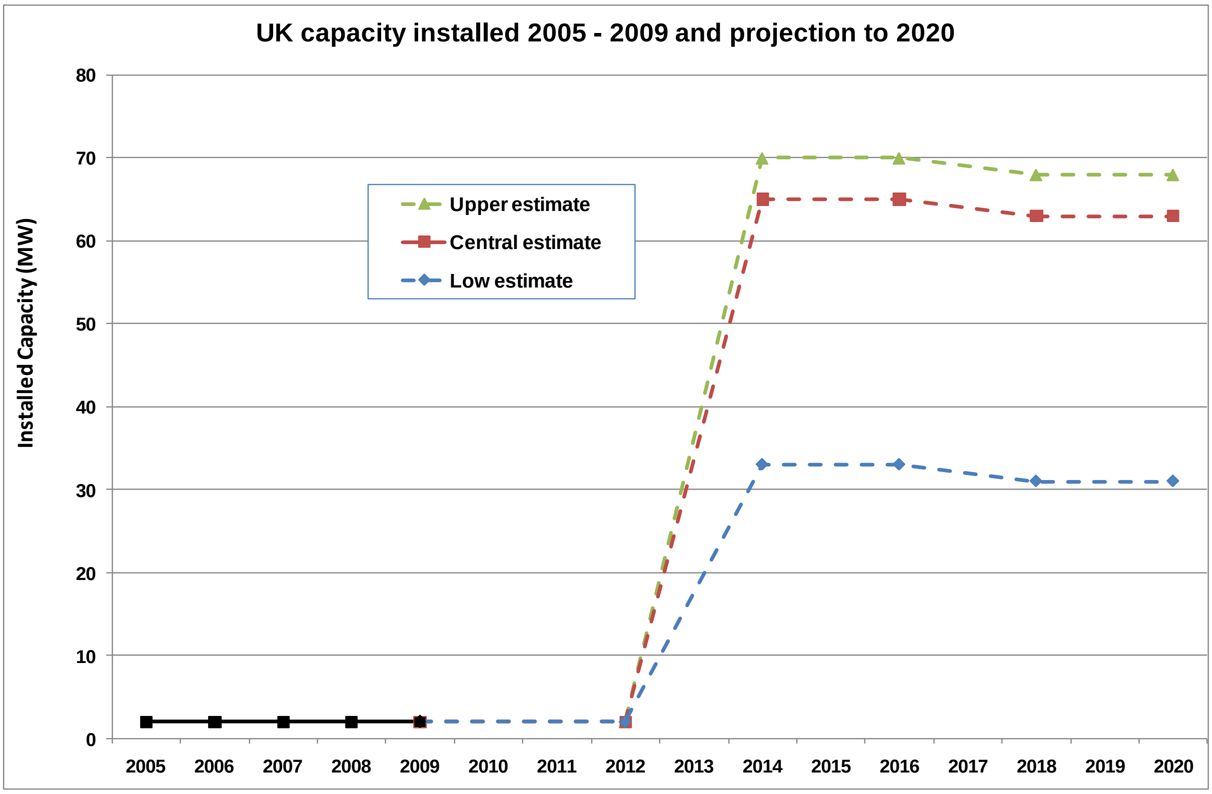
[35] The Redevelopment of the Weardale Works 2002 – 2008 laying the foundations for a new are. The Weardale Taskforce, Durham County Council, One North-East, Lafarge Cement, December 2009.
[36] EGS Energy website 26/03/2010 http://www.egs-energy.com/

[37] Geothermal Engineering website 26/03/2010 http://www.geothermalengineering.co.uk/page/projects-and-developments.html
[38] Eastgate borehole, interim report, December 2004, D Dufton PB Power, P L Younger University of Newcastle and D Manning University of Newcastle

According to Cornwall County Council Natural Resources Department, the Redruth project was submitted for planning approval in early March. The application is only for drilling and testing the resource not power station or infrastructure development. EGS Energy has yet to submit a formal planning application[39], [40].

In both cases the resource will need to be evaluated before it any surface energy conversion plant can be considered. It has therefore been assumed that planning for power plants will be submitted and approved at least two years from 2010.

**Figure 2: Historic deployment and range of future projections to 2020**




The central estimate assumes that the three schemes under development, plus Southampton operate at a 50% load factor until 2017-18 when Southampton shuts down. The other schemes continue to operate at a uniform rate until 2019-20,

The low estimate assumes that the heat capacity from the two Cornish projects is half the current estimates (i.e. EGS 3 MWth and Geothermal Engineering 28MWth). The high estimate assumes that the Geothermal Engineering scheme manages to achieve a rated output of 60MWth and the EGS project produces 6MWth. Both Eastgate and Southampton still operate at 2MWth. Until the three projects are fully proven estimates are conjectural in the absence of technical data. Geothermal energy is difficult to predict with certainty until exploratory boreholes have been drilled and flow rate and temperature data confirmed. The lower estimate is conservative. The upper estimate assumes that a single site is unlikely to yield substantially more energy than the central estimate.

If these projects can be successfully developed there is the prospect of further development in Cornwall and the north of England. However, this will be influenced by the successful technical and commercial demonstration of these projects. There will also need to be more detailed resource assessment. For these reasons it has been assumed that only three new projects will be developed by 2020.

[39] Article which mentions projects in Cornwall at pre-planning stage, http://www.cornwall.gov.uk/default.aspx?page=22652
[40] Telecom with Cornwall County Council Natural Resources planning department (01872 322611) on 26/03/2010

# 19.4 Achieving future deployment – key dependencies

## 19.4.1 Impact of financial incentives

The introduction of the Renewable Heat Incentive (RHI) and ROCs has influenced the revival of commercial interest in deep geothermal energy. The RHI offers all three schemes a potential revenue stream for the use of heat. ROCs are the primary reason for developing the two Cornish projects. Both companies aim to target deep geothermal resources with sufficient surface energy to generate electricity.

## 19.4.2 Impact of consenting processes

Only one geothermal project, Eastgate, is under development. The site is in a former cement works. There are plans to redevelop the entire site as a leisure complex. Consent is unlikely to be an issue.

The two Cornish projects will only apply for consent to carry out exploratory drilling in the first instance. There will need to be a second stage planning application for the power plant development. Cornwall County Council has offered positive support to these projects which have a high local profile. Provide they meet planning requirements it is likely that they could proceed to full-scale development.

## 19.4.3 Integration to energy markets

The two projects that generate electricity will need to rely on ROCs or FITs. The sale of heat could be harder to integrate. EGS Energy plan to supply heat to the Eden project where there is an obvious and co-incident demand. However, the larger, Geothermal Engineering project will need to develop a heat demand equivalent to a 55MW load. Details of the site, and a potential heat load, are not known.

The Eastgate project is being developed with a heat load application in mind. Other deep geothermal projects which are developed to supply heat will need to locate near a co-incident demand. There is a possibility of one site in central Newcastle.

## 19.4.4 Supply chain issues and constraints

The deep geothermal resource is limited at present and therefore significant supply chains issues are likely to occur. It is possible that there may be shortages of specific technical skills such as drilling, hydraulic stimulation and evaluation. Energy conversion to electricity from a low enthalpy resource will need to rely on imported equipment.

## 19.4.5 Regulatory framework

The regulatory framework should be able to accommodate the limited development of the technology within the UK.

## 19.4.6 Other potential barriers to deployment

One of the potential areas of concern is the potential for induced seismicity. EGS technology relies on hydraulic fracturing of hard crystalline rocks such as granite. Water is injected under high pressure to widen existing joints and fractures in the rock. This can induce movement and the release of seismic energy causing shock waves. The development of EGS projects has created shock waves that have been felt at the surface. Public concern has even caused schemes to close. There is some dispute as to whether this phenomenon will occur in the UK's projects. It is likely that localised monitoring will be necessary to discriminate between induced seismicity and naturally occurring earthquakes.

## 19.4.7 Summary of constraints

- Planning approval likely to be positive, especially as there are only three projects under development or proposed.
- Development of markets for heat could be restricted unless a suitable load can be developed.
- Induced seismicity is potentially capable of stopping or closing projects.

A summary of the constraints is presented in the Table 2 below, with a green/amber/red rating to indicate the impact each constraint may have on projected deployment.

### Table 2: Deep geothermal heat: summary of constraints and key dependencies

| Potential constraints | Significance | Comment |
|---|---|---|
| Returns insufficient to stimulate sufficient deployment | Amber | Projects which have the potential to generate electricity would received 2 ROCs. Until drilling and appraisal has been completed developers will not know if they can generate sufficient electricity to justify a return on investment. Heat supply will depend on the viability of electricity generation. The only 'heat only' project still requires further technical appraisal before the resource can be proven and developed. |
| Planning (local policies, obtaining permissions) | Green | Planning for all three projects is likely to be positive. There is regional support for the development of these projects to meet renewable energy targets and stimulate regeneration. |
| Integration to energy markets | Green | Electricity generation will need to rely on ROCs. Heat depends on the extent of local demand within the proximity of each scheme |
| Supply chain issues and constraints | Green | Deep geothermal energy is limited at present. Development may require some expertise outside the UK. Electricity generation equipment will need to be imported. |
| Regulatory constraints | Green | Geothermal schemes can generate saline fluids which will need to be reinjected into the heat exchange reservoir. Provided this is carried these schemes should be compliant with environmental regulations. |
| Institutional barriers | Amber | Geothermal heat is suitable for large base load applications such as district heating. If it is not co-incident with demand there is unlikely to be a market. It will also compete with low risk heat from fossil fuels and renewable sources. |
| Unclear policy (national, regional, local) | Amber | There is no clear policy on the development of geothermal energy or active funding for it (other than the recent geothermal challenge). Regional / national resource assessment could be substantial. |
| Motivating investors to act | Amber | Although there are poetnatilly large geothermal resources and the prospect of firm generation, deep geothermal remains a relatively high risk technology to develop. |
| Other constraints (please specify under comments) | Amber | Induced seismicity has created negative preceptions of EGS schemes. |

| | |
|---|---|
| Green | **Unlikely to present a constraint to achieving the central projection.** |
| Amber | **Could constrain achieving the central projection and will certainly constrain achieving the upper projection** |
| Red | **Likely to constrain achieving the central projection; could result in only the low projection being achieved** |

# 20 First generation biofuels

## 20.1 Introduction

Currently in the UK first generation technologies for biofuel production refer mainly to the fermentation of sugars to bioethanol and the trans-esterification of fats and oils to biodiesel. These technologies are commercially proven and there are many plants in operation around the world. The most common bioethanol technologies use sugar beet or wheat in the UK, or corn or sugar cane overseas. The most common biodiesel processes in the UK use used cooking oil or tallow as a feedstock, but biodiesel can also be made from rape seed oil, palm oil or soy oil. In addition in the UK pure vegetable oil (PVO) and biogas are also used as transport fuels. These are also commercial technologies, although there are far fewer plant in operation than for bioethanol and biodiesel.[41]

The main commercial issues for current biofuels are the price of feedstock and competing price of fossil fuels. A number of feedstocks for these processes can also be used for food or feed crop and their price and availability is impacted by the price of commodities in these markets. There have been successful biofuels markets for some years, notably in Brazil (bioethanol from sugar cane) and the USA (bioethanol from corn). In the EU the dominant market is for biodiesel from used cooking oil, tallow or various plant oils, and the amount produced has increased steadily since the late 1990s.

UK growth in biofuels production is related to the introduction of duty incentives in 2004 and the Renewable Transport Fuel Obligation in 2008. In 2008/9 2.7% of UK road transport fuels was supplied from biofuels (1284 Ml), twice the supply in 2007/8. Biofuels from UK grown crops (mainly oil seed rape and sugar beet) met 5% of the total supplied. Biofuels from other feedstocks (used cooking oil and tallow) increased the biofuels from UK feedstocks to 9% of total biofuels supplied.

In 2008/9 the land used in the UK to grow biofuels crops was estimated by the Renewable Fuels Agency (RFA) to be 33,000ha of land. This RFA data also shows that a significant proportion of UK biofuels are currently sourced abroad (biofuels from crops grown overseas made up at least 64% of the total supplied under the RTFO in 2008/9) and many market players think this will continue and expand (see, for example, some of the industry responses to the Renewable Energy Strategy consultation). Thus it is most accurate to examine UK biofuels in terms of global (or at least EU) supply, as importing will continue to impact supply. In 2008/9 the RFA estimated that around 1.3 Mha of land outside the UK were used for crops producing biofuel feedstocks for the UK market, primarily soy in the USA and Argentina and oilseed rape in Germany (RFA 2010).[42]

In the UK suppliers can currently blend up to 5% of road fuel with biofuels without the need for labelling; in 2010 this will increase to 7%. If the UK is to achieve its 10% target in 2020, it is likely that we will need higher blends from around 2016. The amount that can be achieved from first generation biofuels is elastic and will be related to the amount that is required to achieve the 10% target. In the Renewable Energy Strategy this is given as 49TWh/y and we have assumed that this represents a 10% figure for transport fuel. We have estimated that this would be made up of 50% bioethanol and 50% biodiesel, based on a view of availability of bioethanol and the more common use of biodiesel in the UK vehicle parc.

For this study we have examined biofuels supplied in the UK market since 2005. This shows a rapid growth from around 118 million l in 2005 to 1361 million l in 2009. Most of this growth is currently in biodiesel, which supplies more than 3 times as much as bioethanol. However, it is predicted that biodiesel will hit supply and blending constraints before bioethanol, which means that the market share of bioethanol may increase relative to biodiesel.

[41] In fact there are many anaerobic plants in the UK that produce a biogas containing 40-60% methane. . These plants predominantly generate heat or power. In this report, however, we are only interested in the plants where biogas is cleaned up or upgraded to biomethane suitable for use as a vehicle fuel. This is discussed in the anaerobic digestion module.
[42] RFA (2010) states “In 2008/09, 24% of the biofuel used in the UK came from Brazil, Argentina, Malaysia and Indonesia (with small volumes imported from Pakistan and Malawi).”

## 20.2 Historical deployment

Table 1 and Figure 2 show UK biofuels supply 2005-2009 and projections to 2020. Historical data comes mainly from the HMRC's tradeinfo database, the Hydrocarbon Oils Bulletin.[43]

Biofuels are not economically competitive against fossil fuels in the UK, and their deployment has been stimulated mainly by Government incentives, as indicated above:

- The Government put a fuel duty incentive in place in 2004, currently 20ppl. This is due to be withdrawn for all but biodiesel from used cooking oil from April this year.
- The Renewable Transport Fuel Obligation put in place an Obligation on suppliers to supply an annually increasing proportion of their fuel from biofuels. The RTFO was introduced in 2008 and will continue until at least 2020. The system allows the suppliers to purchase certificates if they cannot meet the Obligation.

