Department of Energy and Climate Change

Review of the generation costs and deployment potential of renewable electricity technologies in the UK

Study Report

REP001

Final | Updated October 2011

This report takes into account the particular instructions and requirements of our client.

It is not intended for and should not be relied upon by any third party and no responsibility is undertaken to any third party.

Job number 215030

Ove Arup & Partners Ltd
13 Fitzroy Street
London
W1T 4BQ
United Kingdom
www.arup.com

ARUP

Contents

Executive Summary

Arup was appointed by the Department of Energy and Climate Change (DECC) in October 2010 to look at the deployment potential and generation costs of renewable electricity technologies in the UK up to 2030, taking into account sensitivities as to the range of cost inputs, investor behaviour and barriers to deployment. Arup was supported on cost data gathering exercises for some technologies by Ernst and Young (E&Y).

The data and analysis from this study will be used to inform the levels of renewables subsidy under the Renewables Obligation (RO) and/or Feed-In Tariffs (FITs).

The project was split into two parts:

- Part A – Maximum feasible resource potential of renewable electricity technologies, constraints to renewable electricity technologies expansion and potential annual build rate scenarios from now to 2030; and
- Part B – Generation costs of renewable electricity technologies.

DECC required a full assessment on a comparable basis of the renewable technology families and subcategories as listed in Table 1. This list includes technologies currently eligible under the RO and some new sub-categories.

Table 1: Energy generation categories used in this study

Technology family	Sub-categories by: Technology/ fuel/ geography/ resource
Onshore Wind	Large (>5MW) and smaller (<5MW)
Offshore Wind	Round 2, Round 3, Scottish Territorial Waters
Hydro	Large (>5MW) and smaller (<5MW)
Wave (marine technology)	Near shore, offshore
Tidal Stream (marine technology)	Shallow, deep
Tidal Range (marine technology)	Tidal barrages, tidal lagoons, tidal reefs
Geothermal	With/without CHP
Solar PV	
Dedicated Biomass (Solid) All sources	Regular biomass, energy crops, virgin wood (e.g. forestry residues), waste wood, perennial energy crops (e.g. SRC willow, miscanthus), biomass fuel type including torrification / pre-treatment of biomass
Biomass Co-firing All sources	
Dedicated Biomass (Solid) Power Station Conversion	
Dedicated Bioliquids All sources	Made from: food crops waste e.g. cooking oil dedicated bioliquid crops
Energy from Waste	Solid Recovered Fuel (SRF) derived from wastes such as

Technology family	Sub-categories by: Technology/ fuel/ geography/ resource
	Municipal Solid Waste (MSW)
Anaerobic Digestion (AD)	Feedstock: food waste; whole food crops (with sustainability levels); manures and slurries
Dedicated Biogas	Sewage gas
	Landfill gas
Advanced Conversion Technologies (ACT)	Gasification
	Pyrolysis
Renewable Combined Heat and Power (CHP)	All biomass/bioliquid technologies listed
	Waste combustion with combined heat and power (RO definition)

Marine technologies (tidal range, tidal stream and wave) have been included, but as marine studies previously commissioned by DECC have been published, DECC did not require any significant primary research/data gathering. Consultation was undertaken on the published studies to ascertain whether the data, assumptions and conclusions in the reports were accepted by industry stakeholders and to determine which data set was considered to be the most representative and realistic.

Data was prepared for all of the technologies covered by the sub-divisions in Table 1. The exact sub-divisions used within the analysis below this level, depended on the extent to which it was possible to differentiate between different deployment rates (part A) or capital and operating expenditure (part B).

The early part of the study involved a comprehensive desk study, which took into account and built upon the considerable and extensive literature and research already produced for DECC. Arup gathered new data from a number of sources including DECC, independent generators, suppliers/electricity companies and their own research.

During its development, DECC, and Arup/E&Y have worked together to achieve agreement on the substance of this key state of the industry report.

Consultation was undertaken with various renewable energy organisations to brief them on the scope and content of the study and to confirm the findings of the available evidence base: where appropriate Arup clarified key assumptions. An extensive range of other stakeholders across all aspects of the renewable energy sector was consulted on the study, primarily to ascertain cost data but also where appropriate to discuss deployment.

The work comprised:

- An assessment of the maximum feasible resource potential of the renewable electricity technology families and subcategories from 2010 to 2030;
- An assessment of the constraints to renewable electricity generation technologies expansion for each electricity technology family and sub-category from now to 2030;

- Three scenarios of potential annual build rates from now to 2030 for each technology family listed in Table 1, differentiating by sub-category where appropriate; and
- An assessment of generation costs of renewable electricity technologies.

The team considered the following constraints:

- Supply chain: fuel supply (where applicable), equipment and materials, skilled labour availability and installation capacity;
- Planning: Government consent, local authority planning approval for power plant;
- Grid constraints: construction of and connection to the transmission network; and reinforcement of the transmission network; and
- Other constraints: physical constraints (including availability of suitable sites) and any other potential barriers (technical, legal, etc), which could limit the deployment or maximum feasible potential.

The potential for major refurbishment and repowering of existing infrastructure was taken into account.

Based on the supply chain, planning, grid and other constraints identified, three deployment scenarios were developed on the maximum amount of capacity that could be built per year in the UK (MW/year) as follows:

- **Low scenario**: the maximum amount of capacity that could be built per year per renewable technology between now and 2030 in the UK given current constraints;
- **Medium scenario**: the maximum amount of capacity that could be built per year per renewable technology between now and 2030 in the UK if some of the constraints are relaxed; and
- **High scenario**: the maximum amount of capacity that could be built per year per renewable technology between now and 2030 in the UK if additional constraints are relaxed.

Output from all three scenarios is presented in terms of annual installed capacity (MW/yr), cumulative installed capacity (MW) and energy generation (GWh/yr). For each technology a view was also developed as to what deployment trends were likely to look like beyond 2030.

A commentary on the regional distribution of deployment for each of the deployment scenarios across England, Scotland, Wales and Northern Ireland is provided where applicable.

The review of generation costs draws on publicly available information, Arup and E&Y proprietary cost data and project cost data collected through extensive consultation with industry stakeholders. The work involved:

- Reviewing industry literature to gather benchmarks on project costs for the technologies covered in the report. This includes information on capital expenditure (capex), operating expenditure (opex) and capacity factors.
- Consulting with stakeholders to collect project cost data, a view on cost drivers and other technical/operational project information relevant for

levelised cost modelling. Levelised costs are a full economic assessment of the cost of the energy-generating system including all the costs over its lifetime (e.g. initial investment, operations and maintenance, cost of fuel, cost of capital).

- Establishing project cost ranges (high, median, low) for different groups of installed capacity for each renewable technology. This includes current project cost for pre-development, capital expenditure and operational expenditures. Other key financial and technical project data have also been collected from stakeholders including efficiency, capacity factors and hurdle rates.
- A forecast of project costs based on main cost drivers and learning rates (cost savings achieved via technological improvements over time).
- Inputting current and projected costs, and technical/financial project parameters into DECC's levelised cost model. The actual modelling of levelised cost is excluded from this study. Also the project has not gathered data on biomass fuel availability and prices, which is the subject of separate research.

The main aim of the study is to provide baseline data to inform a further modelling exercise within DECC for the RO banding review.

The baseline information on deployment potential and capex and opex data has been split down to finer levels than any previous work (some 30 plus sub-categories when either size category, geographic or technology sub-division is taken into account). This allows the more detailed economic modelling to take place. It is thus more comprehensive than any of the previous evidence bases.

There has been significant primary research in some technologies (particularly waste based energy generation, biomass and bioliquids), and for these topics the report presents new, more detailed material.

This report provides a detailed summary of renewable generation costs and deployment and has identified significant deployment potential which should allow the achievement of UK Government targets.

The report does not give the whole picture, as fuel costs, waste gate fees and a comparison of aggregate deployment outputs results against UK Government targets are excluded. Furthermore, levelised generation costs are not included. A brief overall summary by technology follows below:

Onshore Wind - This still has significant deployment potential of around 17.3GW by 2030 (medium forecast), but the deployment rates are slower than previously modelled. So generally, forecast 2020 figures will only be reached on the high ambition scenario. This is mainly due to planning and grid constraints. Deployment of onshore wind in Scotland is anticipated to remain an important and increasing part of the onshore wind generation. The capex and opex data is very similar to previous studies.

Offshore Wind – This has a very significant deployment potential; generally similar to existing data (a potential 41GW by 2030 under the medium deployment forecast) but a slightly slower rate of deployment is anticipated in the next 5 to 10 years, reflecting the phasing of the larger projects after 2015. Capex/opex data gathered is limited and reflects uncertainties in the sector, hence future projections must be viewed with caution.

Hydro – This study shows no significant changes from the data in previous studies. A large increase in small hydro (of <5MW size) is possible but, this results in a small net contribution 600MW by 2030 (medium forecast) in output.

Marine Technologies (wave, tidal stream and tidal range) – This study has reiterated the data from previous work - that there is limited deployment by 2020, but up to 4,000MW of capacity by 2030 (all medium forecast). Tidal stream is seen as the most promising technology in the short term, however the costs and funding gaps have been re-confirmed as still challenging.

Geothermal – This study has reached similar conclusions as previous studies; the technology has a low potential by 2020, but greater by 2030 (especially for renewable heat) - but the capex and opex appear still challenging. The medium deployment forecast indicates 990MW by 2030.

Solar PV – This is a technology with very significant deployment potential of 16.6GW by 2030 (medium forecast), but with very high capex.

Dedicated Biomass (Solid) - In the light of new data on global fuel availability this study has quantified a moderate to high deployment potential of 2.8GW (medium forecast) in the >50MW category using largely international sustainable biomass. It would appear to offer a relatively low capex, high capacity generating option, achievable over the next 10 years.

Biomass Co-firing - Solid biomass co-firing has the potential to increase in quantity and to continue to make a reasonable 1.2GW (medium forecast by 2020) generation contribution. The contribution from co-firing declines to 2020.

Dedicated Biomass (Solid) Power Station Conversion - The partial or full conversion of existing coal or oil power station units to biomass is a new area and one for which the project data has to be viewed with caution. Most existing research has not anticipated a contribution from this sector. It could, however, offer up to 1.8GW (high forecast) of high capacity factor, low planning risk deployment between 2010 and 2030 at low levels of capex and opex.

Dedicated Bioliquids - As per dedicated solid biomass in the light of new data on global fuel availability this study has quantified a medium to high deployment potential using largely international sustainable bioliquids. It offers a relatively low capex, high capacity generating option achievable over the next 10 to 20 years. Cost data for dedicated bioliquids in the larger project scale should be viewed with caution as there is a limited dataset, and deployment and cost assumptions differ slightly.

Energy from Waste – Energy from Waste is a complex topic with many key assumptions necessary on input data. It remains an important part of the UK's waste management strategy. The renewable electricity deployment predicted is quite modest - c.260MW by 2020 (low forecast) and slightly lower than previous data. This is due to the limitations on fuel supply. Waste is a finite resource and there are competing demands for its use. It also has a fairly high capex and opex but this is likely to be offset in part by gate fees for the waste fuel.

Anaerobic Digestion (AD) – A high deployment potential is anticipated by 2020 relative to current levels, though its electrical contribution is still fairly modest at c.380MW (medium forecast). Like Energy from Waste the input assumptions are complex and it becomes resource limited by 2025. Potential has been identified from a range of AD generation types.

Landfill Gas (Dedicated Biogas) - The study has identified that negligible new build is anticipated. With a declining resource over time, landfill gas therefore makes little contribution by 2025. It remains a strong contributor at 0.4GW of installed capacity to 2020 (medium scenario).

Sewage Gas (Dedicated Biogas) – This is anticipated to provide little or no significant additional contribution - 175MW maximum by 2030 (all forecast), when viewed in comparison with most other technologies.

Advanced Conversion Technologies (ACT) - Deployment potential forecast is very modest (almost negligible relative to other technologies at 50MW by 2030 under the high deployment forecast). This is lower than previous studies and reflects concerns over technology maturity, the resource that will be available for this technology and high capex and opex.

Renewable Combined Heat and Power (CHP) - Most studies consider the potential for CHP from all fuel sources (mostly non-renewable), and thus identify a high potential. Renewable CHP is more constrained by matching sites of generation with heat load customers. In the low to high deployment forecast the range of Renewable CHP is estimated to be between 1.5GW and 6.0GW of the electrical renewable thermal deployment highlighted by 2030. These figures come mainly from larger scale dedicated biomass (c.50% of the contribution), with more limited contribution from the Waste to Energy, Geothermal, Bioliquids, Sewage Gas and Anaerobic Digestion sectors. Further analysis of Renewable CHP deployment beyond this study is needed as the evidence base for deployment potential is limited.

Figures 1 to 4 provide a summary of the total forecast renewable deployment and energy generation (electricity and heat). This study highlights the significant opportunity to deliver renewable energy generation across the UK. If constraints on grid connection, planning and supply are relaxed sufficiently, an additional 35 to 56GW of installed capacity could be reached by 2020 and a further 73 to 126GW by 2030.

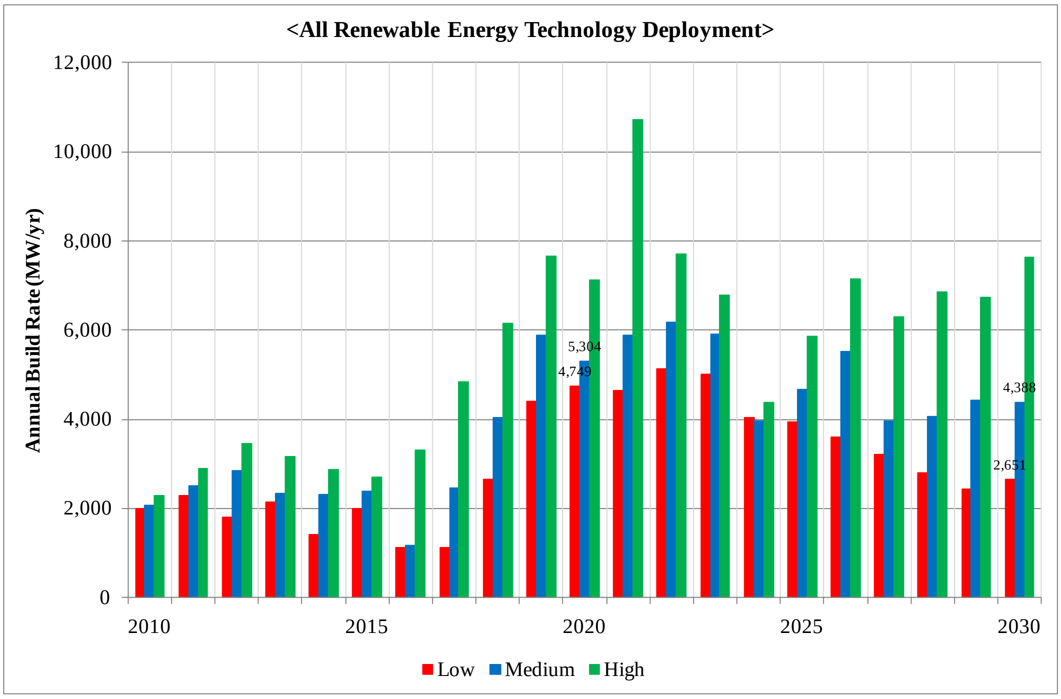


Figure 1: UK Total Renewable Technology Annual Build Rate (MW/yr)

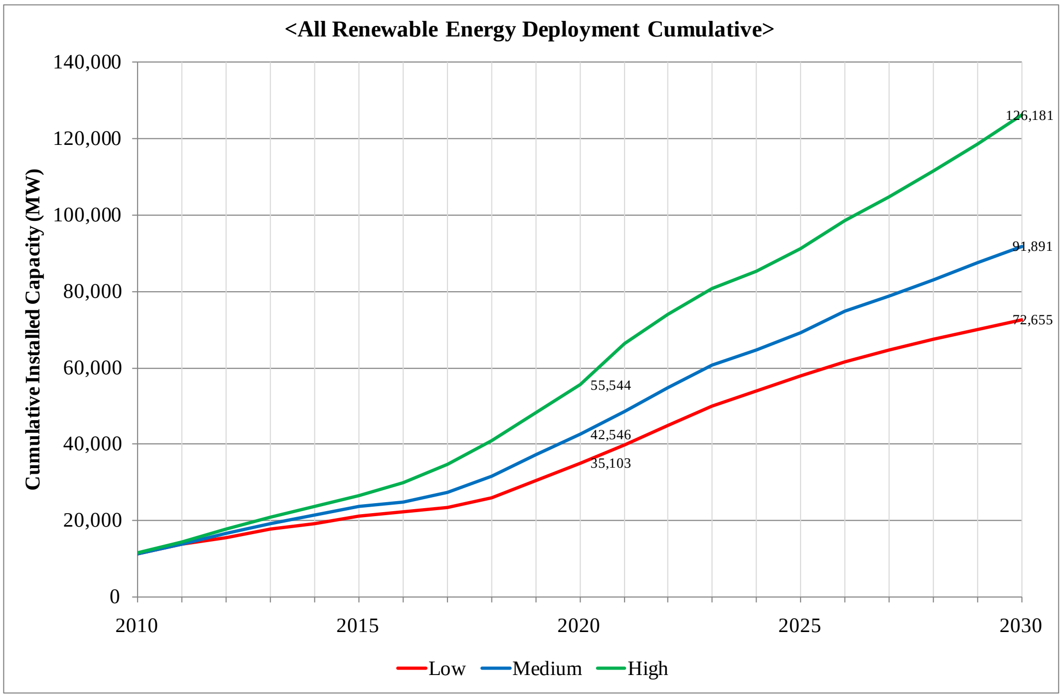


Figure 2: UK Total Renewable Technology Cumulative Installed Capacity (MW)

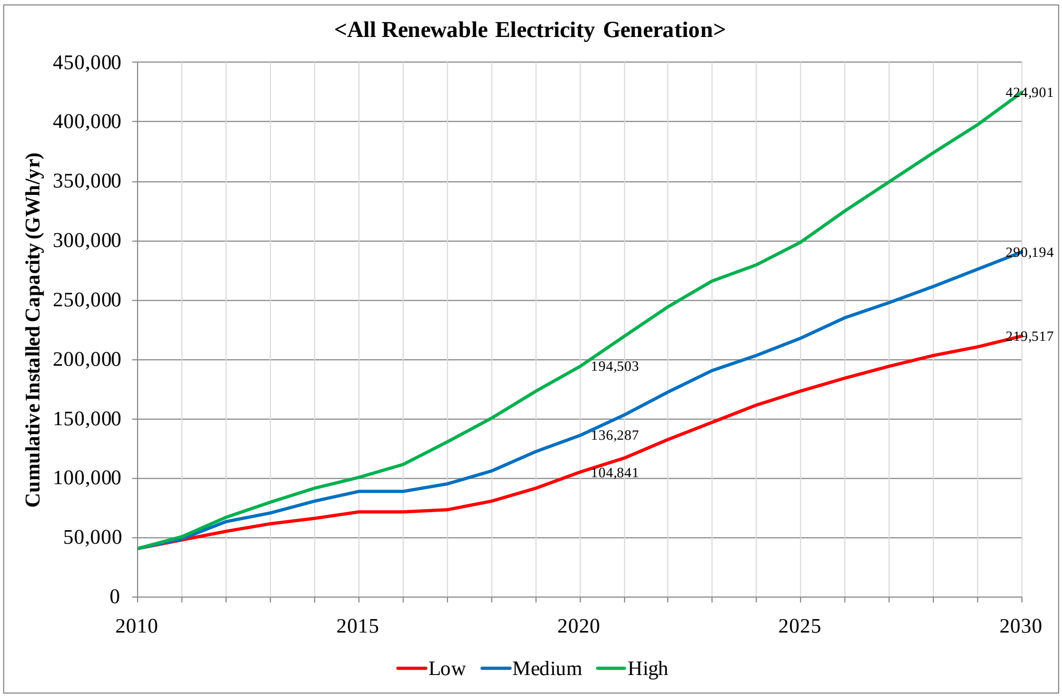


Figure 3: Total Renewable Technology Annual Energy Generation (GWh/yr)

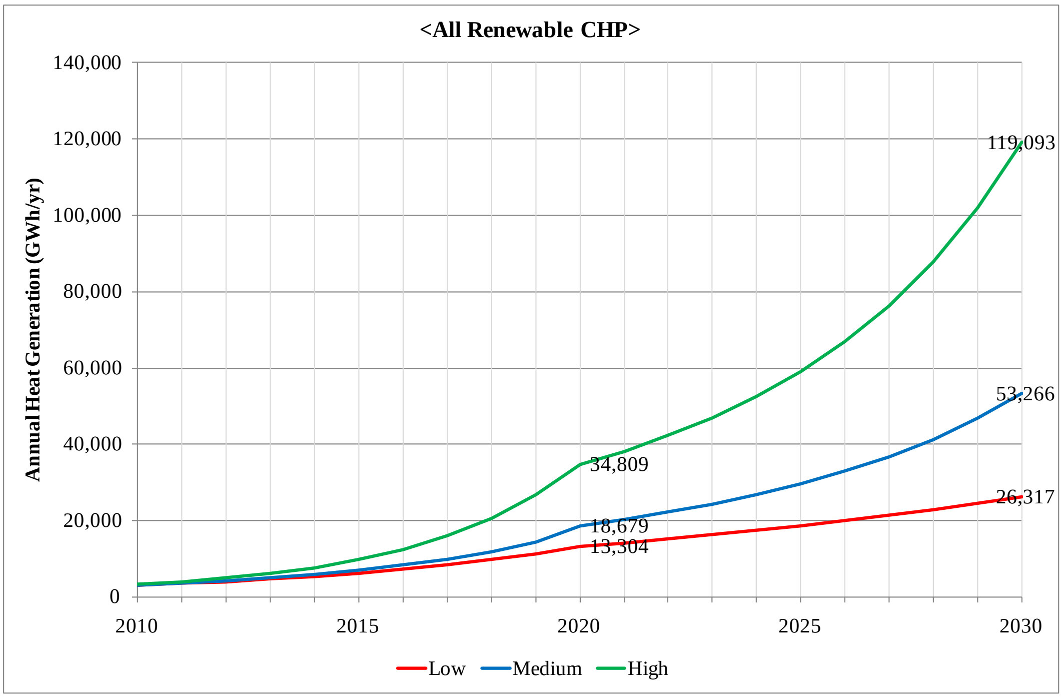


Figure 4: Total Renewable Technology Annual Heat Generation from CHP (GWh/yr)

Abbreviations

ACT	Advanced Conversion Technology
AD	Anaerobic Digestion
AEA	AEA Technology plc
AONB	Area of Outstanding Natural Beauty
BVG	BVG Associates
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
CIW	Commercial and Industrial Waste
DECC	Department of Energy and Climate Change
DEFRA	Department of Environment Farming and Rural Affairs
DS	Dry Solids
DUKES	Digest of UK Energy Statistics
E&Y	Ernst & Young LLP
EA	Environment Agency
EFW	Energy from Waste
EGS	Enhanced Geothermal System
EIA	Environmental Impact Assessment
EMEC	European Marine Energy Centre
EPC	Engineering Procurement Contract
EU	European Union
FIT	Feed-in Tariff
GHG	Green House Gases
HDR	Hot Dry Rock
IEA	International Energy Agency
IED	Industrial Emissions Directive
LCPD	Large Combustion Plant Directive
LFG	Landfill Gas
M&E	Mechanical and Electrical
MBT	Mechanical Biological Treatment
MOD	Ministry of Defence
MSW	Municipal Solid Waste
NAO	National Audit Office
NCV	Net Calorific Value
NGET	National Grid Electricity Transmission Ltd
NIEA	Northern Ireland Environment Agency
NNFCC	National Non-Food Crops Centre
O&M	Operation and Maintenance
OESEA	Offshore Energy Strategic Environmental
OFTO	Offshore Transmission Network Operators
ORED	Office for Renewable Energy Deployment
PFI	Private Finance Initiative
PPO	Pure Plant Oil
PV	Photovoltaic
R&D	Research and Development
RED	Renewable Energy Directive
RHI	Renewable Heat Incentive.

RO	Renewables Obligation
ROC	Renewable Obligation Certificate
RUK	Renewables UK
SEA	Strategic Environment Assessment
SEPA	Scottish Environment Protection Agency
SRC	Short Rotation Coppice
SRF	Solid Recovered Fuel
STW	Scottish Territorial Waters
UCO	Used Cooking Oil
VS	Volatile Solid
WATERS Fund	Wave and Tidal Energy Fund
WID	Waste Incineration Directive
WwTW	Waste Water Treatment Works

1 Introduction

The Coalition Agreement makes clear the Government's commitment to maintaining a banded Renewables Obligation (RO) alongside committing to implementing a full Feed-in-Tariff (FIT), with the aim of securing a significant increase in investment in renewables.

The Department of Energy and Climate Change (DECC) is currently considering the future form of electricity market arrangements, including the implementation of the commitment in the Coalition Agreement to "establish a full system of Feed-in Tariffs in electricity – as well as the maintenance of banded Renewables Obligation Certificates". The Consultation document on Electricity Market Reform was published in the autumn of 2010, and a White Paper is proposed for publication in the summer of 2011.

The RO and/or any new FIT system will therefore be integral to meeting the UK's share of the EU Renewable Energy Directive targets.

Arup, supported for certain cost data gathering exercises by Ernst & Young, was appointed in October 2010 to look at the deployment potential and generation costs of renewable electricity technologies taking into account sensitivities as to the range of cost inputs, investor behaviour and barriers to deployment.

DECC has indicated that improving its evidence base on the costs of renewables will allow it to improve the value for money of its financial mechanisms essential in the current financial climate.

The data and analysis from this study will be used to inform the levels of renewables subsidy under the RO and/or FIT.

The project was split into two parts:

Part A – Maximum feasible resource potential of renewable electricity technologies and build rate scenarios; and

Part B – Generation costs of renewable electricity technologies.

An integrated team completed both parts of the project in parallel.

DECC required a full assessment on a comparable basis of the renewable technology families and subcategories as listed below in Table 2. This list includes technologies currently eligible under the RO and some new sub categories. These sub-categories were to be viewed as indicative.

Table 2: Renewable electricity technologies to be covered

Technology family	Sub-categories by:	
	Technological/ fuel/ geography/ resource	Installed capacity
Onshore wind	Average wind speed (low, high)	Micro (<50kW) Small (50kW-5MW) Medium (5-10MW) Large (10-50MW) Very large (>50MW)
Offshore wind	Average wind speed (low, high)	Small (<100MW)

Technology family	Sub-categories by:	
	Technological/ fuel/ geography/ resource	**Installed capacity**
(taking into account OFTO regime)	Distance from shore	Medium (100-500MW) Large (500-1000MW) Very large (>1000MW)
	Water depth	
	Round 2, Round 3, Scottish Territorial Waters (STW) (all using MW weighted average conditions)	
Hydro		Very small (<1MW) Small (1MW-5MW) Medium (5-10MW) Large (>10MW)
Wave	Nearshore, offshore	
	Low, medium, high resource	
Tidal stream	Shallow, deep	
	Low, medium, high resource	
Tidal range	Site-specific estimates/low, medium, high resource	
	Tidal barrages, tidal lagoons, tidal reefs	
Geothermal	With/without Combined Heat and Power (CHP)	
Geopressure	With/without CHP	
Solar PV (photovoltaics)	Solar intensity levels (north/south variation);	Micro (<50kW) Small (50kW-5MW) Medium (5-10MW) Large (>10MW)
Dedicated Biomass (Solid)	Regular biomass; energy crops Virgin wood (e.g. forestry residues) Waste wood Perennial energy crops (e.g. SRC willow, miscanthus) Municipal Solid Waste (MSW) (including a proportion of Commercial and Industrial waste)	Micro (<50kW) Small (50kW-5MW) Medium (5-50MW) Large (50-100MW) Very large (>100MW)
	For non-waste feedstock, different sustainability levels >50%, 60%, 70% and 80% GHG (green house gas) savings	
Dedicated Biogas	Anaerobic digestion Feedstock: food waste; whole food crops (with sustainability levels); manures and slurries (assumptions on various levels of energy crops use will be provided)	Micro (<50kW) Small (50kW-5MW) Medium (5-10MW) Large (>10MW)
	Landfill gas	
Dedicated	Diesel generator versus steam boiler	Micro (<50kW)

Technology family	Sub-categories by: Technological/ fuel/ geography/ resource	Installed capacity
Bioliquids	Conversion existing diesel generator versus new build	Small (50kW-5MW) Medium (5-10MW) Large (>10MW)
	Made from: food crops waste, e.g. cooking oil Should also specify different sustainability levels (>35%, >50%, >60% GHG savings) in line with RED	
Advanced Conversion Technologies	Standard gasification	Micro (<50kW) Small (50kW-5MW) Medium (5-10MW) Large (>10MW)
	Advanced gasification	
	Standard pyrolysis	
	Advanced pyrolysis	
Co-firing of biomass and fossil fuel (retrofit onto existing fossil fuel capacity)	Up to 4% biomass by energy content 4-20% 20%+ Full conversion of existing fossil fuelled generation to dedicated biomass.	
	Fuel: Gas vs Coal; biomass fuel type including torrification / pre-treatment of biomass	
Renewable Combined Heat and Power (CHP)	All biomass/bioliquid technologies listed plus geothermal/geopressure	Micro (<50kW) Small (50kW-5MW) Medium (5-50MW) Large (50-100MW) Very large (>100MW)
	Waste combustion with combined heat and power (RO definition)	
	Co-firing with CHP, separate boilers	
	Heat to power ratios	
	Steam revenue e.g. industrial vs district, avoided heat generation costs (onsite use)	

Marine technologies (tidal range, tidal stream and wave) have been included, but DECC did not require any significant primary research/data gathering for them.

Consultation was undertaken on the published marine studies commissioned by DECC. The purpose of the consultation was to ascertain whether the data, assumptions and conclusions in the reports were accepted by industry stakeholders and to determine which data set was considered to be the most representative and realistic.

Regarding all the sub-divisions in Table 2, they were examined only to the extent that feasible resource potential/build rates (part A) or capex and opex (part B) vary according to these categories.

Fuel costs and waste gate fees are not in the scope of this project**,** but have been included in DECC's derivation of levelised costs and will be included by DECC in the separate project stage to model banding scenarios.

Feedstock availability for solid and liquid biomass has been based on assumptions provided by DECC. In particular the following reports:

AEA (2010) – UK and Global Bioenergy Resource

NNFCC (2011) – Evaluation of Bioliquids Feedstocks and heat, Electricity and CHP technologies

Assumptions were comparable across technologies, using common inputs to allow the impacts of different support scenarios on the electricity supply market to be modelled.

The work took into account and built on the considerable and extensive literature and research already produced. However Arup gathered new data from a number of sources including independent generators, suppliers/electricity companies and their own research and worked closely and flexibly with DECC officials.

2 Study Approach

2.1 Methodology

The study methodology was undertaken as one project, but in two parallel workstream. These were:

Part A – Maximum feasible resource potential of renewable electricity technologies and build rate scenarios; and

Part B – Generation costs of renewable electricity technologies.

2.2 Part A - Maximum feasible potential of renewable electricity technologies and build rate scenarios

The early part of the study comprised a comprehensive desk study. This took into account and built on existing research, in particular key references were:

SKM (2008) – Quantification of the Constraints on the Growth of UK Renewable Generating Capacity URN 08/1026

The Offshore Valuation Group (2010) – The Offshore Valuation 2010

DECC (2010) – 2050 Pathways Analysis Report

E4tech (2009) - Biomass Supply Curves for the UK

DECC (July 2009) – The UK Renewable Energy Strategy

Renewables Advisory Board (2008) 2020 VISION – How the UK can meet its target of 15% renewable energy

DECC (2010) - National Renewable Energy Action Plan for the United Kingdom

Renewable Energy Association (2010) – Renewable Energy Industry Roadmap

MacKay (2009) – Sustainable Energy without the hot air

The existing renewables growth trends and planning pipeline data available on Restats (https://restats.decc.gov.uk/cms/welcome-to-the-restats-web-site)

The team also considered a range of studies commissioned by the National Non Food Crops Centre (NNFCC) relating to economics and GHG performance of various bioenergy and EfW technologies.

Following the desk study, consultation was undertaken with various renewable energy organisations; to brief them on the study's scope and content, to confirm the available evidence on deployment and where appropriate clarify key assumptions e.g. The Crown Estate, Renewable UK etc. An extensive range of stakeholders across all aspects of the renewable energy sector have been consulted for the study, in the main to ascertain cost data (as per part B below) and also where appropriate to discuss deployment.

The key study assessment and outputs comprised the following:

An assessment of the *maximum feasible resource potential* of the renewable electricity technology families and sub categories listed in Table 2 above to 2020, and to 2030.

An assessment of the constraints to renewable electricity generation technologies expansion for each electricity technology family and sub-category listed in Table 2, in the UK to 2020 and 2030, as set out below.

Outputs of three scenarios of potential annual build rates from 2010 to 2030 for each technology family listed in Table 2, differentiating by sub-category where appropriate.

The impact of the following constraints on growth was assessed:

Supply chain fuel supply (where applicable), equipment and materials, skilled labour availability and installation capacity;

Planning Government consent, local authority planning approval for power plant;

Grid constraints construction of and connection to the transmission network and reinforcement of the transmission network; and

Other constraints physical constraints, including availability of suitable sites and any other relevant constraints (technical, legal etc), which could limit the deployment.

The potential for major refurbishment and repowering has also been taken into account.

Two workshops were held with officials from DECC and other Government departments on 17th December 2010 and 17th February 2011 to review progress and discuss finding to date.

Based on the desk study, consultation responses, constraints and DECC input, three scenarios were developed for each technology on the maximum amount of capacity that could be installed per year in the UK (MW/year) as follows:

Low scenario: the maximum amount of capacity that could be built per year (i.e. MW/year) *per renewable technology* between 2010 and 2030 in the UK given the identified constraints;

Medium scenario: the maximum amount of capacity that could be built per year (i.e. MW/year) *per renewable technology* between 2010 and 2030 in the UK if some of the constraints were relaxed; and

High scenario: the maximum amount of capacity that could be built per year (i.e. MW/year) *per renewable technology* between 2010 and 2030 in the UK if additional constraints were relaxed.

The outputs from all three scenarios are presented in terms of annual installed capacity (MW/yr), cumulative installed capacity (MW) and annual energy generation (GWh/yr).

For each technology a view was formed as to what deployment trends could look like beyond 2030.

For each of the deployment scenarios a commentary is provided on the regional distribution of deployment, where applicable, by England, Scotland, Wales and Northern Ireland.

It is important to understand in relation to the deployment scenarios developed for Part A that no consideration was made, as per DECC instructions, of financial constraints. These scenarios therefore represent *maximum annual build rates*, that might need significantly more than current support available under the Renewables Obligation and Feed-in-Tariffs to be fully achieved.