However, there have been rapid increases in fuel prices at the pump in the UK and this has stimulated some fleet operators and private motorists to use higher blends of biodiesel to decrease their costs. This is usually UK supplied biodiesel produced from used cooking oil.

## 20.3 Projected deployment to 2020

Projections have been calculated from the projected increase of the RTFO to 2013/14 and three predicted trajectories thereafter. These estimates are based on the need to achieve 10% by energy content in the Renewable Energy Directive. The central estimate assumes that the 10% target will be met, using 8% first generation biofuels, with the remainder being met by electric vehicles or advanced biofuels or biomethane – or a combination of all three; the lower estimate assumes only 7% will be met and that this will probably be through biofuels. The upper estimate is based on the central estimate but assumes 10% supply from first generation biofuels because biofuels will also be important to achieving the Fuel Quality Directive (FQD). In all scenarios the estimates to 2013/14 assume that the RTFO targets will be met.[44] In addition we have not taken the development of electric vehicles or biomethane into account in the lower and upper estimates: in these estimates if these technologies are successful then it is likely they will either displace biofuels or the amount of fossil fuel supply will decrease and so the volume of biofuels needed to achieve the target will decrease. The net effect of this would be that amount achieved through biofuels will be lower, but we have not modelled these interactions in this module.

All of the projections assume that for first generation biofuels 50% of the biofuels will be bioethanol and 50% will be biodiesel. This is because bioethanol production is projected to increase globally far more rapidly than biodiesel production, so there will be more supply available; and most sources indicate that there is no blending problem with ethanol in petrol to 10%, but there are blending problems with biodiesel. However, it is likely that biodiesel will hold its own in the EU where there is high demand for diesel.

The low estimate assumes that various constraints will prevent UK supply achieving more than 7%. We have also assumed in this scenario that the 10% target will not be met. The 7% figure is based on the technical issues associated with blending and assumes that these blending issues are important in resulting in a missed target. It is possible, however, that in missing the target for reasons related to sustainability the level achieved could be as low as 5%.

The main constraints considered in the setting of the low estimate include:

- The UK Government indicated that it would only sign up to the 10% limit if advanced biofuels were developed.[45] It has also expressed concern about the sustainability of biofuels, slowing UK targets to allow more sustainable fuel supply to be developed. Mandatory sustainability

[43] https://www.uktradeinfo.com/index.cfm?task=bulletinarchive&bulletincat=2
[44] These can be found in the Renewable Transport Fuel Obligations Order 2007 (as amended) (version in force on 15 April 2009)
[45] DfT (2007) UK Report to European Commission under Article 4 of the Biofuels Directive (2003/30/EC) http://www.dft.gov.uk/adobepdf/165240/UK_Report_to_the_European_C1.pdf States that the UK wants the proviso that "the binding nature of the target is only appropriate subject to production being sustainable, second-generation biofuels becoming commercially available and the Fuel Quality Directive being amended accordingly to allow for adequate levels of blending."

criteria have been introduced within the RED, but if these prove unsatisfactory a further slowing may be considered. In addition there are stringent GHG targets for biofuels after 2017, for which there may be some difficulty in sourcing supply.

- There are constraints on the level of biofuels that can be blended with conventional fuels before effects are noticed in the current fleet. It has been estimated that we will reach this blending limit around 2016. At this point a further strategy will be needed to ensure that the UK can meet the 10% target. Current suggestions include placing more emphasis on high biofuels use in fleet vehicles, such as local authority fleets and HGVs, particularly for fleets that use dedicated refuelling depots. It is also likely that vehicle manufacturers will offer a range of options for higher biofuel use, such as flex-fuel and dual fuel cars. However, considerable infrastructure investment is required for fuel supply and refuelling for these options.

There is a potential for biomethane to help overcome these issues. Defra’s recently published Biomethane Implementation plan (Defra 2010) says: “The 2010 Budget announced funding for a project to demonstrate the potential to use biomethane as a road transport fuel, and encourage greater uptake in the future. Subject to a feasibility study commissioned by the Department for Transport, the project will make available £3.5 million to fund biomethane trials for trucks and heavy goods vehicles in several areas across the UK.” Most biogas produced in the UK is currently used for heat and power on site and for some export of electricity. Injection of upgraded biomethane into the gird is the subject of a Defra Demonstration grant project at United Utilities in the North West. This additional funding for demonstration of biomethane as a vehicle fuel is welcome, but it will compete with the other uses for biogas. We have therefore concluded that it is unlikely that biomethane will be a significant vehicle fuel before 2015, but that, provided the infrastructure is in place, it could make a contribution after this date. A separate module has been prepared for biomethane and we have assumed that if the use of biomethane as a vehicle fuel is successful that it could also impact on the amount of biofuel required in the central estimate – i.e. that 8% of the target will be met by first generation biofuels, but that the rest of the target will be met by something else, probably electric vehicles, advanced biofuels or biomethane.

The other issue that could have an important influence on biofuels supply to 2020 is the FQD. Depending on how successful the UK is in achieving the Greenhouse Gas savings required in the FQD it may be necessary to rely on savings from biofuels. There may be circumstances in which a greater than 10% level of biofuels supply is required in order to achieve the FQD targets. In this case the level achieved by 2020 could go above 10% of UK supply – although it is unlikely that biofuels would be able to achieve much more than 2% (by volume) more than 10%. In our upper estimate we have assumed that the central estimate figures remain and that this additional 2% results in 10% supply from biofuels (by energy content). We have not taken the contribution of biomethane, advanced biofuels or electric vehicles into account in this estimate. We have assumed that these are not successful, which means that the UK has to fall back on first generation biofuels. However, should any of these technologies be successful they will contribute to the target and the amount from first generation biofuels will decrease (this is taken into account in the central estimate).

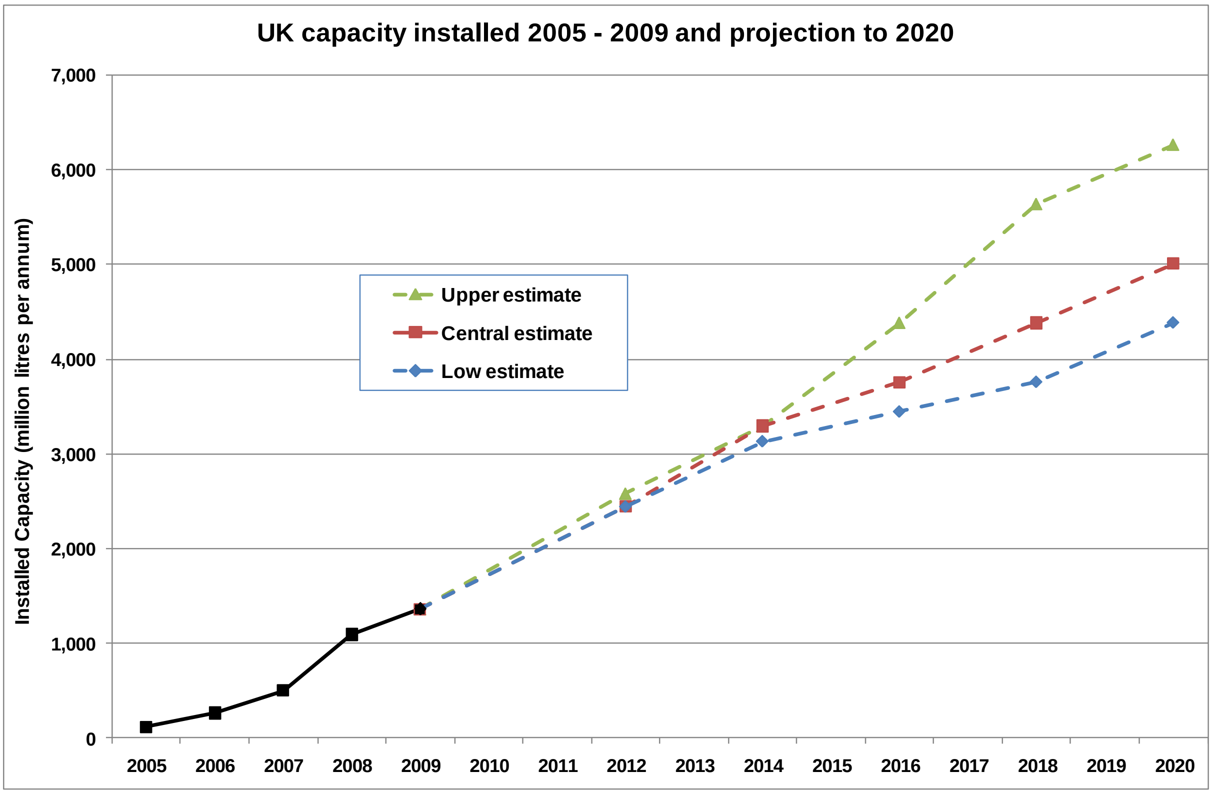
**Table 1: Historic and projected capacity development and deployment 2005 – 2020**

| | Unit | Total capacties/output in the different categories at the end of the stated year/period | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
| | | 31/12/05 | 31/12/06 | 31/12/07 | 31/12/08 | 31/12/09 | 31/12/12 | 31/12/14 | 31/12/16 | 31/12/18 | 31/12/20 |
| Under development | Ml | | | | | | | | | | |
| Planning submitted | Ml | | | | | | | | | | |
| Planning approved | Ml | | | | | | | | | | |
| Operational (central) | Ml | 118 | 264 | 500 | 1,092 | 1,361 | | | | | |
| Projected operational | Ml | | | | | | 2,442 | 3,293 | 3,757 | 4,383 | 5,009 |
| Energy production | GWh | 822 | 2,216 | 4,303 | 9,903 | 12,105 | 19,145 | 25,812 | 29,454 | 34,363 | 39,272 |

**Range of projected operational capacity**

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Low estimate | Ml | | | | | 1,361 | 2,442 | 3,131 | 3,444 | 3,757 | 4,383 |
| | GWh | | | | | | 19,145 | 24,545 | 27,000 | 29,454 | 34,363 |
| Central estimate | Ml | 118 | 264 | 500 | 1,092 | 1,361 | 2,442 | 3,293 | 3,757 | 4,383 | 5,009 |
| | GWh | 822 | 2,216 | 4,303 | 9,903 | 12,105 | 19,145 | 25,812 | 29,454 | 34,363 | 39,272 |
| Upper estimate | Ml | | | | | 1,361 | 2,580 | 3,293 | 4,383 | 5,636 | 6,262 |
| | GWh | | | | | | 20,225 | 25,812 | 34,363 | 44,181 | 49,090 |

**Figure 2: Historic deployment and range of future projections to 2020**




# 20.4 Achieving future deployment – key dependencies

## 20.4.1 Impact of financial incentives

The fuel duty incentive will be lost to most biofuels from April this year. This incentive has had a major influence on biofuels supply (see, for example, AEA 2010) and its loss will impact biofuels supply, particularly the way in which biofuels supply is achieved. Firstly it will increase the importance of the RTFO and the way in which the RED is implemented. Secondly many of the smaller players in the UK who supply fleets directly with high blend biodiesel claim that they will face financial difficulties (AEA 2010). For this reason the Government is extending the duty incentive on biodiesel from used cooking oil.

The introduction of the RTFO has not been without problems, including a misdrafting that led to a discrepancy in the target, the slowing of the annual increase in the target as a consequence of concern about the indirect impact of biofuels (Gallagher 2008) and various economic issues that faced the industry including import of subsidised biodiesel from the USA and the credit crunch and recession. The industry is also nervous of how the RED will be implemented. This has increased caution and the perception of risk associated with biofuels and decreased investor confidence.

Despite all of these issues, the RTFO targets were achieved for 2008/9 and large scale bioethanol plants are being developed. The Ensus plant on Teeside has just started operation. Vivergo should be in operation later this year and Vireol hope to begin operation in 2012. In addition the vehicle industry continues its examination of options for higher blend biofuels, spurred by increasing targets across the EU and the USA.

### 20.4.2 Impact of consenting processes

There have been no major issues to date associated with consent. The major biofuels plants planned have obtained planning permission and often the development of biofuels has been seen as an opportunity to create much needed jobs and trade.

Many of the changes needed have been undertaken as part of the routine upgrading of facilities at refineries and these have not had consenting issues. The supply of biofuels has not required high profile changes at the forecourt and no issues have been reported here. This situation may change as higher blends require more infrastructure changes.

### 20.4.3 Integration to energy markets

Generally there are no problems at low blends. The major issues will be post 2016, when high blends are required. This may require development of refineries, forecourts, supply infrastructure (e.g. pipelines) and adoption of fleets, particularly HGVs. It may also require changes to cars to enable them to take higher blend biofuels. There is no clear strategy at the moment for how higher blends will be introduced, although it has been suggested that fleet vehicles offer greater opportunities. The recently announced biomethane initiatives (Defra 2010) may address some of the barriers to use of biomethane in fleet vehicles.[46]

The other integration issue which is important to biofuels is the integration with other fuels/technologies that enable the 10% renewable transport fuels targets to be achieved. If other technologies and fuels are developed it is not likely that they will increase what the UK achieve, but that they will substitute for biofuels. This will happen either because they are cost competitive with biofuels or because they decrease the amount of fossil fuel supplied (e.g. in the case of electric vehicles) and therefore decrease the volume of biofuels required. This is an area that needs to be examined in greater detail. In this module we have assumed that first generation biofuels are the dominant renewable fuel used to achieve the renewable fuel target. However, if 3% is achieved from electric vehicles and 2.4% is achieved from biomethane, as indicated in the upper estimates of the modules on these technologies, then the volume of biofuel needed to achieve the 10% target will be lower. This situation will depend on the state of the art of the alternative technologies, their commercial economics, government incentives to encourage their implementation and the infrastructure available, as well as the issues that are currently impacting biofuels, such as sustainability.

[46] Defra (2010) says: "We will …be considering the appropriate support for biomethane as a road transport fuel and explore how utilisation may be increased, how deployment barriers can be overcome and how the uptake of technology in this area can be stimulated." In addition DfT are proposing to make £3.5M available for biomethane trials for trucks and heavy goods vehicles.

### 20.4.4 Supply chain issues and constraints

There are a number of issues that are important to the supply chain for biofuels feedstocks. These related to competition and sustainability issues and both are related in part to alternative markets for the commodities in question, notably the food, but also the feed and fibre markets.

Competition: Most feedstocks used in first generation biofuels have another, alternative market, even many of the waste feedstock (e.g. tallow). Putting aside moral arguments, the impact of these alternative markets ultimately results in price increases and shortages. Many of these feedstocks are crops and are subject to all the normal variations in crop harvest yields, such as poor harvests due to weather or pests. Consequently there is variation in supply and price changes related to these variations. This is something that first generation biofuels suppliers have to live with and generally cope with by ensuring as much flexibility in plant design as possible. However, it is not possible for a bioethanol plant designed to use wheat to take another radically different feedstock, so there are limits to the extent to which biofuels producers can plan for restricted supplies. For many biofuels feedstocks, shortages in supply impact the food and feed market as well and in these circumstances the price of these commodities will rise, as happened in 2007 (Defra 2008, 2009).

Sustainability: This is related to the sustainability of using food crops for biofuels, thus taking up land for fuel which has a knock on effect on land use change and indirect land use change. The indirect effects of biofuels were examined in the Gallagher review in 2008 (see RFA web site), but essentially they involve impacts external to the immediate feedstock supply. Most commonly they are explained in terms of substitution of food crops: if a food crop is used in one area for biofuels production, the demand for the food crop does not disappear, but is displaced elsewhere, which may involve other indirect effects, such as (indirect) land use change or substitution of an alternative oil in another food or pharmaceutical market. These indirect effects are difficult to measure or to control, but there is greatest concern regarding the indirect land use change impacts such as deforestation or drainage of wetland, both of which result in the loss of carbon sinks and release of greenhouse gases (GHG) to the atmosphere. In some cases it can be demonstrated that such changes negate the carbon savings from the use of biofuels.

The RED addresses this by restricting the areas from which biofuels can be taken and by increasing the GHG savings expected over time, to 60% in 2018 (from installations that start operation after 1/1/17). The details of this approach are still being examined and so the issue creates major uncertainty for biofuels.

### 20.4.5 Regulatory framework

There are two important changes that will impact biofuels. These are the implementation of RED and the FQD. Implementing RED has required changes to the RTFO. The adoption of sustainability criteria in RED is important to suppliers, who are waiting to hear how the verification will be implemented and how indirect land use change will be addressed. This creates uncertainties in the supply chain, which will need to be addressed to achieve the 10% target.

The FQD requires the EU to meet a minimum reduction in GHG emissions from road transport of 6%. This can be achieved by improving efficiency of refining, supply and vehicles.

In 2012 the Commission will review the target to see if it can be increased. An aspirational target of 10% has been put forward, but in the first instance an increase of 2% from other technological advances (e.g. electric vehicles) will be considered. Subject to that review, a further 2% is envisaged to be achieved by the use of CDM credits for flaring reductions not linked to EU oil consumption.

### 20.4.6 Other potential barriers to deployment

One of the major issues with biofuels uptake is the ability of the UK vehicle parc[47] to accept higher blends. The general consensus is that older vehicles will not be able to accept higher blends. E10 and B7 represent the limit that general un-adapted vehicles can take (this is typically called the "blending

[47] "Parc" refers to the "population of vehicles on the road" or vehicles in use.

wall").[48] However, most commentators think that E15 or B10 will be needed to achieve the target. While cars could be retrofitted this is likely to be expensive and not feasible for older cars.

The core issue is that vehicle manufacturers are not certain what fuels will be available in 2020 and therefore what modifications are required. There are long lead times on the development of new vehicles and these will be increased for biofuels by the need to test new fuels.
It is likely that the EU will lead in this issue, as manufacturers are more likely to develop their strategies based on the whole European market rather than just one country.

Alternative strategies to achieve the target include focussing on fleet vehicles that refuel at dedicated stations. However, it is not clear what could be achieved through this strategy.

### 20.4.7 Summary of constraints

| Potential constraints | Significance | Comment |
|---|---|---|
| Returns insufficient to stimulate sufficient deployment | Amber | The biofuels percentage is mandated, but there may be a problem near to 2020 when costs increase due to international competition. |
| Planning (local policies, obtaining permissions) | Green | Planning not an issue for refineries, but could be an issue for production plant and storage failtiies. No issues to date, but this could change as more facilties are required near 2020. |
| Integration to energy markets | Amber | To date integration has been straightforward. After 2016, however, biofuels blending ratios will need to increase and it is not yet certain how this will proceed. |
| Supply chain issues and constraints | Amber | Supply may be limited by requirements for sustainability; and by international competition. |
| Regulatory constraints | Amber | Regulation has been the main driver for biofuels. However, the need to address indirect impacts from feedstock production has provided major uncertainties. |
| Institutional barriers | Amber | Standards for blending and development of vehicles for >7% biofuels will be greatest challenges. |
| Unclear policy (national, regional, local) | Red | There have been many comments from industry that changes in UK policy have lead to uncertainty among investors and delays in investing in infrastructure in UK. |
| Motivating investors to act | Red | As indicated above, major uncertainty related to UK policy has made investors nervous. As this happended at the same time as the Credit Crunch there has been a slowing in investment in UK. |
| Other constraints (please specify under comments) | Red | The major constraints on biofuels relate to limitations on supply, concerns about environmental sustainability and concerns about the impact of expansion of first generation biofuels on food prices. These are not insignificant. After 2020 there are major technological constraints which need to be overcome if we are to achieve more than 10% biofuels (e.g. advanced conversion is needed, development of UK vehicle park, development of supply infrastructure etc.) |

| | |
|---|---|
| Green | Unlikely to present a constraint to achieving the central projection. |
| Amber | Could constrain achieving the central projection and will certainly constrain achieving the upper projection |
| Red | Likely to constrain achieving the central projection; could result in only the low projection being achieved |

### References

AEA (2010) Assessment of the impacts of the RTFO in the UK (http://www.renewablefuelsagency.gov.uk/sites/renewablefuelsagency.gov.uk/files/_documents/Impacts_of_the_RTFO_on_UK_business_-_AEA_for_RFA.pdf)

Defra (2008) The impact of biofuels on commodity prices (see: http://www.defra.gov.uk/evidence/series/documents/impact-biofuels-commodities.pdf)

Defra 2009 The 2007/08 Agricultural Price Spikes: Causes and Policy Implications - prepared by cross Whitehall group of officials (the Global Food Markets Group) (see: http://www.defra.gov.uk/foodfarm/food/pdf/ag-price100105.pdf)

EC (2009) Directive 2009/28/EC on the promotion and use of energy from renewable sources http://eur-lex.europa.eu/lexUriServ/LexUriServ.do?uri=OJ:L:2009:140:0016:0062:EN:pdf

Gallagher (2008) The Gallagher Review of the indirect effects of biofuels production (see: http://www.renewablefuelsagency.gov.uk/sites/renewablefuelsagency.gov.uk/files/_documents/Report_of_the_Gallagher_review.pdf)

[48] Personal communication from SMMT.

Defra (2010) Accelerating the Uptake of Anaerobic Digestion in England: an Implementation Plan. (see: http://www.defra.gov.uk/environment/waste/ad/documents/implementation-plan2010.pdf)

# 21 Second generation biofuels

## 21.1 Introduction

The term "second generation" biofuels refers to a range of technologies that convert lignocellulosic feedstocks to biofuels. There are two main conversion pathways:

- **Biological processing**: the conversion of cellulosic biomass to ethanol. Sometimes the conversion of cellulosic biomass to biomethane using anaerobic digestion is also included as a second generation technology. See figure 1.

- **Thermochemical processing** in which a combustion technology is used to produce chemicals that are then synthesised or refined into biofuels. Often these technologies are referred to as Biomass to Liquid technologies or BTL. See Figure 2.

The classification of a technology as first or a second generation relates to the feedstocks used and the complexity of the conversion pathways. First generation fuels use simple sugars and starches and relatively straightforward fermentation or chemical pathways. Second generation processes use lignocellulose feedstocks, which have to be subjected to processing to sugar and starch (hydrolysis) for fermentation to be possible; or to thermochemical conversion and subsequent refining for it to be possible to obtain biofuels through chemical synthesis. This means that the processing pathways to second generation biofuels are expensive compared to first generation, but that the feedstocks, which can often be wastes or residues are relatively cheap. Further differences are shown in Figure 3.

**Figure 1 Simplified diagram of second generation lignocellulose to ethanol using fermentation (Source: UNCTAD 2008)**

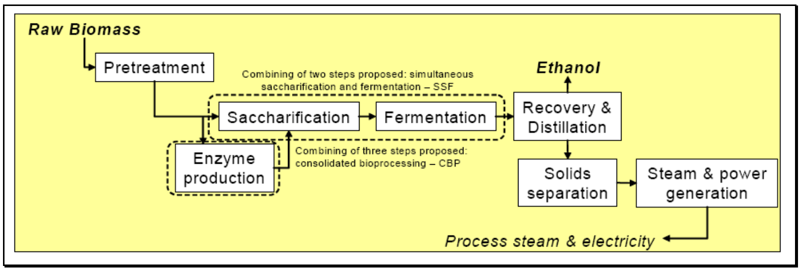



**Figure 2: Process routes to hydrocarbons from thermal conversion, biomass to liquid pathways (source: COPE 2009)**

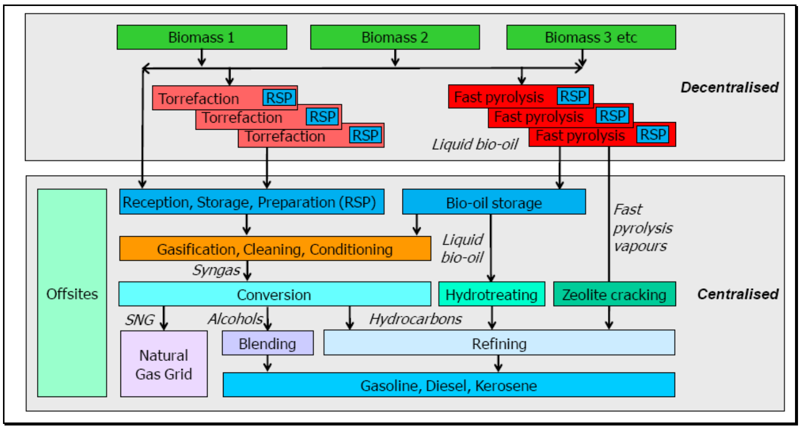


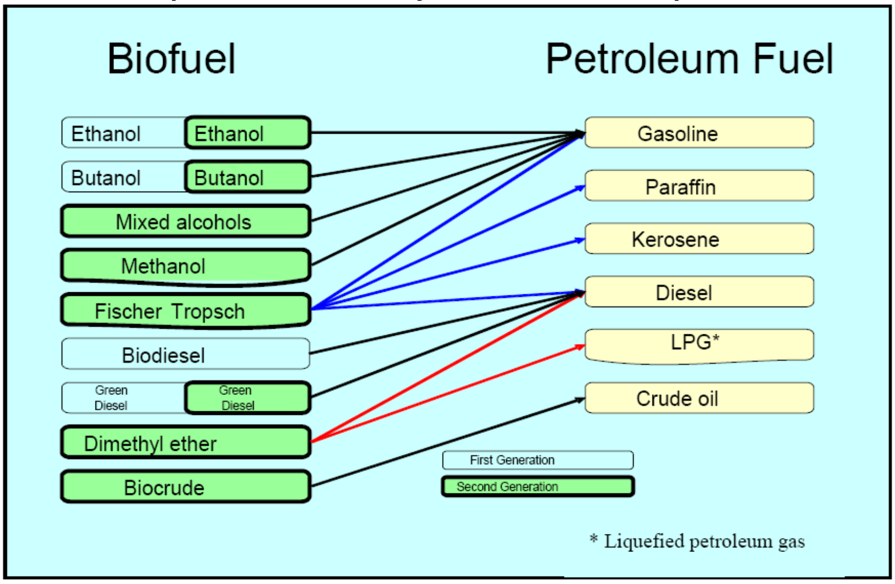
**Figure 3 Comparison of first and second generation technologies for biofuels.**

| | 1st Gen. | 2nd Gen. |
|---|---|---|
| Biofuels readily usable in existing petroleum infrastructure | Yes | Yes |
| Proven commercial technology available today | Yes | No |
| Relatively simple conversion processes | Yes | No |
| Markets for by-products of fuel production needed | Yes | Yes/No |
| Capital investment per unit of production | Lower | Higher |
| Feedstock cost per unit of production | Higher | Lower |
| Total cost of production | High* | Lower |
| Minimum scale for optimum economics | Modest | Large |
| Land-use efficiency | Low | High |
| Direct food vs. fuel competition | Yes | No |
| Feasibility of using marginal lands for feedstock production | Poor | Good |
| Ability to optimize feedstock choice for local conditions | Limited | High |
| Potential for net reduction in petroleum use | Good* | Better |
| Potential for net reduction in fossil fuel use | Modest* | High |
| Potential for net reduction in greenhouse gas emissions | Modest* | High |

* Except for first-generation Brazilian sugar cane ethanol, which would get a more favourable mark.

Figure 4 shows the fuels that these second generation biofuels can be blended with.

**Figure 4 Biofuels and the petroleum fuels they can substitute for (Source: UNCTAD)**




There are many reviews of these processes, some of which give an indication of status (e.g. UNCTAD 2008, E4Tech 2008, Sims et al 2008, Evans 2007)[49]

## 21.2 Historical deployment

Evans (2007) describes biofuels as “currently in demonstration phase”, which seems to be echoed by most analysis of the subject.

There are some important demonstrations at the moment, including a major programme of demonstrations funded by the EC and a proposed $272M programme to support biorefineries in the

[49] NNFCC have also supported a series of reports on each second generation process, all of which are available on their web site. The Carbon Trust have also supported a series of idea assessment in this area. The Carbon Trust continues to support advanced bioenergy accelerator programmes on algae, pyrolysis and novel biofuels.