In the second phase of the Banding Review, DECC and their consultants are combining these financially unconstrained scenarios with an assessment of project economics (based on the generation costs from part B, biomass and waste fuel price assumptions, and revenue assumptions) in order to assess the potential impact of RO bandings on renewable deployment levels, along with other impacts, particularly those to which the Secretary of State for Energy and Climate Change is obliged to give regard according to the legislation governing the Renewables Obligation.

This report therefore provides two key sets of input assumptions to the analysis of the second stage of the banding review: maximum build rates for renewable technologies and their generation costs.

2.3 Part B – Generation costs of renewable electricity technologies

2.3.1 Review

The review of project cost draws on publicly available information, Arup and E&Y proprietary cost data and project cost data collected through extensive consultation with industry stakeholders. The work involved the following steps:

Reviewing industry literature to gather benchmarks on project costs for the technologies covered in the report. This included information on capital expenditure, operating expenditure and capacity factors.

Consulting with stakeholders to collect project cost data, a view on cost drivers and other technical/operational project information relevant for levelised cost modelling.

a. In total approximately 200 industry stakeholders were contacted, across technology groups and the whole of the UK, with a standardised questionnaire.

b. Stakeholders included mainly developers or facility owners, of which over 70 returned questionnaires with information on projects that have been recently completed or are in construction or development. Project cost data relate to commercial close dates and have been adjusted for 2010 prices.

c. The majority of questionnaire responses were discussed with stakeholders to gather further information on projects and validate the cost data provided.

Establishing project cost ranges (high, median, low) for different groups of installed capacity for each renewable technology. This included current project cost for pre-development, capital expenditure and operational expenditures. Other key financial and technical project data have also been collected from stakeholders including efficiency, capacity factors and hurdle rates.

Projecting future project cost based on main cost drivers and learning rates.

d. For each renewable technology the main cost drivers (e.g. steel, labour, industrial commodities etc) were used to build a composite cost index. Historic trend analysis, based on Bloomberg data, was used to inform the evolution of individual cost drivers. Appendix A shows alternative cost scenarios for key cost drivers. DECC instructed us to assume no change in exchange rates in the base case cost projections.

e. Expected industry learning effects have been applied to respective technology costs. Learning rates have been driven by global deployment with the exception of where the UK leads industry development (i.e. offshore wind, wave and tidal stream). Also, where the local supply chain has yet to evolve (e.g. ACT, geothermal), Arup has included expected supply chain development and specialisation in the learning rates for the respective technology.

Inputting current and projected costs and technical/ financial project parameters into DECC's levelised cost model. The actual modelling of levelised cost is excluded from the scope of Arup's work. Each technology chapter features levelised cost ranges as calculated by DECC using their levelised cost model and applying technology specific discount rates. Annex D shows levelised costs as calculated by DECC using a methodology consistent with that used by PB (forthcoming) for levelised costs for non-renewable technologies, and Mott Macdonald (2010). In calculating levelised costs, DECC used biomass fuel costs and waste gate fee assumptions based on AEA (2010) and the WRAP Gate Fee Report 2010, and heat (steam) revenue assumptions for CHP technologies detailed in Chapter 19 on Renewable CHP. It needs to be noted that the levelised costs for wind and marine technologies do not include system balancing costs.

2.3.2 Limitations of cost analysis

We have used reasonable effort to verify data given to us by stakeholders but we have not carried out a detailed audit of the underlying cost items that constitute development, construction and operating costs.

The impact of capital and operational cost drivers were derived using information collected through the stakeholder consultation and proprietary in-house data. A comprehensive analysis, from first principles, has not been undertaken for the project cost drivers.

The stakeholder consultation, and the subsequent analysis, was limited in scope and time, with a view to build cost ranges that inform the levelised cost modelling. A more detailed review of each technology may reveal issues in relation to individual data that has not been included in our analysis.

Limited information was received in relation to developers' or investors' project hurdle rates. Many stakeholders decided not to disclose their own confidential hurdle rates.

The scope of this work did not include a review of fuel costs. Fuel costs have been excluded from the operating expenditure shown in the report, but have be taken into account in DECC's derivation of levelised cost and will be included in the subsequent modelling stage of the Renewables Obligation banding review.

The volume of information collected for each technology varies with the size of each industry, the number of stakeholders active and their level of enthusiasm in contributing to the study. Consequently, for some technologies, further in-depth industry work may be required to clarify findings. Additionally, given a lack of project data for all variations of installed capacity, it has not been possible to fully investigate how scale affects project cost for all technologies.

The unit cost ranges on project capital and operating expenditure are explained by a variety of issues including scale effects, a trade-off between capital and operating costs, technological variations, requirements for fuel processing, different plant efficiencies and site specific conditions. The totality of these factors, captured through costs and technical parameters, drive levelised costs. As stand-alone figures, the cost ranges for each technology need to be interpreted cautiously, as they do not include fuel costs or gate fees. They do not provide an absolute measure of financial viability.

The project has not gathered data on biomass fuel availability and prices, which is the subject of separate research.

2.4 Technology Families

The technologies listed in Table 2 of this report are those prepared by DECC as the input to this project. In practice, Table 2, particularly for the waste and biomass technologies, contains a mixture of resources (e.g. municipal waste stream) and methods of energy production via electricity generation (e.g. ACT or co-firing).

For reasons of practicality (available data etc.), this list has been reduced to that below, Table 3.

Table 3: Energy generation categories used in this study

Technology family	Sub-categories by: Technological/ fuel/ geography/ resource
Onshore wind	Large (>5MW) and smaller (<5MW)
Offshore wind	Round 2, Round 3, STW
Hydro	Large (>5MW) and smaller (<5MW)
Wave	Nearshore, offshore
Tidal stream	Shallow, deep
Tidal range	Tidal barrages
Geothermal	With/without CHP
Solar PV	
Dedicated Biomass (Solid) All sources	Regular biomass; energy crops, virgin wood (e.g. forestry residues) , Waste wood , perennial energy crops (e.g. SRC willow, miscanthus), biomass fuel type including torrification/ pre-treatment of biomass
Biomass co-firing All sources	
Dedicated Biomass (Solid) Power station conversion	

Technology family	Sub-categories by: Technological/ fuel/ geography/ resource
Dedicated Bioliquids All sources	Made from: - food crops; - waste, e.g. cooking oil; and - dedicated bioliquid crops.
Energy from Waste	Solid Recovered Fuel (SRF) derived from wastes such as MSW
Anaerobic digestion	Feedstock: food waste; whole food crops (with sustainability levels); manures and slurries
Dedicated biogas	Sewage gas
	Landfill gas
Advanced Conversion Technologies	Advanced gasification
	Advanced pyrolysis
Renewable CHP	All biomass/bioliquid technologies listed
	Waste combustion with combined heat and power (RO definition)

2.5 Conventions

1. Note that 'MW' in this report refers generally to megawatts of electrical installed generating capacity, except for clarity in the Combined Heat and Power chapter where 'MWth', meaning megawatts of installed thermal generating capacity, is used in contrast to 'MWe', which refers to installed electrical generating capacity.
2. The maximum build rate scenarios, except for the CHP chapter, represent the total electrical installed capacity that could be possible under varying scenarios of non-financial constraints (but excluding financial constraints from the analysis). The CHP chapter maximum build rates in MWe are a subset of the maximum build rates in MW in the other chapters.
3. The maximum build rates scenarios in the main report are those for the UK. Annex C presents maximum build rates scenarios for Northern Ireland, and in a few cases for Scotland, which are a subset of those for the UK. These desegregations were required by DECC for the subsequent modelling phase of the Renewables Obligation Banding Review, as Northern Ireland is part of the Single Electricity Market of the island of Ireland (whilst there is one market for Great Britain), and in some technologies in Scotland (wave and tidal stream), RO bandings have varied from those for the rest of the UK

.

3 Onshore Wind >5MW

3.1 Summary

Onshore wind within the UK still has significant deployment potential when compared to current deployment. It has the opportunity if deployment constraints are relaxed to deliver an additional 10-14GW of installed capacity by 2020 and a further 15-24GW by 2030. This would provide an increase of between 100% and 500% from present generation levels.

3.2 Introduction

Onshore wind is the one of the most established renewable technologies, with a strong history in the UK and a growing global market. It is recognised as a key component of the UK renewables mix, with strong deployment to date in all parts of the UK, but especially in Scotland.

This study has considered onshore wind in two size categories:

- < 5MW
- > 5MW

All forecast produced in this report are not financially constrained. There is no consideration of current or future financial support mechanisms.

3.3 Literature Review

The literature review concluded that, as expected, there is a lot of previously published data in respect of onshore wind of all scales, both in terms of resource assessment and deployment.

3.4 Constraints

3.4.1 Supply Chain

The Global supply chain is not considered a constraint to the deployment of onshore wind; turbines are available in sufficient quantity to supply existing demand. Onshore wind turbines are considered a mature global technology with significant international deployment. It is considered that the international turbine manufacturing sector is capable of addressing the UK supply chain. Time lags due to turbine supply to the larger projects, form in a larger part of the anticipated deployment, are generally not proving significant.

3.4.2 Planning

Planning constraints, including site and land availability, population distribution, public acceptability, aviation, radar, highway access, peat and national and international landscape and ecological designations all affect onshore wind deployment. Recent proposed changes to the planning system in England with an emphasis on localism are perceived as inhibiting deployment. This is because the Localism Bill is seen as potentially giving further weight to local opposition, whether at the Member level or in local opposition groups. The recent introduction of the major planning regime (under the Planning Act 2008) is seen as of little benefit in England where the vast majority of wind projects are (and will continue to be) below 50MW, due to resource availability. Gaining rapid and affirmative initial approval to projects in Wales remains a challenge where local opposition remains strong.

In Scotland and Northern Ireland, planning has been less of an issue (especially in NI with its centralised planning service) but increasingly, cumulative issues are affecting more projects.

Initial planning refusal rates have been examined, but the historic annual build rate in the UK (approximately 525MW/year) is seen as the best starting point for deployment modelling. However it is informative to see the UK historical build rates in context with historical build rates in Spain and Germany (see Figure 5 below.[1]

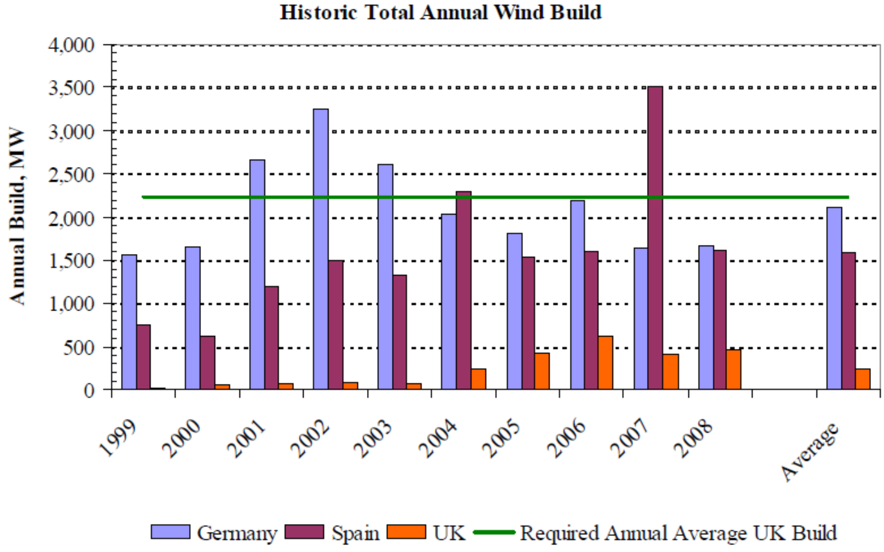


Figure 5: Historic total annual wind build

3.4.3 UK Grid

Generally the UK grid is not considered a significant medium or long-term constraint to the deployment of onshore wind to 2020, especially given the recent go ahead for the Beauly-Denny line in Scotland. However, it is recognised that some grid bottlenecks do exist (such as into Mid Wales and in the west of Northern Ireland) but that it is assumed that National Grid and other key UK stakeholders such as the District Network Operators have programme(s) in place to deliver the necessary improvements at a high enough rate that does not significantly restrict deployment.

3.4.4 Technical

It is not anticipated that there will be any significant need for technical innovation within onshore wind in the short to medium term.

[1] IPA Water and Economics – The winds of change (2009)

3.5 Limitations and Assumptions

3.5.1 Limitations

No specific limitations have been identified.

3.5.2 Assumptions

Repowering has been assumed to contribute to a degree in all future deployment scenarios. Some of the current UK wind farms date from the 1990s and use sub-1MW turbines. Repowering with larger modern turbines could increase both the installed capacity and also, since the turbines are higher and can capture more wind, the energy yield.

It is assumed in the high scenario that changes are made to the nature of grid access charges such that this reduces the influence of this factor as a constraint.

It is assumed that will involve turbines of around 2-3MW rated capacity and up to 150m tip height. This is primarily a function of transport and access considerations.

3.6 Maximum Build Rate Scenarios

3.6.1 Available Resource

The maximum feasible resource potential has been assessed by a number of studies to range between 20GW and 30GW e.g. 2050 Pathways, Committee on Climate Change Fourth Carbon Budget. Most of the estimates of onshore wind deployment in the UK put the available resource in the range 10-15GW, see Figure 6.

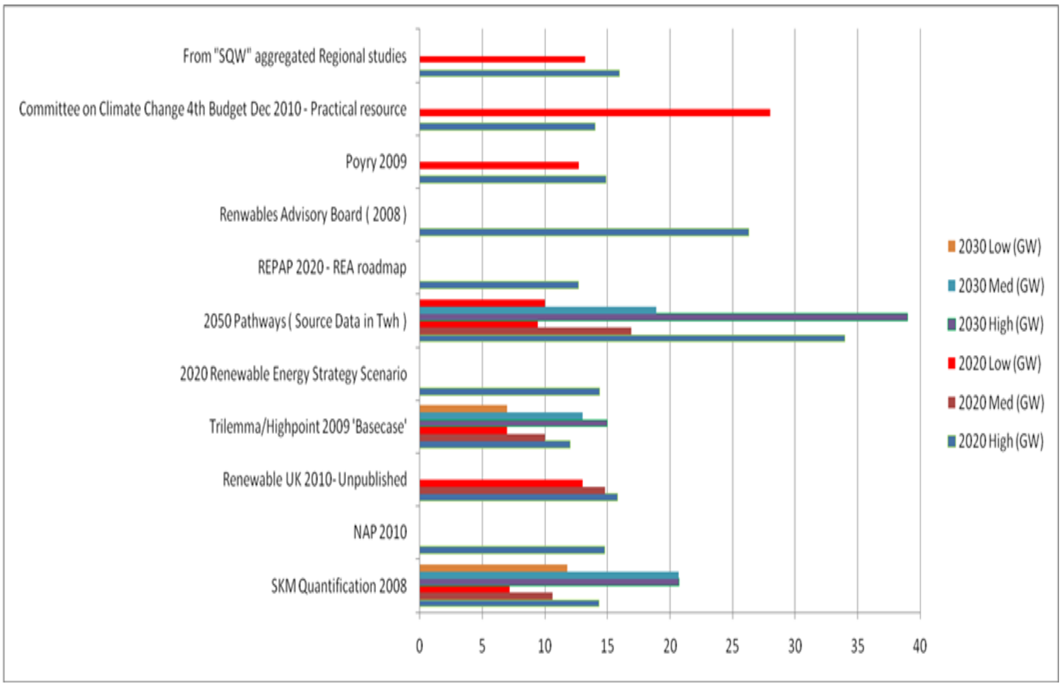


Figure 6: Estimated onshore wind resource

An average UK load factor of 28% was used in the development of the annual energy generation data[2]. As the UK is increasingly using larger and more efficient turbines this is likely to be a slight underestimate of future generation load factors. However, a counteracting issue would be the likely future deployment in areas such as central and southern England with generally lower annual wind speeds. This study has therefore used the current data of 28% as a UK average going forward for simplicity –but it is acknowledged that is likely to vary slightly over time depending on the eventual geographic distribution of the larger deployment opportunities.

3.6.2 Low Scenario

The low onshore wind scenario assumes 2010 annual build rates of 350MW to 650MW, i.e. around or slightly above current levels. A small increase in annual deployment over current levels is considered likely over the next 5-9 years, taking into account the large pipeline of projects currently in the planning system across the UK, 6.5GW approx (RenewableUK, 2010).

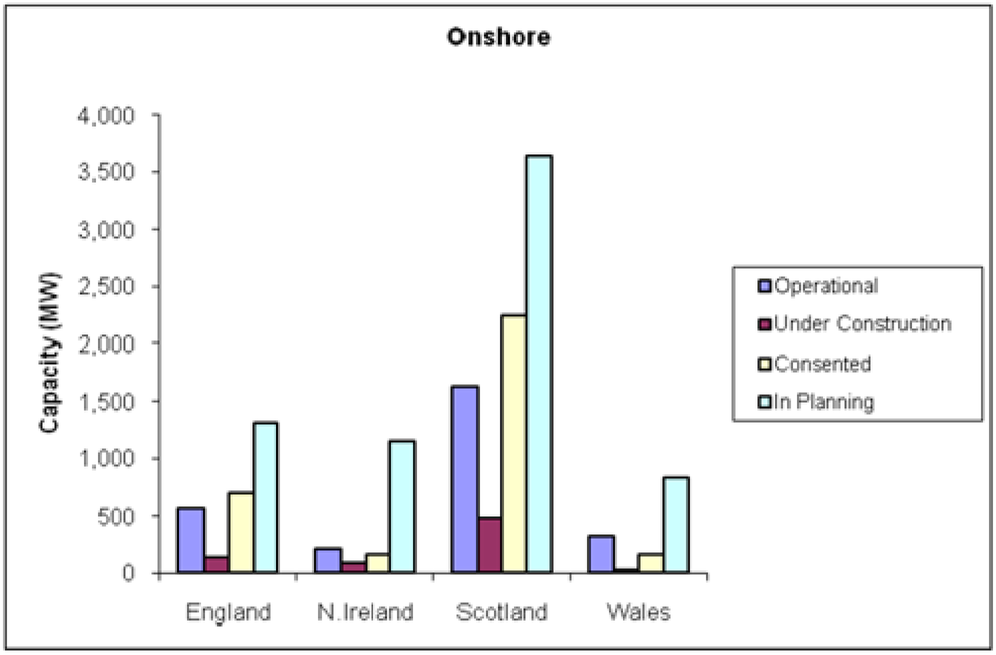


Figure 7: 2010 onshore capacity by planning status[3]

This scenario results in approximately 10GW by 2020 and 15GW by 2030. This is lower than estimates by RenewableUK and reflects in the most part a reassessment of English deployment rates.

[2] Source UK onshore wind capacity factors 1998-2004: www.berr.gov.uk/files/file43950.pdf

[3] Scottish Enterprise – Energy Industry Market Forecasts Renewable Energy 2009-2014 – The Wind Market

3.6.3 Medium Scenario

The medium onshore wind scenario assumes 2010 annual build rates of 600MW to 800MW, i.e. above current levels. This for the most part reflects a higher planning success rate but with broadly similar assumptions in respect of the nature of planning constraints. As with the low scenario, a small increase in annual deployment over current levels is considered likely over the next 5-9 years taking into account the large pipeline of projects currently in the planning system across the UK, 6.5GW approx (RenewableUK, 2010).

This scenario results in approximately 11GW by 2020 and 17GW by 2030. This is still lower than estimates prepared by RenewableUK.

3.6.4 High Scenario

The high onshore wind scenario assumes 2010 annual build rates of 1,200MW to 900MW i.e. above current levels. A significant increase in annual deployment over 2010 levels is considered likely over the next five to nine years; taking into account the large pipeline of projects in the planning system across the UK, 6.5GW approx (RenewableUK, 2010). After this period the annual build rate reduces reflecting the increasing utilisation of available sites.

These levels of annual deployment will necessitate higher planning approval rates. Initially it could be acceptance of cumulative landscape and visual impacts in landscapes, but by 2020 it would require the acknowledgement that some parts of the UK would experience wind farm landscapes. It would also envisage MOD and radar constraints being solved in South West Scotland and the North of England, releasing resource. It also assumes that all grid reinforcement envisaged by National Grid will occur.

It would also assume all wind farms built in the 1990s are repowered.

This scenario results in approximately 14GW by 2020 and 24GW by 2030. This is broadly comparable with the RenewableUK data.

The three scenarios developed are presented in Figures 8 to 10.

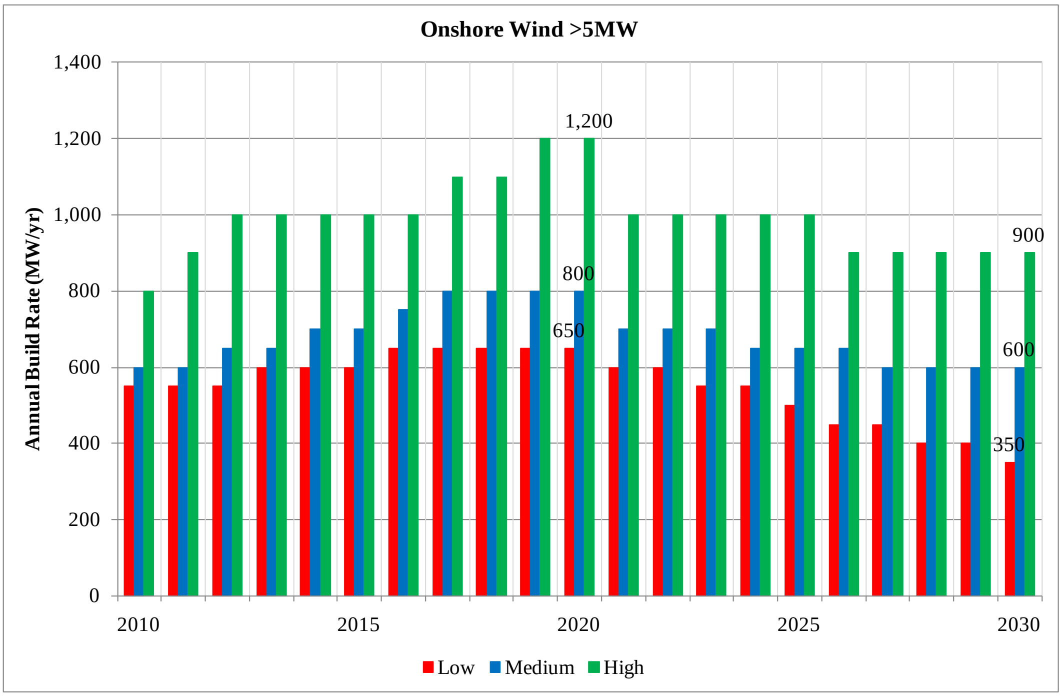


Figure 8: UK Onshore Wind (>5MW) Annual Build (MW/yr)

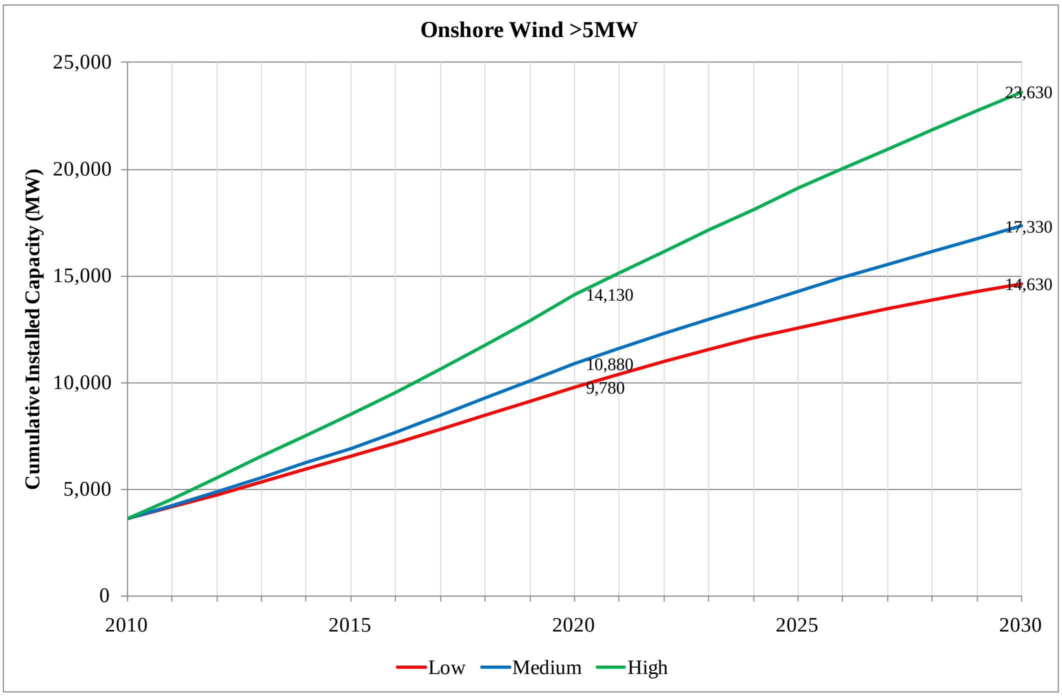


Figure 9: UK Onshore Wind (>5MW) Cumulative Installed Capacity (MW)

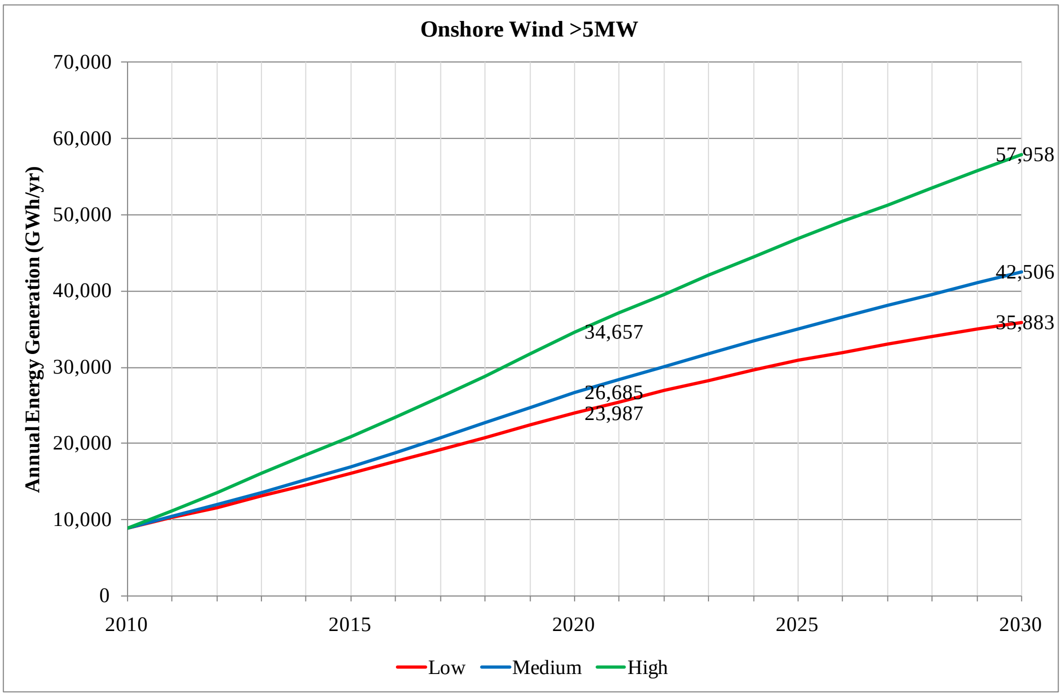


Figure 10: UK Onshore Wind (>5MW) Annual Energy Generation (GWh/yr)

3.7 Beyond 2030

In all three Arup scenarios, annual build rates reduce after 2020 due to a lack of site availability in the context of current constraints. It is expected that despite a contribution from repowering and site extensions, annual rates of deployment will reduce from 2030 to 2050.

Especially in England, higher population density suggests that even with a full relaxation of current planning constraints, the available resource is finite and may effectively be exhausted by 2030. Deployment after 2030 would be likely to derive mainly from Scotland, Wales and Northern Ireland, although in the case of Wales and Northern Ireland it is likely to be much more modest in scale as in these nations the resource available will become more limited after 2030. To maintain onshore wind deployment levels beyond 2030, less populated areas where planning conditions are very restrictive may need to be considered, for example AONBs and National Parks in England and Wales.

It is also conceivable that between 2030 and 2050 cumulative deployment of onshore and offshore wind will reach levels where the issue of intermittent generation on the National Grid may limit further deployment.

3.8 Project Cost

3.8.1 Key Assumptions

DECC requested that current cost data should be collected for onshore wind at a variety of scales spanning:

- < 50 kW
- 50 kW – 5 MW
- 5 MW – 50 MW
- > 50 MW

Analysis of the data suggested that the presentation of the cost ranges at three scales would provide a more appropriate size grouping. The 5MW – 50MW and >50MW scales have therefore been consolidated due to limited variation in the data. Accordingly, this report presents results at three scales:

- Micro-wind (50kW)
- Small-scale wind (50kW – 5MW)
- Large-scale wind (>5MW)

Data have been collected from publicly available industry reports and questionnaire responses from stakeholders spanning manufacturers, developers and utilities.

Project hurdle rates varied by site and stakeholder, with a nominal post-tax range of 10% - 11% noted. Stakeholders typically assumed project lifespan between 20 and 25 years.

3.8.2 Capital Expenditure

Turbine costs are the most significant element of capital expenditure at a price of circa £1m/MW. Grid connection, foundations and civil infrastructure constitute the remaining costs.

Pre-development costs were found to vary significantly depending on the site, with costs ranging between £20,000/MW and £108,000/MW for large-scale wind farms. These costs include, amongst others, public enquiries, licensing, radar mitigation, design consultancy and habitat enhancement measures. Costs vary on a project-by-project basis as variation is frequently driven by difficulty in obtaining planning consent and dealing with appeals.

The unit capital costs of micro-wind appear to be over double that of small and large-scale wind farm costs, primarily due to economies of scale. Once at the 50kW – 5MW wind farm size, costs per MW of installed capacity do not change significantly. Data collected in this range tended to be sites with one or two large turbines (1MW to 2.3MW in size). While the large wind farms usually have a greater number of turbines, the actual capacity of the individual turbines is similar. This modular nature of wind farms appears to explain the lack of economies of scale.

Capital costs for micro-wind systems range from £2.8m/MW to £4.3m/MW, with a median of £3.8m/MW. The range in costs is due to site location, turbine type, the technology used and variation in size. The variability in site conditions, particularly in urban environments, results in inconsistent capacity factors and project payback periods vary accordingly.

Small-scale wind capital costs range from £1.2m/MW to £1.9m/MW with a median cost of £1.5m/MW, while large-scale wind capital costs are between £1.2m/MW and £1.8m/MW with a median cost of £1.5m/MW. Site characteristics appear to be primarily responsible for cost variations at both these scales. Project costs are dependent on many factors including the distance to the grid, environmental mitigation, wind speeds, access routes, soil composition and insurance.

The data collected show marginal cost reductions at a larger wind farm size. Approximately 70% - 80% of capital costs are usually expensed in Euros meaning that exchange rate fluctuations have a significant impact on project costs.

Table 4: Onshore Wind – capital costs (financial close 2010)

£'000/MW	<50kW	50kW – 5MW	> 5MW
High	4,330	1,858	1,820
Median	3,762	1,548	1,524
Low	2,786	1,174	1,184

Figure 11: Onshore Wind – capital costs (2010)

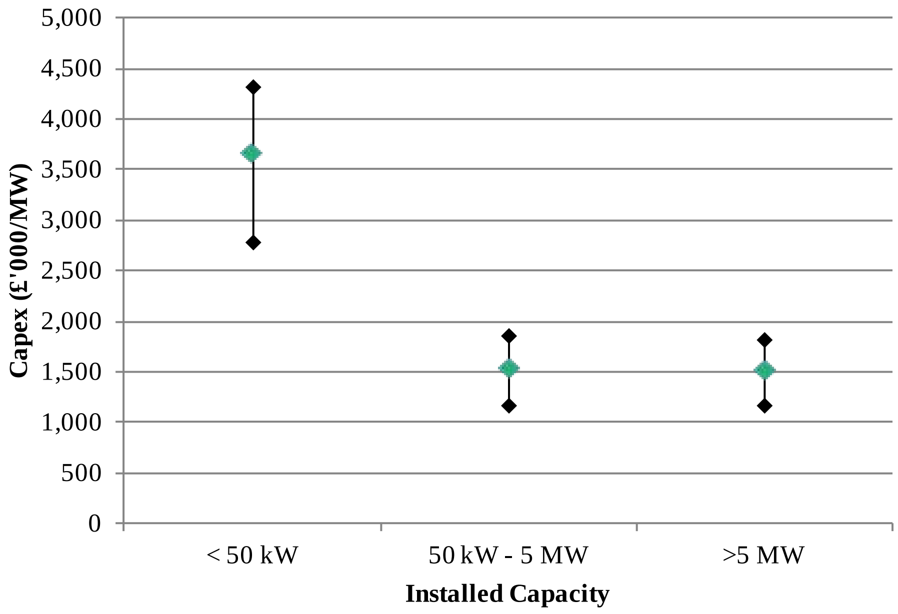


Table 5: Onshore Wind – capital cost breakdown

Capital cost item	%
Pre-development	3%
Construction	88%
Grid costs	5%
Other infrastructure	5%

Stakeholders considered the key cost drivers to be exchange rates and steel prices. DECC asked that the cost projection exclude exchange rate movements due to the uncertainty of such movements. Expected increases in steel prices are the primary positive price inflator over the next 20 years.

However a small decline in prices is expected over the next 10 years due to further industry learning. The Blue Map deployment study expects an increase in global deployment from 247GW in 2010 to 1,057GW by 2030. The IEA learning rate of 7% has been used along with the Blue Map global deployment levels to derive future cost reductions through further industry learning. Global deployment rates have been used for learning effects to reflect the global supply chain.

Minor cost reductions are expected between 2010 and 2020, however from 2020 to 2030, prices are expected to increase as the impact of rising steel prices outweighs the cost reduction from industry learning. Overall the cost projections are relatively flat, with an expected overall decrease of 0.5% through the next 20 years.

As the price drivers do not differ for large and small-scale wind it is expected that costs for both scales will change at the same rate.

Table 6: Onshore Wind - capital cost projections at financial close date (real) (>5MW)

Capital cost (£000s/MW)	2010	2015	2020	2025	2030
High	1,820	1,795	1,791	1,800	1,810
Median	1,524	1,503	1,500	1,507	1,515
Low	1,184	1,168	1,165	1,171	1,177

Table 7: Onshore Wind – capital cost projections at financial close date (real) (50 kW – 5MW)

Capital cost (£000s/MW)	2010	2015	2020	2025	2030
High	1,858	1,833	1,828	1,838	1,847
Median	1,548	1,527	1,523	1,531	1,539
Low	1,174	1,158	1,155	1,161	1,167

3.8.3 Operating Cost

Operating costs for large and small scale wind comprise O&M contracts, insurance, land rental, grid charges and labour.

Figure 12 below shows significant variations in operating costs at all scales for the 5 to 20 year period of the project's life. The costs for micro-wind vary from £34,000/MW/year to £61,000/MW/year, with prices varying due to site conditions, technology type and turbine size.

Operating costs for small and large-scale wind appear to get progressively more expensive with size. For small-scale wind they vary between £39,000/MW/year and £70,000/MW/year, with a median of £48,000/MW/year. The site characteristics for the 50kW to 5MW range and the >5MW plus range vary significantly as at the smaller scale there can be single turbine projects on industrial sites and business parks.

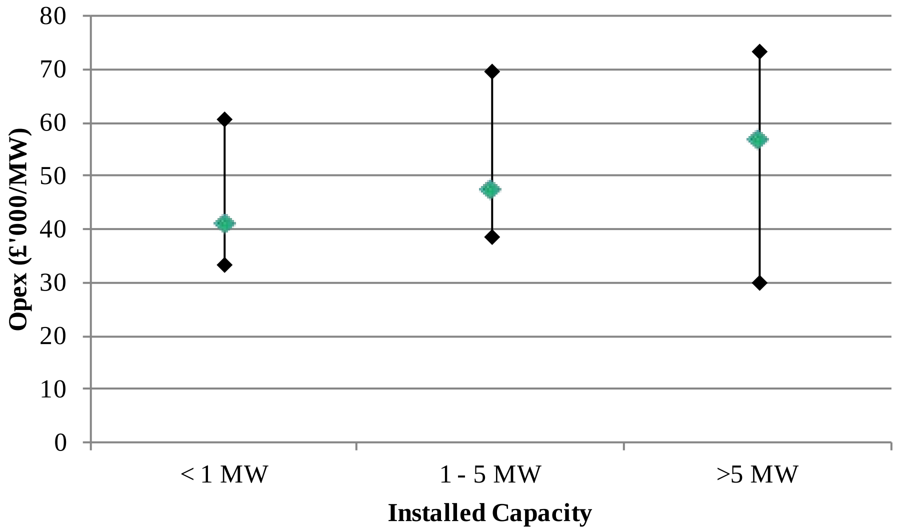
Large-scale wind projects show the greatest range in operating expenditure, with a median of £57,000/MW/year, a low of £30,000/MW/year and a high of £73,000/MW/year. Similar to the small and micro-scales, it appears this range is predominantly due to varying site characteristics.

Operating costs vary throughout the life of a wind farm. After the first five years of the project life, stakeholders noted that costs increase significantly. The increase is born out of the necessity for increased maintenance and the limited range of O&M suppliers which may be causing a lack of competitive pricing. We expect this to be likely to affect smaller developers more than large utilities, in some cases resulting in a tripling of costs, as they do not have the same negotiating power when discussing contract renewals with suppliers.

Table 8: Onshore Wind – operating costs (financial close 2010)

£'000/MW	<50kW	50kW – 5MW	>5MW
High	60.7	69.8	73.4
Median	41.4	47.6	57.2
Low	33.6	38.7	30.2

Figure 12: Onshore Wind – operating costs (financial close 2010)



Stakeholders identified labour and spare part costs as being the key future price drivers for operating costs. No industry learning has been incorporated into cost projections for operating expenditure.

It was assumed that there would be a slow increase in labour costs over the next 20 years, while spare part prices will be affected by the changes in the prices of steel and other commodities that are used in turbine manufacturing. These factors lead to a projected minor increase in operating costs at all scales of onshore wind.

Table 9: Onshore Wind - operating cost projections (real) (>5MW)

Operating cost / MW per year (£000)	2010	2015	2020	2025	2030
High	73	74	75	76	77
Median	57	58	59	59	60
Low	30	30	31	31	32

Table 10: Onshore Wind – operating cost projections (real) (50 kW – 5MW)

Operating cost / MW per year (£000)	2010	2015	2020	2025	2030
High	70	71	72	73	74
Median	48	48	49	50	50
Low	39	39	40	40	41

3.9 Levelised costs

Using the Arup and E&Y capital and operating cost profiles[4], DECC has calculated levelised costs of an onshore wind reference plant at financial close in 2010, 2015, 2020, 2025 and 2030. The levelised cost ranges are based on Arup's low, medium and high capital cost estimates. The levelised costs have been calculated by assuming a pre-tax real hurdle rate of 9.6%, based on Arup stakeholder information and the Oxera report[5] for the CCC. The assumed load factor is 29% for Onshore Wind >5MW and 25% for Onshore Wind <5MW. The assumed installation lifetime is 24 years.

£ / MWh		2010	2015	2020	2025	2030
Onshore >5MW	low	75	72	71	69	68
	medium	91	88	86	84	82
	high	108	105	103	101	99

[4] To note that the levelised costs are based on a separate set of capital and operating costs provided by Arup and E&Y that assume constant steel prices over time; capex includes infrastructure costs are incurred in the core facility, but do not include 'other' infrastructure costs that relate to costs incurred outside the site, such as water, roads, waste disposal and land costs. Levelised costs use different size categories for some technologies.

[5] www.oxera.com/main.aspx?id=9514

Onshore <5MW	low	82	80	78	76	75
	medium	104	102	99	98	96
	high	127	125	122	120	118

Note: Dates refer to financial close.

3.10 Regions

Regional issues directly affect onshore wind deployment. The principal factor is population density and the distribution of that population; this is used as a proxy as detailed constraint based mapping resource estimates are not available by devolved nation.

The *average* population density differs significantly between the home nations ranging from 380 per km^2 in England to 57 per km^2 in Northern Ireland (MacKay (2009). However even this average figure masks the subtle differences between population distribution within some nations, such that areas like the Southern Uplands of Scotland and Mid Wales have sufficiently low population densities to allow large (>50MW+) wind farms. By comparison Spain, which has seen much higher cumulative onshore wind deployment historically, has an average population density of 80 people per km^2.

Population density directly affects the ability of onshore wind to be deployed by virtue of the noise constraints around properties (particularly isolated and scattered evenly distributed properties in the wider countryside) which can range from 300-1,000m.

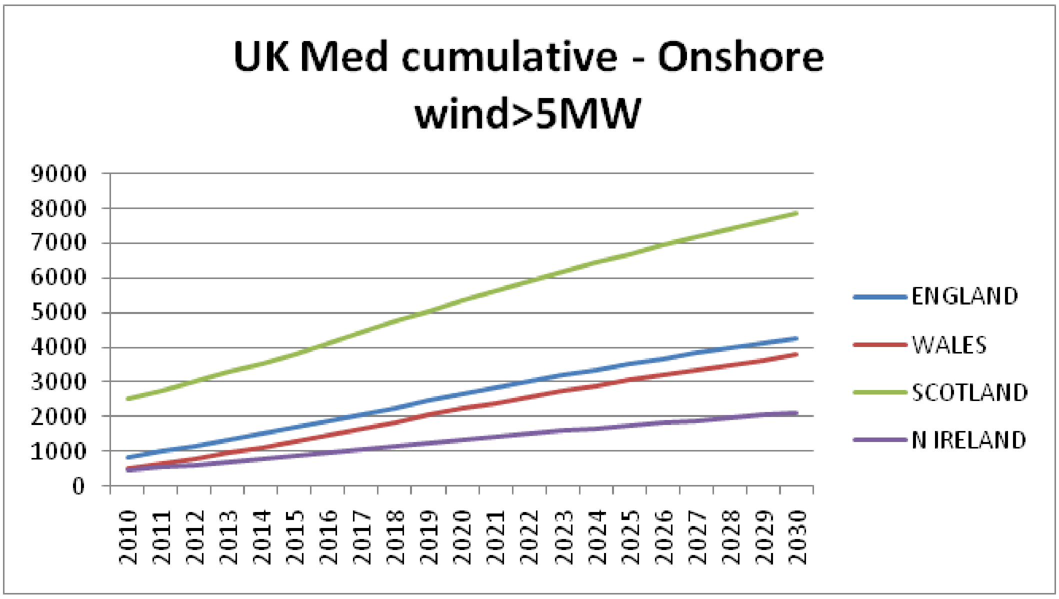
The lack of available land and sites, in part reflecting the population distribution issue, is reflected in the current levels of developer interest (as measured by projects in the planning system) in the UK which split by proportion approximately in 2009-10 as follows: England (25%), Wales (24%), Scotland (39%) and Northern Ireland (12%)[6]. Despite the much greater land area of England compared with the other nations, England only receives about 25% of developer interest measured by MW installed capacity.

The differences between regional onshore wind deployment per year between UK nations will depend on a number of factors, including the resources available, changes in technical and/or policy constraints, developer interest, and national planning success rates. It is probable that over time a greater percentage of the UK's onshore delivery will come from Scotland. This is both because the current data from Wales reflect a peak of project submittal following the issue a few years ago of its national spatial planning policy for onshore wind, and because the planning success rates in both England and Wales are disproportionally lower.

[6] based on an analysis of data contained in RenewableUK (2010)

Using the 2010 split of current developer interest, the overall UK medium scenario onshore large-scale wind deployment data would be distributed approximately as shown, in Figure 13.

Figure 13: UK cumulative onshore wind (>5MW)



4 Onshore Wind <5MW

4.1 Summary

Electricity production through <5MW wind has been considered. The estimated installed capacity in 2010 is about 329MW.

For the low build scenario the installed capacity will reach 777MW of installed capacity by 2030.

For the medium build scenario, the maximum generation capacity is forecast to be 1,306MW by 2030.

For the high build scenario the maximum generation capacity is forecast to be 1,738MW by 2030.

4.2 Introduction

Onshore wind turbines <5MW have lower energy outputs than large commercial wind turbines such as those found at wind farms. The size of wind turbine under consideration is between 50kW and 5MW. Many turbines have been installed throughout the UK as part of new developments and retrofits.

It should be noted that all forecast produced in this report are not financially constrained. There is no consideration of current or future financial support mechanisms.

4.3 Literature Review

In total six reports and documents relating to micro-wind technology were reviewed. A limited body of work has been undertaken to explore the delivery potential, constraints and resources.

4.3.1 Limitations

Limitations of the study include:

Scenarios are not directly comparable as they are constrained by different factors.

The availability of historical data on installations <5MW is very limited. Most sources only provide information below 500kW.

Data is now available from DECC which provides a breakdown of kW eligible for FiT support. However, the data is only available for one year (2010).

4.3.2 Assumptions

It has been assumed that the RenewableUK growth forecast is the most representative of what is likely to occur in the UK. They are the trade and professional association for the wind and marine power sector and therefore have a unique and informed perspective on how the current market is developing.

The forecast annual growth rates are: 25% (low); 35% (medium); and 40% (high). All new installations are assumed to be built with the latest wind technology and have an average load factor of 25%.

4.4 Constraints

4.4.1 Supply Chain

The fledgling wind turbine market is noted as having a short supply of manufacturers and O&M companies.

4.4.2 Planning

National and local planning processes have tended to delay and prevent deployment of wind projects.

4.4.3 UK Grid

One of the main challenges wind development faces is the cost of procuring access to local grid infrastructure. These costs can be significant and can stop a project from being deployed.

4.4.4 Technical

Engineering innovation is still required to lower the cost of wind turbines further. Costs are expected to fall over time, which will allow further deployment.

4.4.5 Other

If micro-wind is to be delivered on a significant scale, strong policies will need to be in place to provide confidence to potential owners.

4.5 Maximum Build Rate Scenarios

4.5.1 Available Resource

Based on an assumption that financial support is not a constraint on deployment, the maximum micro wind capacity will be 1,738MW by 2030. The forecast assumes that a large number of sites, particularly housing and public buildings, will be available.

4.5.2 Micro-wind Scenarios

For the analysis we have used growth curves and applied these to the UK micro-wind deployment. This has formed the basis of our medium scenario (35% p.a.), the high (40% p.a.) and low (25% p.a) scenarios.

4.5.3 Maximum Build Rate Plots

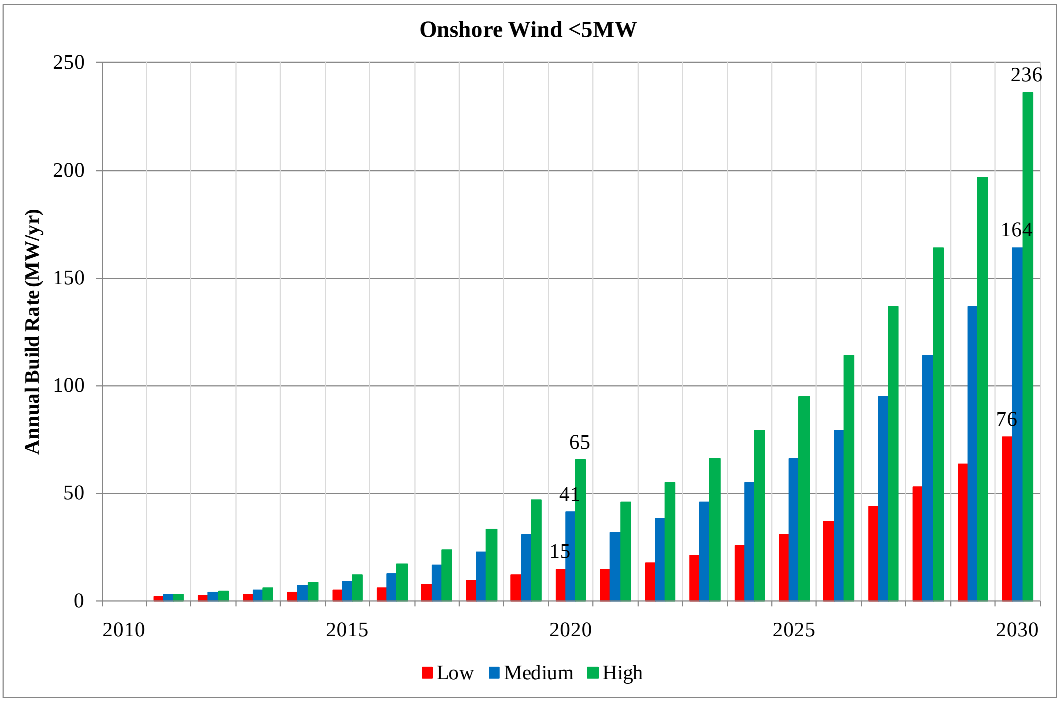


Figure 14: UK Onshore Wind (<5MW) Annual Build Rate (MW/yr)

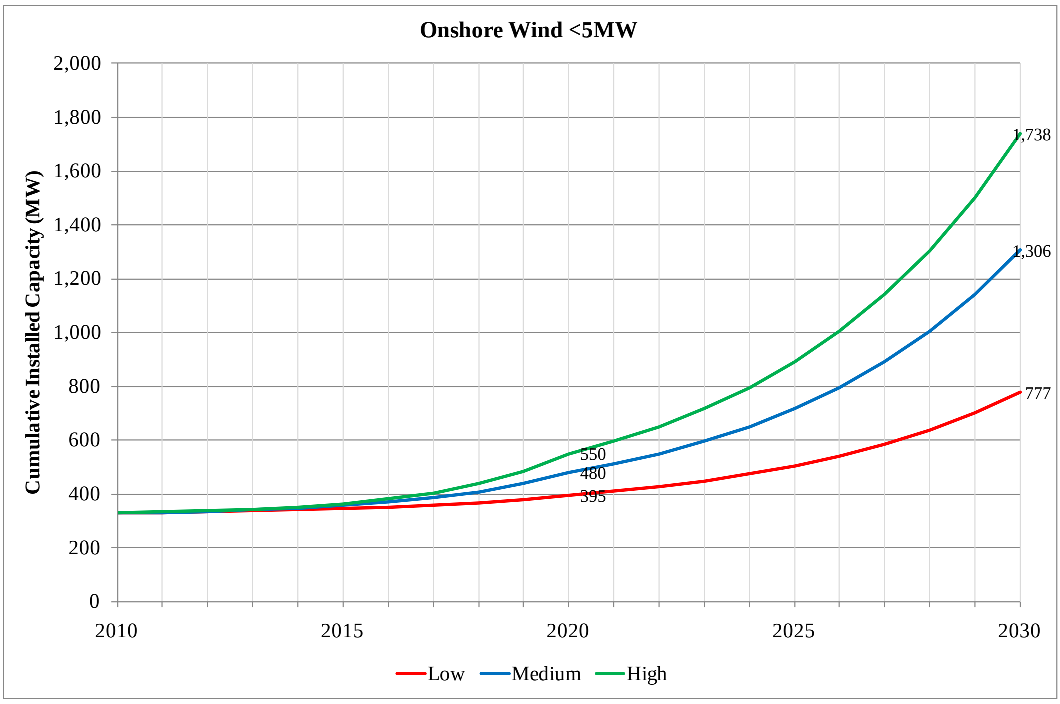


Figure 15: UK Onshore Wind (<5MW) Cumulative Installed Capacity (MW)

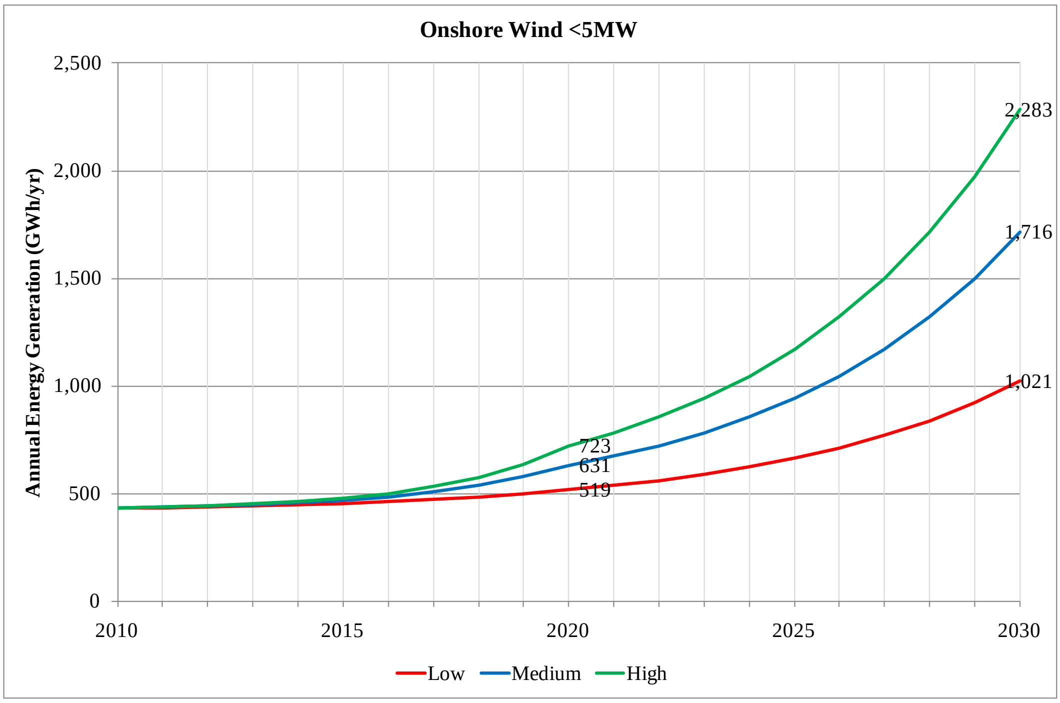


Figure 16: UK Onshore Wind (<5MW) Annual Energy Generation (GWh/yr)

4.6 Beyond 2030

It is assumed that the UK can continue to encourage the deployment of micro-wind over the next 20 years. Beyond 2030 annual growth is expected to level off at approximately 20% per annum.

4.7 Project Cost

See Section 3.8.

4.8 Regions

See section 3.10.

5 Offshore Wind

5.1 Summary

Three scenarios for future offshore wind development, up to 2030, have been developed based on a number of assumptions and constraining factors including, but not limited to, the following:

- Supply chain constraints – including turbine manufacture and installation vessel resourcing;
- Grid constraints – competing technologies and future investment to accommodate widespread offshore wind development across the UK; and
- Planning and the competing seabed uses sectors – normal planning considerations associated with development control, environmental and technical considerations and how they influence the size of scheme.

The low scenario resulted in approximately 14GW by 2020 and 35GW by 2030. The medium scenario resulted in approximately 18GW by 2020 and 41GW by 2030. The high scenario resulted in approximately 22GW by 2020 and approximately 52GW by 2030.

The scenarios reflect a slightly lower deployment estimate up to 2020 than recent publications by Renewable UK and The Crown Estate. Our forecast does not disagree with resource availability, but more the timescale for delivery.

5.2 Introduction

Offshore generation has a critical role to play in delivering the UK's renewable energy targets and security of supply needs. The last decade has seen offshore wind in the UK progress from an immature technology into a proven technology that is expected be a significant contributor to achieving UK renewables targets.

In 2001, the first leasing round of the UK offshore wind programme resulted in 12 sites being allocated with the potential for around 1GW of constructed capacity (Round 1). Following an offshore wind Strategic Environmental Assessment (SEA), a second leasing round competition was held in 2003, granting potential capacity of over 7GW (Round 2). Opportunities are now being explored to extend some of these planned offshore wind farms by up to 1.6GW (Round 2.5), as well as developing approximately 5.4GW of capacity within STW. From 1st April 2011, discussions have been taking place with potential developers on the opportunity for offshore wind energy in Northern Ireland waters. This will help shape the leasing and development process which is planned to commence later in 2011.

In 2009, an Offshore Energy Strategic Environmental Assessment (OESEA) published by DECC concluded that an additional 25GW of offshore wind capacity by 2020 would be acceptable as long as appropriate mitigation measures were put in place, in addition to existing plans for 8GW[7]. Following a third leasing round competition in January 2010, The Crown Estate awarded Zone Development Agreements (exclusivity awards) for up to 32GW of capacity (Round 3).

[7] http://www.offshore-sea.org.uk/consultations/Offshore_Energy_SEA/index.php

In February 2011, DECC published a second OESEA (known as OESEA2)[8], to consider the environmental implications of DECC's draft plan/programme to enable further licensing/leasing for offshore energy. The OESEA2 is currently out for consultation. The OESEA2 made the following recommendations:

- Reflecting the previous OESEA and the relative sensitivity of multiple receptors in coastal waters, it is recommended that the bulk of new offshore wind farm generation capacity should be sited away from the coast, generally outside 12 nautical miles.
- The potential for any further capacity extensions to existing Round 1 and 2 wind farm leases requires careful site-specific evaluation since significant new information on sensitivities and uses of these areas is now available.
- A characterisation and sensitivity study for England's seascapes would aid the assessment of possible impacts at a strategic level, particularly cumulative impacts.

This chapter provides a forecast of future offshore wind development within the UK up to 2030, taking into consideration existing literature, broad assumptions, key constraints to development, and finally, three separate scenarios for future development. Offshore wind deployment has been considered on a project-by-project basis to inform the evidence base as opposed to several size categories.

It should be noted that all forecast produced in this report are not financially constrained. There is no consideration of current or future financial support mechanisms.

5.3 Literature Review

The literature review concluded that there are a lot of recently published data in respect of offshore wind, both in terms of resource assessment, supply chain, deployment and resource. However, given the evolving nature of The Crown Estate leasing for future development, much of this literature can become outdated extremely quickly.

5.4 Limitations & Assumptions

5.4.1 Limitations

At present there is limited information available from internet sources and published literature on developer appetite. It would have been a useful exercise to consult with all developers involved in offshore schemes beyond Round 2 to understand the estimated timelines for future development and phasing. It should be noted that the data presented in this report represent the current status of existing offshore schemes and that the scenarios have been developed on that basis.

There is limited information about future offshore wind deployment beyond Round 3.

[8] DECC 2011, OESEA2 Environmental Report.

5.4.2 Assumptions

A detailed set of assumptions regarding the key constraints to development are discussed in more detail in Section 5.5. These have been used to influence the levels of deployment within each of the scenarios.

The following assumptions relate to offshore wind in general, they have not been used to influence the scenarios:

- Load Factor - A load factor of 40% has been assumed for this technology taking into account existing energy generation and future efficiency increases associated with technological advances.
- Design-life of Technology - The design-life of offshore wind turbines has been assumed to be 25 years, in line with onshore wind turbine technologies.

It should be noted that this study has considered the installed capacity of individual wind farm sites as opposed to turbine sizes.

5.5 Constraints

5.5.1 Supply Chain

The key supply chain issues affecting offshore wind include turbine manufacture, balance of plant manufacture, and installation and commissioning resources such as the availability of specialist installation vessels.

- Turbine Manufacture - Includes all sub-systems that are required to produce the turbine itself. The market for these sub-components is often global, with suppliers not just dedicated to the production of wind turbines. BVG's 2010 report[9] suggests that the availability of wind turbines as a whole is a key constraint for the offshore wind supply chain. Operation of all The Crown Estate sites would require an increase in turbine manufacturers (both international and UK based).
- Balance of Plant Manufacture – (such as foundations, cables, and substations) the main constraint appears to be the supply of cabling and this is expected to be critical path; however, there is evidence to suggest manufacturers are trying to break into the market[9].
- Installation and commissioning resources - A key constraint for offshore wind development is the lack of installation vessels. There is also an issue with the general lack of construction facilities/ports in the UK. However, new vessels are in construction/being developed, and the availability of construction ports is being addressed through research and development funding from DECC and from the Scottish Government[10].

Supply chain capacity is one of the key constraining factors of wind generation deployment in the UK. New development zones (i.e. Round 3 and STW) assume fast development and construction rates and for this to occur, the supply chain must be capable of very intense growth. In particular availability of turbines and a lack of installation equipment are identified as key constraints. Existing literature suggests that given a favourable economic environment and necessary progress

[9] BVG Associates (2010), Towards Round 3: Building the Offshore Wind Supply Chain
[10] http://www.decc.gov.uk/en/content/cms/news/pn10_111/pn10_111.aspx

with grid infrastructure, current constraints will be addressed in time to deliver[9].

5.5.2 Planning

The assessment of future/current offshore wind farms is carried out by the Infrastructure Planning Commission, Marine Scotland, the Department of Environment and the Northern Ireland Environment Agency (NIEA), who have all been created to streamline the planning regime to enable nationally significant infrastructure projects to be assessed in a more efficient, transparent and accessible way. All four organisations remain at an early stage of development and it is difficult to predict how long applications will take to go through to determination.

The selection of offshore wind zones is made by marine spatial planning from The Crown Estate in combination with high-level offshore SEA which determines the effect of further development on other maritime sectors that are also competing for use of the seabed (e.g. oil and gas, fisheries, shipping, MOD and conservation).

Individual environmental assessments for each site can take a number of years to complete in order to satisfy statutory requirements and planning obligations. At all scales of offshore wind development, there are unknowns and sizeable costs associated with project development and these can add significant delays to the timeline of the project.

Research into the time constraints associated with existing Round 1 and Round 2 projects have been used to inform the development of scenarios for future sites. At present, it takes approximately two years for a scheme to be consented following submission of a planning application.

5.5.3 UK Grid

Further pressure on the transmission system and the arrangements for accessing it are anticipated with the development of future offshore wind schemes. Developments in respect of the transmission capability and also the arrangements for allocating access to it are important factors for future development.

A considerable amount of investment is required in order to accommodate the anticipated wind generation capacity over the coming years. Ofgem introduced the Offshore Transmission Operators (OFTO) regime in 2009, the principal features of which are:

- Transmitting electricity offshore at 132kW and above will be a prohibited activity without a licence;
- National Grid Electricity Transmission Ltd (NGET) will be responsible for operating and co-ordinating both onshore and offshore grid connections;
- Through a competitive tender process, companies will bid for an open-ended licence to be the Offshore Transmission Network Owner (OFTO) of particular offshore networks;
- OFTOs will be entitled to earn a regulated rate of return on the costs of building and operating these networks for a period of 20 years, such costs ultimately being recovered from generators via NGET; and

- The new regime will be implemented through amendments to the existing system of licences, codes and agreements that govern onshore electricity transmission.

National Grid, as the UK's System Operator and chosen National Electricity Transmission System Operator, publishes an annual Offshore Development Information Statement which aims to facilitate the development, in offshore waters, of an efficient co-ordinated and economical system of electricity transmission[11]. Future scenarios have been developed to understand how the grid infrastructure will cope with additional offshore capacity; however they have not been considered within this study as they only intend to illustrate how the electricity transmission network would need to be developed to enable different levels of generation.

In 2010, the Department for Enterprise, Trade and Investment consulted on the draft Offshore Renewable Energy Strategic Action Plan which proposed targets of 600MW installed capacity of offshore wind and 300MW installed capacity from tidal resources by 2020. Since that consultation, the Northern Ireland Executive has published its Strategic Energy Framework which confirmed that Northern Ireland will seek to achieve a challenging 40% of its electricity consumption from renewable sources by 2020.

This transboundary technical and economic study concluded that by 2020, up to 42% of electricity by demand generated from renewable sources could be absorbed by the grid. The study also found that significant grid strengthening would be required.

5.5.4 Technical

The Crown Estate has facilitated ongoing offshore wind technology development by granting leases for several demonstration sites across the UK. These sites will play a key part in addressing both technical and cost challenges to facilitate construction further from shore in increasing water depths.

As offshore wind technology develops, the size of turbines has increased from 2MW on early Round 1 sites in 2003 to 3.6MW on the most recent installations[12]. By the middle of this decade, it is expected that 5-7 MW turbines will start to be deployed at scale. Clipper Windpower is developing and will manufacture a 10MW offshore turbine in the North East[13]. Beyond turbine and construction evolution, it is not anticipated that there will be any significant technical innovation within offshore wind in the short to medium-term.

5.5.5 Other Constraints

Attrition Rates

Projects often aim to deliver the maximum installed capacity available to them from the outset. However, following rigorous consultation and a full

[11] National Grid Electricity Transmission plc, Offshore Development Information Statement 2010, September 2010

[12] The Beatrice demonstration project in the UK has installed two 5 MW turbines. Offshore wind farms in other countries have also installed 5 MW turbines at demonstration sites.

[13] http://www.clipperwind.com/pr_02182010.php

understanding of the technical and environmental constraints, projects often reduce in size. For this study, an attrition rate has been applied to each scenario regarding Round 3 sites, STW sites and Northern Ireland sites. Arup's own research has been carried out on existing Round 2 schemes which indicates that there is currently an average attrition rate of 7%. Variable rates have been applied to each scenario reflecting different levels of confidence.

5.6 Maximum Build Rate Scenarios

5.6.1 Available Resource

The maximum feasible resource potential has been assessed by a number of studies, the largest resource estimate occurring within the Offshore Valuation Group (2010) – approx 116GW of fixed offshore wind. This report also includes an estimate of approx 350GW for floating offshore wind.

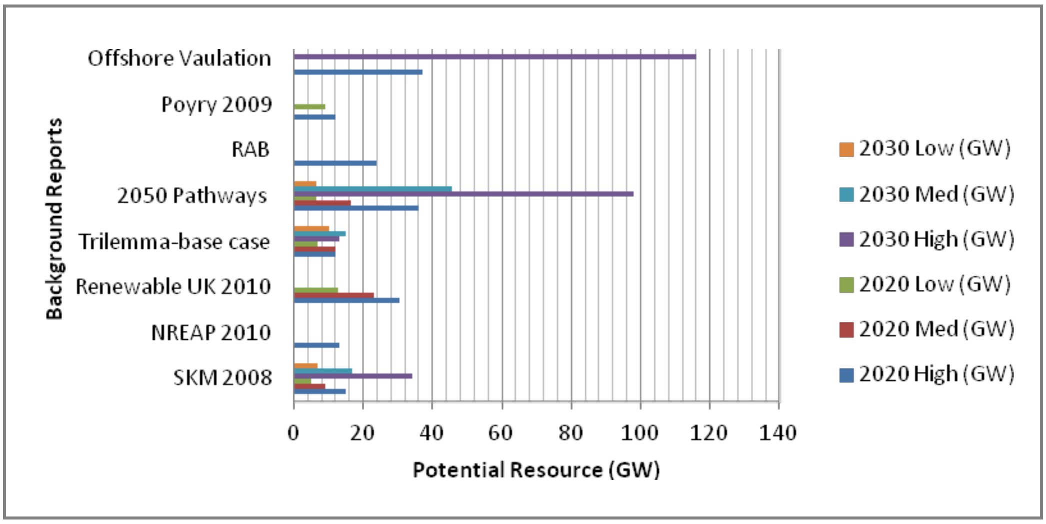


Figure 17: Existing literature, potential resources

5.6.2 Low Scenario

The low scenario for offshore wind development assumes slower development of sites, with activity spread over a longer period (2010-2030) and results in a steady growth (approx 1.26GW/yr) until 2030. This is greater than the historic rate, but this was mainly at the smaller Round 1 sites. It should be achievable assuming that continuation of the supply chain is not affected by significant expansion of onshore wind or offshore wind in other countries.

The low scenario has made the following assumptions:

- Round 1 schemes fully developed by 2012;
- Round 2/2.5 schemes fully developed by 2018;
- STW schemes fully developed by 2027;
- Demonstration sites fully deployed by 2015;
- 60% of Round 3 Schemes deployed by 2030;
- Attrition factor of 30% to Round 3 and STW findings from schemes, and 14% to Round 2/2.5 schemes (based on double the rate of existing developments); and
- Given the large number of phases associated with Round 3 developments, some slippage will serve to lengthen the period of activity for the supply chain.

This installed capacity scenario results in approximately 14GW of installed capacity by 2020 and 35GW by 2030. This is lower than estimates by Renewable UK and The Crown Estate, however it reflects in the most part a reassessment of Round 3 deployment rates.

5.6.3 Medium Scenario

The medium scenario for offshore wind development assumes a higher rate of development than the low scenario over the same period and results in a steady growth (approx 1.77GW/yr) until 2030. A significant proportion of the total capacity by 2030 is achieved from the current sites that have been leased by The Crown Estate.

The medium scenario has made the following assumptions:

- Round 1 Schemes fully developed by 2012;
- Round 2/2.5 schemes fully developed by 2018;
- STW schemes fully developed by 2026;
- Demonstration sites fully deployed by 2014;
- 80% of Round 3 Schemes deployed by 2030;
- Attrition factor of 20% to Round 3 and STW schemes, and 7% to Round 2/2.5 (based on findings from existing developments);
- Given the large number of phases associated with Round 3 developments, some slippage will serve to lengthen the period of activity for the supply chain; and
- Some new capacity beyond Round 3 is expected 2028-2030 - Installed capacity/yr assumed similar start-up rate as Round 3 but larger turbines raises capacity of potential sites.

This scenario results in approximately 18GW by 2020 and 41GW by 2030 of cumulative installed capacity. This is lower than estimates by Renewables UK and The Crown Estate.

5.6.4 High Scenario

The high scenario for offshore wind development assumes a higher rate of development than the medium scenario over the same period and results in a steady growth (approx 2.5GW/yr) until 2030.