USA over the next 4 years (as well as other research – over $500M in funding in total). Some of the key demonstrations are listed below, but note that none of them are in the UK:

| Plant | Comment |
|---|---|
| **Choren Industries** | 15000t/y BTL plant in Freiberg, http://www.choren.com/en/choren_industries/vision/ Also involved with CNIM, France – 23,000t/y BTL plant using wood residue feedstock (construction in 2011). |
| **Stora Ens/Neste** | Thermochemical conversion to biocrude. (commissioned 2009) |
| **Enerkem** | Use of treated wood to produce syngas. Planning a 100,000t/y MSW gasification plant that will produce ethanol |
| **Enerfish** | Use of food industry residues for biofuels. Not yet built See http://www.enerfish.eu/p-download-t-newsletter/download-enerfish's-newsletters.html |
| **BioDME** | gasification of black liquor to DME In construction. See: http://www.biodme.eu/ |
| **PERSO** | 4t/d pilot plant to convert organic municipal waste to ethanol |
| **BioSNG** | 1 MW pilot plant – wood biomass to SNG. Demonstration of the Production and Utilization of Synthetic Natural Gas (SNG) from Solid Biofuels. In operation since 2002. |
| **Dong energy** | 20,000t/y straw to ethanol plant. (Commissioned 2009) Will produce 5.4Ml bioethanol a year. See: http://www.dongenergy.com/en/business%20activities/reserach%20and%20devlopment/pages/inbicon-converting_straw_into_ethanol.aspx |
| **Range Fuels** | 113,000 t/y thermochemical ethanol plant, Georgia USA |
| **Flambeau** | Wisconsin 16,500t/y BTL plant |
| **USA** | Six large lignocellulosic ethanol plants built with DoE assistance in USA – Range from 30,000-113,000t/y:<br>AKICO – 13.9M gals ethanol. Feedstock: wood, garden and vegetable waste<br>Abengoa: 700t/d corn stover, wheat, straw, stubble and switch grass<br>BlueFire: situated on a landfill, 19M gals ethanol/y. Feedstock 700t/d sorted green and wood waste from landfills<br>Brion: 125 M galls ethanol. 25% of feedstock will be cellulosic from corn fibre, cobs and stalks<br>Iogen: 18M gals ethanol/y. 700t/d agricultural residues, including straw, stover, switch grass and rice straw.<br>Range fuels: 40M gals ethanol and 9M gals methanol. Will use 1,200t/d wood residues and wood based energy crops. |
| **Shell** | Supporting work on advanced biofuels and micro-algae. In partnership with Iogen is operating a commercial demonstration in Canada. Also has partnership with Choren. |
| **BP** | Working with Du Pont and ABP to develop biobutanol, which is a proven process, but they are examining new feedstocks and attempting to make the process more commercial. |

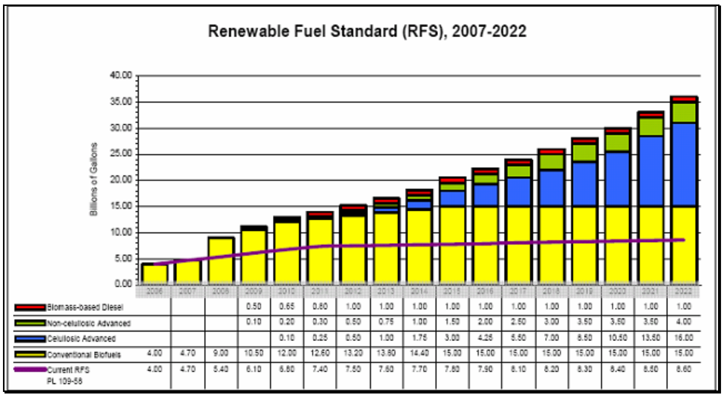
## 21.3 Projected deployment to 2020

Both the EU RED and the US Renewable Fuel Standard acknowledge the need for second generation biofuels, for sustainability and volume reasons. The Renewable Fuel Standard indicates that it expects some biofuels from second generation biofuels in 2012 (see figure 5),[50] but most analysts are cynical about the likelihood of achieving this.[51] The EU RED stepped back from making the EU target dependent on second generation biofuels and instead included incentives for their use. However, SETIS expect market entry by 2015-20 (http://setis.ec.europa.eu/mapping-overview/technology-map/technologies/biofuels).[52]

[50] In 2013, EISA envisages 1 billion gallons of ethanol will come from second-generation ethanol produced from cellulose, rising to as much as 16 billion gallons by 2022.
[51] See, for example, John Kemp (2009) Obama's biofuel challenge. http://www.reuters.com/article/idUSTRE5053LN20090106
[52] SETIS is the strategic energy technology plan information system of the European Commission.

Without second generation fuels it is unlikely that biofuels would be able to supply more than 10% of our road fuel supply. In addition it is thought that the fuels produced tend to be more reliable in quality than first generation fuels. This adds up to eagerly awaited breakthroughs and large R,D&D programmes, supported at the multi million £ level, both in the EU and USA. In addition the UK is supporting work, including a £27M sustainable Bioenergy Centre.

**Figure 5 Potential contribution of different biofuels to the US Renewable Fuel Standard** (the green and blue areas are advanced biofuels). Source: Harnish (2008)




The USA has an extensive biofuels programme, which has been funded at more than $1b and includes much work to improve the costs and efficiency of the lignocellulose to bioethanol route. The EU has supported a series of demonstrations as indicated above and much more besides.[53]

Cope (2009) provides the following timeline for the implementation of thermochemical processing development phases. These are cumulative figures and demonstrate that it will take around 11 years from the start of a serious demonstration plant to achieve full commercial-scale operation. This report says that it is unlikely that there will be any large-scale commercial BTL plants before 2020.

| **Demonstration plant** | |
|---|---|
| Design | 1 years |
| Construction | 1.5 years |
| Operation | 2 years |
| Resolution of design uncertainties | 1 years |
| **Full scale plant** | |
| Design | 2 years |
| Construction | 2 years |
| Commissioning | 1 year |

The IEA report (Sims et al 2008) also says that full commercialisation of biochemical or thermochemical conversion routes to second generation biofuels are “some years off” … “in spite of several decades of R&D and more recent investment in several pilot and demonstration plants in the USA, EU and elsewhere. Even with generous government subsidies the commercial risks remain high, especially with the recently fluctuating oil prices and global financial turmoil adding to investment uncertainty.”

Cope (2009) lists a number of technical challenges for BTL technologies as follows:

- Identification of likely feedstocks and testing in a suitable gasifier to establish the effects of different feed materials and the feasibility of multiple feeds and multiple feed systems if required.
- Demonstration of large scale biomass gasification. A substantial integrated demonstration plant would be needed to prove the system at a scale in excess of that currently available.
- Demonstration of an effective gas cleaning train. A substantial integrated demonstration plant would be needed to prove the system.

[53] See http://www.biofuelstp.eu/fuelproduction.html#second

- Experience in gasification of bio-oil (fast pyrolysis liquid) and possibly bio-oil – char slurries if either process route is selected.
- Upgrading of fast pyrolysis vapours and liquids to hydrocarbons avoids the challenges of gasification and orthodox biofuel synthesis and needs to be more thoroughly evaluated.
- Development of syngas catalysts more suited to biomass based processes with particular consideration of biomass derived contaminants.

In the lignocellulose ethanol area Evans (2007) says that further work is needed on:

- Improving raw feedstocks (e.g. more digestible feedstocks)
- Pre-treatment – to decrease chemical and heat inputs suing novel biochemical and chemical approaches.
- Enzymes and fermentation organisms – a range of advanced enzymes/microbes are needed for biomass hydrolysis and fermentation; and cost improvements are vital. He describes the work being done in the USA and the various key players in this work.

However, progress has been made on both biochemical and thermal chemical processes. For example, Sims et al (2008) point out that there have been developments of improved micro-organisms for biochemical conversion; and there is a better understanding of the overall feedstock supply chain and the feedstock needs for thermochemical conversion. However, the overall stumbling block remains cost. Sims et al 2009 say that demonstration and industrial scale plants will be continually improved over the next 10 years with the aim of making the processes competitive with petroleum and first generation biofuels. They end with the following key messages:

- technical barriers remain for 2nd-generation biofuel production;
- production costs are uncertain and vary with the feedstock available, but are currently thought to be around US $0.80 - 1.00/liter [US $3.02-$3.79 per gallon] of gasoline equivalent;
- there is no clear candidate for "best technology pathway" between the competing biochemical and thermo-chemical routes;
- the development and monitoring of several large-scale demonstration projects is essential to provide accurate comparative data;
- even at high oil prices, 2nd-generation biofuels will probably not become fully commercial nor enter the market for several years to come without significant additional government support;
- considerably more investment in RD&D is needed to ensure that future production of the various biomass feedstocks can be undertaken sustainably and that the preferred conversion technologies are identified and proven; and
- once proven, there will be a steady transition from 1st- to 2nd-generation biofuels (with the exception of sugarcane ethanol that will continue to be produced sustainably in several countries).

In the light of this information we would not expect more than 1% of UK fuel supply to come from second generation biofuels in 2020 (<5TWh).

## Achieving future deployment – key dependencies

### 21.3.1 Impact of financial incentives

One of the big issues for second generation biofuels is that it is not commercially competitive at present and therefore represents risk to investors. The incentives in the RTFO are probably not sufficient to bring this technology on and it is likely that Government funding will be required for R&D to decrease the cost and for demonstration of the technologies in the UK. A major factor in development of demonstration gasification plants in the past has been the logistics of supply (of feedstock) and preparation of the feedstock. It is likely that such issues will be UK orientated and so even for plants that have been demonstrated abroad may present problems in the UK.
Despite this both Shell and BP have heavily invested in second generation biofuels, and it may be that commercial plants will be developed in this way.

### 21.3.2 Impact of consenting processes

These plants would be regarded similarly to chemical or biochemical processing plant and would be subject to the same planning and permitting processes. These will hold up the development of the technologies in the UK, but, providing the site is carefully chosen should not be a great barrier.

There may be issues for large plants proposed in inappropriate rural or out of town locations.

### 21.3.3 Integration to energy markets

One of the reasons for interest in second generation fuels is that they have a better potential than first generation biofuels for integration into energy markets (and other markets, such as high value chemicals).

### 21.3.4 Supply chain issues and constraints

Supply of feedstock will be a big issue for commercial scale second generation plants. To be commercial these plants will (in general) need to be large and will therefore need large volumes of feedstock. Most of the feedstocks are expected to be residues – but many of these are already sold into alternative energy markets, or for other products, such as animal feed or panel board. Obtaining a secure supply for the lifetime of the plant will require a supply infrastructure to be developed, including the stockpiling and storage of large quantities of potentially degradable, inflammable biomass.

The plant operators will need to be flexible; to take what feedstocks are available and they will need to understand the market in which they are operating. Potentially the UK will need to import feedstocks or import second generation fuels.

### 21.3.5 Regulatory framework

The regulatory framework is the same as for first generation biofuels, except where wastes are concerned. If wastes are used for feedstock the plants will need to be compliant with waste licensing and handling regulations and may need to be compliant with waste combustion emissions regulations.

The uncertainties in the regulations concerning biofuels are likely to be as valid for second generation biofuels as they are for first generation biofuels.

### 21.3.6 Other potential barriers to deployment

There continue to be many technological barriers to deployment of second generation biofuels. These have been summarised above.

### 21.3.7 Summary of constraints

| Potential constraints | Significance | Comment |
|---|---|---|
| Returns insufficient to stimulate sufficient deployment | Red | This is a big commercial barrier to full scale plants at present. |
| Planning (local policies, obtaining permissions) | Amber | Likely to be similar to other large chemical or biochemical processing plants. |
| Integration to energy markets | Green | The fuels produced will be good fuels that easily integrate with energy markets |
| Supply chain issues and constraints | Red | The plants will need to be large to be commercial, so the strategy for obtaining feedstock and infrastructure associated with this will need careful consideration. In addition many suitable feedstocks currently have alternative markets |
| Regulatory constraints | Green | Regulation is one of the main drivers for second generation biofuels. |
| Institutional barriers | Green | The major barriers are in the development of cost competitive technologies, not institutional barriers. |
| Unclear policy (national, regional, local) | Amber | The changes in the current legislation probably add a perception of ris at present. |
| Motivating investors to act | Red | Investors will follow Government policy leads in this area and consistent policy backed by Government funded R&D will be important. However, both Shell and BO have their own 2G biofuels initiatives. |
| Other constraints (please specify under comments) | Red | This is a technology in which there are many technical constraints that need to be overcome for the technology to be competitive. |

| | |
|---|---|
| Green | Green = unlikely to present a constraint to achieving the central projection. Add comment if it would constrain achieving the upper projection |
| Amber | Amber = could constrain achieving the central projection and will certainly constrain achieving the upper projection |
| Red | Red = likely to constrain achieving the central projection; could result in only the low projection being achieved |

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# 22 Biogas to transport fuel

## 22.1 Introduction

This section should be read in conjunction with the section on ‘Biogas injection into gas grid’, where the basis of the total biogas resource projection was explained. The total biogas resource for 2020 was divided among four separate modules as follows:

| **Installed capacities of biogas use (MW biogas)** | **Low** | **Central** | **High** | **Section of the report dealing with the resource** |
|---|---|---|---|---|
| Biomethane to gas grid | 480 | 970 | 1310 | In Biogas injection into gas grid |
| **Biomethane to transport fuel** | **30** | **60** | **70** | **In this section** |
| Biogas to CHP | 230 | 460 | 620 | In Bioenergy for electricity** |
| Biogas to heat only | 130 | 260 | 350 | In Energy from waste – heat |
| Total resource as predicted | 870 | 1750 | 2360 | |

** The scope for large CHP plants is expected to diminish due to the RHI and any AD plants installing CHP will tend to use much of the waste heat on site based requirements; thereby creating little or export heat.

The UK ranks relatively low in installed capacity of AD plants generally, but the spate of recent announcements (FIT and the impending RHI) in addition to the ROC mechanism is increasing the activities in this area greatly. However, under the current level of Government support, the scope for biogas to transport fuel will be limited.

Biogas has been produced and used in vehicles for a number of years now, notably in Sweden, where interest has been driven largely by the reduced environmental impact, clean air, energy security and the fact that biogas can be produced from a variety of feedstocks. Despite the extensive natural gas grid the success has not been repeated in the UK. The situation is unlikely to change greatly in the short term, despite the predicted acceleration in the implementation of AD plants. The support given to biogas schemes for heat or injection into gas grid is much more attractive than the support for transport fuel through the RTFO (at 1.8 p/kWh[54]). Overall, there is increasing knowledge base, awareness and understanding of the competing options for biogas use.