The high scenario has made the following assumptions:

- Round 1 schemes fully developed by 2012;
- Round 2/2.5 schemes fully developed by 2018;
- STW schemes fully developed by 2023;
- Demonstration sites fully deployed by 2014;
- Round 3 sites fully deployed by 2030;
- Attrition factor of 10% to Round 3 and STW schemes, and 7% to Round 2/2.5 (based on existing developments);
- Given the large number of phases associated with Round 3 developments, some slippage will serve to lengthen the period of activity for the supply chain; and
- Some new capacity beyond Round 3 is expected 2028-2030 - Installed capacity/yr assumed similar start-up rate as Round 3 but larger turbines raises capacity of potential sites.

This scenario results in 22GW by 2020 and 52GW by 2030. This is lower than estimates by Renewable UK and The Crown Estate.

It is a possibility that the 5GW of STW projects may happen on a slightly accelerated timescale to that shown in the above scenarios. Potentially the majority of the STW sites may either apply for consent later in 2011 or in 2012, with construction commencing around 2015 and concluding 2-4 years after that. Under this scenario STW sites would therefore be developed broadly in parallel with the first major Round 3 projects, suggesting little supply chain constraint to both being under construction at the same time. This would indicate the full development of STW sites by approximately 2017-2020 under a high scenario. The effect of this would be to increase cumulative deployment in the overall High scenario discussed above to around 25GW by 2020.

5.6.5 Maximum Build Rate Plots

Figures 18, 19 and 20 below present the annual deployment rates, cumulative installed capacity (MW), and annual energy generation (GWh/yr) for offshore wind to 2030.

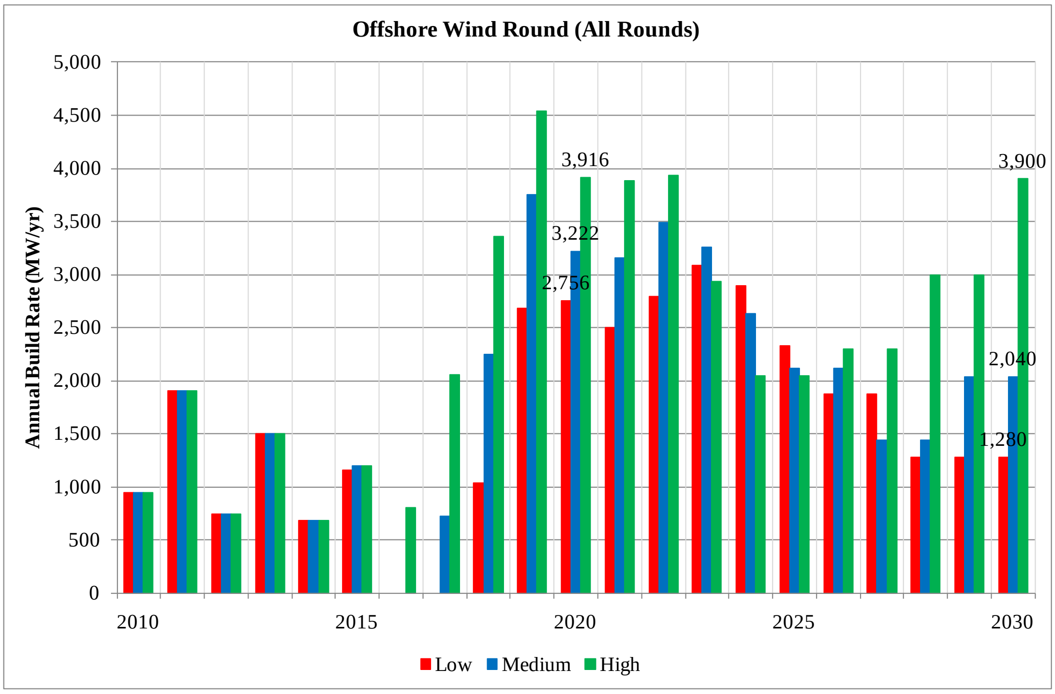


Figure 18: UK Offshore Wind Annual Build Rate (MW/yr)

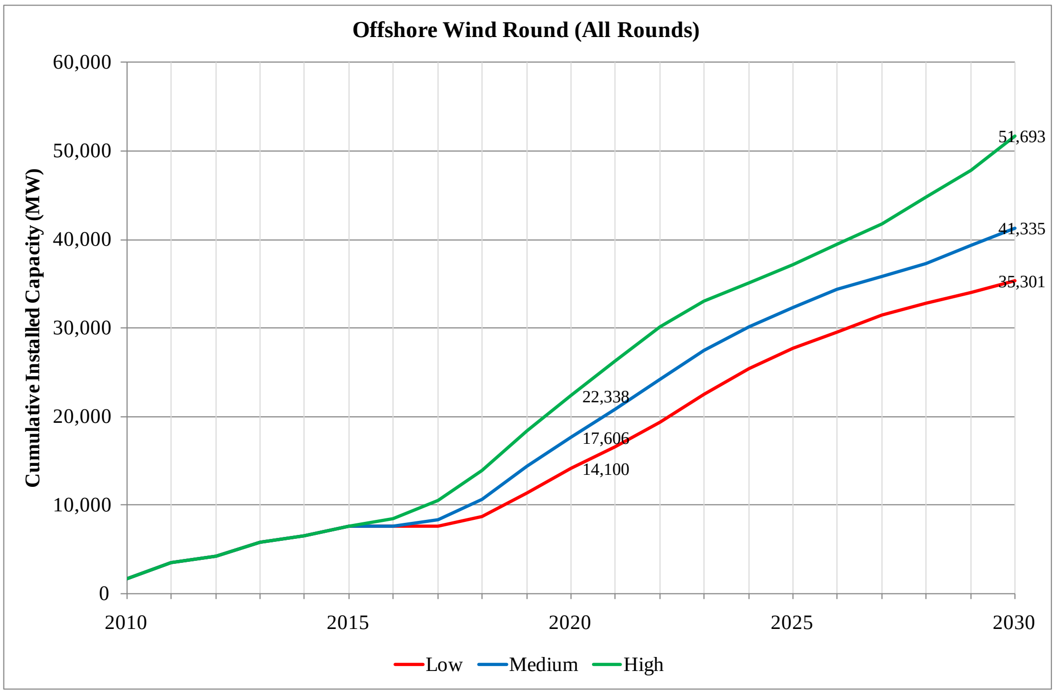


Figure 19: UK Offshore Wind Cumulative Installed Capacity (MW)

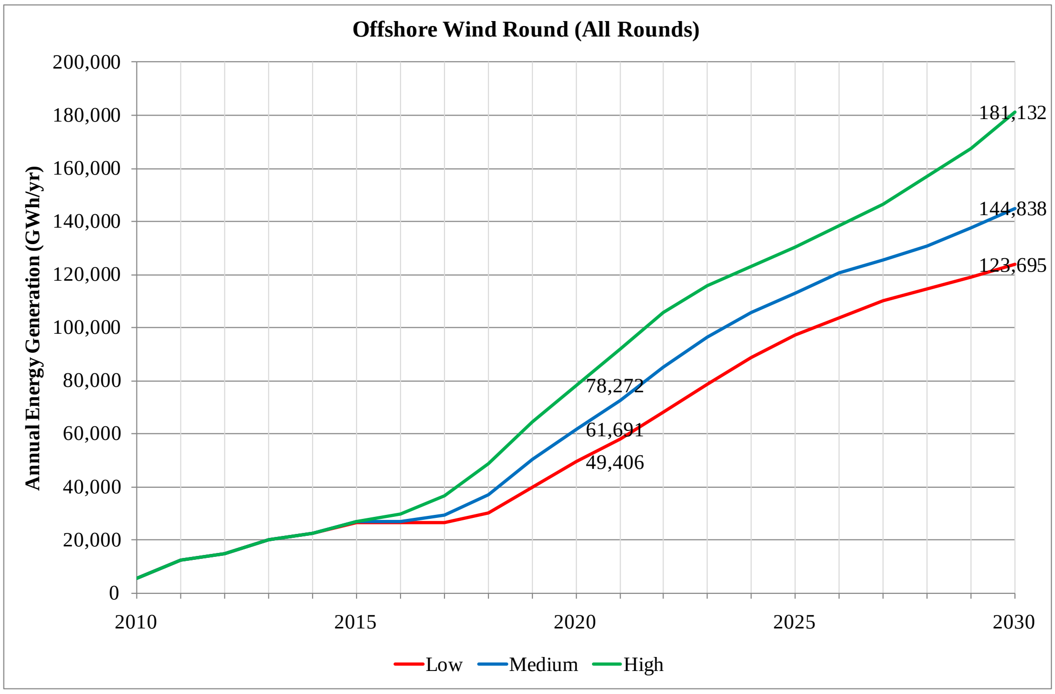


Figure 20: UK Offshore Annual Energy Generation (GWh/yr)

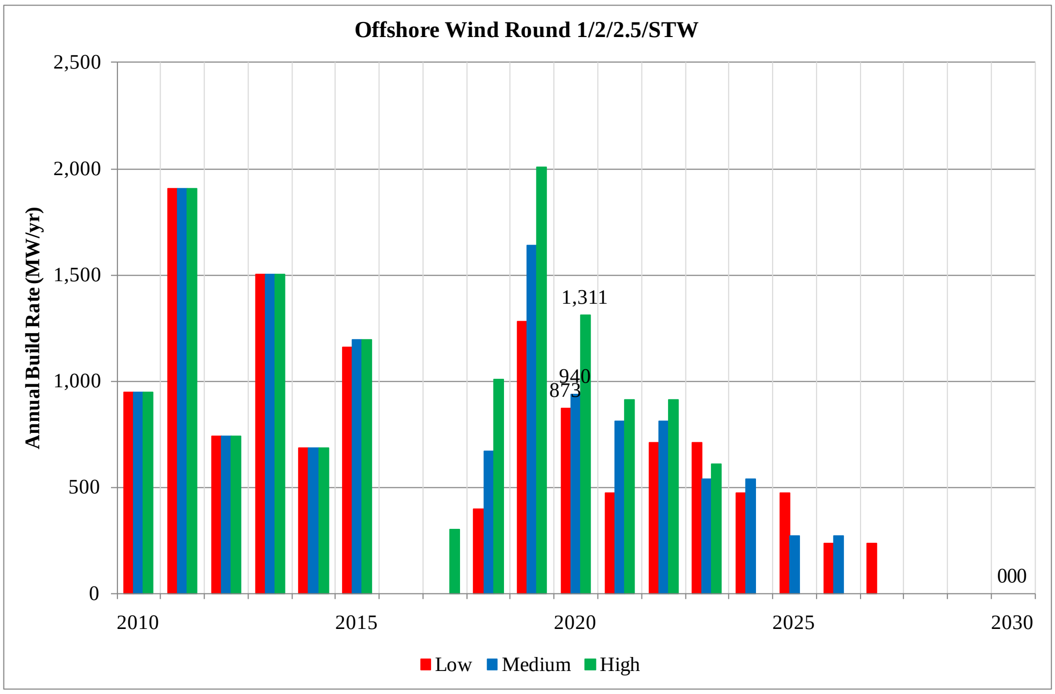


Figure 21: UK Offshore Wind Annual Build Rate (Rounds 1/2/2.5/STW) (MW/yr)

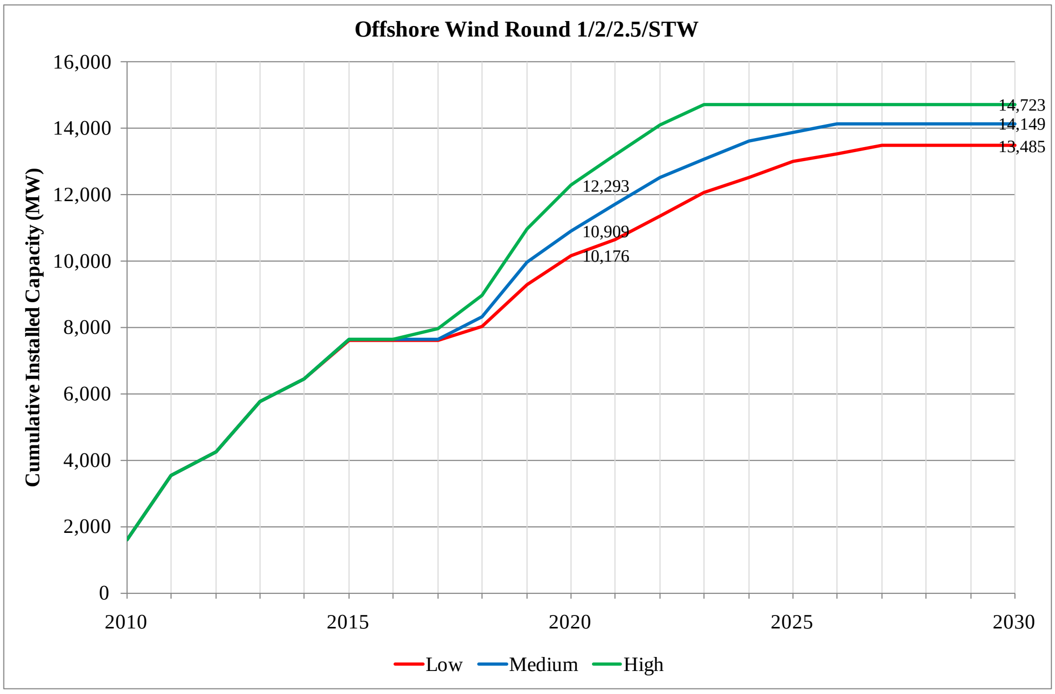


Figure 22: UK Offshore Wind Cumulative Installed Capacity (Rounds 1/2/2.5/STW) (MW)

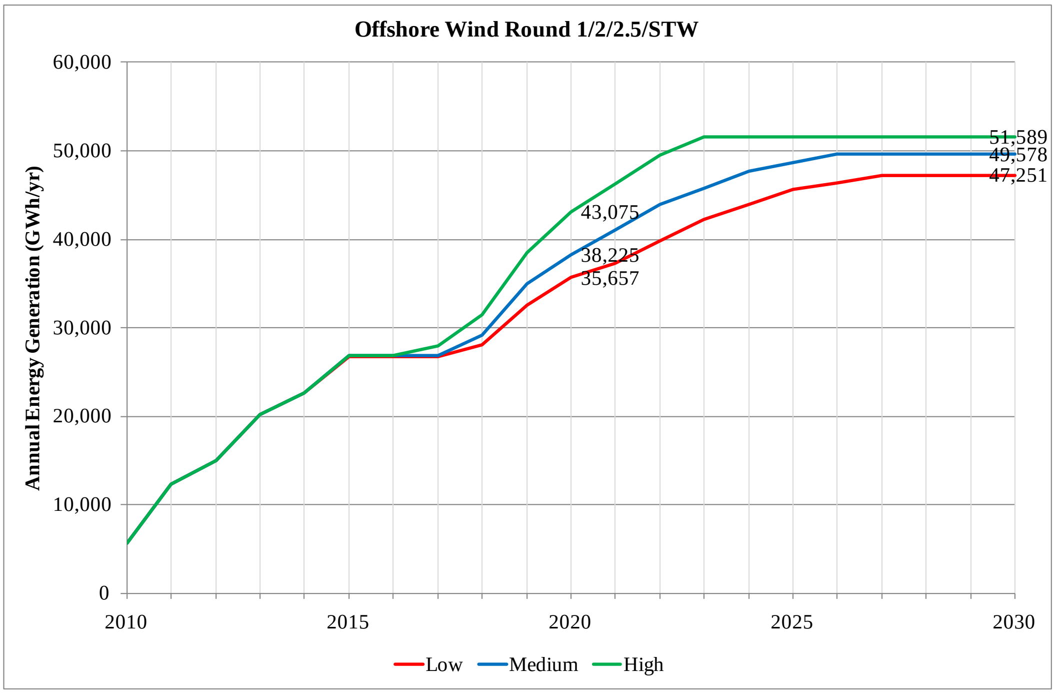


Figure 23: UK Offshore Annual Energy Generation (Rounds 1/2/2.5/STW) (GWh/yr)

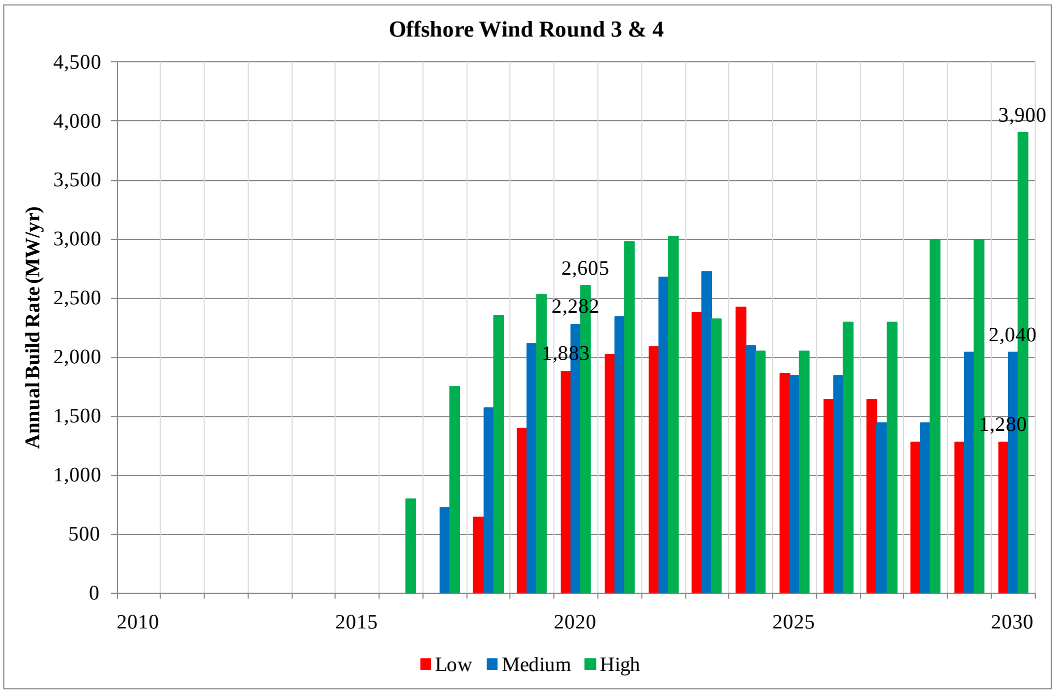


Figure 24: UK Offshore Wind Annual Build Rate (Rounds 3/4) (MW/yr)

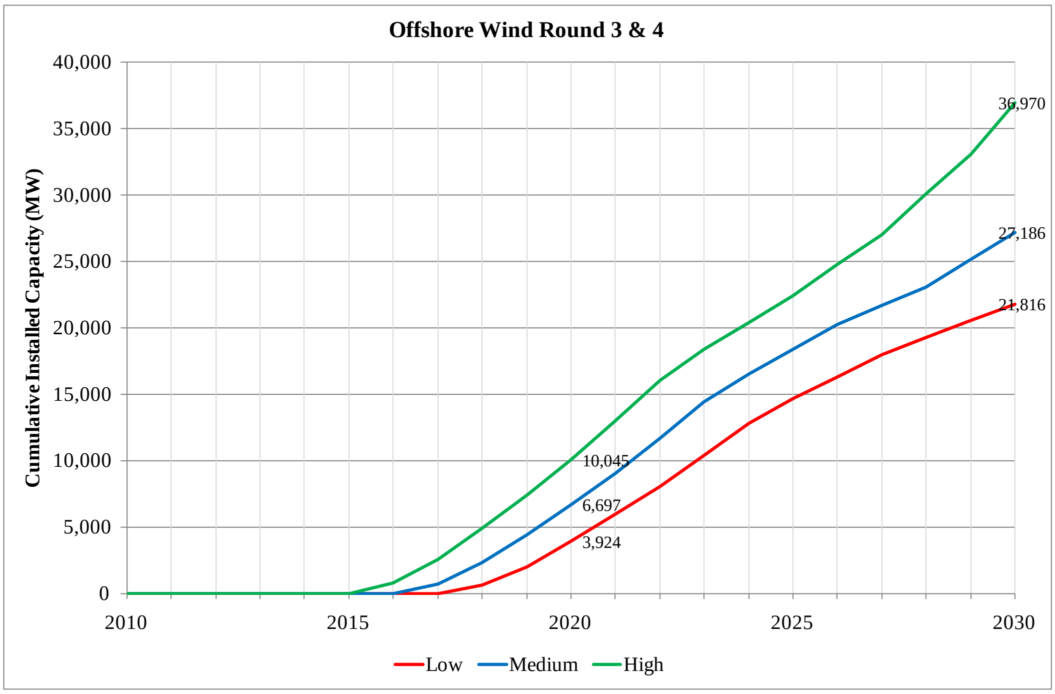


Figure 25: UK Offshore Wind Cumulative Installed Capacity (Rounds 3/4) (MW)

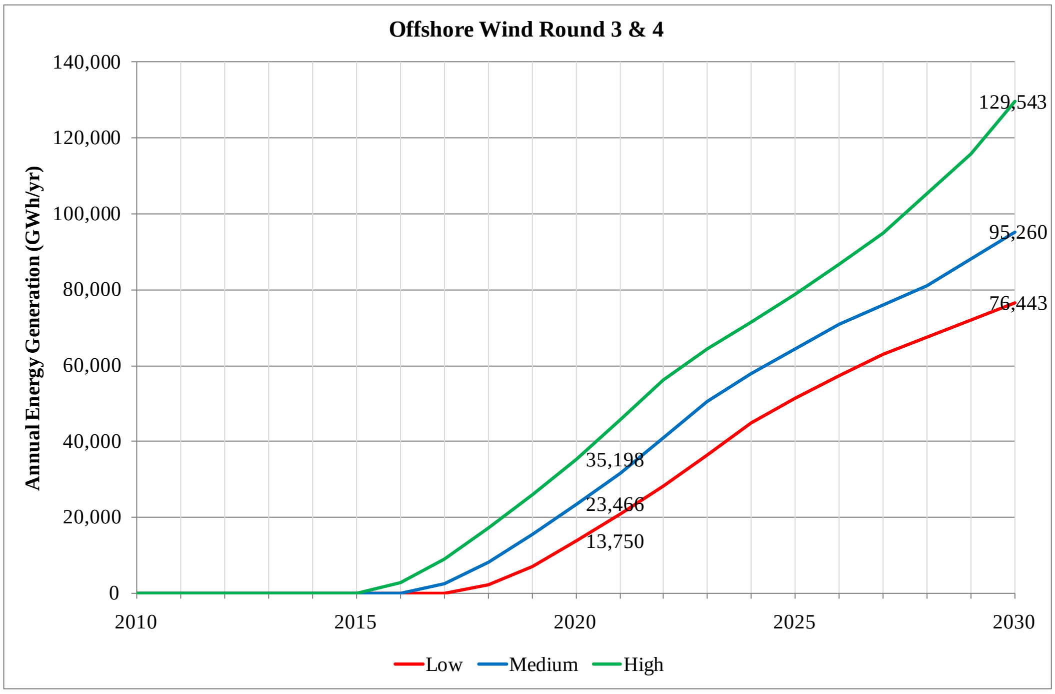


Figure 26: UK Offshore Annual Energy Generation (Rounds 3/4) (GWh/yr)

5.7 Beyond 2030

For the low and medium scenarios, Round 3 deployment will continue beyond 2030. Beyond Round 3, there are clear indications that The Crown Estate is likely to draw up plans to award leases for Round 3.5/4 offshore wind farms, potentially as soon as 2016/2017.

Given the estimated resource for floating wind devices, largely within the North Sea, the development of this advanced technology will continue based on demonstration site development and innovative new designs.

5.8 Project Cost

5.8.1 Key assumptions

DECC requested that current cost data be collected for offshore wind at four scales:

- <100MW
- 100MW – 500MW
- 500MW – 1,000MW
- >1,000MW

Analysis of the data suggested that the presentation of cost ranges at two scales, above and below 100MW, would provide a more appropriate size grouping. These two ranges in effect represent data sets for early stage Round 1 and later stage Round 1/Round 2 projects.

Cost data were also collected for Round 3 projects, although stakeholders were keen to highlight that these were estimates and highly likely to change. The data presented for this range should be viewed in light of this stakeholder caveat.

Information has been collected from publicly available industry reports and questionnaire responses from a variety of stakeholders including manufacturers, developers and utilities.

On the whole, stakeholders were hesitant to provide data on project hurdle rates, but those that did indicated a post-tax nominal rate of 10-12%. Stakeholders typically assumed project life spans between 20 and 25 years.

5.8.2 Capital Expenditure

Similar to onshore wind, turbine costs are a significant element of capital expenditure. Onshore grid connection, vessel costs and foundations make up the majority of the remaining costs.

For this study, the sizeable offshore grid connection costs have been excluded given that under the OFTO regime developers will recoup these costs. Instead OFTO costs have been included in the operational expenditure section.

Pre-development costs for the 100<MW scale varied between £194,000/MW and £510,000/MW. These costs include pre-licensing, technical development costs, bird and marine surveys, EIA studies and public enquiries amongst others. Costs vary due to specific site conditions, planning hurdles and the requirement for appeals. There are significant economies of scale as pre-development costs do not vary greatly from project to project, regardless of scale. This can be seen for the 100MW plus range where costs are much lower, ranging from £45,000/MW, to £115,000/MW. Estimates for Round 3 pre-development costs are slightly higher, falling between £47,000/MW and £143,000/MW.

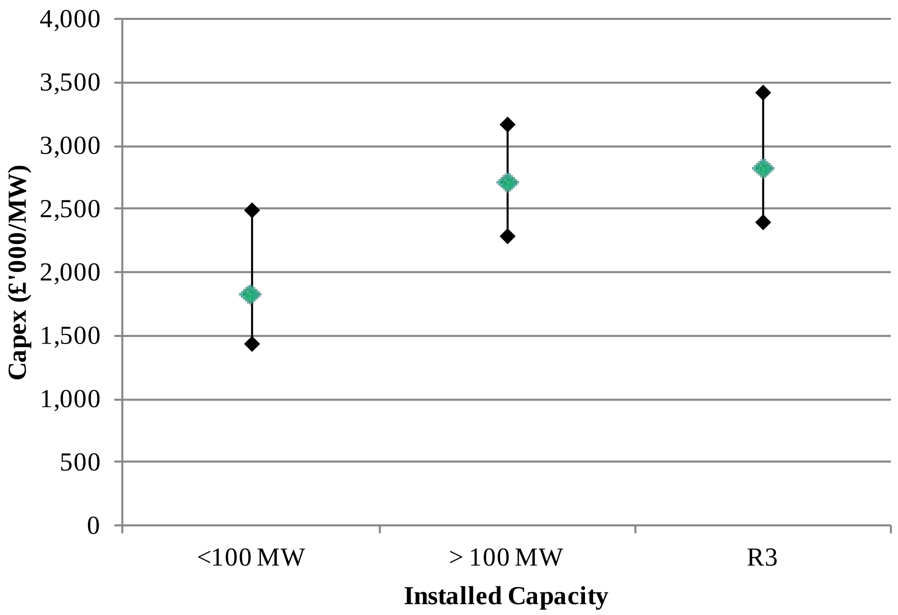
The capital costs of <100MW offshore wind projects varies from £1.4m/MW to £2.5m/MW, with a median of £1.8m/MW. The costs increase for the >100MW scale, which has a median cost of £2.7m, and a similar range to the <100 MW scale. The range for both these scales is caused by asset-specific site conditions including the wind speed, depth of water, sea bed conditions and distance from shore. Whilst there appears to be negative economies of scale, the increase in costs is most likely due to the timing of construction with the smaller projects tending to be the oldest, and the larger projects the newest. Offshore capital costs increased substantially between 2006 and 2010, largely driven by supply chain constraints (see “Cost of Financial Support for Offshore Wind”, Ernst & Young 2009), resulting in the <100MW projects being cheaper per MW than the >100MW projects.

There is still a great deal of uncertainty in relation to Round 3 costs. Early indications suggest that costs are expected to exceed the other two scales, with estimates ranging from £2.4m/MW to £3.4m/MW, reflecting the technical characteristics of those sites that are generally further offshore and in deeper water.

Table 11: Offshore Wind – capital costs (financial close 2010)[14]

£'000/MW	<100MW	>100MW	Round 3
High	2,506	3,183	3,430
Median	1,841	2,722	2,825
Low	1,444	2,300	2,400

Figure 27: Offshore Wind – capital costs (financial close 2010)



The majority of the capital expenditure is spent on the construction and turbine contracts for the construction of the project. Grid costs include onshore grid connection and other infrastructure costs include land options.

[14] It should be noted that the increase in cost is not, in our experience, related to the size of the asset but is related to the timing of construction with costs having increased substantially over the last 5 years (see "Cost of Financial Support for Offshore Wind", Ernst & Young 2009)

Table 12: Offshore Wind – capital cost breakdown

Capital cost item	%
Pre-development	2%
Construction	91%
Non-OFTO grid costs	2%
Other infrastructure	5%

Stakeholders considered the key drivers of future capital costs to be steel prices, exchange rates, labour and vessel costs. The potential for other manufacturers to come into the sector was also highlighted as a potential downwards driver of turbine costs in the future. DECC asked that exchange rates be excluded from the cost projection analysis due to the uncertainty of future exchange movements.

Industry learning is the primary cause of anticipated declining turbine costs. A learning rate of 12% was assumed for offshore wind, which while higher than the IEA's figure of 9%, is in line with the Carbon Trust's base scenario. This rate was applied to the UK build out rate derived during Part A of this study, which anticipates an increase in deployment from 1,340MW in 2010 to 37,277MW in 2030. It is expected that the scaling up of offshore wind turbines will provide the greatest contribution to falling turbine prices per MW. The learning rate was applied to UK deployment levels, with the assumption that the UK will be the global leader in offshore wind.

Despite the impact of anticipated rising steel and labour prices, capital costs for projects both above and below 100MW are expected to decrease between 2010 and 2030.

The greatest decline in prices will occur between 2010 and 2020 when it is anticipated that prices will fall by 24%, while for the 2010 to 2030 period costs are expected to decline by 30%.

Included in tables 13 to 15 is a DECC scenario, which assumes a 2.5% decrease in turbine prices in both 2015 and 2017 due to the entrance of a new manufacturer to the sector. However this only impacts on the turbine element of capital costs.

Table 13: Offshore Wind – capital cost projections at financial close (real) (<100MW)

Capital cost (£000s/ MW)	2010	2015	2020	2025	2030
High	2,506	2,121	1,910	1,813	1,750
Median	1,841	1,558	1,403	1,332	1,285
Low	1,444	1,222	1,101	1,045	1,008

Table 14: Offshore Wind – capital cost projections at financial close dates (real) (>100MW)

Capital cost (£000s/ MW)	2010	2015	2020	2025	2030
High	3,183	2,694	2,426	2,303	2,222
Median	2,722	2,304	2,075	1,970	1,901
Low	2,300	1,947	1,753	1,664	1,606

Table 15: Offshore Wind – capital cost projections at financial close dates (real) (>100MW, DECC Scenario)

Capital cost (£000s/ MW)	2010	2015	2020	2025	2030
High	3,183	2,671	2,386	2,264	2,185
Median	2,722	2,284	2,040	1,936	1,869
Low	2,300	1,930	1,724	1,636	1,579

The cost projections for Round 3 projects were carried out in a different manner due to the uncertainty of current costs and future price drivers. Rising steel and labour prices were incorporated in the analysis in the same way as for the other two scales but industry learning was treated differently. The Carbon Trust report indicates that learning rates could be between 9% and 15% depending on government support and investment in the sector. Therefore a learning rate of 9% was applied to the high cost estimate, a rate of 12% to median cost estimate and 15% to the low cost estimate.

The proposed capital cost projections are reflective of the current technology paradigm (monopole foundations, 3-4MW turbines). There is a significant level of R&D in relation to wind turbine technology and foundation design that may impact the overall costs and economic viability of these projects together with a maturing of the supply chain. Given the uncertainty surrounding the roll-out of ongoing R&D programmes, these changes have not been incorporated into the learning rates, therefore driving a potentially conservative capital projection.

The resultant cost projections for 2030 range from £1.5m to £2.7m which reflects the uncertainty that surrounds future Round 3 costs.

Table 16: Offshore Wind – capital cost projections at financial close dates (real) (Round 3)

Capital cost (£000s/ MW)	2010	2015	2020	2025	2030
High	3,430	3,371	2,864	2,616	2,447
Median	2,825	2,699	2,211	1,954	1,784
Low	2,400	2,265	1,756	1,500	1,336

5.8.3 Operating Cost

Operating costs for offshore wind projects include O&M services from wind turbine suppliers, vessel hire and other O&M support, labour costs, insurance and grid charges. The ranges presented are the average annual costs for the life of the project.

Operational costs varied between £100,000/MW/year and £167,000/MW/year for the <100MW scale and from £117,000/MW/year to £184,000/MW/year for the > 100MW scale. The variation at both these scales is born out of the asset specific nature of operational expenditure for offshore wind, with contract costs depending on the overall site characteristics. Although likely to be the cause of the higher operating costs for the >100MW scale. Analysis of costs against the individual site characteristics of water depth and distance from shore did not show any direct correlation.

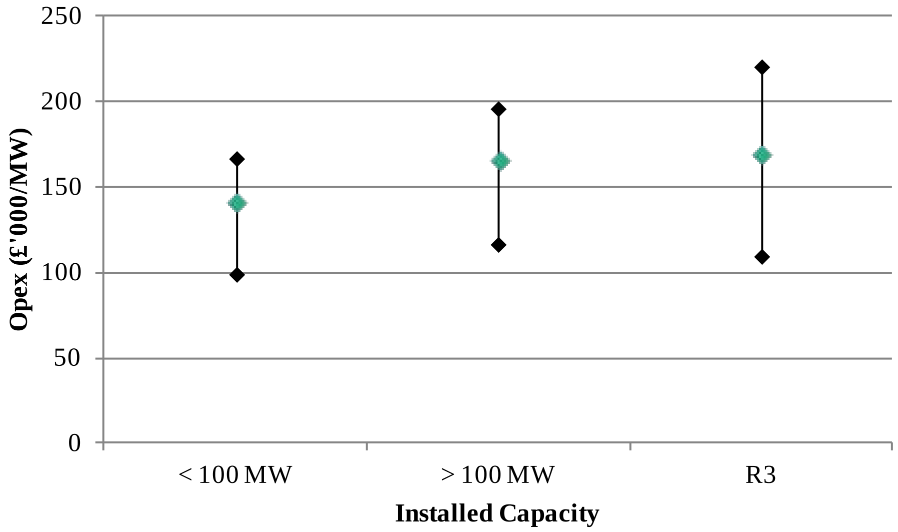
It is estimated that operating costs for Round 3 wind projects will be between £221,000/MW/year and £110,000/MW/year. The large range is again primarily due to site-specific characteristics, but is also accentuated by stakeholder uncertainty over future costs.

There remains the potential for a step change in the O&M costs after the turbine warranty expires (years 1-5), similar to the increases seen in the onshore wind sector.