EST data indicates that around 250 CNG vehicles were funded, comprising 120 light commercial vehicles, 100 heavy vehicles (including buses) and 20-30 cars. However, there are several reasons why the UK market has lagged behind other European markets with natural gas vehicles, including:

- There are very few natural gas fuelled vehicles or natural gas refuelling stations in the UK. However, a grant programme to part-fund the construction of natural gas refuelling stations was announced in August 2005 by DfT (managed by EST) and it is hoped this will improve the situation in due course;
- Natural gas vehicles and engines are available from many manufacturers including Cummins, Ford, General Motors, Iveco, Volkswagen and Volvo. However, these manufacturers do not seem to actively promote the natural gas option in the UK.
- Reluctance of operators to try new fuels especially with higher capital costs for the vehicles.
- The Bus Service Operators Grant removes any financial incentives for bus companies to use CNG, a market that has been very strong in other EC countries.

These are the general symptoms of a new technology that does not have a track record.

[54] Assumes that biomethane will attract RTFO levy discount on energy equivalent basis, giving 1.8 p/kWh, on the basis of 20 pence per litre discount on biodiesel.

## 22.2 Historical deployment

In the last 3-4 years there has been a rise in the AD plants installed in the UK. However, the technology for turning biogas to vehicle fuel is likely to be limited in scope as there are several barriers and the current level of support through RTFO is much smaller (~1.8 p/kWh) than that for biogas use for heat (5.5 p/kWh), electricity (up to 11.5 p/kWh) or to deliver to gas grid (4 p/kWh). The biggest technical barrier is the lack of infrastructure for providing CNG for vehicle users. The technology and infrastructure required is similar to that applied for landfill gas and there has been a small success in the UK, mainly due to the enthusiasm of local HGV fleet operators and local authorities. The limited success with a few HGV fleets has been due to:

- The ability to generate savings from lower fuel costs for high mileage vehicles;
- Investment in a significant fleet of vehicles to get economies of scale in terms of vehicle costs and refuelling infrastructure;
- Mutually beneficial involvement in the vehicle technology by the operators and manufacturers of the vehicles.

## 22.3 Projected deployment to 2020

As mentioned earlier, an initial estimate was made of the projected biogas deployment to 2020 and this was used to compare industry's response. A limited range of views were expressed by those involved in AD technology. We have not managed to consult the vehicle manufacturing industry. Of the total resource we project some 3% being dedicated towards transport fuel, mainly driven by support for demonstration projects in this area and wider need to reduce transport fuel emissions through corporate and social responsibility. There may be limited economic advantages too.

**Low estimate**
As mentioned above, we expect a limited scope overall. Under the low estimate we foresee any applications to be small and driven by companies with vehicle fleet operated by them; examples include water companies with fleet of vehicles used in transporting sludge to agricultural sites but also companies that would be providing waste management services. United Utilities are currently planning to run a vehicle fleet under a demonstration project supported by Defra and their view is that there will be a handful of companies that will want to replicate what they are doing. As a result we have assumed around 1000 m3 of biomethane going to transport vehicles. The drivers will be avoided costs of methane and the need to reduce Carbon footprint.

**Central estimate**
This estimate is based on the fact that economic returns for biogas to vehicle fuel are likely to remain poor and any use as vehicle fuel will be driven by enhanced support or specific economic advantages at sites that operate vehicle fleets.

**High estimate**
This is based on a pro-rata increase of around 35% against the rather limited scope foreseen in 2020.

**Table 1: Historic and projected capacity development and deployment 2005 – 2020**

Biomethane to transport

Weighted average load factor: 70%

| | Unit | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Total capacities/output in the different categories at the end of the stated year/period | | | | | | | | | |
| | | 31/12/05 | 31/12/06 | 31/12/07 | 31/12/08 | 31/12/09 | 31/12/12 | 31/12/14 | 31/12/16 | 31/12/18 | 31/12/20 |
| Under development | MW | | | | | 0 | | | | | |
| Planning submitted | MW | | | | | | | | | | |
| Planning approved | MW | | | | | | | | | | |
| Operational (central) | MW | 0 | 0 | 0 | 0 | 0 | | | | | |
| Projected operational | MW | | | | | | 0 | 16 | 44 | 78 | 110 |
| Energy production | GWh | 0 | 0 | 0 | 0 | 0 | 0 | 96 | 267 | 480 | 676 |

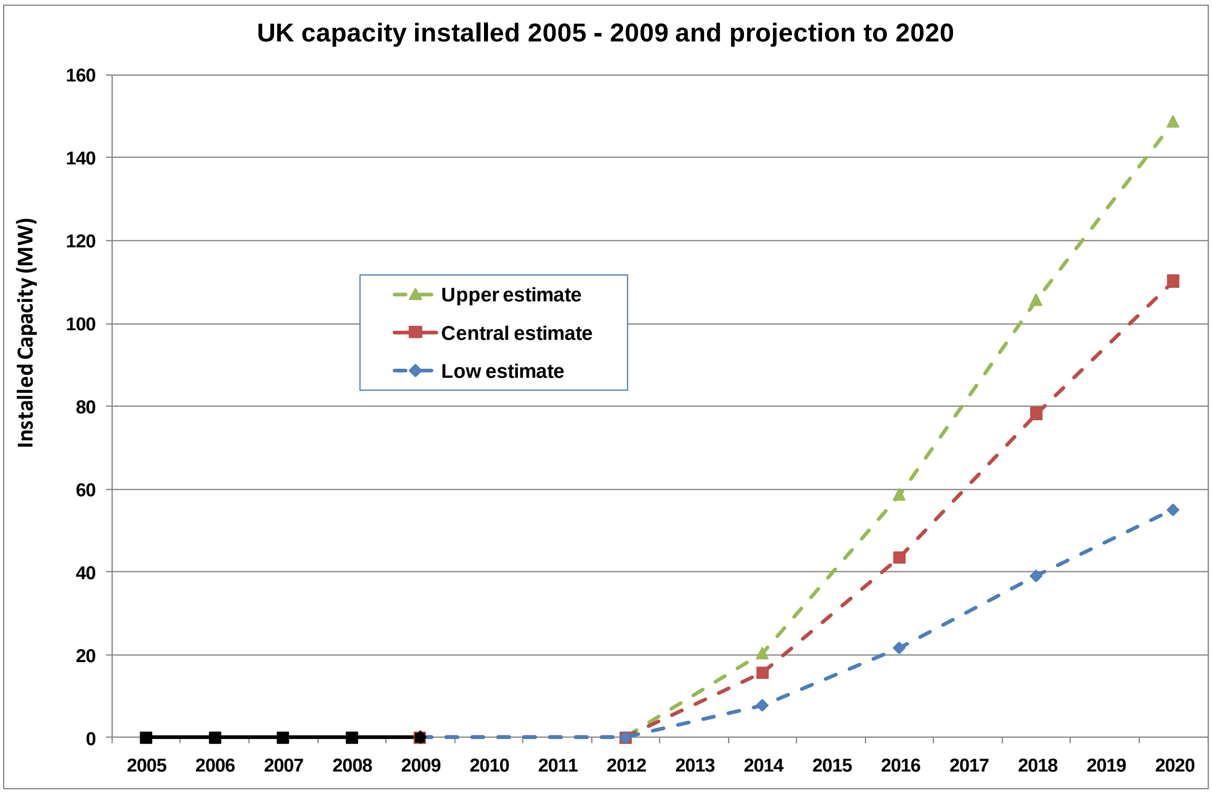
Range of projected operational capacity

| | Unit | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Low estimate | MW | | | | | 0 | 0 | 8 | 22 | 39 | 55 |
| | GWh | | | | | | 0 | 48 | 133 | 240 | 338 |
| Central estimate | MW | 0 | 0 | 0 | 0 | 0 | 0 | 16 | 44 | 78 | 110 |
| | GWh | 0 | 0 | 0 | 0 | 0 | 0 | 96 | 267 | 480 | 676 |
| Upper estimate | MW | | | | | 0 | 0 | 20 | 59 | 106 | 149 |
| | GWh | | | | | | 0 | 125 | 360 | 648 | 912 |

## Load Factors/energy output

A load factor of 70% is used and generally accepted by the industry, due to seasonal variation of practically all feedstock, except food waste from households. It is expected that this will rise with the use of energy crops.

**Figure 2: Historic deployment and range of future projections to 2020**



## 22.4 Achieving future deployment – key dependencies

These comments are based on limited industry views and are as summarised in the table below.

**Table 2: Significance of various potential constraints on deployment**

| Potential constraints | Significance | Comment |
|---|---|---|
| Returns insufficient to stimulate sufficient deployment | Red | At present the RTFO is not as attractive as the the incentives announced in the RHI scheme (for consultation). Any stimulation will be through grant provided to demsontration projects. |
| Planning (local policies, obtaining permissions) | Green | Planning policy is generally supportive of AD development, provided that site-specific environmental issues can be dealt with satisfactorily. The most important issues for AD plants are transport, odour and noise. No major obstacles are foreseen. |
| Integration to energy markets | Red | There is a general lack of infrstructure and thereby seen as an incovenient market. There will be some small committed vehicle fleet users of this as fuel; for isntance local authorites or large companies such as water or retail companies. (Access to the gas grid provides the most convenient energy market.) |
| Supply chain issues and constraints | Green | The infrasture does not exist for this option, other than for local fleet. But supply chain is not seen to be an issue. |
| Regulatory constraints | Green | AD plants are generally favoured as long as they are to be built to the required standards. Planning consent, Environmental Permit by the Environment Agency or PAS110 accreditation for the disposal digestate are no longer seen as constraints. |
| Institutional barriers | Amber | At present this is not favoured as the emphasis seems to be on liquid biofuels. The use of biomethane is seen to be minor. Some incentives my arise through CSR and wider responsibility. |
| Unclear policy (national, regional, local) | Red | There is no major drive to encourage this option. |
| Motivating investors to act | Red | Invesors are not attracted to this option due to low returns. |

| | |
|---|---|
| Green | **Unlikely to present a constraint to achieving the central projection.** |
| Amber | **Could constrain achieving the central projection and will certainly constrain achieving the upper projection** |
| Red | **Likely to constrain achieving the central projection; could result in only the low projection being achieved** |

# 23 Electric vehicles

## 23.1 Introduction

Electric vehicles have been around in various forms since the early 1990's and are most commonly associated with low power, low range applications such as milk floats and golf buggies. In recent years there have been a number of drivers that have resulted in electric cars being developed as an option for mainstream transport. These drivers include climate change rising rapidly up the political agenda and the difficulties faced in reducing greenhouse gas emissions (GHG) from the transport sector, particularly as transport consumption and economic growth have strong linkages. The European Commission has put in place average $CO_2$ emissions limits for new cars set at 130g/km to be phased in between 2012 and 2015, with the intention to tighten this limit to 95g/km by 2020.

From a climate change perspective one of the main benefits of electric vehicles is that they provide the opportunity to decarbonise the transport sector to a very significant extent (assuming that the percentage of grid electricity from low and no-carbon sources is increased significantly into the future). Electric vehicles also benefit from reducing fossil fuels used in the transport sector, diversifying energy sources and increasing energy security. In addition to this, electric vehicles reduce tailpipe emissions of air quality pollutants.

However, there are a number of barriers to the uptake of electric vehicles. Electric vehicles are significantly more expensive than comparable petrol or diesel vehicles due mainly to the high cost of the Lithium-iron batteries used to store the electrical energy on board the vehicle. Another barrier is the restricted range of the vehicles (typically 60 to 100 miles) before recharging is required, and the lack of charging infrastructure. However, arguably the greatest barrier is public perception. Consumers lack confidence in electric vehicle reliability and see the range restrictions and lack of charging infrastructure as an inconvenience.

There are a number of incentives that are in place and planned that are aimed at encouraging people and companies to purchase and use electric vehicles, including grants to reduce the capital cost of purchasing electric cars, exemptions and reductions in taxes (e.g. company car tax) and duties (e.g. vehicle excise duty) and other charges such as parking fees and congestion charging. In addition to this the network of public electric charging points is being increased in a number cities across the UK.

This analysis is considering the deployment of battery electric cars only, it does not include electric vans or plug-in hybrid electric vehicles.

## 23.2 Historical deployment

The total number of electric cars registered in the UK in 2008 was around 0.01% of the total cars registered in the UK and it is estimated that this remained below 0.1% in 2009.

## 23.3 Projected deployment to 2020

The low, central and high projections are broadly based on three scenarios developed by AEA in a report for the Committee on Climate change in 2009. Some detailed modelling was done to develop MACC curves for electric vehicle penetration. However, the market is rapidly changing and things have moved on since 2009, but three of the scenarios have been simplified and been taken as a good an estimate as any for projected uptake into the future. The following things have been considered in broad terms when estimating the projected deployment of electric vehicles into the future:

- The speed of the UK economy picking up.
- Bringing down the capital costs with fiscal incentives such as the government grants of £2,000 to £5,000 towards the capital cost of purchasing an electric car.

- Increasing the network of charging points across the UK with the governments "plugged-in Places" scheme to part fund electric vehicle charging infrastructure in three to six lead cities between April 2010 and March 2013.
- Projected increases in manufacturing of electric vehicles and their availability on the market.
- Additional benefits to the users such as exemption from congestion charging, company car tax, vehicle excise duty, free parking, free charging, use of bus lanes or introduction of electric vehicles lanes.

For the lower projections it is assumed that the economy is slow to recover and the fiscal incentives and other benefits have little impact on encouraging the uptake of electric vehicles and that availability of electric cars on the market is limited.

For the central projection it is assumed that the economy makes a steady recovery, that fiscal incentives and other benefits have a moderate impact on the uptake of electric vehicles and the availability of electric cars on the market is moderate.

For the upper projection it is assumed that the economy recovers quickly, that fiscal incentives and other benefits make a significant impact on the uptake of electric vehicles an the availability of electric cars is high.

Figure 1 show the estimated percentage penetration of electric cars in the UK car fleet to 2020. The low estimate being around 1%, central around 2% and high around 3%.