Table 17: Offshore Wind – operating costs (financial close 2010)[15]

£'000 / MW	<100 MW	>100 MW	Round 3
High	166.8	183.6	220.8
Median	141.0	165.6	168.7
Low	99.6	117.0	110.2

Figure 28: Offshore Wind – operating costs (financial close 2010)



Stakeholders identified labour and spare part costs as the most important drivers of future O&M costs. As offshore wind is still a nascent market it is assumed there will be some industry learning for operating costs. The Carbon Trust indicates that there will be a learning rate of 10% for O&M costs. This has been applied to the O&M portion of operating costs (49%) along with the UK deployment rate from Part A.

The cost of spare parts will be influenced by steel and commodity prices, which have been included in the calculation of the cost projections. However it is assumed that commodity prices will not change significantly between 2010 and 2030, resulting in a minimal impact on the change of costs through time. Labour costs are set to rise at a slow rate, which has been reflected in the analysis.

These factors are outweighed by the impact of industry learning and as such, costs are expected to fall by 11% between 2010 and 2020, and by 15% between 2010 and 2030.

---

[15] It should be noted that the increase in cost is not, in our experience, related to the size of the asset but is related to the timing of construction with costs having increased substantially over the last five years (see "Cost of Financial Support for Offshore Wind", Ernst & Young 2009)

The same assumptions have been made for Round 3 operating cost projections as for the other two scales.

Table 18: Offshore Wind – operating cost projections at financial close dates (real) (<100MW)

Operating cost/ MW per year £000'	2010	2015	2020	2025	2030
High	167	156	149	145	143
Median	141	131	126	123	120
Low	100	93	89	87	85

Table 19: Offshore Wind – operating cost projections (real) (>100MW)

Operating cost/ MW per year £000'	2010	2015	2020	2025	2030
High	196	183	175	170	167
Median	166	155	148	144	142
Low	117	109	104	102	100

Table 20: Offshore Wind – operating cost projections (real) (Round 3)

Operating cost/ MW per year £000'	2010	2015	2020	2025	2030
High	221	214	185	169	158
Median	169	162	132	117	107
Low	110	104	81	69	61

5.9 Levelised costs

Offshore wind Round 2/2.5/Scottish Territorial Waters

Using the Arup and E&Y capital and operating cost profiles[16] for offshore wind plants greater than 100MW, DECC has calculated levelised costs of an offshore wind reference plant at financial close in 2010, 2015, 2020, 2025 and 2030. The levelised cost ranges are based on Arup's low, medium and high capital cost estimates. The levelised costs have been calculated by assuming a pre-tax real hurdle rate of 11.6% until 2019 and 9.6% post 2020 in line with the hurdle rate assumed for onshore wind. This is based on Arup stakeholder information, the Oxera report[17] for the CCC and DECC assumptions on the hurdle rate profile over time. The assumed load factor is 38% and the assumed plant lifetime is 24 years.

£ / MWh		2010	2015	2020	2025	2030
Offshore	low	149	123	95	87	81
	medium	169	139	107	98	91
	high	191	158	121	111	104

Note: Dates refer to financial close.

Offshore wind Round 3

The table below shows levelised costs for Offshore Wind Round 3. The levelised costs have been calculated by assuming a pre-tax real hurdle rate of 13.2% dropping to 9.6% by 2030, based on DECC assumptions. The assumed load factor is 38% and the assumed plant lifetime is 22 years. The low levelised costs represent the medium Offshore Wind costs from above to indicate the possible range in which these cost estimates could lie, given the highly uncertain nature of the cost data received from stakeholders. For Round 3 Offshore Wind there are significant challenges in deploying in often deeper water further from shore. At the same time early Round 3 deployment is likely to often take place in lower cost locations within zones. There is also significant potential for greater efficiencies in manufacture, installation and operation of wind farms as the industry moves to significantly larger turbines**.** Stakeholders who provided Round 3 cost data emphasised the high level of uncertainty surrounding those costs. These Round 3 levelised costs should, for these reasons, be treated with a high degree of caution**.**

Within the levelised costs, as described above, for both Round 2 and Round 3, the capital costs are assumed to reduce at a 12% learning rate, i.e. down by 12% for every doubling of wind capacity, with deployment according to Arup's central trajectory. This level of cost reduction reflects the Government's focus driving innovation in offshore wind through market pull from the Renewables Obligation

[16] To note that the levelised costs are based on a separate set of capital and operating costs provided by Arup and E&Y that assume constant steel prices over time; capex includes infrastructure costs are incurred in the core facility, but do not include 'other' infrastructure costs that relate to costs incurred outside the site, such as water, roads, waste disposal and land costs. Levelised costs use different size categories for some technologies.

[17] www.oxera.com/main.aspx?id=9514

and EMR, and technology push through programmes to support innovation in key areas. In addition to the assumed learning rate, as described above, it has also been assumed that offshore wind turbine generator costs will have one-off step falls, with the introduction of new manufacturing capacity and competition into that market.

£ / MWh		2015	2020	2025	2030
Offshore Round 3	low	168	127	113	92
	medium	192	145	129	105
	high	225	170	151	122

Note: Dates refer to financial close.

5.10 Regions

The developments of offshore wind schemes are driven by The Crown Estate leasing. Although leasing in some cases relates specifically to waters around a particular country, the collective installed capacity of all leasing is considered a more appropriate assessment of development rather than breaking each scheme down to specific regions/countries.

6 Hydro

6.1 Summary

For medium and large hydro (>5MW), the majority of sites have already been developed and the main constraint to further development is site availability. Existing installed capacity is 1,458MW, remaining exploitable resource is estimated at 38MW and the maximum feasible resource is therefore 1,496MW. The low, medium and high scenarios result in the available resource being fully utilised by 2028, 2019 and 2016 respectively.

The available hydro resource at small scale (<5MW) is made up of a large number of sites geographically spread throughout the UK. The main constraints to development are capacity of the environmental regulators to process a high number of applications, and willingness of developers to invest in new sites. The potential environmental impacts of scheme proposals and their acceptability may also be constraining factors in some cases. The maximum installed capacity available at this scale is thought to be approximately 1,200MW. This is made up of approximately 200MW existing, 650MW exploitable/available resource in Scotland, 250MW in England and Wales and 100MW in Northern Ireland. The largest number of sites are in the <100kW range and the biggest contribution to installed capacity is likely to come from the 100-500kW range. The low, medium and high scenarios result in 330MW, 360MW and 510MW total installed capacity being in place by 2020 respectively and 460MW, 620MW and 1,040MW installed by 2030.

6.2 Introduction

Hydropower generation converts the kinetic energy of water into electrical energy as the water falls through a height drop to drive a turbine. The technology is simple, robust and reliable with low maintenance costs in relation to other renewable technologies.

Hydropower in the UK is already well developed and based on established technology. Many of the large hydropower sites in Scotland and Wales were constructed between the 1940s and 1960s. Continual improvements in turbine efficiency are being made but these are small increments as the technology is already mature.

There are limited opportunities for further large-scale development of hydro in the UK. Most of the economically attractive sites have already been exploited and environmental concerns are limiting further development of large dams.

This study considered electricity generation from hydropower at medium to large scale (>5MW) and at small-scale (<5MW). There was little benefit of a division between medium scale (5-10MW) and large scale (>10MW) developments as there are so few remaining sites available; around six sites in Scotland are within the 5-10 MW scale.

It was not possible to divide the analysis between small scale (1-5MW) and very small scale (<1MW) as suggested by DECC due to the difficulty in comparing data between different reports, which split the ranges at different thresholds: 500kW; 1MW; and 1.5MW. Currently, the nearest threshold levels for FiTs are at

100kW and 2MW.

It should be noted that all forecast produced in this report are not financially constrained. There is no consideration of current or future financial support mechanisms.

6.3 Literature Review

The reports were used to quantify the available untapped hydropower resource in different regions of the UK and to identify constraints to development. The studies used different methodologies for the assessment of resource potential.

Data from the Digest of UK Energy Statistics (DUKES) was used as the baseline for existing installed capacity, annual generation and historical growth rates.

6.4 Limitations & Assumptions

6.4.1 Limitations

No published literature was identified in relation to the hydropower resource potential in Northern Ireland. Assumptions for resource availability have been based on 2010 deployment in Northern Ireland a comparison with similar regions in England and discussions with DECC and ORED staff.

This study specifically excludes pumped storage schemes. Whilst these sites have an important role to play in managing the UK electricity supply, particularly with a higher proportion of renewable electricity generation, they are net users of electricity.

6.4.2 Assumptions

For medium and large sites a load factor of 36.7% was used. This was derived from the average performance of existing >5MW sites in the five years 2005-2009. For small sites a slightly lower load factor of 35.7% was used, this was derived from the average performance of existing <5MW sites over the same period.

Typically, mechanical and electrical equipment refurbishment and/or replacement would be required before civil structures are asset life expired. M&E design life for hydropower installations is typically 20 to 30+ years depending on the size of the installation. Civil structures will have a design life of typically 60-100 years. The initial construction of a hydropower scheme may have included a dam or weir, mill leats, pipelines, tunnels, road infrastructure, buildings or electrical grid connection which could still be in a serviceable condition when the M&E equipment requires replacement or refurbishment.

For the purpose of this analysis it was assumed that any sites currently operating that will reach the end of their operational life within the next 20 years will be repowered at the same capacity. In most cases, it is straightforward to retrofit a new turbine, generator and control gear to existing structures or more simply to refurbish the existing equipment. The recently announced support for "remanufactured as new" hydro equipment under the FiTs scheme announced by DECC on 28th October 2010 will incentivise developers to continue generating rather than mothball their sites.

It was assumed that there will be, for example, no downsizing of sites in order to fall within a different ROC/FiT banding. For example an existing 120kW turbine could be down-sized to 100kW which will move the scheme to the next FiT band and generate higher revenue from a smaller amount of electricity generated. There is anecdotal evidence that down-sizing is occurring by hydropower developers in order to maximise the revenue from FiTs. This would particularly affect small sites, meaning that the cumulative impact on hydropower capacity would be very small in the early years of FiTs but would increase gradually over time. The assumption of no down-sizing is used because the actual impact is difficult to quantify and the overall effect on the UK renewable energy mix will be very small.

6.5 Constraints

6.5.1 Supply Chain

For medium and large sites, there are not considered to be any significant supply chain issues. It is thought that the technical, design, construction and supply capacity within the small hydropower market will grow in line with demand and is unlikely to be a constraint to development. The burden of training and capacity building will largely fall to industry to develop its own skills in house as there are very few training courses available.

6.5.2 Planning

Few medium and large hydropower developments involving new reservoirs would be considered environmentally acceptable. In practise this limits the number of large sites available for development. The remaining capacity at this scale is estimated at 38MW.

Most hydropower sites require effective environmental mitigation measures to protect habitats and ecology. In particular, the Water Framework Directive requires water quality and ecology to be maintained or improved which adds cost to proposed schemes. This is particularly problematic for small low-head run-of-river schemes for which the cost of environmental mitigation, such as improved fish passage, can make the schemes financially non-viable.

There is an insufficient evidence base about the cumulative impact of multiple schemes on the same river, particularly related to fish and their habitat. This might affect the environmental regulator’s ability to grant licences for schemes in close proximity to each other on the same watercourse.

The introduction of FiTs has already led to an increase in the number of sites applying for environmental permits and planning permission. There is currently a lack of regulatory capacity (within the EA, SEPA and NIEA) to respond to the increased number of applications. The regulators are taking measures to streamline their approach to the permitting of hydropower schemes and to provide better guidance to developers on the standards required. This should help to ease the bottleneck and reduce the response times, although this is likely to remain a key constraint.

The complexity and timescales of planning consent and environmental licensing for small schemes may put developers off.

6.5.3 UK Grid

For medium and large sites, the suitable locations for hydropower deployment are in remote locations, particularly in Scotland and require reinforcement of the grid to allow new generators to be connected.

For small schemes the high upfront cost of grid connection, particularly in rural areas, can have a major impact on financial viability.

Grid connection is considered to be a constraint to further development at all scales.

6.5.4 Technical

There were no major technical constraints identified for hydro; as the technology is mature.

However, there are potential technical developments yet to be made in fish screening and fish friendly turbines although there is technology already available. The main constraint to development is the lack of independent performance testing of these technologies to support or refute the manufacturers' claims of fish friendliness which leaves regulators in a weak position when making decisions.

6.5.5 Other Constraints

The key constraint affecting medium and large hydro is site availability. There are a handful of potential sites remaining in Scotland and none identified in England, Wales or Northern Ireland. There are a large number of small sites widely distributed around the UK with a correspondingly large number of site owners. The rate of development will therefore be dependent on the rate at which developers and investors decide to develop these sites. This will be affected by their capacity and willingness to recognise the benefits of hydropower and therefore largely driven by financial incentives.

Stability in the financial landscape will encourage investment, particularly for the large number of small sites identified. The continued commitment to the FiT during the spending review is a positive step towards this.

During the changeover from ROCs to FiTs there was a lack of a viable process for microgeneration certification which affects sites <50kW. There is now a transitional arrangement in place for registering installers and suppliers until a permanent process is developed. This will not be a constraint in the future.

Rainfall patterns could be regarded as a potential resource constraint as they will affect future generation potential although they are unlikely to significantly affect deployment rates.

6.6 Maximum Build Rate Scenarios

6.6.1 Available Resource

Existing medium and large scale developments totalled 1,458MW installed capacity and 4,664GWh annual generation in 2009. The untapped hydro resource is estimated at only 38MW capacity and 122GWh annual generation, all located in Scotland. The maximum feasible resource is therefore 1,496MW and 4,811GWh. The available resource is nearly fully utilised and expected to be exhausted within five to 18 years. Future annual generation figures are based on a capacity factor of 36.7% derived from the average performance of existing >5MW sites in the five years 2005-2009. Actual annual generation will vary dependent on rainfall.

The available resource at small scale (<5MW) is geographically spread throughout the UK. Existing developments totalled 186MW installed capacity and 598GWh annual generation in 2009. The maximum installed capacity available at this scale is thought to be approximately 1,200MW. This is made up of approximately 200MW existing, 650MW untapped potential in Scotland, 250MW in England and Wales and 100MW in Northern Ireland. The largest number of sites are in the <100kW range and the biggest contribution to installed capacity is likely to come from the 100 to 500kW range. Future annual generation figures are based on a capacity factor of 35.7% derived from the average performance of existing <5MW sites in the five years 2005-2009.

6.6.2 Low Scenario

For medium and large hydro (>5MW), there is a small number of sites that are left to develop. The low scenario is based on the average net annual deployment being the same as 2009, and net growth rate of 2MW/yr until the available capacity is exhausted in 2028.

The annual build rate is shown as a constant rate to reflect the average over a period of years. Due to the small number of sites remaining the annual growth rate would be less consistent with some years seeing no development and some in which several schemes are developed.

The low scenario for small sites (<5MW), is based on the primary constraint being the rate at which the SEPA, EA and NIEA can respond to new applications. Therefore the deployment rate in 2009 is taken as the same for all future years i.e. no future growth in capacity of the environmental regulators to approve more schemes. This is pessimistic as the regulators are already rolling out ways of streamlining the consenting process for hydropower.

6.6.3 Medium Scenario

For medium and large sites (>5MW) the medium scenario is based on the average net annual deployment being the same as the average net growth rate in the period 1996-2009 of 4.1MW/yr until available capacity is exhausted in 2019.

The medium scenario for small schemes is based on the historical trend of increasing annual growth rates for small and very small schemes (<5MW) and taking the same annual build rate as 2009 for the first four years (2010-2013).

This assumes the general upward trend is continued as investors gain in confidence with better financial incentives and capacity of developers, regulators and the supply chain is increased.

6.6.4 High Scenario

For medium and large sites (>5MW) the high scenario is based on the average net annual deployment being one and a half times the average net growth rate in the period 1996-2009, being 6.2MW/yr until available capacity is exhausted in 2016.

For small sites, the high scenario is based on double the medium growth scenario. This assumes all existing constraints are removed i.e. the licensing process is streamlined, financial incentives are increased such that cost of environmental mitigation (e.g. fish passes) and grid connections become less dominant.

6.6.5 Maximum Build Rate Plots

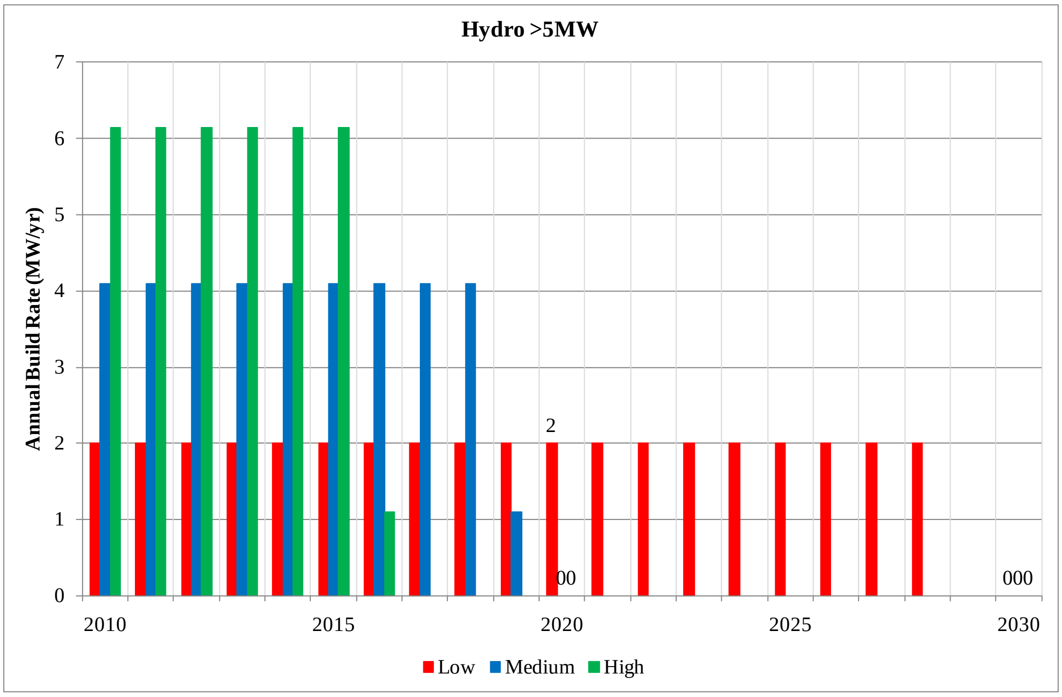


Figure 29: UK Hydro > 5MW Cumulative Installed Capacity (MW/yr)

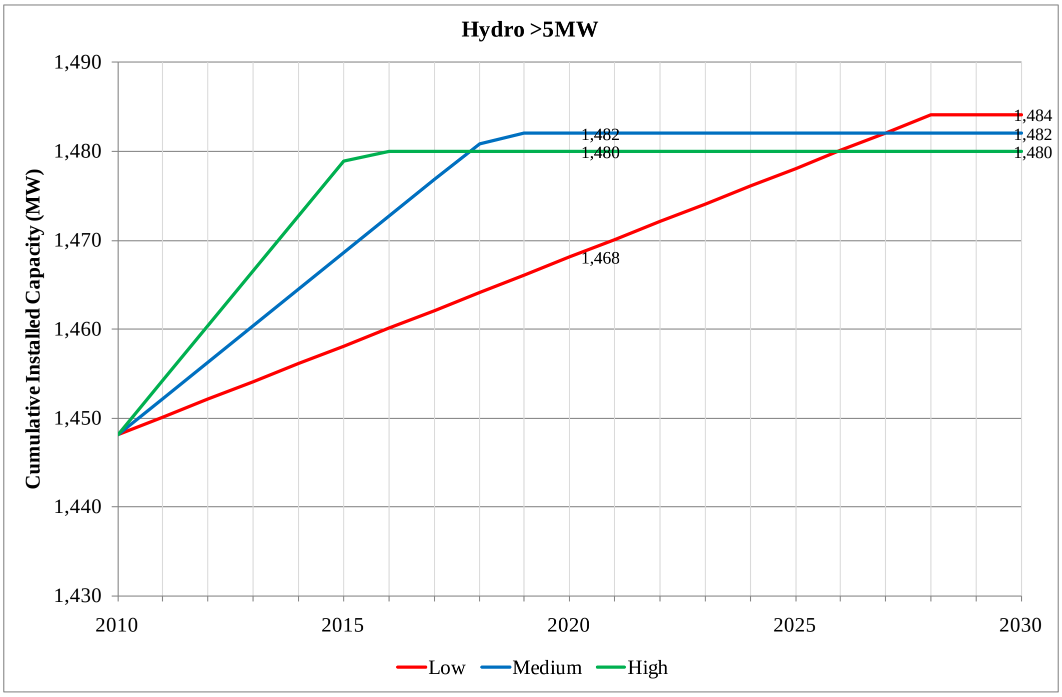


Figure 30: UK Hydro > 5MW Cumulative Installed Capacity (MW)

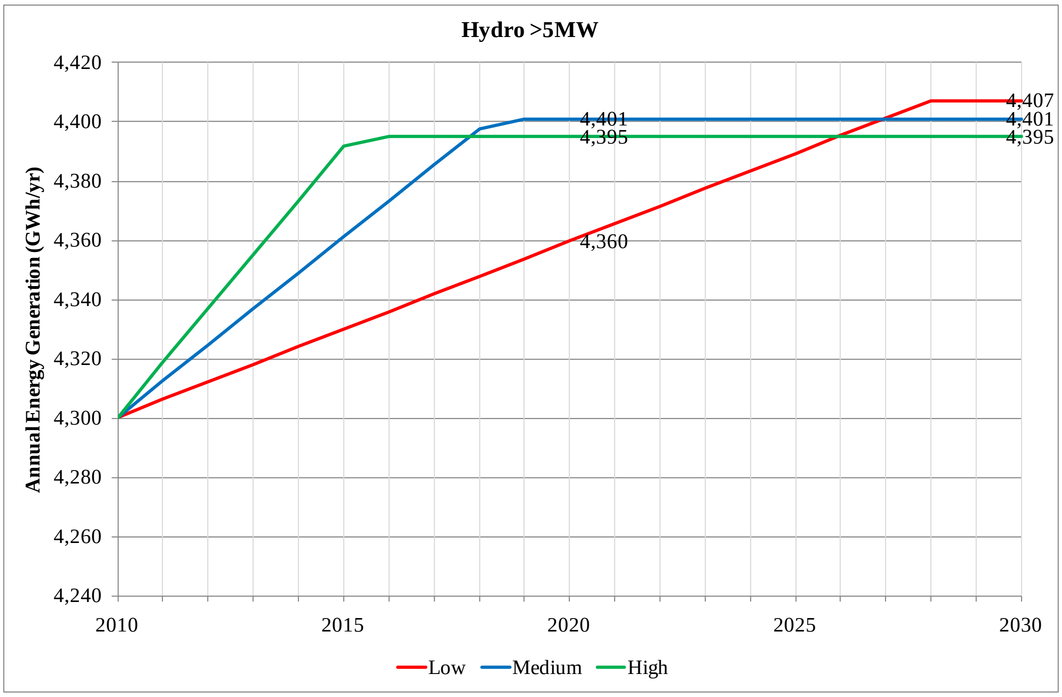


Figure 31: UK Hydro > 5MW Annual Energy Generation (GWh/yr)

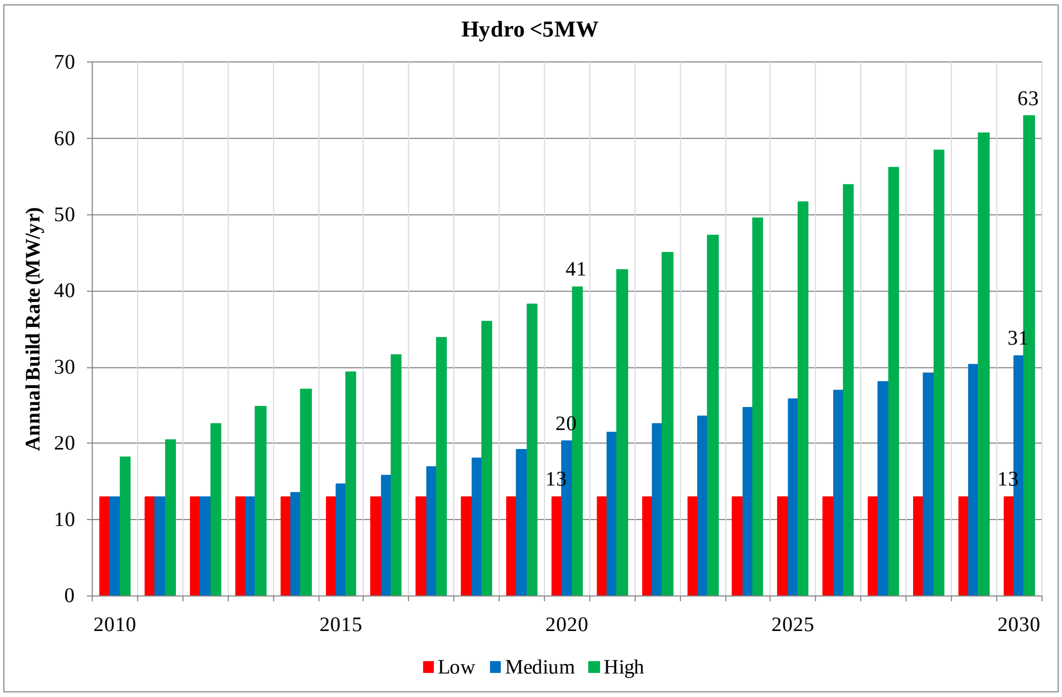


Figure 32: UK Hydro < 5MW Annual Build Rate (MW/yr)

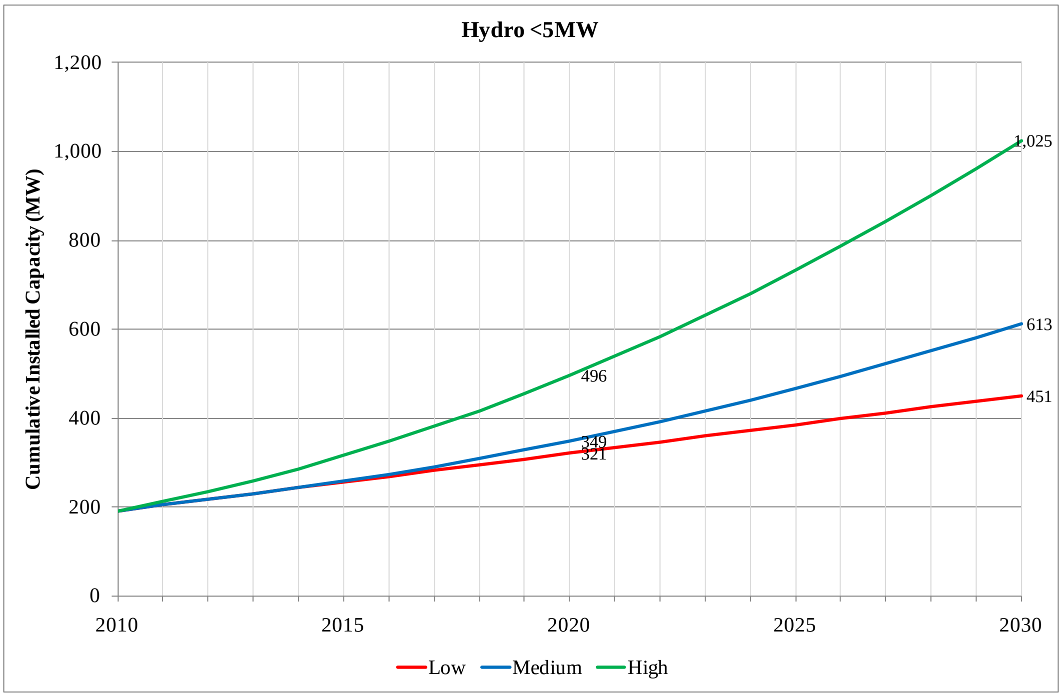


Figure 33: UK Hydro < 5MW Cumulative Installed Capacity (MW)

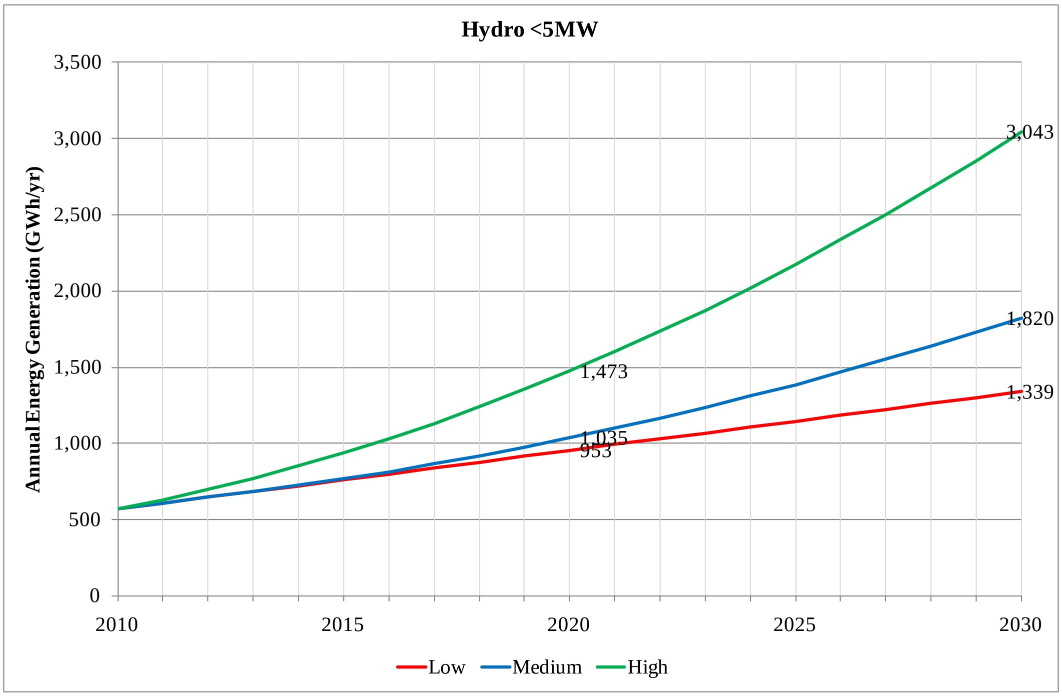


Figure 34: UK Hydro < 5MW Annual Energy Generation (GWh/yr)

6.7 Beyond 2030

For medium to large sites (>5MW) there is no further development anticipated beyond 2030 as all available resource would already be utilised, within the existing constraints. Repowering of existing sites would be the dominant factor to maintain or increase existing generation.

For small sites (<5MW) it is anticipated that the rate of deployment would start to decline beyond 2030 as available resources become fully exploited. This is particularly the case the for high growth scenario in which the majority of the available resource would be exploited by 2030.

6.8 Project Cost

6.8.1 Approach and Key Assumptions

The majority of information collected on the project cost for hydropower is based on industry benchmarks. Additional project cost data were collected through stakeholder consultations. There are two principal types of hydropower project: high head and low head. Cost data for both types of plants have been included in this study. Pumped storage hydropower plants have not been considered.

6.8.2 Capital Expenditure

Capital expenditure for hydropower is based on cost benchmarks for 58 proposed projects and information provided from six stakeholders. The main capital expenditure items for hydropower projects are civil structures, such as dams, water intakes or penstocks, generation equipment, electrical equipment and grid connections.

Pre-development costs vary considerably from £75,000 to £821,000/MW. Pre-licensing and planning make up the majority of this cost. The variation in cost is related to the complexity of permitting for a specific site, as it lengthens the pre-development period. Project scale is also key in driving a large range in unit costs.

The key points to note on the variation in unit capital cost are:

- Costs reflect economies of scale at larger installed capacities. Larger plants also experience reduced variation in unit cost.
- There are limited opportunities for design standardisation as site conditions vary significantly. The bespoke nature of design and construction of each plant can lead to significant variation in capital cost, particularly at smaller project scales.
- The type of hydropower plant employed further affects project capital cost. Capital costs of low-head plants are generally greater on a unit basis of installed capacity.

Table 21 below presents capital cost ranges for different installed capacity bands, and costs ranges are illustrated graphically below. Pre-development cost has not been included in the capital cost ranges.

Table 21: Hydropower – capital costs (financial close 2010)

£000s/MW	<1 MW	1 – 5 MW	>5 MW
High	9,507	4,982	2,858
Median	4,481	2,800	2,307
Low	2,797	2,423	1,448

Figure 35: Hydropower – capital costs (financial close 2010)

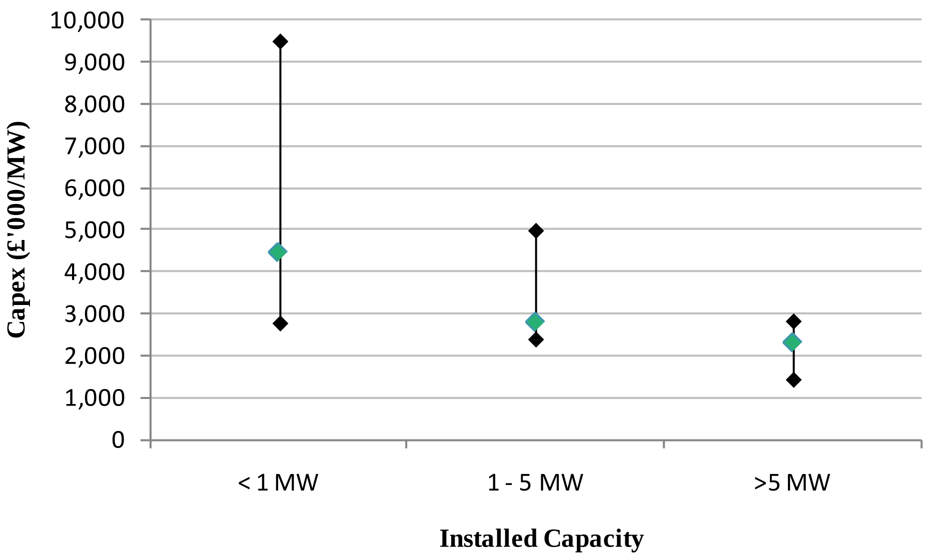


Table 22 below gives an indication of how capital costs are broken down for an average plant. The majority of capital cost relates to construction. M&E costs, which include generation equipment, make up approximately 20-30% of capital costs. Other infrastructure costs may have not been provided as every project will have many site specific requirements which are included in the construction cost.

Table 22: Hydropower – capital costs breakdown

Capital cost item	%
Pre-development	6%
Construction	92%
Grid Connection	2%
Other Infrastructure	0%

Costs of labour, steel and concrete are considered to be the principal drivers for future capital expenditure. This is due to the large capital expenditure on civil structures. Steel and labour are also significant in the manufacture of generation equipment.

As an established technology, limited learning effects are expected for hydropower. Only minor cost saving may be possible through continued optimisation of equipment and deployment techniques. Stakeholders believe there may be diseconomies of scale in that the average plant size is getting smaller as the most suitable sites for large plants are developed.

Table 23 below presents the range of current capital costs and how they are expected to change over time. These costs represent the <1MW installed capacity range.

Table 23: Hydropower – capital cost projections at financial close dates (real)

£000s/MW	2010	2015	2020	2025	2030
High	9,507	9,649	9,792	9,938	10,086
Median	4,481	4,548	4,616	4,684	4,754
Low	2,797	2,839	2,881	2,924	2,967

6.8.3 Operating Cost

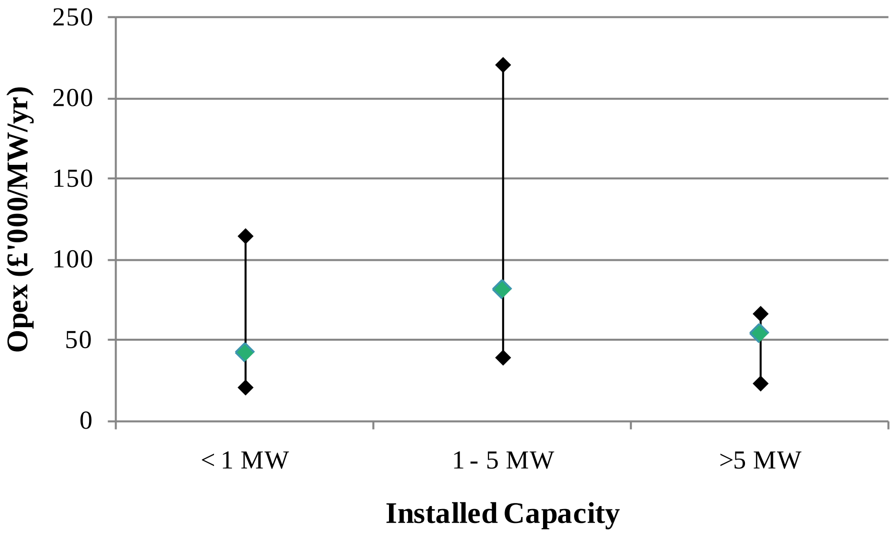
Operating costs for hydro plants are principally driven by routine maintenance, business rates, insurance and environmental monitoring. Operating cost ranges show an unexpected pattern, the <1MW band has a lower unit cost than the larger installed capacities. It is expected that the smaller plants are largely operated by land owners who include aspects of the operating costs within their estate management. The opportunity cost of land use has not been factored into operating costs.

Table 24 below presents operating cost ranges for different capacity bands.

Table 24: Hydropower – operating costs (financial close 2010)

£000s/MW	<1 MW	1 – 5 MW	>5 MW
High	115	222	66
Median	42	81	54
Low	21	40	24

Figure 36: Hydropower – operating costs (financial close 2010)



Labour costs and business rates are assumed to be the principal driver of future operating expenditure.

- Labour is required to maintain the plant and repair equipment. The technology is well established and there is significant operating experience within the industry. As a result, no further learning effects are anticipated in relation to routine maintenance.
- Business rates have increased markedly in real terms over the last decade following a change in the valuation basis. Stakeholders expect further real increases in business rates but the exact magnitude is unclear.
- Rental costs are expected to stay fairly constant in real terms.

Table 25 below presents the current operating costs for the <1MW installed capacity band and how they are expected to change with time.

Table 25: Hydropower – operating costs projections at financial close dates (real)

£000s/MW	2010	2015	2020	2025	2030
High	115	117	119	121	124
Median	42	43	44	44	45
Low	21	21	22	22	23

6.8.4 Levelised costs

Using the Arup and E&Y capital and operating cost profiles[18] for hydro plants smaller than 5MW and larger than 5MW, DECC has calculated levelised costs of a small and large hydro reference plant at financial close in 2010, 2015, 2020, 2025 and 2030. The levelised cost ranges are based on Arup's low, medium and high capital cost estimates. The levelised costs have been calculated by assuming a pre-tax real hurdle rate of 7.5%, based on the Oxera report[19] for the CCC. The assumed load factor for small and large hydro is 46% and the assumed plant lifetime is 41 years.

£ / MWh		2010	2015	2020	2025	2030
Hydro 0-5MW	low	67	68	68	68	68
	medium	104	105	105	105	106
	high	215	217	218	218	219
Hydro 5-16MW	low	42	42	42	42	42
	medium	59	59	59	60	60
	high	74	75	75	75	76

Note: Dates refer to financial close.

6.9 Regions

Hydropower resource is generally located in hilly and mountainous areas of the UK, mainly in Scotland and (mostly North) Wales. Existing installed capacity in the UK is distributed as follows: 88.5% in Scotland, 9.0% in Wales, 1.7% in England and 0.7% in Northern Ireland, South West, North East, North West and East Midlands are the biggest contributors in England. Future sites are likely to be concentrated in the same regions.

18 To note that the levelised costs are based on a separate set of capital and operating costs provided by Arup and E&Y that assume constant steel prices over time; capex includes infrastructure costs are incurred in the core facility, but do not include 'other' infrastructure costs that relate to costs incurred outside the site, such as water, roads, waste disposal and land costs. Levelised costs use different size categories for some technologies.

19 www.oxera.com/main.aspx?id=9514

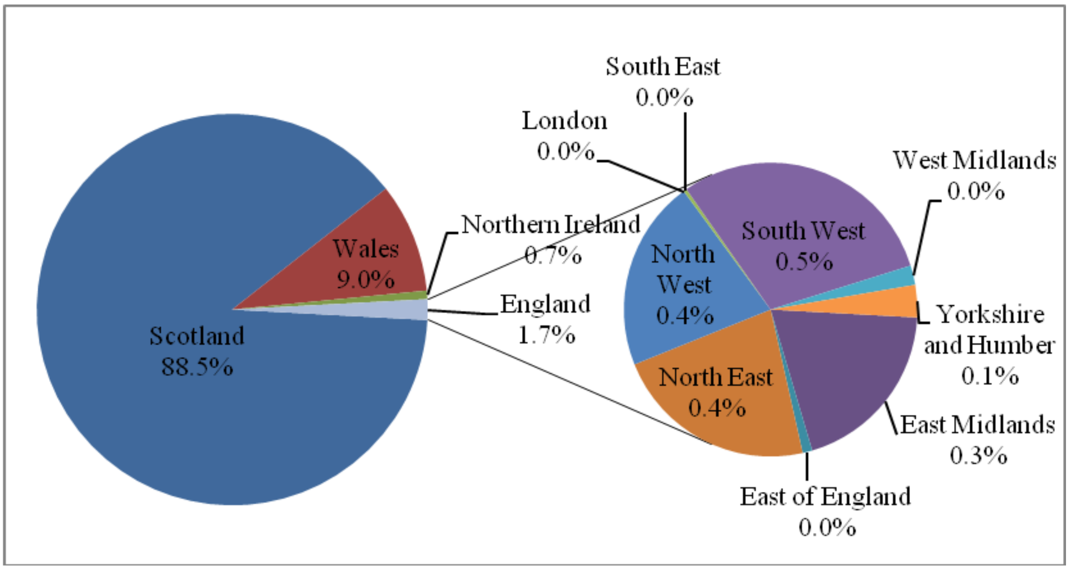


Figure 37: Distribution of Existing Hydropower Installed Capacity

All the remaining medium and large sites identified are located in Scotland. There may be a limited number of small (1-5 MW) sites in Wales.

Very small (<1MW) installations can be found in nearly all regions of the UK although there is likely to be very little hydropower generation from London, the South East and East Anglia.

7 Marine Technologies

7.1 Summary

Three forecasts of future marine technology deployment have been developed up to 2030. These are based on a number of assumptions and constraining factors including, but not limited to, the following:

- Supply chain constraints – industry is likely to be developed around existing offshore wind deployment facilities;
- Commercial – wave and tidal technologies are yet to be commercialised. Investment and R&D is still required to develop commercial technology and the infrastructure to aid deployment;
- Grid constraints – best sites for marine technology are located in remote areas where the availability of the grid capacity could prove to be a constraint; and
- Planning at this stage is not considered to be a major constraint. However, the current system has only dealt with a few demonstration projects. As deployment of marine technology increases, there is likely to be a conflict with other sectors for prioritisation.

For wave, the low scenario resulted in approximately 186MW by 2020 and 500MW by 2030. The medium scenario resulted in approximately 186MW by 2020 and 1,680MW by 2030. The high scenario resulted in approximately 279MW by 2020 and approximately 2,520MW by 2030.

For tidal stream the low scenario resulted in approximately 241MW by 2020 and 500MW by 2030. The medium scenario resulted in approximately 272MW by 2020 and 1,420MW by 2030. The high scenario resulted in 406MW by 2020 and approximately 2,160MW by 2030.

Tidal range deployment only begins in 2021. The low scenario results in approximately 250MW by 2030. The medium scenario results in 950MW by 2030. The high scenario results in 1,000MW by 2030.

7.2 Introduction

Three families of marine energy technologies have been considered in this study: wave, tidal stream and tidal range. Wave devices extract energy from the sea's surface generated by the friction of winds blowing over the water. Tidal stream devices extract energy from water flows generated by varying sea levels caused by tides. Tidal range installations extract potential energy generated by the change in height from a high to a low tide.

The UK is recognised as the global leader in the development of wave and tidal stream technologies. The first commercial-scale devices of both technologies were predominantly designed, developed and fabricated in the UK and installed in UK waters. At the end of 2010, the UK had 0.82MW of installed wave energy capacity and 1.55MW tidal stream installed capacity generating electricity into the national grid. Large-scale tidal range technology is mature and has been exploited in the form of tidal barrages, most notably in Rance, France (240MW) and Annapolis Royale, Nova Scotia (20MW). There are around ten small-scale barrages installed around the world, one of which is on the River Tawe, Swansea

(0.2MW).

This study did not undertake primary data gathering or research on marine technologies and was instead based on published studies commissioned by DECC and the Scottish Government. Under each technology, sub-categories were considered in the development of maximum build rate scenarios and pricing. For wave technologies, no segregation was made between near shore and offshore devices, in line with the published studies. Tidal stream technologies were split into ‘shallow’ (<50m depth water) and ‘deep’ (>50m depth water) technologies when considering the maximum build rates. However, given the degree of uncertainty over the growth rates beyond 2015, they were considered together when calculating the total installed capacity. Tidal range technologies include barrages, lagoons and reefs. Barrage technologies and the associated costs are a well understood and mature technology. Lagoons and reefs are unproven designs and there is little published information on their potential or costs. As such they were excluded from this study.

Consultation was undertaken on the published studies commissioned by DECC. The purpose of the consultation was to ascertain whether the data, assumptions and conclusions in the E&Y Report, The Offshore Valuation and the RenewableUK report were accepted by the industry and to determine which data set was considered to be the most representative and realistic. In addition, stakeholders were asked to rank key constraints in order of most significant impact on build rates. The consultation took the form of a questionnaire circulated to a select list of 19 stakeholders from across the industry, including 10 stakeholders specified by DECC. Two follow-up meetings were held with RenewableUK to discuss the development of the maximum build rate scenarios.

Please note that all forecast produced in this report are not financially constrained. There is no consideration of current or future financial support mechanisms.

7.3 Literature Review

A significant volume of work has been published over the past three to four years looking into cost reduction, growth potential, constraints and the practicably extractable marine energy resources.

Primary findings of the literature review were as follows:

- The E&Y report was assessed by Arup to provide the most realistic growth projections of the above reports above. This was primarily as the base case, optimistic and pessimistic growth projections are based on data collated from device developers up to and including 2009 and use Black & Veatch’s industry experience to project growth.
- The average annual build rates for wave and tidal stream technologies projected in Scenario 1[20] of The Offshore Valuation were found by Arup to be in line with those suggested by Black & Veatch over the period from 2010 to 2030. The average annual build rates for marine technologies in Scenarios 2 and 3[21] were greater than the maximum growth rates predicted by Black &

[20] The Offshore Valuation P.41 Scenario 1: Maximising the role of offshore renewables in meeting UK electricity demand. Offshore renewables are developed up to the point at which any further development would require exports of electricity to other countries.

[21]The Offshore Valuation P.41 Scenario 2: The UK as a net exporter of electricity generated by

Veatch and were therefore assessed to be too high to be representative of achievable deployment rates.

- Conversely, the contributions from marine technologies in the suggested 'Deployment by Technology' projections for 2050 for all Scenarios[22] in The Offshore Valuation were assessed by Arup to be low when compared to the 2050 projections by Black & Veatch.
- The growth projections used in the RUK report were based on Scenario 3 of The Offshore Valuation. As above, the average annual build rates for marine technologies were assessed by Arup to be too high to be achievable over 2010 to 2030 when compared to the Black & Veatch growth projections.
- The high and medium growth scenarios presented in the SKM report are assessed by Arup to be in line with the optimistic case and base case scenarios presented by Black & Veatch. The low scenario predicts lower growth than presented by Black & Veatch and is therefore assessed to be too pessimistic.

As a result of the literature review, the E&Y report was considered to provide the most realistic growth predictions and associated costs of the available published reports. The methodology and data from this study were used to generate the feasible maximum build rate scenarios.

7.4 Limitations & Assumptions

7.4.1 Limitations

As specified by DECC, no primary data gathering or research into marine technologies has been undertaken by Arup for the build rate projections or associated costs. The build rate scenarios and projection data presented here are taken from the E&Y report and supporting data provided by Black & Veatch. The underlying assumptions and constraints identified and applied by Black & Veatch have been adhered to. Black & Veatch's underlying assumption regarding constraints was based on an assessment of the impact associated with planning, supply chain and grid on the maximum resource calculations. These estimations were based on the technical and professional opinion of Black & Veatch and as such the actual impact of the constraints is yet to be determined. The build rate projections made for wave and tidal stream technologies beyond 2015 are therefore speculative and Arup concludes that actual build rates could vary from those presented.

A limitation identified in the use of the E&Y report is the age of the data set used as the basis of the costs and growth projections. The data collected from the device developers are from 2009 and as such do not account for recent changes in the industry, primarily the capital funding released through the Marine Renewables Proving Fund[23] and the Scottish WATERS fund[24] and the licences

---

offshore renewables. Scenario 3: The UK as a net producer of energy through offshore renewables.

[22]The Offshore Valuation P.17-21'Deployment by Technology' projections.

[23] An 18 month scheme was announced by DECC in March 2010 and is administered by the Carbon Trust to provide £22.5m of public finance to the leading wave and tidal stream developers to accelerate deployment of pre-commercial devices.

[24] A £12 million Scottish Government fund to support the testing of new wave and tidal prototypes in the seas around Scotland. It is managed and administered by Scottish Enterprise, in partnership with the Scottish Government and Highland & Island Enterprises.

agreed in Round 1 of the Pentland Firth strategic area[25]. The impact of this on the growth projections is that the E&Y projected growth rates to 2020 are potentially lower than they would be if these factors were taken into account.

There is a private sector proposal by Corlan Hafren for a tidal barrage scheme between Cardiff and Weston, which, if it goes ahead, could feasibly be constructed by 2030. This proposal was not included in the E&Y report.

7.4.2 Assumptions

Sufficient public and private investment will be leveraged in to the marine energy industry over the next five years to commercialise the leading technologies. RenewableUK estimates that the capital funding gap is of the order of £130m to £250m to support the build of a first array[26]. A previous estimate by The Carbon Trust[27] identified a funding gap of £432m from the deployment of first device to the first array.

Significant repowering will not occur within the study period of 2010 to 2030 as the design life of the devices would not expire within this period. In reality, some decommissioning of demonstration devices would occur.

7.5 Constraints

7.5.1 Introduction

The following constraints were verified by stakeholders during consultation and ranked in order of those that have the greatest limiting impact on maximum build rates. In some cases stakeholders provided more detail on particular aspects of the constraints that affected growth.

7.5.2 Supply Chain

The supply chain is expected to be developed to some extent by the offshore wind industry, for example port upgrades, fabrication yard expansion and skilled labour and engineering services would be driven forward. This is expected to relax some of the current supply chain constraints in time for the large-scale deployment of wave and tidal stream devices.

7.5.3 Planning

The results of the consultation process indicate that the UK consenting regime is not considered by developers or industry bodies to be a significant constraint to growth in the short-term (to 2020). However, it was noted that the consenting process has to date dealt with single demonstration devices with a short-term

[25] In March 2010, The Crown Estate announced the winners of the Round 1 leasing competition for the Pentland Firth and Orkney Waters. Agreements were made for six wave and four tidal stream development sites for a total of 1.6GW of installed capacity.
[26] RenewableUK (2010) Channelling the Energy – A Way Forward for the UK Wave and Tidal Industry Towards 2020.
[27] Carbon Trust (2009) Focus for success – A new approach to commercialising low carbon technologies.

project duration. As larger array/farm projects on long-term (>20 years) commercial leases begin to go through the planning process, the degree to which the planning regime is a constraint will be characterised. Potential conflicts that could cause the consenting regime to become a constraint relate to the prioritisation of the seabed for other uses or the protection of environmental designations.

The consultation process flagged up that stakeholders would welcome a review of the environmental monitoring requirements as projects pass through the consenting process. The pre-construction EIA and any related post-construction environmental monitoring requirements can constrain growth through the stringency of measures required and/or can financially constrain growth due to the extent of measures that developers may have to fund and implement.

Planning for grid connection or reinforcement sites was not assessed to be a constraint to growth by stakeholders.

7.5.4 UK Grid

The largest areas of wave and tidal stream resources are located off the Western and Northern Isles of Scotland, where current grid capacity and availability is low. The transmission of large-scale variable generation, the ability of the grid to deal with this supply and the reinforcement of the downstream networks are the key constraints. Through the Energy Market Reform Bill, Project TransmiT[28] and the implementation of the ‘Connect and Manage’ scheme by National Grid[29] it is recognised that there is an opportunity to encourage the deployment of marine energy. The outcomes of the consultation process indicated that in the shorter-term (to 2020) the development-lag of the grid in response to the schemes above may constrain growth in key Scottish areas, particularly the Pentland Firth and Orkney Waters. Early grid connection at key locations, such as consented seabed sites in the Pentland Firth, could ease this constraint.

The consultation results flagged that the differences in the transmission charging regime for key resources areas in the north-west of Scotland compared to the key resources areas in the south-west of England could constrain growth. Transmission charging in NW Scotland is much more expensive than in England.

Second generation wave and tidal stream devices that could exploit lower energy resource areas closer to locations of high population density could relax the constraint on grid in the long-term (beyond 2020).

7.5.5 Technical

Wave and tidal stream offshore and nearshore technologies have yet to be commercialised. Engineering innovation is still required to develop commercial-scale technologies and the associated infrastructure to deploy them. The availability of funding to support this research and development, and the mechanisms, by which it would be administered, was highlighted as a significant constraint to the development of the industry in the short-term by all stakeholders.

[28] Project TransmiT is Ofgem’s independent review of the charging and connection arrangements for gas and electricity transmission networks.
[29] The aim of ‘Connect and Manage’ is to accelerate the time it takes for new energy generation projects to be connected to the national grid.

7.5.6 Other

Stakeholder responses suggested that in the short-term, the availability of seabed due to the current technology-specific licensing regime administered by The Crown Estate could be a constraint. Relaxing measures, in particular changing the licensing regime to provide up to 100MW for the leading four or five developers at sites where grid connection could be prioritised were suggested. Alternatively, changing the licensing regime to consider demonstration of the technologies at consented test sites (such as EMEC or WaveHub) as a prequalification requirement for an Agreement for Lease was proposed.

Outcomes from the consultation also advised that at present the Agreement for Leases issued by The Crown Estate exclude other developers from exploiting those areas of seabed for a certain length of time. This has the potential to limit the number of available development sites and constrain growth in the future.

7.6 Maximum Build Rate Scenarios

7.6.1 Available Resource

The practical[30] wave resource that can be exploited for electricity generation has been estimated to be in the order of 50TWh/yr[31]. The practical tidal stream resource has been estimated to be in the order of 18TWh/yr[31]. Over the period to 2030, the practicably extractable wave and tidal stream resource will not be a constraint on installed capacity.

Tidal range resource is site-specific. The highest resource sites around the UK are those with the largest tidal range. The Severn is the highest resource site with an estimated 17TWh/yr of potentially extractable energy. It was excluded from the E&Y report. The high resources sites included in the E&Y report were the Mersey (1.4TWh/yr), Duddon (0.2TWh/yr), Wyre (0.13TWh/yr), Solway (0.2-12TWh/yr[32]) and Conwy (0.06TWh/yr).

7.6.2 Low Scenario

The following changes have been made to the “pessimistic” scenario methodology applied to wave and tidal stream device deployment in the E&Y report:

- Grid - cumulative installed capacity was constrained to a maximum of 190MW combined for wave and tidal stream technologies to 2020 and 500MW to 2030. This has been increased to 1GW combined for wave and tidal stream in 2020 and unconstrained at 2030 to take into account the Connect and Manage implementation scheme and the increased awareness/pressure on National Grid to upgrade bottlenecks.
- Financial support - the 20% reduction applied to unconstrained deployment to represent the attrition rate of projects that do not receive debt financing has been lifted.

[30] Practical resource is the exploitable resource that could be extracted by conceivable marine technologies after consideration of external constraints.
[31] The Carbon Trust (2006), Future Marine Energy p.7.
[32] These figures come from Halcrow, Mott MacDonald, RSK (March 2010) Solway Energy Gateway Feasibility Study.

The tidal range scenario is as presented in the E&Y report.

7.6.3 Medium Scenario

The following changes have been made to the "base case" scenario methodology applied to wave and tidal stream device deployment in the E&Y report:

- Financial support. The 20% reduction applied to the unconstrained deployment to represent the attrition rate of projects that do not receive debt financing has been lifted.

Tidal range scenario as presented in the E&Y report.

7.6.4 High Scenario

The following changes have been made to the "optimistic" scenario methodology applied to wave and tidal stream device deployment in the E&Y report:

- Financial support - the 20% reduction applied to unconstrained deployment to represent the attrition rate of projects that do not receive debt financing has been lifted.

The tidal range scenario is presented in the E&Y report.

7.6.5 Maximum Build Rate Plots

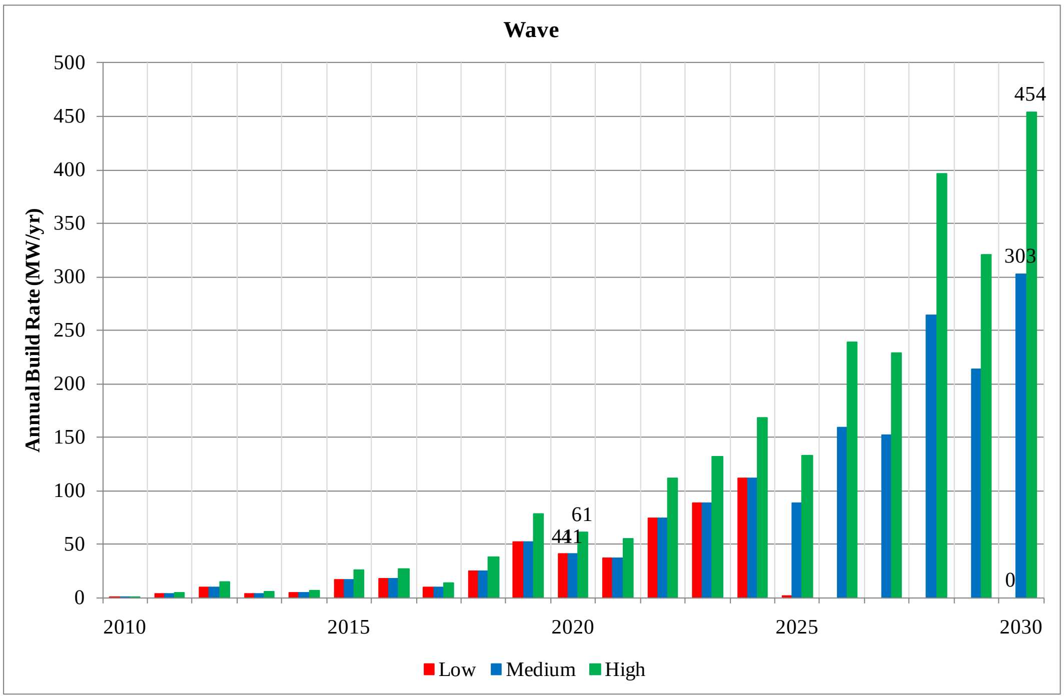


Figure 38: UK Wave Annual Build Rate (MW/yr)

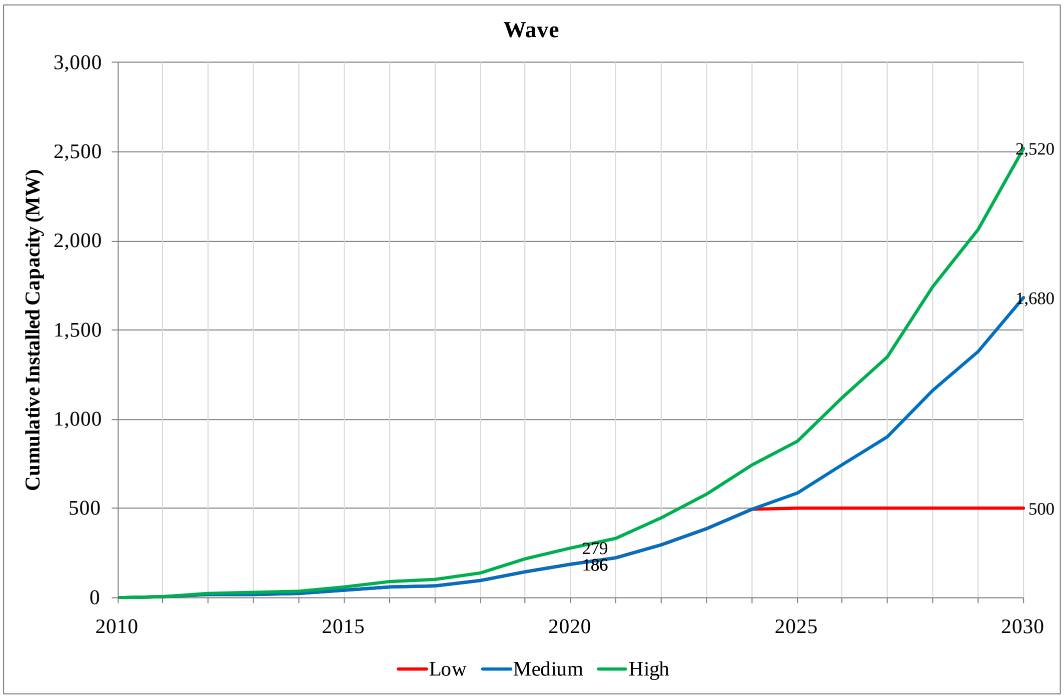


Figure 39: UK Wave Cumulative Installed Capacity (MW)

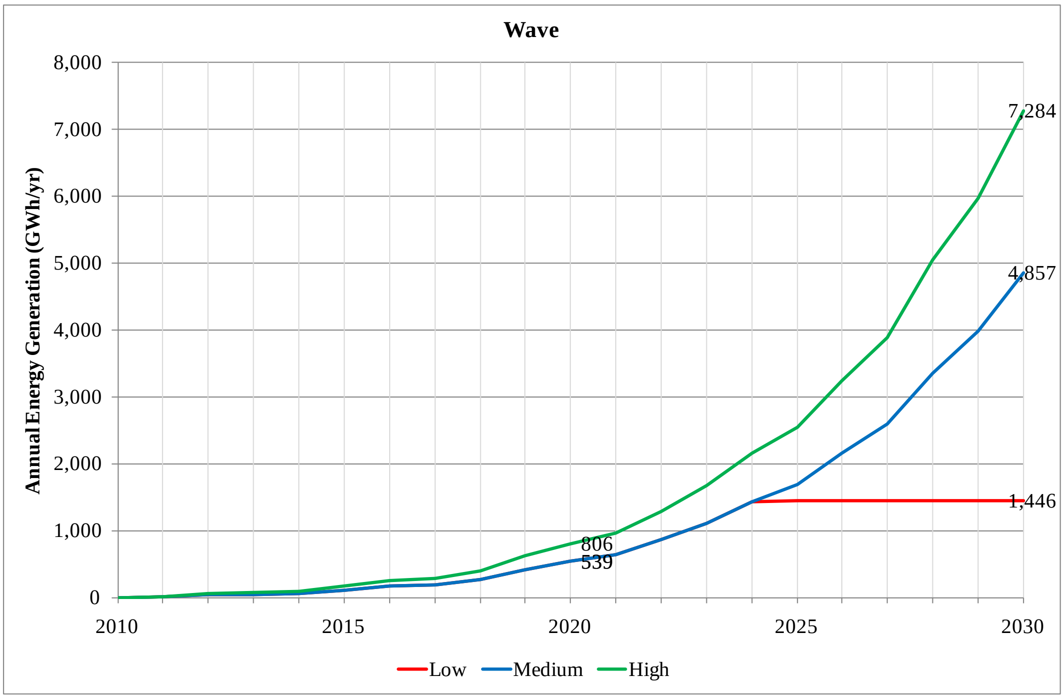


Figure 40: UK Wave Annual Energy Generation (GWh/yr)

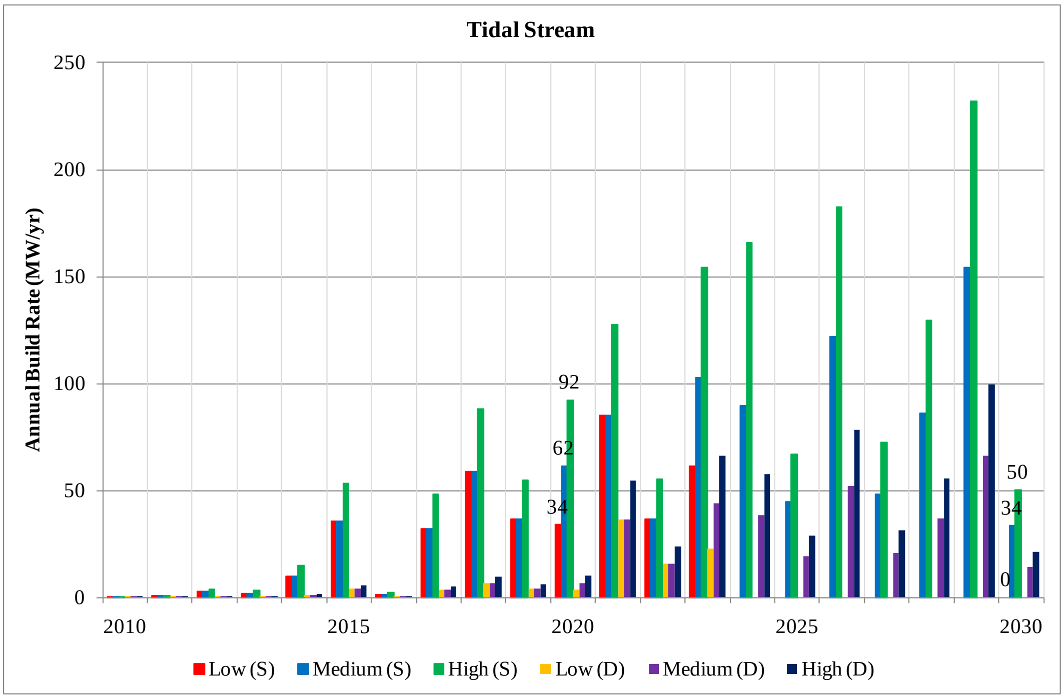


Figure 41: UK Tidal Stream Annual Build Rate (MW/yr)

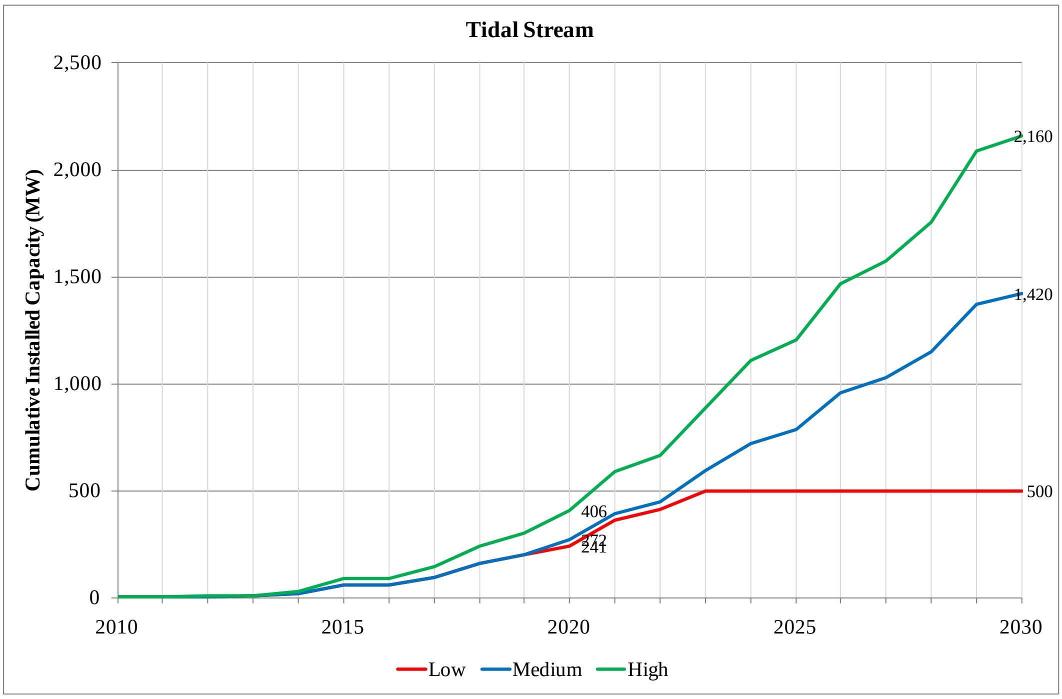


Figure 42: UK Tidal Stream Cumulative Installed Capacity (MW)