**Figure 1: Historic deployment and range of future projections to 2020**

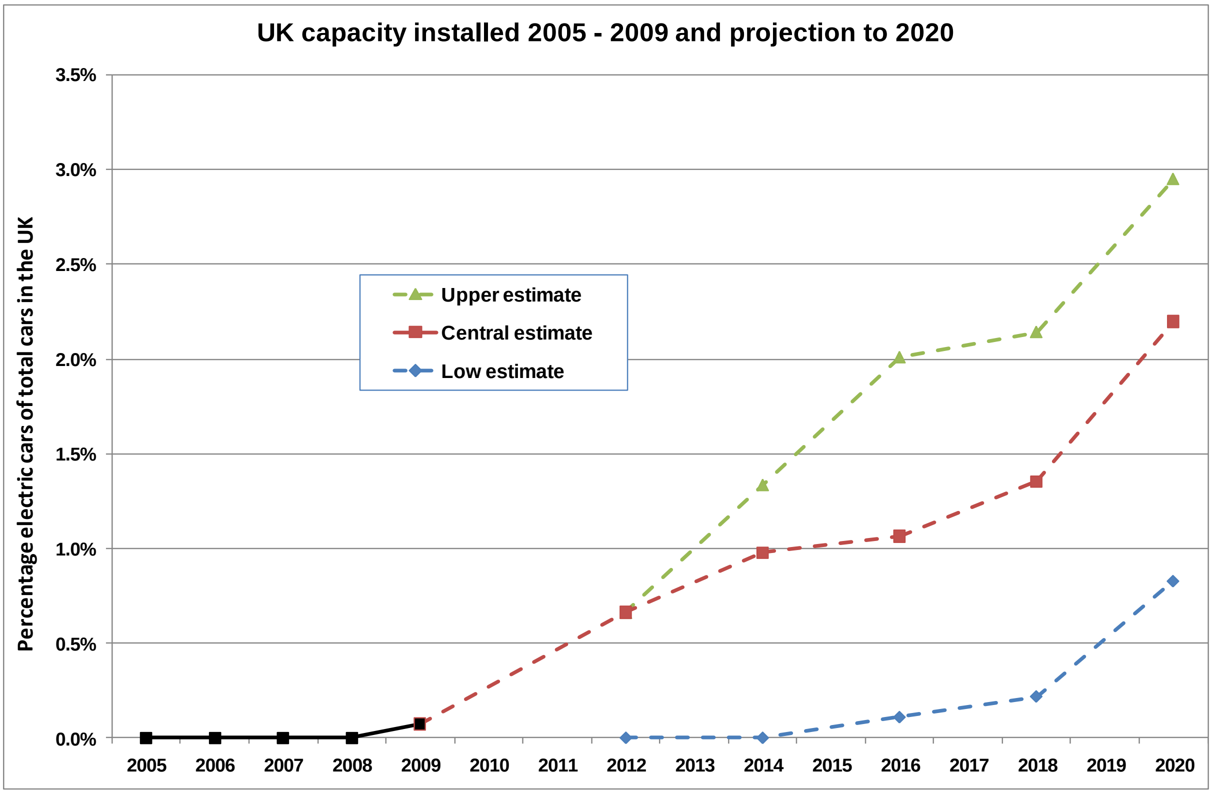



Table 1 shows the estimated energy consumption in electric cars for the central projection up to 2020. This shows that in 2020 electric cars are estimated to be using around 2.2 TWh of grid electricity per year. The EC Renewable Energy Directive sets a target for the UK of reaching 10% of transport energy from renewable energy sources by 2020. To understand what contribution electric vehicles is making towards this target, the percentage renewable energy mix in grid electricity (either UK or EU figures can be taken for this) in 2020 and the UK projected transport energy use in 2020 needs to be taken into consideration. In addition the EC Renewable Energy Directive states that renewable energy sources consumed by electric road vehicles shall be considered to be 2.5 times the energy content of the input of electricity from renewable energy sources (Article 3, paragraph 4c). Assuming that the UK reaches 30% of grid electricity from renewables by 2020 and that the projected total transport energy use is 49 TWh per year in 2020, the central projection of electric cars would contribute only around 1.4 TWh, less than 3% of the target.

**Table 1: Historic and projected capacity development and deployment 2005 – 2020***

**Electric Cars**

Data present % Electric cars in UK fleet and Electricity use in Electric Cars

| | Unit | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Total capacties/output in the different categories at the end of the stated year/period | | | | | | | | | |
| | | 31/12/05 | 31/12/06 | 31/12/07 | 31/12/08 | 31/12/09 | 31/12/12 | 31/12/14 | 31/12/16 | 31/12/18 | 31/12/20 |
| Under development | % cars | | | | | | | | | | |
| Planning submitted | % cars | | | | | | | | | | |
| Planning approved | % cars | | | | | | | | | | |
| Operational (central) | % cars | 0.0% | 0.0% | 0.0% | 0.0% | 0.1% | | | | | |
| Projected operational | % cars | | | | | | 0.7% | 1.0% | 1.1% | 1.4% | 2.2% |
| Energy production | GWh | 0 | 0 | 0 | 0 | 39 | 436 | 725 | 878 | 1,226 | 2,174 |

**Range of projected operational capacity**

| | | 2005 | 2006 | 2007 | 2008 | 2009 | 2010-12 | 2013-14 | 2015-16 | 2017-18 | 2019-20 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Low estimate | % cars | | | | | | 0.0% | 0.0% | 0.1% | 0.2% | 0.8% |
| | GWh | | | | | | 0 | 0 | 90 | 198 | 820 |
| Central estimate | % cars | 0% | 0% | 0% | 0% | 0% | 0.7% | 1.0% | 1.1% | 1.4% | 2.2% |
| | GWh | 0 | 0 | 0 | 0 | 39 | 436 | 725 | 878 | 1,226 | 2,174 |
| Upper estimate | % cars | | | | | 0 | 0.7% | 1.3% | 2.0% | 2.1% | 2.9% |
| | GWh | | | | | | 436 | 990 | 1,655 | 1,942 | 2,917 |

* Note: this table shows the electricity consumption of the vehicles before any account is taken of the share of renewables electricity or multiplier that appliers to electric vehicles. The main table in the Excel workbook (Data sheet) multiplies the energy contributions above by the projected share of renewables electricity but currently the multiplier in cell D53 is set to 1.

# 23.4 Achieving future deployment – key dependencies

## 23.4.1 Impact of financial incentives

**Up front capital costs:** The cost of buying an electric car is higher compared to an equivalent petrol or diesel car (in the region of £10k to £15k higher for small and medium cars, which is approximately the cost of replacing the lithium iron battery). There is also the cost of investing in a charging point. These higher capital costs are a significant barrier to potential investors.

**Getting uptake of electric cars by companies and individuals:** The UK government has announced grants of between £2,000 and £5,000 towards the capital cost of buying an electric car . Grants will be available from January 2011 until 2014 with a total scheme budget of £230 million. In addition the government is launching the “Plugged-in Places” scheme to fund a network of public charging points in London Milton Keynes and a number of other designated electric vehicle cities in the UK. However even with such grants the up front costs will be prohibitive for many. Other incentives such as free parking, dedicated electric vehicle lanes or use of bus lanes, an initial period of free charging and vehicle demonstration programmes, may also be needed to encourage the uptake of electric cars nationally. In addition publicising the existing cost benefits where they exist would raise awareness with potential investors, such as, exemption from congestion charging and vehicle excise duty, and no vehicle fuel tax currently applied to electricity used in electric cars and relief from company car tax.

## 23.4.2 Impact of consenting processes

N/A

### 23.4.3 Integration to energy markets

The current **lack of access to public charging points** is a significant barrier, however the government has announced a £20m to £30m 'plugged-in places' project to invest in a wider network of public charging points in 3-6 regions in the UK.

The driver behind companies and car parks installing charging points seems to be the desire to be seen to be environmental rather than for economic reasons. A study by AEA for the DfT in February 2010, looked at the current market for sale of electricity for recharging electric vehicles It concluded that there is currently not a market for the sale of electricity for electric vehicle recharging in the UK. The majority or organisations surveyed did not profit from the sale of electricity; even if a nominal charge (of £1 or £2) is made for using the recharging bays at a particular site, the charge just covers administration fees or the cost of cables required to recharge a vehicle at that site. In cases where the main purpose of the site was to provide parking facilities, it is often less expensive for electric vehicles to park there and recharge their cars, than it is for a petrol or diesel car to park there. The report concluded that the **motivation behind installing electric vehicle recharging infrastructure** in the UK is primarily to promote sustainable transport and improve an organisation's environmental image, rather than profit from the sale of electricity.

### 23.4.4 Supply chain issues and constraints

**The availability of electric cars on the market** is currently quite limited, however information regarding new models and specifications are changing constantly and information regarding manufacturing dates, locations and quantities is also being updated almost on a daily basis. For example on 18 March 2010, Nissan announced that it will manufacture the "Leaf "electric car in the UK (Sunderland) with initial production capacity of 50,000/year in 2013, brining global production to 200,000/year. The Leaf Electric car is planned to be available on the market from 2011.

### 23.4.5 Regulatory framework

**New car emissions limits** being introduced by the EC will encourage lower emissions petrol and diesel cars to be developed. These will ultimately be competing with sales of electric cars and may ultimately displace some of the projected sales of electric cars into the future.

There are a number of very small electric vehicles or quad bikes being developed that are being taken up in the market, but would **not qualify for the capital grants** of £2,000 to £5,000, as they either do not classify as cars, and do not meet the safety standards, range (70 miles minimum) and top speed (in excess of 60 mph) stipulated for this grant.

### 23.4.6 Other potential barriers to deployment

**Public perception, confidence and attitudes**: electric cars are perceived as not being very reliable, the large lithium iron batteries are a relatively new technology and confidence in their performance is not very high. Also the limited range of electric vehicles, coupled with a lack of charging points makes people nervous, and the recharging time is seen as an inconvenience and a technical constraint. A variety of business models that allow battery leasing (to reduce worries about battery life and performance) or battery swapping (to reduce time spent recharging) might help to overcome some of these public perception barriers.

### 23.4.7 Summary of constraints

| Potential constraints | Significance | Comment |
|---|---|---|
| Returns insufficient to stimulate sufficient deployment | Red | **Up front capital costs**: The cost of buying an electric car is higher compared to an equivalent petrol or diesel car (in the region of £10k to £15k higher for small and medium cars, which is approximately the cost of replacing the lithium iron battery). There is also the cost of investing in a charging point. These higher capital costs are a significant barrier to potential inestors. |
| Planning (local policies, obtaining permissions) | Green | |
| Integration to energy markets | Amber | The current lack of **access to public charging points** is a significant barrier, however the government has announced a £20m to £30m 'plugged-in places' project to invest in a wider network of public charging points in 3-6 regions in the UK. |
| Supply chain issues and constraints | Green | The **availability of electric cars on the market** is currently quite limited, however information regarding new models and specifications are changing constantly and infomration regaridng manufacturing dates, locations and quantities is also being updated almost on a daily basis. For example on 18 March 2010, Nissan announced that it will manufacture the "Leaf "electric car in the UK (Sunderland) with initial production capacity of 50,000/year in 2013, brining global production to 200,000/year. The Leaf Electric car is planned to be available on the market from 2011. |
| Regulatory constraints | Green | |
| Institutional barriers | Green | |
| Unclear policy (national, regional, local) | Green | |
| Motivating investors to act | Red | **Getting uptake** of electric cars by companies and individuals: The UK government has announced grants for between £2,000 and £5,000 towards the capital cost of buying an electric car . Grants will be available from January 2011 until 2014 with a total scheme budget of £230 million. In addition the government are funding a network of public charging points in London Milton Keynes and a number of other designated electric vehicle cities in the UK. However even with such grants the up front costs will be prohibitive for many. Other incentives such as free parking, dedicated electric vehicle lanes or use of bus lanes, an initial period of free charging and vehicle demonstration programmes, may also be needed to encourage the uptake of electric cars nationally. In addition publicising the exsisting cost benefits where they exist would raise awareness with potential investors, such as, exemption from congestion charging and vehicle excise duty, and no vehicle fuel tax currently applied to electricity used in electric cars and relief from company car tax. |
| Other constraints (please specify under comments) | Red | **Public perception, confidence and attitudes**: electric cars are percieved as not being very reliable, the large lithium iron batteries are a relatively new technology and confidence in their performance is not very high. Also the limited range of electric vehicles, coupled with a lack of charging points makes people nervous, and the recharging time is seen as an inconvenience and a technical constraint. A variety of business models that allow battery leasing (to reduce worries about battery life and performance) or battery swaping (to reduce time spent recharging) might help to overcome some of these public perception barriers. |

AEA, July 2009, Market outlook to 2022 for battery electric vehicles and plug-in hybrid electric vehicles, Final Report to the Committee on Climate Change.

AEA, February 2010, Is there currently a UK market for the sale of electricity for recharging electric vehicles?, Final report to Department for Transport.

# Appendices

Appendix 1: Data Sources for estimating future growth rates in the uptake of renewable energy technologies

Appendix 2: Allocating resources to bioenergy categories

Appendix 3: Grid Related issues in Achieving 2020 Targets

# Appendix 1

## Data Sources for estimating future growth rates in the uptake of renewable energy technologies

**Where do these data come from?**

These data have been taken from the Renewable Energy Planning Database (**REPD**) and the Renewable Energy STATisticS (**RESTATS**) database.

REPD tracks the progress of potential new projects from inception, through planning, construction and operational stages. These data are required in order to make forecasts about when targets for electricity generation from renewable energy sources will be achieved as failure to do so would result in financial penalties to the UK. Furthermore, these data help identify where problems may be occurring in policy, incentive mechanisms and in the planning process and provide good quality information to Government to assist in evidence-based policy making. These data are gathered on a monthly basis.

RESTATS tracks the performance of these schemes; these data are gathered on an annual basis and the results are published in the Digest of UK Energy Statistics.

For further information about the relationship between RESTATS and REPD, including a representational diagram of RESTATS and REPD information sources & reporting relationships (primarily electricity), please look in the Annex.

**What are the limitations?**

- RESTATS started 1989; REPD started 1995. Therefore some discrepancy in the data held by both
- REPD only records projects that are submitted to the planning system – schemes that do not require planning applications (Sewage gas, most co-firing and historic hydro are therefore not covered)
- RESTATS therefore more comprehensive from the point of view of operational schemes
- REPD currently records electricity-only schemes, hence no data on heat
- RESTATS records information on both electricity and heat but heat data are pretty limited. Heat data vary in quality. Based on limited surveys and models.
- Limited data on Transport Fuels – liquid biofuels only
- REPD Biomass classifications are not comprehensive
- RESTATS and REPD are currently being more closely integrated to improve data quality and consistency

**What is it?**
The information is provided in the form of two spreadsheets:

Technology_Time Series Data from REPD_v1.xls

This spreadsheet contains data extracted from the Planning Database (REPD) with which to populate the Technology Tables. This primarily limited to electricity-only schemes.

| **Workbook** | **Description** | **Comments** |
|---|---|---|
| Operational – REPD | Operational Capacity (MWe) by Country and Percentage - cumulative | |
| Operational by sizeband – REPD | Operational Capacity (MWe) by Size Band - cumulative | |
| Operational - RESTATS | Operational Capacity by Country (MWe) | For comparative purposes |
| Scoping - REPD | Scoping schemes - Capacity (MWe) | Schemes in this status at the end of the reporting year |
| Submitted - REPD | Applications Submitted - Capacity (MWe) | Schemes in this status at the end of the reporting year |
| Approvals - REPD | Applications Approved (includes Awaiting Construction, Under Construction and Operational data) - Capacity (MWe) | No construction commenced dates are recorded.<br>Schemes in this status at the end of the reporting year |
| Approval Rates - REPD | Applications Approved (includes Awaiting Construction, Under Construction and Operational data) - Capacity (MWe) | Approval rates based on the total number of schemes determined in the reporting year |
| Load Factors - RESTATS | Extract from RESTATS database showing time series load factors. Separate table showing what was used for each technology for 2008, regionalised where appropriate. | |
| Heat - RESTATS | | Based on Thousand tonnes of oil equivalent of energy |
| Refusals - REPD | Applications Refused - Capacity (MWe) | IGNORE – needed for other calculations within the spreadsheet |

Data_for_estimates_v2.xlsx

| # | Workbook | Description | Comments |
|---|---|---|---|
| 1 | Data_sheet_February2010 | Snapshot picture as of end of February 2010 | List schemes that are Operational, Under Construction, Awaiting Construction and Submitted (i.e. awaiting a decision) |
| 2 | # schemes submitted by tech | Table 2: Number of Schemes Submitted by Technology | Classified by Size Band (<=5MW and >5M) and by LPA and S36 Submissions |
| 3 | Approval Rate by # determined | Table 6a - Approval rate based on number of schemes determined | Classified by Size Band (<=5MW and >5M) and by LPA and S36 Submissions |
| 4 | Approval Rate by MW determined | Table 6b - Approval rate based on capacity (MW) determined | Classified by Size Band (<=5MW and >5M) and by LPA and S36 Submissions |
| 5 | Avg Time to Operational | Average Time Taken from Application Submission to Commencement of Operation (months) | Also includes T1, average time taken for submission to be determined, and T2, average time taken for project to become operational after approval |

**The Planning System for Renewables**

- Schemes ≤ 50MW (on-shore) are handled by the Local Planning Authorities
- Schemes > 50MW (on-shore) or > 1MW (off-shore) are handled under Section 36 (essentially by a government department)

The data held in the database essentially summarises the experiences of schemes handled in this way. There will be changes to the way in which large schemes are to be handled in England.

- Schemes =100MW or > 1MW (off-shore) to limit of territorial waters will be handled by the by Marine Management Organisation
- Schemes > 50MW (on-shore) or > 100MW (off-shore) will be handled Infrastructure Planning Commission (IPC)

Pre-consent Phase

a) Schemes sometimes go through a **Scoping phase**; these are essentially schemes under development and are tentative ideas being sounded out by the developers before formal submission to planning. The decision to submit may be influenced by the sort response received.
b) A scheme formally submitted to planning for which a decision has yet to be made is described as an **Application Submitted**
c) When a scheme is **determined** (i.e., a formal decision is reached) it may either be Approved or Refused. Refused schemes have the option of going to Appeal for another opinion. For the purposes of this exercise, Appeal submissions have been ignored.

Post-consent Phase

d) When a scheme has been **Approved**, its Post-consent status is described as **Awaiting Construction**. This is a time when the developer assesses the conditions that might come attached to the planning approval and whether he might meet them.

It is also a time when project funding is more seriously considered. Occasionally, schemes might be **Abandoned** at this stage.

e) The **Under Construction** phase is when the first formal ground works begin to take place; in te case of off-shore activities, it is when the first off-shore work takes place and is not used to describe the on-shore work to receive cabling, etc.

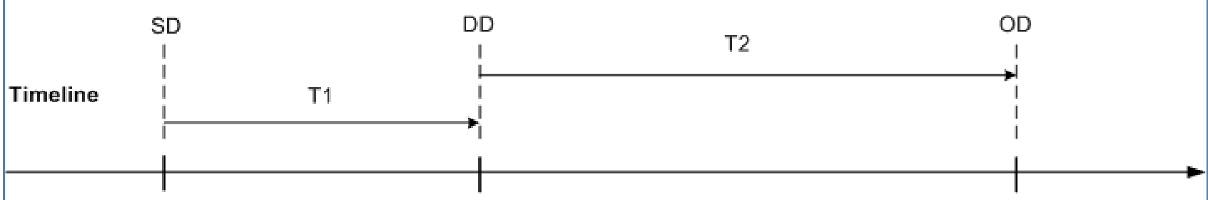
f) Finally, when the project begins to generate power, it is described as **Operational**.

**How can these data be used?**

Essentially, the above describes a model akin to the sales funnel in which prospects (Scoping) get whittled down as each successive stage to those that successfully achieve operational status. The following diagram shows the simple time-line for a planning application; the scoping phase, which is not obligatory, has been ignored. T1 is the average time taken for submission to be determined, and T2, average time taken for a project to become operational after approval. These data are provided in the spreadsheet and may be used to estimate the rate at which schemes might come on-line.

**Timeframes**

**No Appeal**




SD = Application Submitted Date
DD = Application Determined Date
OD = Operational Date

T1 = Average time taken for submission to be determined
T2 = Average time for project to become operational after approval

DDc = SD + T1 Calculated Determined Date
ODc = DD + T2 Calculated Operational Date

# ANNEX

## RESTATS (Renewable Energy STATisticS database) and REPD (Renewable Energy Planning Database)

The Government's UK Renewable Energy Strategy published on 15 July 2009 provides a clear framework for the growth in deployment required by the UK 15% target under the Renewables Directive. It builds on the financial incentives adopted in recent years (such as the RO and RTFO) and shows how these will now be complemented by new measures to support heat (RHI) and small-scale electricity production (FITs). The strategy also provides a wide range of other measures to ensure that renewables can maximise their contribution to energy consumption. Renewables are now at the centre of UK energy policy, providing a very different environment from that in the past and it is crucial that Government have reliable information to monitor the impact of these wide-ranging measures.

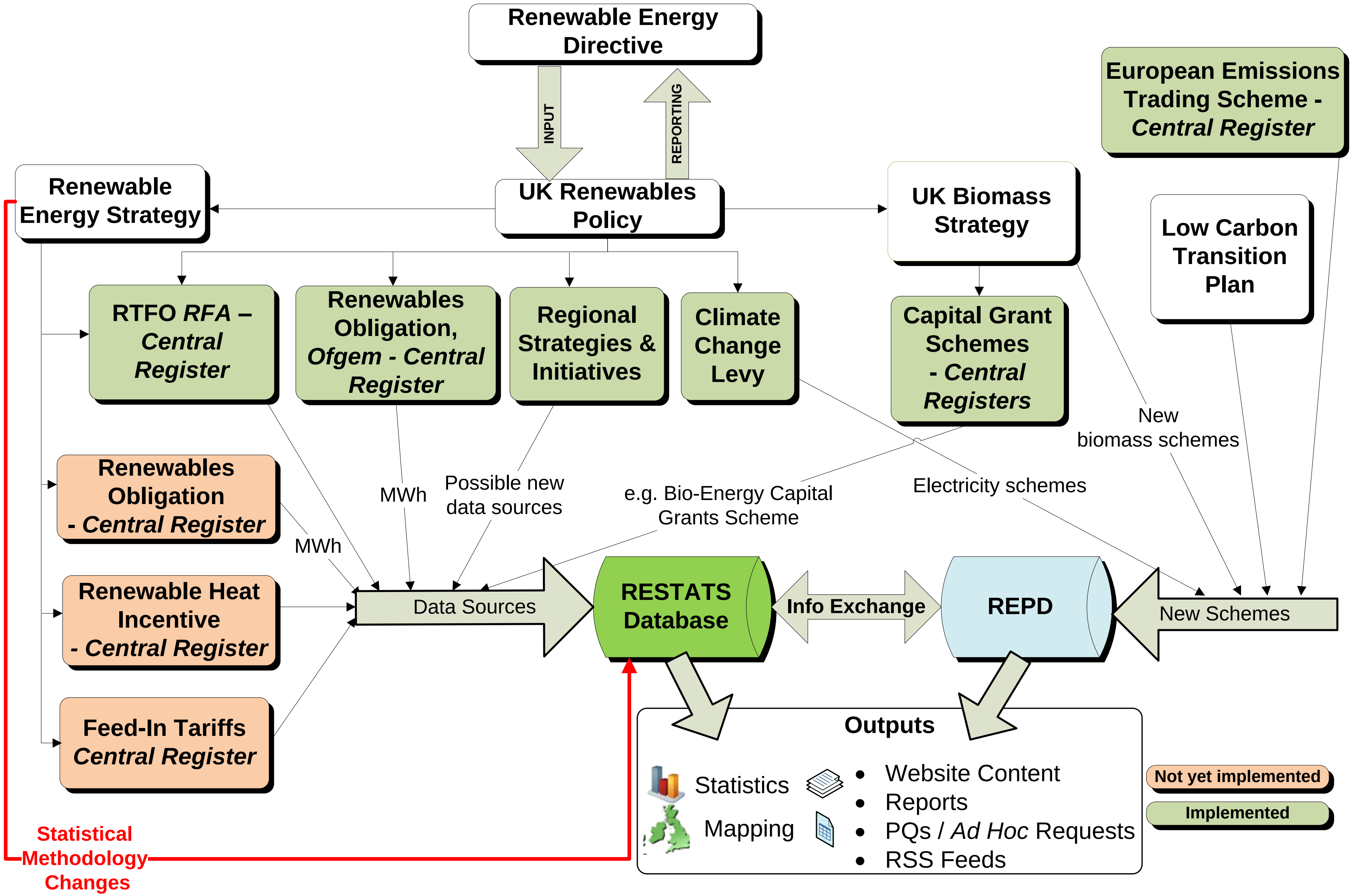
RESTATS, the UK's Renewable Energy STATisticS database, is a project that has been running for 20 years and over this period has become the primary source of accurate, up-to-date energy statistics of UK renewable energy sources. These cover active solar heating; solar photovoltaics (PV – currently included with wind statistics); onshore and offshore wind power; wave power; large- and small-scale hydro; biofuels (biomass and biowastes, including co-firing); geothermal aquifers. It is thus the most reliable means by which the success of the UK renewables programme can be both measured and monitored.

These data are used by the Department of Energy and Climate Change (DECC), the Statistical Office of the European Communities (SOEC, also referred to as Eurostat) and the International Energy Agency (IEA); UK data are published in the Digest of UK Energy Statistics (DUKES), and also published via the DECC and RESTATS web sites. It has proved particularly valuable in recent years by providing independent statistical evidence in support of various aspects of renewables activities and has been used by Government, industry and various contractors in a range of activities related to related to renewable energy.

In parallel and complementing RESTATS, the Renewable Energy Planning Database (REPD) project meets the need to track the progress of potential new projects from inception, through planning, construction and operational stages. These data are required in order to make forecasts about when targets for electricity generation from renewable energy sources will be achieved as failure to do so would result in financial penalties to the UK. Furthermore, these data help identify where problems may be occurring in policy, incentive mechanisms and in the planning process and provide good quality information to Government to assist in evidence-based policy making.

The growing importance of renewables makes RESTATS and the REPD even more important activities than in the past, since they provides a means of monitoring progress against the UK target of 10% of electricity from renewables by 2010 and even more so for the 15% 2020 targets for total renewable energy. This is therefore arguably the most reliable means by which the success of the UK's renewable energy activities can be measured and monitored. Further details may be found on: *http://www.restats.org.uk*

**Representational diagram of RESTATS and REPD information sources & reporting relationships**



# Appendix 2

# Allocating resources to bioenergy categories

A large number of wastes and biomass have been considered within the report modules that cover bioenergy, which together are expected to contribute around half of the renewable energy production in 2020. As was mentioned earlier, this sector poses a particular challenge in associating feedstocks to the different forms of bioenergy. There is a wide range of waste categories, but also energy crops and imported biomass, that will collectively provide the scope of the bioenergy contribution in the UK. We have aimed to avoid double-counting or omitting resources however, given the limited nature of this exercise, the data presented here must be taken as an initial view of the future deployment potential.

The waste feedstocks are particularly complex in that they vary from wet wastes such as food wastes (from households, retailers, commercial premises, industry) to a range of livestock wastes (cattle and pig especially) and wastes that are highly sought after (such as wood waste, poultry waste, straw, tallow and MBM) by bioenergy project developers and plant operators. This is further complicated by the fact there has been considerable movement within the waste management sector, in terms of the definition and categorisation of waste, especially due to the Landfill Directive and Waste Incineration Directive. These have changed the balance between on-site industrial practices and off-site practices offered by service providers; for instance MBM has been used by the renderers on their own site to provide process heat but now it goes to waste to electricity plants due to combustion plants needing to be designed to high engineering specification. The table below lists the different wastes and feedstocks that are captured within the ensuing sections.