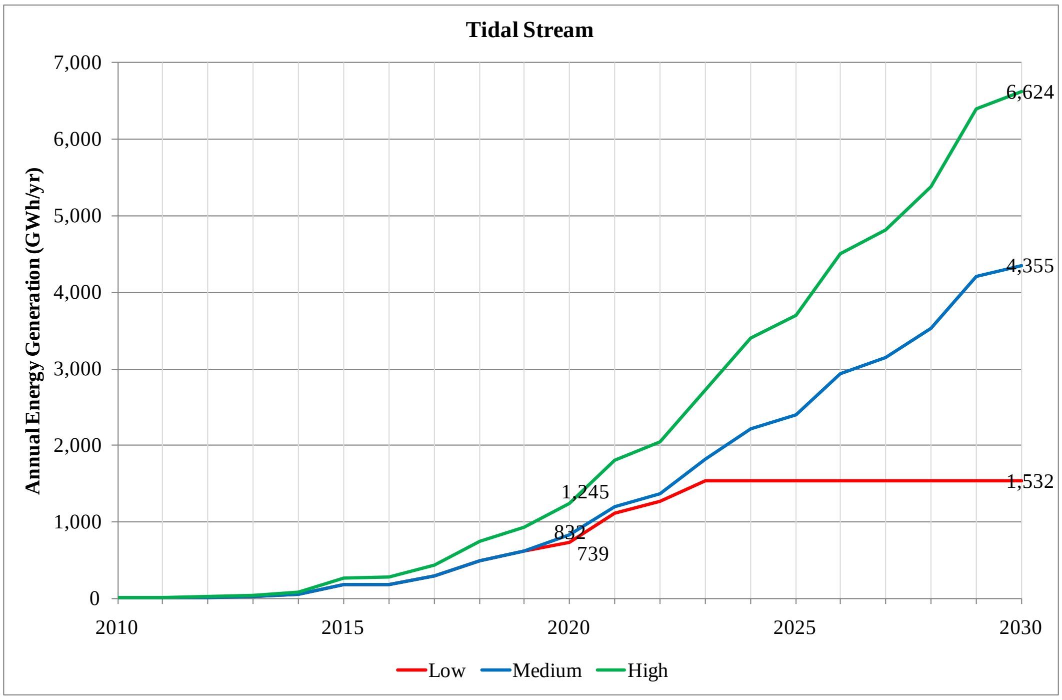


Figure 43: UK Tidal Stream Annual Energy Generation (GWh/yr)

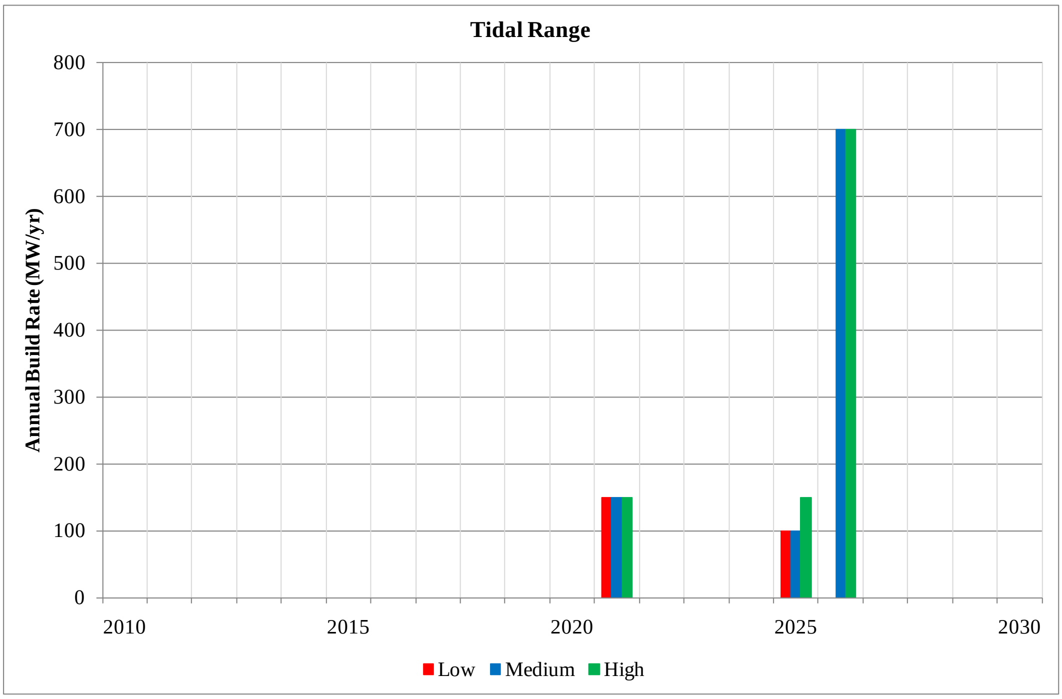


Figure 44: UK Tidal Range Annual Build Rate (MW/yr)

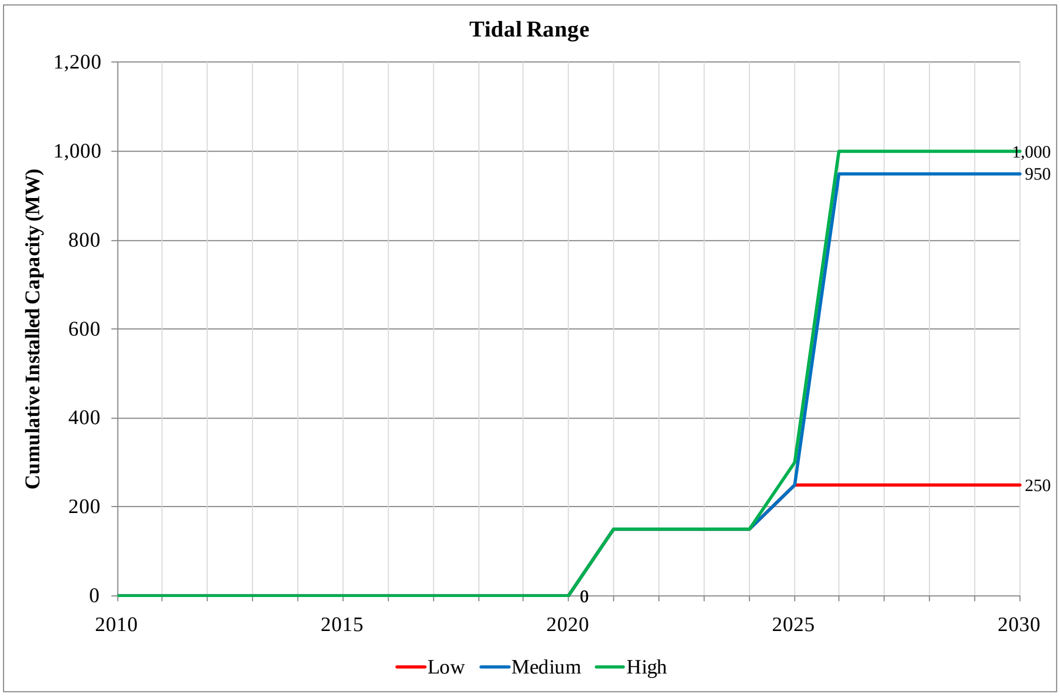


Figure 45: UK Tidal Range Cumulative Installed Capacity (MW)

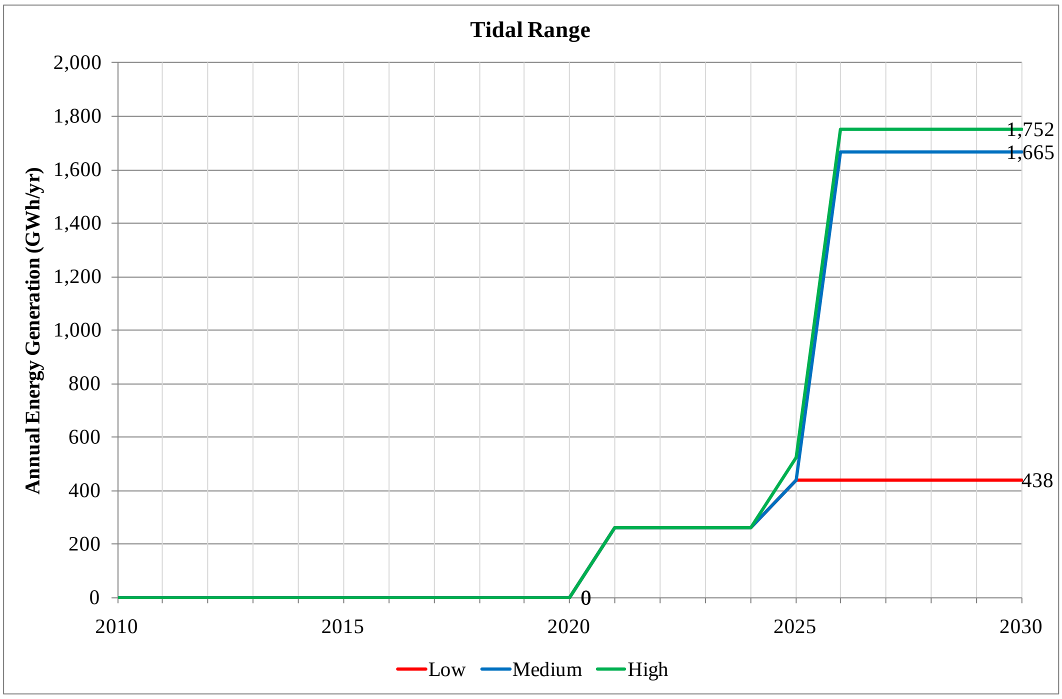


Figure 46: UK Tidal Range Annual Energy Generation (GWh/yr)

7.7 Beyond 2030

As the most attractive wave and tidal stream sites are developed, the overall build rates for both technologies are likely to begin declining slowly. Deployment of 'deep' tidal stream technology will increase as rates of deployment of 'shallow' technology decrease. Tidal lagoons, fences or reefs may have been proven and commercialised

7.8 Project Cost

7.8.1 Approach and Key Assumptions

This section is a review of cost assumptions for marine technologies in recent industry reports. The focus is on key parameters that drive levelised costs, including capital expenditure and operating cost ranges and performance parameters of marine devices shown in the E&Y report and the RUK report. Only tidal stream and wave technologies were considered. As indicated previously, no primary data collection was envisaged by DECC.

For tidal stream and wave technologies, E&Y and RUK carried out stakeholder consultations to form a view on project cost at various stages of deployment. The E&Y report shows costs at pre-demonstration stage (for prototypes), demonstration stage, and once devices reach commercial stage. RUK, in contrast, gives an indication of full costs involved at prototype stage and presents an alternative estimate of costs at demonstration stage.

- E&Y have drawn their cost information from a sample of the leading wave and tidal stream technology developers. Data have been partly validated and weighted according to strength. Data have also been supplemented by Black & Veatch proprietary information and other government and DECC data.
- The RUK has collected an alternative set of cost projections, for projects at demonstration stage, based on 11 projects from six utilities and seven technology developers in the sector.

Costs for tidal range projects have been taken from the E&Y report, which is believed to be a fair reflection of current project cost.

7.8.2 Capital Expenditure

Capital expenditure for marine devices is expected to reduce dramatically, from the stage of first array scale development and installation, to demonstration stage and full commercialisation.

A different view on project costs at prototype stage is presented in both RUK and E&Y/B&V reports below. However, the cost estimates at prototype/pre-demonstration stage in both reports are not directly comparable:

- The RUK report estimates that a total investment of circa £30m is required to get a single marine device from concept stage to successful deployment and full installation including grid connection of a single prototype.
- The E&Y report shows the cost of deploying a prototype at pre-demonstration stage. Deployment is estimated to cost in the range of £6.1m to £8.6m/MW for wave devices, and £7.5m to £12.4m/MW for (shallow) tidal stream devices. These cost estimates do not appear to include a full apportionment of prototype development cost, including concept and design development.

A comparison of cost projections was carried out for demonstration stage deployment of marine devices:

- The E&Y report defines the demonstration stage as being reached once four developers deploy their first 10MW projects, i.e. a global deployment of

40MW of capacity is reached. E&Y has considered this for different resource environments (high/medium/low), with cost ranges varying marginally. The costs reproduced in this section are for the medium resource environment.

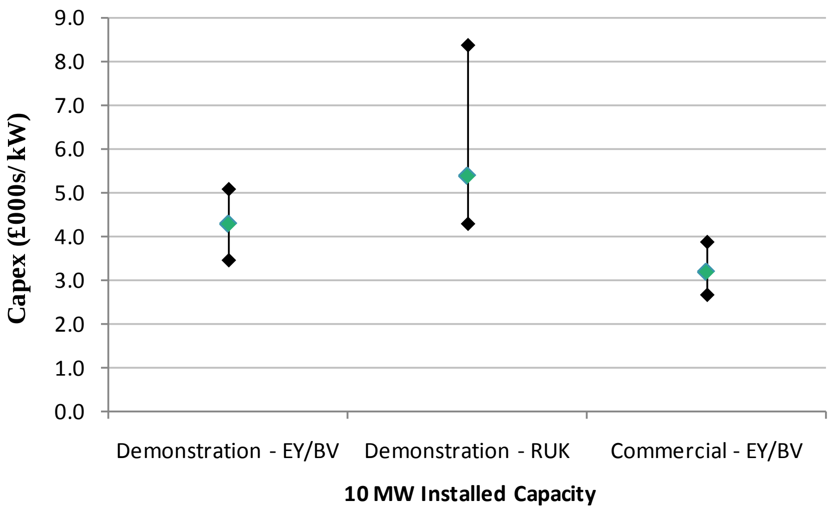
- The RUK report similarly assumes deployment of 10MW arrays of marine devices at demonstration stage.

It is important to note that these estimates at demonstration stage relate to costs that developers/utilities think may be achievable with given levels of deployment and learning rates. The E&Y report has further given an indication how project cost may decrease once devices reach commercial stage, defined as deployment of 10MW projects once 50MW have been installed by one developer.

Figure 47 below show the comparison between the capital expenditure for tidal stream and wave devices at demonstration stage (RUK and E&Y/B&V data) with commercial stage (E&Y's view on how costs may reduce once devices reach commercial stage).

- Large cost ranges, in particular in the RUK report figures, reflect the variety of marine devices currently in development. The RUK report did not provide a cost breakdown of this capital expenditure for reasons of commercial confidentially.
- A trade-off between higher capital expenditure and lower operating cost is expected, i.e. devices that are optimised for higher capital expenditure should achieve lower operating costs.

Figure 47: Tidal stream – capital expenditure projections



The capital expenditure for tidal stream devices mainly relates to costs for structures, foundations and moorings. The costs shown from the E&Y report relate to shallow tidal stream, which is expected to be deployed first. Capital expenditure is in the range of £3.5m and £5.1m/MW. Deep tidal stream devices and floating turbines are similar in technology and structure but deployment is expected at a later stage once project economics have improved and the technologies required to install turbines in the areas of greatest current have been developed.

The RUK report shows a higher range for capital expenditure at demonstration stage, between £4.3m and £8.4m/MW, which is partly attributed to unknowns around installation cost and construction risks. RUK expects that developers will still include high levels of contingency at demonstration stage. RUK also notes that demonstration stage will only be reached with sufficient deployment pre-2020 to reduce costs to the level shown above.

Further significant capital expenditure reductions are anticipated through learning as deployment increases and devices reach commercial stage. The E&Y report predicts a reduction of capital expenditure at commercial stage to £2.7m to £3.9m per MW.

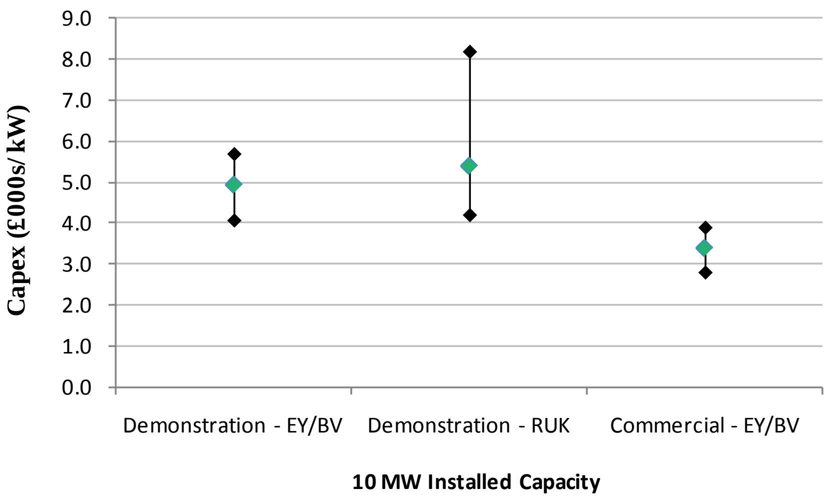
For tidal range, the Table below shows the current commercial construction cost estimate from the E&Y report (2010). Costs are assumed to stay constant over time.

Table 26: Tidal range – capital expenditure projections

	£'000/MW
Low	2,000
Medium	2,750
High	3,450

Figure 48 shows projected capital expenditure ranges for wave devices in development at demonstration and commercial stage.

Figure 48: Wave – capital expenditure projections



The E&Y report projects an overall cost range and median costs that are on average lower than the costs expected by RUK at demonstration stage. The E&Y report projects capital expenditure to be in the range of £4.1m and £5.7m/MW. This compares to a range of £4.2m to £8.2m/MW expected by RUK. Again, RUK assumes a greater variety of devices and contingencies at demonstration stage, and significant trade-offs with operating costs that may justify this large cost range.

E&Y project costs for marine devices to reduce to between £2.8m/MW and

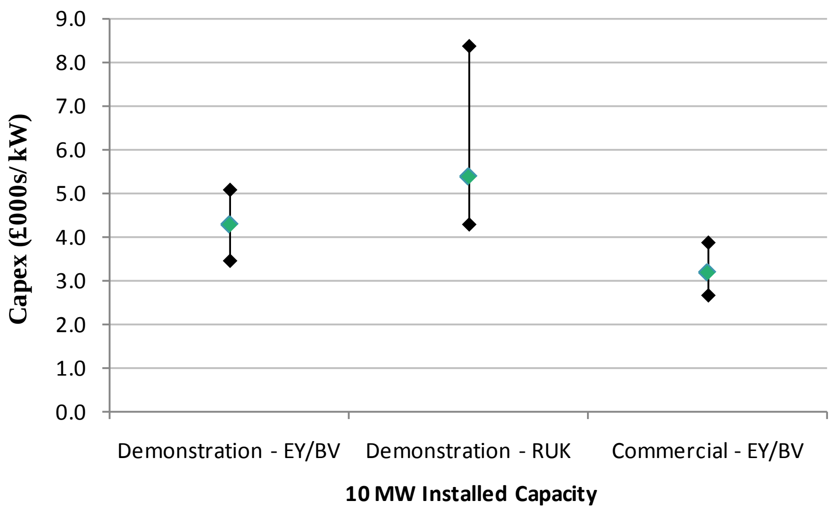
£3.9m/MW at commercial stage.

7.8.3 Operating Cost

The operating costs for marine devices typically include planned and unplanned maintenance cost, and monitoring of activities and refits.

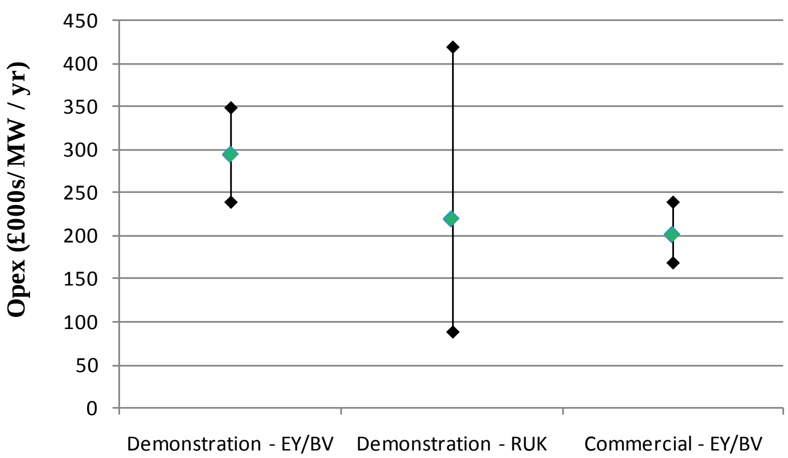
Figures 49 and 50 show E&Y and RUK projections of operating costs for tidal stream and wave devices.

Figure 49: Tidal Stream – operating expenditure projections



At demonstration stage, the E&Y cost projections for tidal stream, from £0.23m to £0.38m/MW/year, are markedly higher than costs assumed by RUK. RUK projects operating costs in the range of £0.12m to £0.22m/MW/year. This might reflect a trade-off RUK assumes between capital expenditure and operating cost. At commercial stage, E&Y/B&V expect operating costs to fall drastically to a smaller range of £0.12m to £0.19m/MW/year.

Figure 50: Wave – operating expenditure projections



A cost comparison for wave devices shows that RUK expects a massive range of operating cost based on a large number of device options that are expected in the market at demonstration stage. Despite the large cost range of £0.09m to £0.42m/MW/year, RUK expects lower median costs of £0.22m/MW/year, compared to £0.29m projected by the E&Y report.

The assumed cost reductions as devices reach demonstration and commercial stage are heavily dependent upon sufficient levels of deployment and, as a consequence, learning rates achieved within the marine industry. Both reports highlight that actual learning rates for each doubling of globally deployed capacity are subjective and difficult to predict.

- The E&Y report assumes that learning rates will be smaller than those historically seen for onshore wind devices, reflective of the more complex steps required to commercialise marine technology. Possible ranges of expected learning rates are between 9.9% and 16.9% for wave devices (13.2% base case), and 9% to 16.9% (13% base case) for tidal stream devices.
- The RUK report expects learning rates between 10% and 15% in line with previous industry reports, and states that learning could be even higher subject to a sufficient level of knowledge sharing within the industry and continuous and uninterrupted development.

This suggests a consensus on achievable learning rates. However, RUK notes that the learning rates E&Y applied to costs are steep and contingent upon sufficient deployment levels.

Both reports broadly concur on assumed capacity factors used to calculate the potential MWhs of energy produced by marine device, but some discrepancies exist in relation to capacity factors at demonstration stage:

- RUK notes that utility companies in their investment plans for demonstration stage use an average capacity factor of 30% for marine devices.
- The E&Y/ BV report assumes a similar capacity factor of 33% for wave, but a higher factor of 47% for shallow tidal. However, E&Y/BV suggests that the capacity factor for shallow tidal will reduce to 33% by the time devices reach commercial stage and projects will not be deployed at highest energy locations only.

The difference of capacity factors at demonstration stage relates to different assumptions on site conditions. E&Y/BV assumes deployment of tidal demonstration projects in high energy locations, whilst RUK assumes that technology will be tested in less extreme environments similar to conditions that apply at commercial deployment stage. RUK also argues that capacity factors, if at all, could be lower at demonstration stage, due to a lack of mature O&M support and its impact on availability levels.

For tidal range, the Table below shows the current commercial operating cost estimate from the E&Y report (2010). Costs are assumed to stay constant over time.

Table 27: Tidal range – operating expenditure projections

	£'000/MW
Low	46.8
Medium	37.2
High	27.7

7.8.4 Levelised costs

DECC has calculated wave and tidal levelised costs, based on the same commercial cost assumptions as E&Y(2010)[33], and the same proportions of different types of resource quality. As with E&Y(2010), the estimates use the Black & Veatch learning rates for each cost subcomponent, but the impacts of cost drivers, such as commodity prices, have not been added on top of the learning rates. The levelised costs have been calculated using new hurdle rate assumptions from the Oxera report[34] for the CCC and DECC assumptions on the hurdle rate profile over time; 13.8% for Wave, going down to 11.6% by 2030; 14.5% for Tidal Stream, going down to 11.6% by 2030; and 11.9% for Tidal Range. The levelised costs assume a load factor of 30% for Wave; 27% for Tidal Stream shallow; 41% for Tidal Stream deep in 2020 dropping to 33% thereafter; and 20% for Tidal Range. Further, it is assumed that Wave and Tidal Stream have a lifetime of 20 years, while Tidal Range is assumed to have a 40 year financial lifetime (120 years design life).

In common with Ernst & Young (2010), levelised costs are not presented for 2010 and 2015 financial close, as it is assumed these dates correspond to pre-demonstration small prototypes and small demonstration arrays, rather than to fully commercial deployment.

£ / MWh		2020	2025	2030
Wave	low	208	168	130
	medium	237	191	147
	high	266	214	163
Tidal stream shallow	low	196	174	149
	medium	227	201	171
	high	262	232	196

33 www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/energy_mix/renewable/explained/wave_tidal/funding/funding.aspx

34 www.oxera.com/main.aspx?id=9514

Tidal stream deep	low	162	163	121
	medium	190	191	140
	high	221	221	161
Tidal range	low	206	206	206
	medium	275	275	275
	high	340	340	340

Note: Dates refer to financial close.

It should be noted that wave and tidal stream technologies are at an early stage in their development, and as such their future generation costs are particularly uncertain. Their future evolution depends on the intensity of the wave/tidal resource exploited (Ernst & Young (2010) considered three different qualities of resource), technological learning rates, UK and global deployment rates, supply chain development, global commodity markets, exchange rates and so on.

7.9 Regions

Key areas of extractable wave resources are off the west and north-west coasts of Scotland, particularly off the Western and Northern Isles (75% of the resource), the south-west coast of Wales (10% of the resource) and the western Cornish coast (10% of the resource)[35]. These are the locations where wave device deployment is expected to 2030.

Areas of tidal stream resource occur where tidal flows are constricted between two bodies such as between the mainland and offshore islands. Key resource areas are recognised as off the north coast of Scotland around the Pentland Firth, between south-west Scotland and Northern Ireland, around the north coast of Northern Ireland, between Scotland and the Isle of Man, off the north, west and south coasts of Wales, and in the English Channel in the region around the Isle of Wight[36]. The resources in Scotland, Northern Ireland and Wales are key regions for deployment of tidal stream devices to 2030.

In practice, The Crown Estate leasing rounds will dictate in which order the areas of wave and tidal stream resources will be exploited. Leasing rounds underway at the time of issue are further Scottish leasing (in addition to the Pentland Firth and Orkney Waters) relating to the Saltire Prize, demonstration leases for sites other than EMEC[37] and WaveHub[38] and Northern Irish waters ‘design discussion’ ahead of a leasing round expected towards the end of 2011.

[35] The Offshore Valuation (2010) p.31.
[36] The Offshore Valuation (2010) p.37.
[37] European Marine Energy Centre in Orkney.
[38] WaveHub large-scale wave energy device testing centre in Cornwall.

8 Geothermal

8.1 Summary

Based on a number of assumptions and constraining factors including, but not limited to, a forecast of Geothermal deployment up to 2030 has been developed:

- Supply chain constraints – few have been identified, with equipment likely to be sourced from outside of the UK. There is unlikely to be any significant change in the next five to ten years;
- Grid constraints – not perceived to be significant. Likely scale of power generation should justify forming a connection to the grid;
- Planning at this stage is not considered to be a major constraint. With much of the installation taking place below ground, surface intrusion is minimal.

The earliest geothermal deployment is assumed to begin in 2014. The low scenario resulted in approximately 35MW by 2020 and 175MW by 2030. The medium scenario resulted in approximately 100MW by 2020 and 990 by 2030. The high scenario resulted in 480MW by 2020 and 4,005MW by 2030.

8.2 Introduction

Geothermal power has been the technology assessed. Geothermal temperatures in the UK are only moderate at best so it is likely that any development would produce a large amount of low or medium temperature heat as a by-product of power generation, so that in order to be viable, geothermal schemes will have to combine heat and power production. Geopressure was on the list of technologies nominated by DECC for consideration but the technology has no real footprint in the UK and there is therefore no basis for forecasting future development. The term geopressure has been used in the UK for the technology associated with exploitation of the pressure drop in gas transmission pipelines for power generation using a turbo-expander coupled to a generator, usually to re-heat the gas. There are no schemes of this type in the UK. Elsewhere, particularly in the US, the term simply refers to the high pressures which occur in petroleum reservoirs due to the weight of the overlying geological strata. This has resulted in methane being present in solution in high pressure brines and this is recognised as a potential source of energy. The minimum scale for the incremental development of geothermal power has been taken as 5MWe (this would have an associated heat output of 20MWt). The capital cost of geothermal development is large – and not scaleable – that this is the minimum capacity taken by Arup as being financially viable.

There are currently no active geothermal projects in the UK producing electricity. At Southampton a direct-use low enthalpy project provides district heating from the Sherwood Sandstone aquifer at 76^{o}C from a depth of approximately 1,800m. The estimated capacity of this geothermal project which was constructed in 1987, is 2.76MWt.

A number of geothermal projects in the UK are currently in the planning stages. A hot dry rock (HDR) project in Redruth, Cornwall has recently been given planning permission with construction due to start later in 2011. This project is projected to deliver 55MWt and 10MWe. Another HDR trial project at the Eden

Project site in Cornwall is being designed to provide 3MWe.

Drilling has just started in central Newcastle to a proposed depth of 2,000m to encounter saturated rock at a temperature of 80^{o}C. The plan is to use this in a district heating scheme – it is not a power project.

A district heating scheme is also being developed at the Eastgate eco village site in Weardale. A 995m trial borehole was drilled in 2004. The bottom hole temperature after drilling was about 46^{o}C. The existing borehole may be used in a district heating scheme and there are plans to drill a second borehole to 2,500m and install a binary cycle power plant.

8.3 Literature Review

Following the literature review a summary of the preliminary findings are presented below:

- Geothermal resources are linked to distinct geological settings, where high temperatures occur at anomalously shallow depths.
- The main resource locations are within the deep geological basins of Mesozoic age in various locations across the UK and the Palaeozoic Midland Valley in Scotland.
- EGS potential is mainly associated with granite batholiths, which are present in Cornwall, Scotland, the Lake District and Weardale and in the Mourne Mountains in Northern Ireland.
- Use of geothermal energy in the UK is currently very low, however, it accounts for significantly larger proportions of energy use in other countries. Technology is likely to be more mature in these countries and will be available to be used in UK.
- Low enthalpy geothermal and HDR in particular can be used to generate electricity and heating. The split between heating and electricity production is related to whether heat loads are required near to geothermal production and whether electricity can be economically produced from low enthalpy geothermal. Current development of geothermal in the UK appears to be concentrating on granites. If this trend continues then much of future geothermal technology will be located within the granites of Cornwall, north of England and Scotland.
- There is limited geothermal potential in Wales. There are low enthalpy geothermal resources in the "Rathlin, Lough Neagh and Larne Basins" of Northern Ireland and Palaeozoic Midland Valley in Scotland.
- Deployment of geothermal projects in future will be linked to the location of potential geothermal resources and the demand for heating.
- Almost nothing is published on geopressure in the UK. There is considerable scepticism in the scientific community.

Key data sources used in this study were:

- British Geological Survey;
- European Geothermal Energy Council;
- The U.S. Department of Energy Office of Energy Efficiency and Renewable

Energy; and

- Geothermal Energy Association.

8.4 Limitations & Assumptions

8.4.1 Limitations

The principal limitation to the study was the minimal existing level of development of geothermal power in the UK.

8.4.2 Assumptions

The main drivers are:

- inclusion of deep geothermal tariff;
- exploration licensing legislation;
- deep geothermal heat included in RHI;
- risk insurance mechanism;
- number of geothermal sources;
- markets for heat and power;
- planning; and
- geothermal schemes are only viable when there is a market for both heat and power.

A load factor of 90% is assumed.

The expected design life of geothermal plants is in the region of 25 years. A primary issue affecting life is the potential for well degradation for example from the corrosion of casing due to brines and the clogging and scaling of casing, pumps and equipment due to water chemistry. These issues can lead to the requirement for regular well rehabilitation such as mechanical cleaning, use of inhibitors or casing replacement. In the worst case, damage to wells due to chemical attack from water could lead to irreversible damage. The water chemistry may be quite different for some EGS plants.

8.5 Constraints

8.5.1 Supply Chain

Broadly speaking, there are few supply chain constraints as far as geothermal power generation is concerned, because the technology is of sufficiently high cost and value that resources can be sourced from outside the UK. No doubt there would be some UK contractors and suppliers in due course but the absence of these at present is not really a constraint. Also, it is unlikely that the scale of future UK geothermal development would be such as to strain the resources of, say, the European geothermal industry. Evidence from this is summarised below:

- There are only two geothermal power projects (as distinct from geothermal heat) being implemented in the UK: Redruth and the Eden project. Both have awarded the principal contracts necessary for drilling the first borehole, and in the Redruth case at least, supplementary specialist contracts for activities such as the geological logging have also been awarded. There are no constraints from the supplier end. Ancillary services such as planning and legal services are being provided by UK firms (e.g. Arup, Evershed) which have plenty of capacity.

There is unlikely to be any significant change in the next five to ten years, although there may be a small reduction in capex/MW in the next five to ten years as the perceived risk might be lower once one project has been successfully implemented. Drilling costs should eventually reduce as the European geothermal sector becomes more mature and drilling capacity increases.

8.5.2 Planning

Planning is not expected to be a constraint to the technology. Because much of the installation is below ground, the surface intrusion is small compared with some other technologies. Drilling has been carried out for oil in sensitive locations and mitigation methods have been developed to reduce impacts to levels acceptable to planning authorities; similar techniques may be used in the drilling of geothermal wells.

8.5.3 UK Grid

The Grid is not expected to be a constraint to the technology. The likely scale of power generation from a geothermal development should justify forming a connection to the grid, even if this is some distance away initially.

8.5.4 Technical

As far as the affects of growing experience of geothermal project implementation in this country are concerned, some of the home-grown expertise is close to retirement age. (These are the individuals who were involved with the Rosemanowes HDR project in the 1980s.) However, the industry is a global one and a lack of expertise in the UK is not a constraint. Specifically:

- UK know-how is scant. The technology is reasonably well established in other countries but few UK companies or individuals have real experience.
- Development of the technology is being driven globally.
- Drilling rather than manufacture is the major cost item. To some extent the costs of drilling are site-specific, depending on the local geology. It is possible that familiarity with drilling conditions at a couple of locations in Cornwall may reduce the cost of drilling for subsequent projects – perhaps by 20% – but this would not be automatically transferable to other regions in the UK with geothermal potential. UK service providers and contractors certainly ought to respond, if a UK geothermal sector becomes established. Whether this would increase efficiency is hard to say.

It is tempting to think that the development of a UK geothermal industry might follow a similar path of rapid and significant technological advance as that of the UK's North Sea oil industry but there are important differences which mean that would probably not be the case. The North Sea was the deepest and most difficult offshore environment for oil and gas exploration thus far. There was no global ready-made know-how available at the start of North Sea development which could be procured and imported. Also, the size of the resource was so large that huge investments could be justified.

Even so, exploration for gas in the southern North Sea was slow in the 1970s compared with the Netherlands, for example, because the price of gas in the UK was relatively low. The development of the North Sea oil industry slowed significantly in the early 1980s because of an unfavourable taxation regime at that time.

8.5.5 Other Constraints

As noted above, the development of geothermal power generation can take place only where suitable geological conditions occur and such locations are quite scarce. The main resource locations are within the deep geological basins of Mesozoic age in various locations across the UK and the Palaeozoic Midland Valley in Scotland and associated with granite batholiths, which are present in Cornwall, Scotland, the Lake District and Weardale and in the Northern Ireland basins. What is not yet clear is what level of density of exploitation might be feasible in areas which have the necessary geological characteristics.

Also, not all geothermally favourable areas coincide with population centres. Although power can be distributed from generating stations in remote locations, geothermal developments will be large producers of heat – and the commercial viability of the scheme will require this heat to provide revenue – which requires a market locally for space heating. In rural areas where there is little demand for space heating for buildings, the solution might be to develop heating for business parks or green housing – as is being done in Croatia, for example.