The opportunities for deployment are clearly inter-related and influenced by a range of factors that we have alluded to in the relevant sections of the report. However, given the overall timescale within which these estimates have been attempted there will be some discrepancy which may have gone un-noticed, not least because the work has been done by a team that has had limited opportunity to cross check any overlaps or data. As such the estimates of the biomass, wastes and thereby the categories of bioenergy within which they have been placed could be subject to variation in future.

| Waste category | Nature of waste and treatment | Section of the report addressing the biomass |
|---|---|---|
| Land filled waste | Landfills containing buried waste, that contain biodegradable matter, which is increasingly restricted | ***Landfill gas*** |
| Municipal solid waste (MSW) | Mixture of household and commercial waste collected by local authorities | ***Waste to electricity*** |
| C&I waste | Commercial and industrial waste | ***Waste to electricity*** |
| RDF | Coarse refuse derived fuel (extracted from MSW or C&I waste) often uses advanced thermal treatment | ***Waste to electricity*** |
| Special industrial waste | Other wastes (such as poultry, MBM, tallow etc)<br>Clinical waste - a limited potential | ***Biomass for electricity*** |
| Waste wood | Clean recycled wood diverted from landfill or imported. By-products from factory operations. | ***Biomass for electricity***<br>***Bioenergy Boilers***<br>***Biomass District Heating*** |
| Wood chips | Wood chips from clearing of forests and energy crops. Saw mill co-product. Chipped recycled wood. | ***Biomass for electricity***<br>***Bioenergy Boilers***<br>***Biomass District Heating*** |
| Poultry waste | Poultry litter: waste with the bedding material from poultry farms. | ***Biomass for electricity*** |
| Waste cooking oil | Used vegetable oil is collected and turned into an approved fuel by one company REG Ltd: used in CHP. | ***Biomass for electricity*** |
| Cereal straw | Cereal straw (baled) and used for power generation. | ***Biomass for electricity***<br>***Bioenergy Boilers***<br>***Biomass District Heating*** |
| Crop residue | Various types – can be used for power or heat generation | ***Biomass for electricity?***<br>***Bioenergy Boilers***<br>***Biomass District Heating*** |
| Forestry residues | Woodchip or pellet. | ***Biomass for electricity***<br>***Bioenergy boilers***<br>***Biomass District Heating*** |
| Bioenergy crops | Miscanthus and Short Rotation Coppice (SRC). | ***Biomass for electricity***<br>***Bioenergy boilers***<br>***Biomass District Heating*** |
| Food waste | From households (source separated)<br>From commercial places<br>From large food processing sites<br>From other food processing sites | Jointly** covered in:<br>***Biogas injection to gas grid***<br>***Biogas to vehicle fuel***<br>***Biogas to heat***<br>***Biogas to electricity is included within Bioenergy for electricity.*** |
| Livestock wastes | Cattle – dairy and other<br>Pig – sows, litters, fatteners and weaners<br>Poultry – egg laying hens | |
| Energy crop | Maize and grass silage as used in AD plants to complement seasonal variation of livestock wastes | |
| Sewage sludge | Residue from sewage treatment works | ***Biomass for electricity*** |
| Solvents | Not a renewable resource | ***Not covered*** |
| Tyres | Not a renewable resource | ***Not covered*** |

** the scope for biogas from all wet wastes is estimated jointly, as they can be combined for anaerobic digestion, and biogas channelled to appropriate use.

# Appendix 3

# Grid Related issues in Achieving 2020 Targets

## Introduction

The achievement of the 2020 renewable energy targets will be dependent on the GB and Irish (for Northern Ireland) electricity transmission and distribution systems allowing the connection and operation of the significant amounts of new renewable generation that will be required. In 2008 there was 6 GW of renewable generation connected to the GB network providing around 5% of the total supply[55]. This will need to increase to around 40 GW if the targets are to be achieved.

Overlaid on this large growth in capacity is the important issue of the nature of the new generation to be connected. The renewable generation will largely be wind, both onshore and offshore, the nature of most renewable resources is that they are intermittent. The remainder of the new build generation is likely to be new gas, nuclear and clean coal. Of these only the gas is likely to have the ability to vary its output over short time periods to match demand changes. The 2020 system will therefore have more plant connected but the majority of the plant will be inflexible either having intermittent output (renewables) or running at a fixed output (nuclear and cleaner fossil fuel plant). The A.C. system must balance supply and demand on a continuous basis to remain stable and therefore there will be significant issues in developing a system that can be operated in a stable manner and delivering this at an acceptable cost. There is unlikely to be one solution to this problem and the 2020 system, and the one that evolves beyond this time, is likely to have to rely on a combination of flexible generating plant, demand side management and electrical energy storage to deliver the solution. A key component to deliver a solution at acceptable cost is the so called smart grid – see below in the distribution section.

The connection and operation issues can be broken down by transmission, distribution and market areas.

## Transmission Issues in Connecting and Operating New and Existing Generation to 2020

The transmission system has evolved over the last 50 or so years to be based around delivering electricity from large, relatively remote (from centres of demand) power stations using coal, gas and nuclear fuels. These stations are generally planned and constructed over a number of years with the transmission capacity to accommodate the electricity flows being built once the plans and contracts for the station's construction were agreed.

It has become clear over the last few years that this model was not delivering transmission capacity at a sufficient rate to accommodate the significant growth in new generation, and in particular from renewable sources that were required to achieve the agreed targets. To address this issue government brought forward the Transmission Access Review (TAR) and following this has issued two consultations on improved grid access.

Following the TAR work, as a short term measure to address the queue of generation projects that had built up, particularly in Scotland, awaiting transmission capacity construction, the government introduced an interim 'socialised connect and manage' policy. This allowed new generation projects to be offered connection dates within a reasonable timescale, commensurate with their construction plans and with the generation, once connected to the system, being managed by paying constraint payments if in a particular period their output could not be accommodated on the system. The

[55] www.berr.gov.uk/files/file46772.pdf - 'Growth Scenarios for UK Renewable Generation and Implications fro Future Developments and Operation of Electricity Networks', SKM, Report to BERR, June 2008.

constraint payments were recovered through the Balancing System use of System Charges (BSUoS) mechanism and the costs passed through to the consumers of the electricity.

The interim arrangements were introduced in parallel with a full review and consultation to agree an enduring regime that would deliver the required transmission capacity both at a cost acceptable to the consumer and in a timely manner and also not inhibit the achievement of the 2020 targets and further growth beyond that time.

There were significant concerns that socialised connect and manage while a simple and transparent mechanism would lead to very high constraint costs. Therefore a range of other options were investigated. At the present time, government is proposing, following the results of a number of studies and discussions with industry and other relevant groups, to introduce an enduring regime largely based on the present interim socialised connect and manage with a few modifications. The view is that the simplicity and transparency of socialised connect and manage outweighs any potential benefits of the more complicated options and that this regime can deliver the required rate of transmission capacity build and that it can do so at an acceptable cost.

The introduction of this enduring regime, assuming it goes ahead, should result in the removal of one of the significant barriers to achieving levels of electricity generation from renewables to meet the 2020 targets. There remains the risk that the constraint costs have been underestimated and that at some time in the intervening period between now and 2020 the enduring regime will require modification.

Alongside the TAR work, the Electricity Networks Strategy Group, which is jointly chaired by DECC and Ofgem, carried out a study in collaboration with the Transmission Operators and GB System Operator[56] to assess how the transmission system needed to develop to accommodate the forecast levels of electricity generation in 2020 from all sources of generation. This study was published in March 2009[57] and subsequently Ofgem has reviewed with the assistance of independent consultants the proposals in the report and agreed the first tranche of funding to allow the time critical pre-construction work to go ahead to deliver the proposed transmission investments[58].

Another review, which has been underway for some time and is viewed by some as potentially having significant bearing on the actual level of required transmission investments, is that of SQSS (The National Electricity System Security and Quality of Supply Standards)[59]. The present SQSS is based on models and algorithms developed for conventional generation mix. With the onset of a system that will have large quantities of wind generation these models may not be so applicable. National Grid (the body responsible for SQSS) is currently leading a review with industry participation of the SQSS. The Parliamentary Energy and Climate Change Committee has recently said that it is imperative in its view that this review is concluded in a timely manner so that its conclusions can be built into the transmission system investment and improved grid access plans.

In summary, at the present time there is a significant amount of work and new regulatory structures being put in place to ensure that the transmission system is not a barrier to achieving the 2020 targets, moreover there now needs to be a period of review to assess whether the regimes and plans put in place are working a delivering capacity in a timely manner and at acceptable cost before any further changes are considered. The remaining concerns with transmission access as a limitation on the 2020 targets are related to planning approvals for the required new lines and upgrades and the constrain costs, as referred to above, being acceptable.

[56] National Grid (transmission owner for England and Wales), Scottish Power Transmission Limited (owner for South of Scotland) and Scottish Hydro Electric Transmission limited (owner for the remainder of Scotland) and National Grid (System Operator for the GB system).
[57] See: http://www.ensg.gov.uk/assets/1696-01-ensg_vision2020.pdf 'Our Transmission Network: A Vision fro 2020' Report by the Electricity Networks Strategy Group (ENSG), March 2009.
[58] See: http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/tar/Documents1/100118_TOincentives_final_proposals_FINAL.pdf
[59] See: http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/

# Distribution System Issues in Connecting and Operating New and Existing Generation to 2020

## Introduction

The electricity distribution system is set for a radical overhaul and changes over the next ten years or so. The present system is largely passive – it takes electricity from the grid supply points (where electricity leaves the transmission system and enters the distribution system) and progressively transforms it down with supply at the required voltage levels to industry, commercial and domestic consumers. Electricity generally flows in one direction – from the supply points to the consumer. With the growth of distributed generation – generating plant connected to the distribution system rather than transmission system – this has started to change – flows can change direction depending on local demand and generation. This requires the system to become more flexible and controllable – transformers set at certain values when fitted and then left are no longer suitable.

### The Smart Grid

The ENSG has recently published a smart grid vision[60] and routemap[61] for the UK. Government is currently considering the implementation of the vision and routemap along with the governance processes involved. The delivery of the vision along with the previously agreed roll-out of smart meters in all domestic properties will be instrumental in facilitating all aspects of the low carbon electricity network from consumer control of energy within the home, through the integration of electric vehicle charging and electric heat pump management to the integration of microgeneration and enhanced demand side response.

The development of the smartgrid will be a progressive one with the technologies and solutions used being related to, inter alia, the nature of the local geography, density of network, local generation volumes. However, without elements of the smartgrid being in place by 2020 or shortly after, the ability to provide significant demand side response from the wider electricity consumer (e.g. to assist in the management of increasing levels of intermittent and base load operating generating plant) at an acceptable cost will be severely constrained.

There are two particular electrical technologies that will place pressure on grid development. These are electric vehicle charging and heat pumps.

### Electric Vehicle Charging

Electric vehicle charging, if carried out via the household connection, will place a significant new load on the system. There is presently uncertainty on which model of vehicle charging will predominate but if the household route predominates there will be a general need to upgrade local networks to accommodate the additional demand. The individual household connections are thought to be generally capable of carrying the loads required (they are rated at up to 100amps) however the planning of local networks is done on a presumption that while individual properties may be drawing significant current at a given time this will not be replicated across the majority. With the advent of vehicle charging and heat pumps (see next section), this will change. Electric vehicle charging has the potential in many cases to be time shifted to periods of low demand or excess renewable generation, in the case of the latter the role of the smart grid will be key in allowing the signals to be sent to initiate and end the charging and control the charge rate.

### Heat Pumps

Air and Ground Source Heat pumps are predicted to have a growing role in providing space heating and will become progressively lower in their emissions as the grid is decarbonised. They generally produce low grade heat at temperature of less than 50C and therefore need to run on a more continuous basis than gas fired boilers and electric heating to provide hot water and space heating with the required temperature and comfort level. It is likely therefore that they will place additional load on the networks and be present at times of high demand such as early on winter evenings. In this

[60] See: http://www.ensg.gov.uk/assets/ensg_smart_grid_wg_smart_grid_vision_final_issue_1.pdf 'A Smart Grid Vision', November 2009.
[61] See http://www.ensg.gov.uk/assets/ensg_routemap_final.pdf 'A Smart Grid Routemap', February 2010.

sense, they could present more of an issue than vehicle charging where there would be some potential to time shift the load.

In summary, at the distribution level they key issue will be connecting large amounts of distributed generation, the full value from the operation of which will depend to some extent at least on the development of the UK smart grid. A related issue will be the likely take up of electric vehicle charging and heat pumps – this is likely to require significant upgrading of local networks capacity if take up is significant in a local area.

## Electricity Market Issues

The GB electricity market currently operates under the BETTA (British Electricity Trading and Transmission Arrangements) regime introduced in 2005 as an extension to NETA (New Electricity Trading Arrangements) , which replaced in 2001 the electricity Pool system introduced with electricity privatisation. Concerns have been raised recently[62] over whether the current arrangements will deliver the governments goals of security of supply, limiting carbon emissions and keeping prices low for consumers. In particular the delivery of security of supply with sufficient capacity margin has been called into question by a number of key organisations.

The issue of managing intermittency has been raised already and it has been suggested[63] that market models that involve a capacity availability payment, in addition to payment for generation (such as the current Irish electricity market model) are likely to provide more market certainty and lead to less spiking of prices at times when demand and supply are constrained. In particular, given that there will be a significant increase in intermittent plant, which in turn will require backup plant (be in fossil, cleaner fossil, energy storage etc) for when it is not available, the market will need to adequately reward such backup plant both when it is generating but also to ensure its availability to generate.

Government needs to make clear whether reform is required and what shape this will take to provide confidence for investors in the new forms of generation plant that are required to both meet the 2020 targets and maintain system stability and plant margins.

## Conclusions

This section has reviewed the electricity network related issues in achieving the electricity generation requirements to meet the UK's 2020 targets. These have been broken down into transmission, distribution and market related issues.

The transmission issues appear to being addressed, the outstanding issue is the completion of the SQSS review and its implications for the plans for additional transmission investments. There will then need to be a period while progress is monitored to assess whether the revisions to the transmission access regime are working and delivering capacity at acceptable cost.

The distribution network will need to be changed radically with this change starting but not being completed by 2020. The smart grid will facilitate the connection and optimal operation of a range of new technologies and facilitate significant demand side response, which could be important in allowing the system operator manage the 2020 (and beyond) system with its high percentages of both intermittent (renewable) and base load (nuclear and clean fossil fuel) plant. Another issue for distribution networks is the management of electric vehicle charging and electricity for heat pumps – both of which are predicted to have significant market penetration approaching 2020. Both technologies will place significant additional demand on local networks and at high uptakes exceed the local networks design capacities – there will therefore need to be a programme of local network upgrades to accommodate this additional demand.

In the markets area there is concern that the current market arrangements are not well suited to delivering security of supply in particular. It is important that any decision on market changes is made in a timely manner and produces an enduring regime that provides certainty to investors in the required generation and network investments required.

[62] For example see: http://www.utilityweek.co.uk/features/uk/changes-for-the-betta-market-r.php
[63] See: http://www.poyry.com/linked/group/study 'Impact of Intermittency - How Wind Variability Could Change the Shape of the British and Irish Electricity Markets', Summary Report July 2009.

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