8.6 Maximum Build Rate Scenarios

8.6.1 Low Scenario

This level of ambition is based upon limited success of demonstration geothermal electricity generation in the UK with one of the three currently planned schemes in operation by 2015. Interest is limited and constrained by lack of clear regulation. Investment profile remains unappealing due to high construction costs and geological/drilling risk and also a limited market for heat. It assumes that following 2015, a successful geothermal plant with an electricity output of 5MW becomes operational approximately every five years.

8.6.2 Medium Scenario

This level of ambition is also based upon successful demonstrations of geothermal electricity generation in the UK with one of the three currently planned schemes in operation by 2015. Interest in geothermal electricity generation is then focused on the optimum resources and sites, mostly in Cornwall. Concentration on sites similar to others already proven reduces risk and improves investment profile. It assumes that following 2015 a successful geothermal plant with an electricity output of 10MW becomes operational approximately every year on average (2019 onwards).

8.6.3 High Scenario

This level of ambition is also based upon successful demonstration of geothermal electricity generation in the UK with two of the three currently planned schemes in operation by 2015. Interest in geothermal electricity generation is expanded to include some areas other than Cornwall. It assumes that following 2015 a successful geothermal plant with an electricity output of 15MW becomes operational approximately every year from 2015 to 2019 and two to three every year from 2019 onwards. A strong market for heat has developed.

8.6.4 Maximum Build Rate Plots

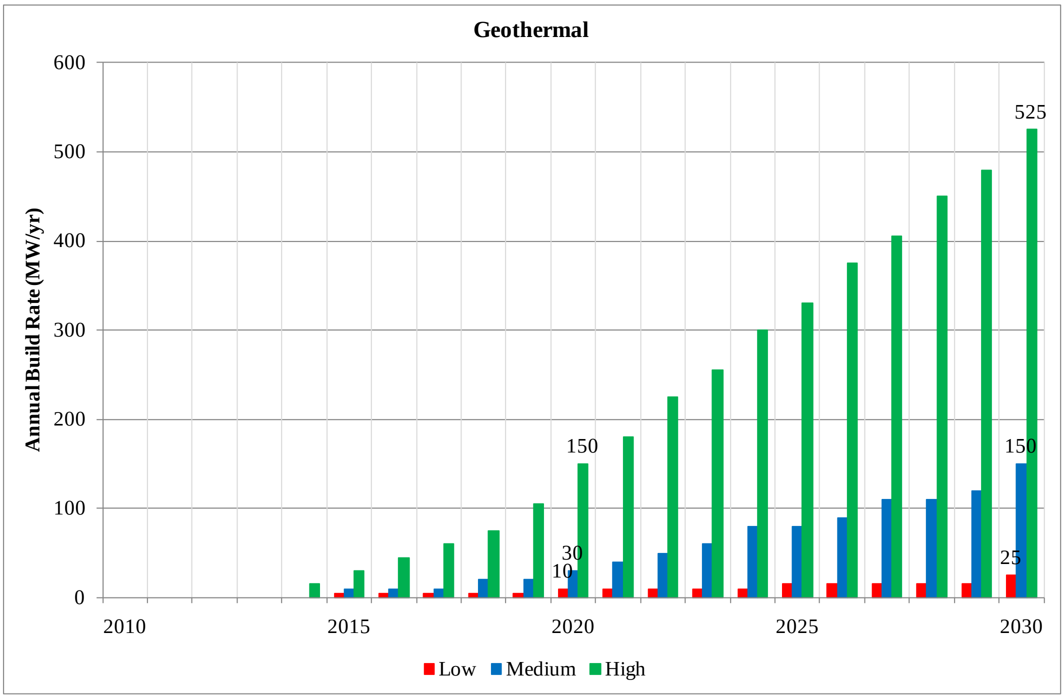


Figure 51: UK Geothermal Annual Build Rate (MW/yr)

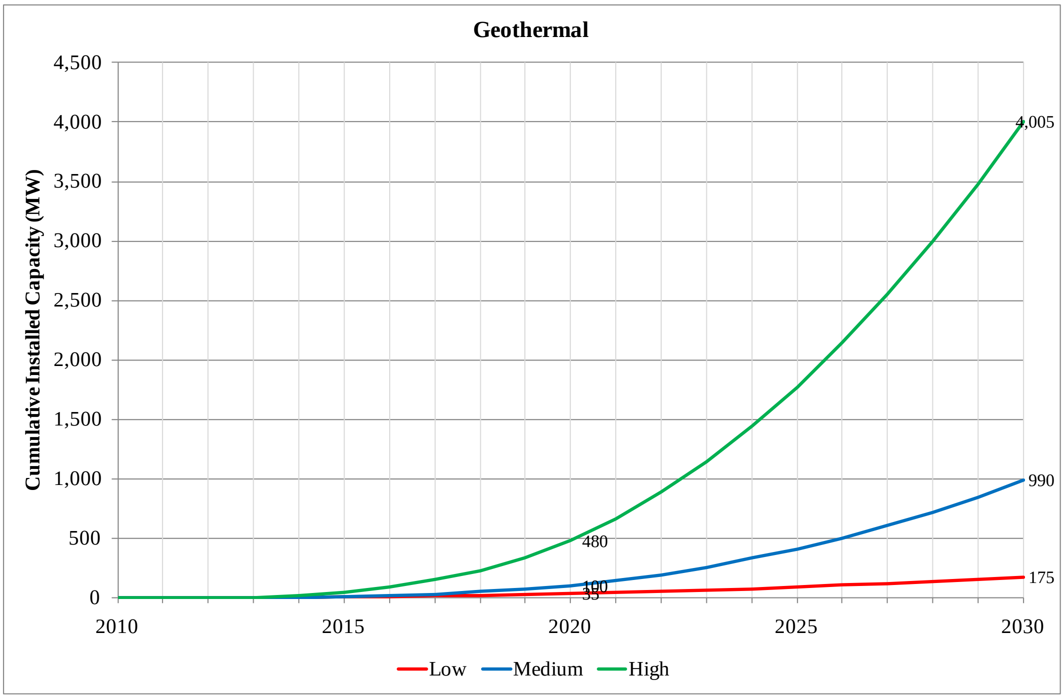


Figure 52: UK Geothermal Cumulative Installed Capacity (MW)

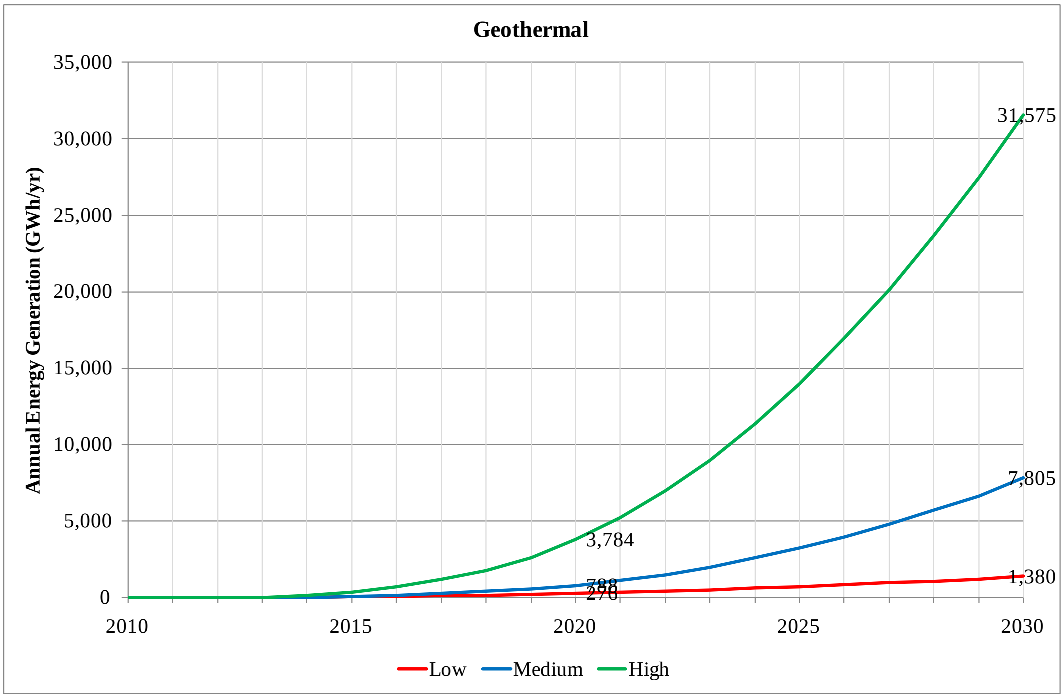


Figure 53: UK Geothermal Annual Energy Generation (GWh/yr)

8.7 Beyond 2030

Factors that might affect growth rates beyond 2030 include:

- Major changes in trading patterns e.g. replacement of current imports of foodstuffs/flowers with home grown products produced in geothermally heated greenhouses; and

- The development of cost effective drilling technology for drilling in places or at depths where geothermal energy could be produced (we consider this to be an outside possibility).

8.8 Project Cost

8.8.1 Approach and Key Assumptions

The information collected on the costs for deep geothermal projects is based on stakeholder consultations with four developers active in the UK. It relates to two types of geothermal projects, hydro-geothermal and enhanced geothermal systems.

Geothermal plants are practically available on a continuous basis, with minimal planned and unplanned downtime. Typical availability factors (net) are up to 98%. Investors assumed post tax nominal hurdle rates for geothermal projects in the UK in the range of 15-25%.

8.8.2 Capital Expenditure

Project pre-development costs vary from £45,000 to £286,000/MW. Site selection, feasibility and planning costs make up the majority of pre-development costs. Pre-development costs vary significantly depending on the availability of geological data in a target area.

The main capital expenditure items for geothermal projects are borehole testing and drilling costs, well stimulation and geothermal pump costs, civils and plant construction and grid connection costs. Drilling costs include a level of contingencies that vary with geological certainty of a site. Capital expenditure varies mainly in relation to the following drivers:

- Cost ranges reflect economies of scale at larger installed capacities. Plant capacity can vary widely dependent on site specific geological conditions and flow rates.
- Drilling costs can vary depending on drilling knowledge of the surface and geological site conditions.
- Grid connection costs vary widely between project sites and depend on the distance to the grid and availability of capacity at the substation.

Table 28 below presents capital cost ranges for projects currently under development. The capacity ranges are for sites of 3.5MW to 10MW of installed capacity.

Table 28: Geothermal – capital costs (financial close 2010)

£'000/MW	< 10 MW
High	7,848
Median	5,571
Low	3,100

Table 29 below gives an indication of how capital costs are broken down for an average deep geothermal plant.

Table 29: Geothermal – capital cost breakdown

Capital cost item	%
Drilling cost	60-70%
Plant and other construction cost	24-34%
Grid Connection	4%
Other Infrastructure	2%

The majority of capital costs relate to drilling costs and the surface plant.

The cost of labour, rig mobilisation costs (commodity prices and local supply chain) and exchange rates are considered to be the main cost drivers of future capital expenditure. The following key drivers are expected to impact on future capital expenditure for geothermal projects:

- A significant reduction in contingencies for drilling costs is expected once multiple wells are developed in a given area and the industry becomes more established. This may also be facilitated by the emergence of exploration insurance or similar guarantee mechanisms that already exist in more established markets like Germany. Overall it is expected that drilling costs could reduce by up to a third through such convoy effects.
- Rig costs are partly driven by commodity prices. Rig mobilisation costs are expected to decrease once the industry develops and UK-based drilling contractors enter the local market.
- Some advances in drilling technology could lead to further learning effects medium- to long-term.

Table 30 below presents the range of capital costs in 2010 and how they are expected to change over time. Convoy effects are expected to reduce costs by 2015 if sufficient deployment takes place and a local industry is established.

Table 30: Geothermal – capital cost projections at financial close dates (real)

£'000/MW	2010	2015	2020	2025	2030
High	7,848	5,103	5,040	4,940	4,848
Median	5,571	3,622	3,578	3,521	3,441
Low	3,100	2,016	1,991	1,959	1,915

8.8.3 Operating cost

Operating costs include plant O&M and annual well clean-out procedures. The expected operating cost range shows a small variability, depending on site conditions and the surface plant's O&M regime.

Table 31: Geothermal – operating costs (financial close 2010)

£'000/MW	<10MW
High	255
Median	190
Low	142

Operating costs are expected to rise slightly in real terms, with labour cost for plant O&M the main cost driver. Overall, the operation of the pumping system and plant is standardised and well established, so no learning effects are expected. Table 32 gives the projected operating costs until 2030.

Table 32: Geothermal – operating costs projections at financial close dates (real)

£'000 / MW	2010	2015	2020	2025	2030
High	255	259	262	266	270
Median	190	193	195	198	201
Low	142	144	146	148	150

8.8.4 Levelised costs

Using the Arup and E&Y capital and operating cost profiles[39] for geothermal

[39]. To note that the levelised costs are based on a separate set of capital and operating costs provided by Arup and E&Y that assume constant steel prices over time; capex includes infrastructure costs are incurred in the core facility, but do not include 'other' infrastructure costs that relate to costs incurred outside the site, such as water, roads, waste disposal and land costs. Levelised costs use different size categories for some technologies.

plants, DECC has calculated levelised costs of a reference plant at financial close in 2010, 2015, 2020, 2025 and 2030. The levelised cost ranges are based on Arup's low, medium and high capital cost estimates. The levelised costs have been calculated by assuming a pre-tax real hurdle rate of 22.7% going down to 12.7% by 2030, based on Arup stakeholder information and DECC assumptions on the hurdle rate profile over time. The assumed load factor is 91% and the plant lifetime is 25 years.

£ / MWh		**2010**	**2015**	**2020**	**2025**	**2030**
Geothermal	low	132	105	77	76	63
	medium	242	190	133	130	103
	high	341	268	184	180	139

Note: Dates refer to financial close.

8.9 Regions

A summary of likely regional distribution is given below:

- Current development of geothermal in the UK appears to be concentrating on granites. If this trend continues, then much future geothermal technology will be located within the granites of Cornwall, north of England, Northern Ireland and Scotland.
- There is limited geothermal potential in Wales. There are low enthalpy geothermal resources in the Bally Castle Basin of Northern Ireland and Palaeozoic Midland Valley in Scotland.

9 Solar PV

9.1 Summary

Electricity production through PV has been considered. The estimated installed capacity in 2009 is about 65MW.

For the low build scenario the installed capacity will reach 13,809MW of installed capacity by 2030.

For the medium build scenario, the maximum generation capacity is forecast to be 16,564MW by 2030.

For the high build scenario the maximum generation capacity is forecast to be 19,262MW by 2030.

9.2 Introduction

Photovoltaic (PV) is a method of converting solar irradiation into electricity using semiconductors. There are five families of materials used in PV panels, these include: monocrystalline silicon; polycrystalline silicon; amorphous silicon; cadmium telluride; and copper indium selenide.

In 2009 the UK had installed PV with a capacity of 65MW of PV capacity. The first large-scale commercial PV plant (>5MW) is yet to be built in the UK. However, over the last two years, there has been a significant increase in planning consents for PV plants, mainly located in the South West of England. Over 20 sites are currently at the planning and development stage in Cornwall. Large-scale plants are mainly located in Germany, Spain, Italy and the USA.

This study of PV has focussed on collating data from existing sources and research on installations in the UK. To develop high, medium and low scenarios historic data on German PV roll-out has been collated to develop growth curves for future build rates.

It should be noted that all forecast produced in this report are not financially constrained. There is no consideration of current or future financial support mechanisms.

9.3 Literature Review

In the UK there is a limited body of research to explore the delivery of PV. This is probably due to the commercial uncertainties surrounding PV farm development in the UK. Initial findings include:

Between 1996 and 2009 UK PV deployment has been growing at an average annual rate of 38% per annum (installed capacity of 0.4MW in 1996; 65MW in 2009).

Over the last ten years German PV developers have reached a cumulative installed capacity of 8,000MW. The rapid increase in deployment can be in part attributed to decreasing capital costs and government support for this sector.

For the analysis a historic PV growth curve for Germany has been adapted and applied to base UK PV deployment figures.

9.4 Limitations & Assumptions

9.4.1 Limitations

Limitations of the study included:

- A lack of available data from PV developers broken down by size of installation;
- Lack of studies into PV development growth in the UK; and
- All data post 2010 is a forecast based solely on growth data from Germany.

9.4.2 Assumptions

It has been assumed that the UK can recreate recent German PV growth rates to form our medium growth scenario. To reflect the uncertainty surrounding future planning and supply chain constraints, low and high scenarios have been developed to be -1% and +1% above the medium scenario. All new installations are assumed to have a specific yield factor equal to 950MWh per MW.

9.5 Constraints

9.5.1 Supply Chain

Due to high demand for PV components there are currently constraints on manufacturing supply. High prices will continue until investment in new production capacity is met. For example, in 2009 due to high demand from German PV developers, there was a worldwide shortage of inverters.

9.5.2 Planning

Most suitable sites for PV deployment are located in South West England where solar irradiation is at its peak. In the future there could be a shortage of suitable sites for deployment over available land. Due to the less intrusive design of PV, the planning system does look favourably upon site development.

9.5.3 UK Grid

One of the main challenges PV developers face is the cost of procuring a grid connection. Although the South West is the best place to locate a PV farm, it is mainly rural. This could potentially create issues for network availability and project cost.

9.5.4 Technical

Engineering innovation is still required to lower the cost of PV. Costs are expected to fall over time, which will allow further deployment of PV on a commercial scale.

9.5.5 Other Constraints

If worldwide support for the delivery of PV continues, there will be constraints on the supply of components, electronics and inverters. If PV is to be delivered on a significant scale, strong policies will need to be in place to provide developers and investors with confidence.

9.6 Maximum Build Rate Scenarios

9.6.1 Available Resource

Under an assumption of no financial constraint, the maximum PV capacity installed is estimated to be 19GW by 2030. The forecast implicitly assumes that a large number of sites are available in the South West of England.

9.6.2 PV Scenarios

For the analysis we have used historic German growth curves and applied these to the PV deployment rates going forward. This has formed the basis of our medium growth scenario, the high and low scenarios represent +1% and -1% around this forecast.

9.6.3 Maximum Build Rate Plots

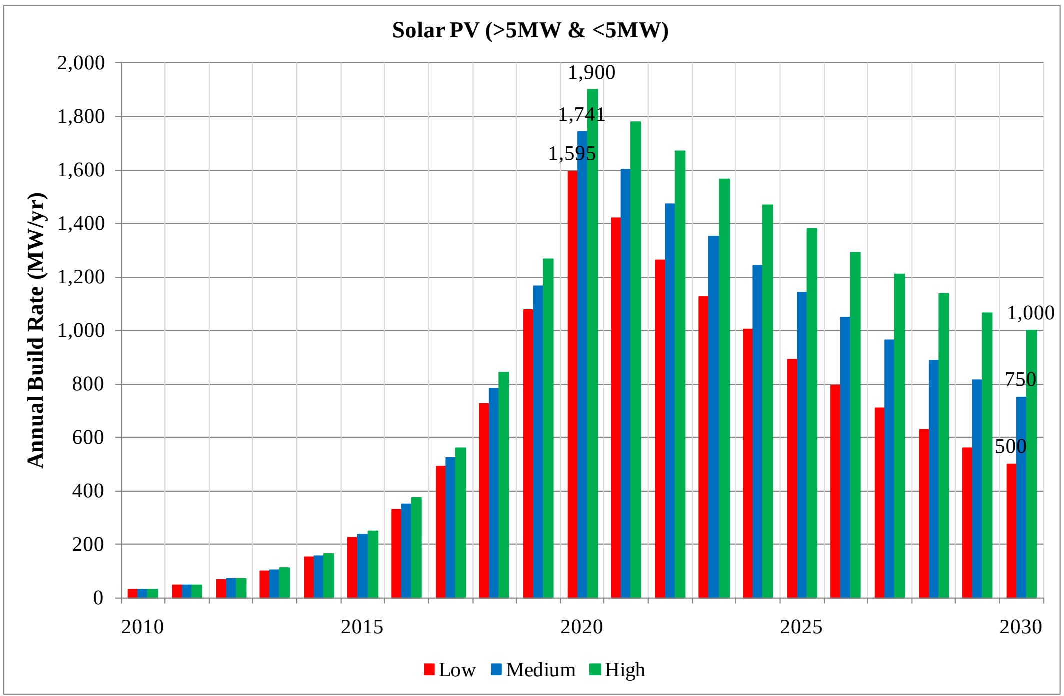


Figure 54: UK PV Annual Build Rate >5MW & <5MW (MW/yr)

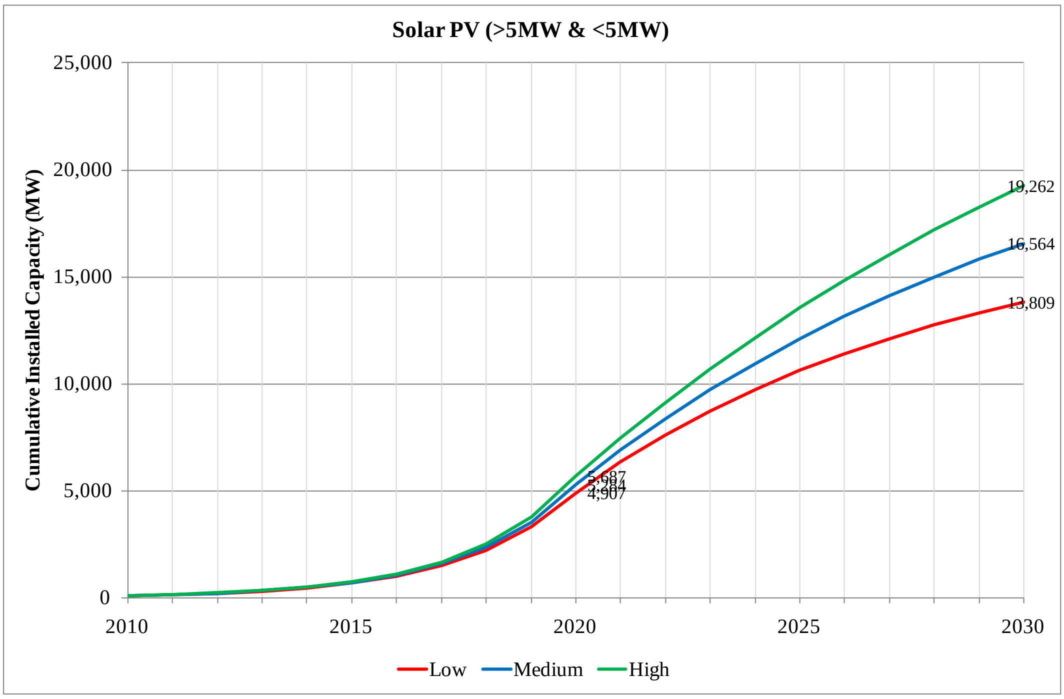


Figure 55: UK PV Cumulative Installed Capacity >5MW & <5MW (MW)

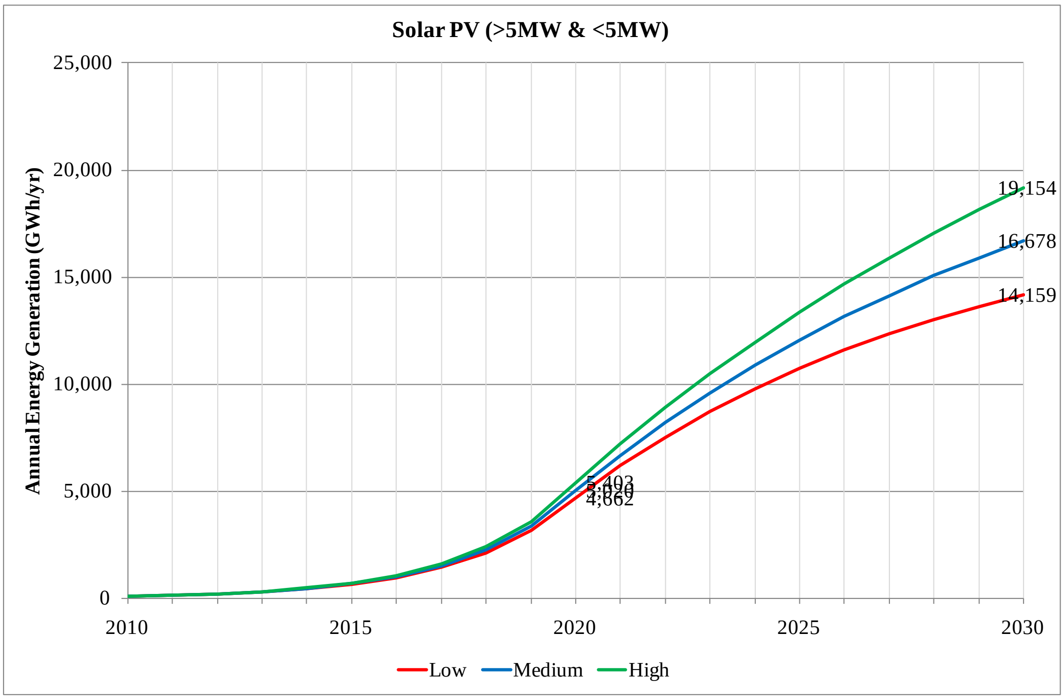


Figure 56: UK PV Annual Energy Generation >5MW & <5MW (GWh/yr)

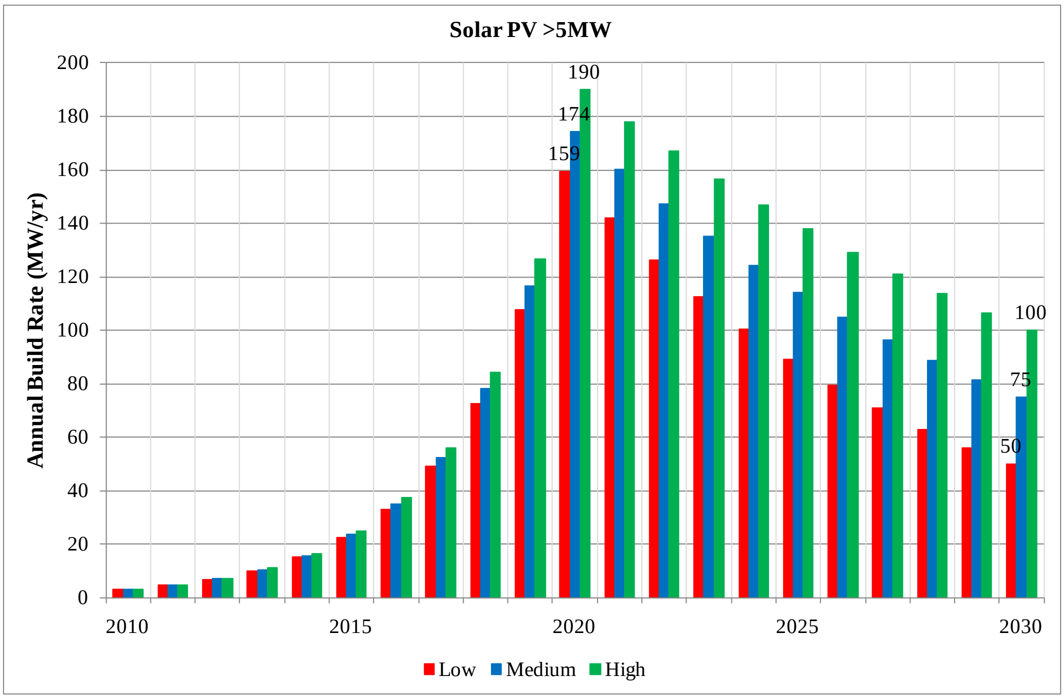


Figure 57: UK PV Annual Build Rate >5MW (MW/yr)

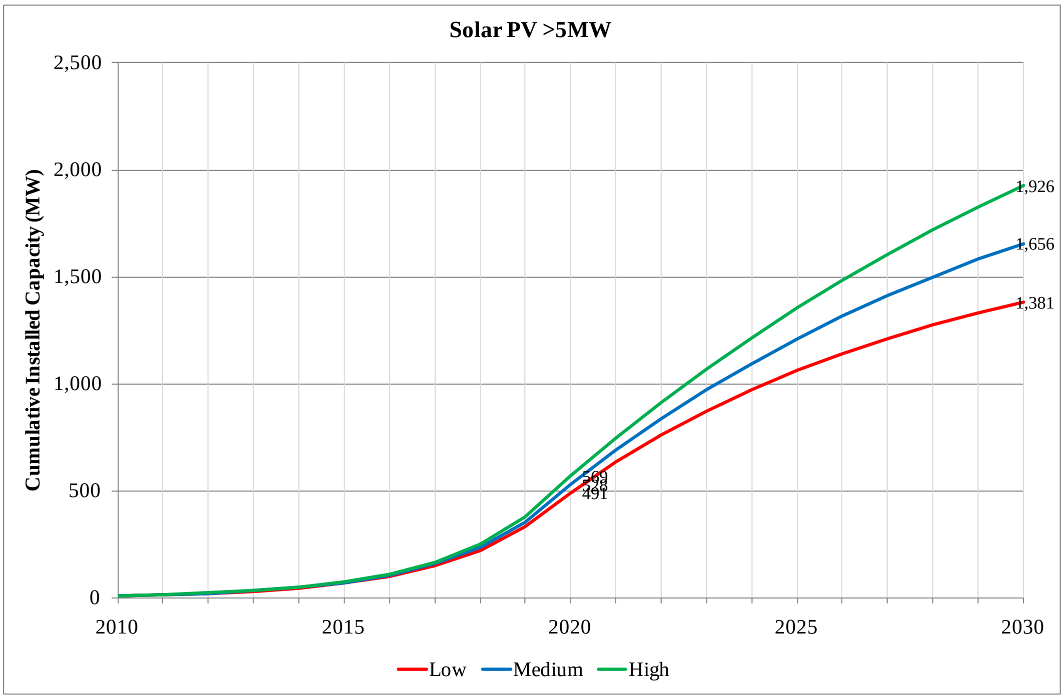


Figure 58: UK PV Cumulative Installed Capacity >5MW (MW)

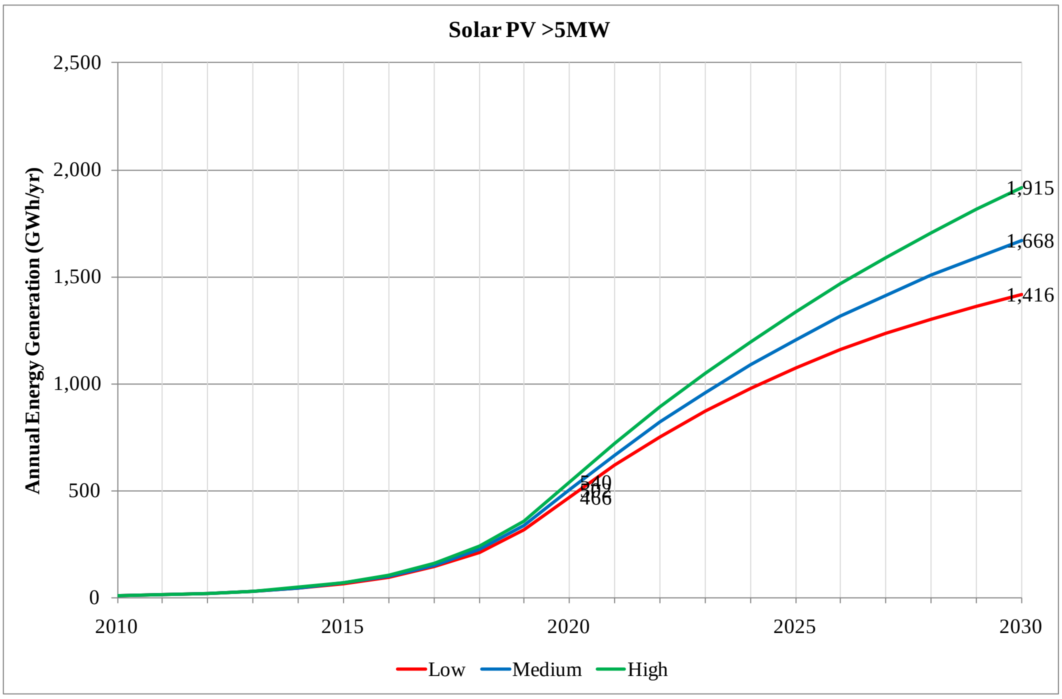


Figure 59: UK PV Annual Energy Generation >5MW (GWh/yr)

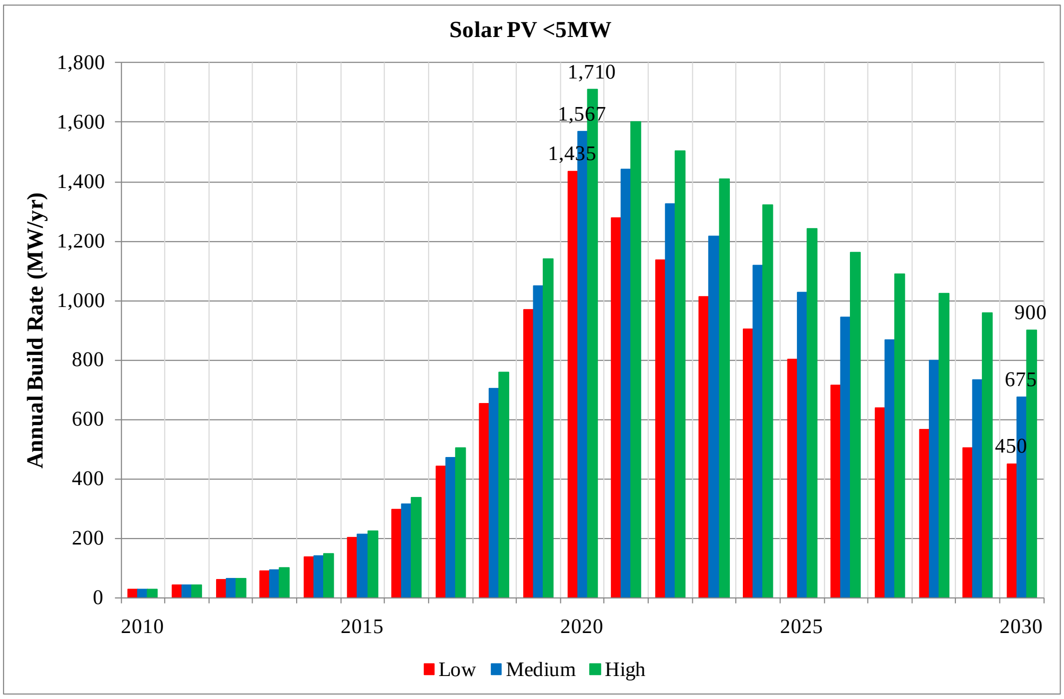


Figure 60: UK PV Annual Build Rate <5MW (MW/yr)

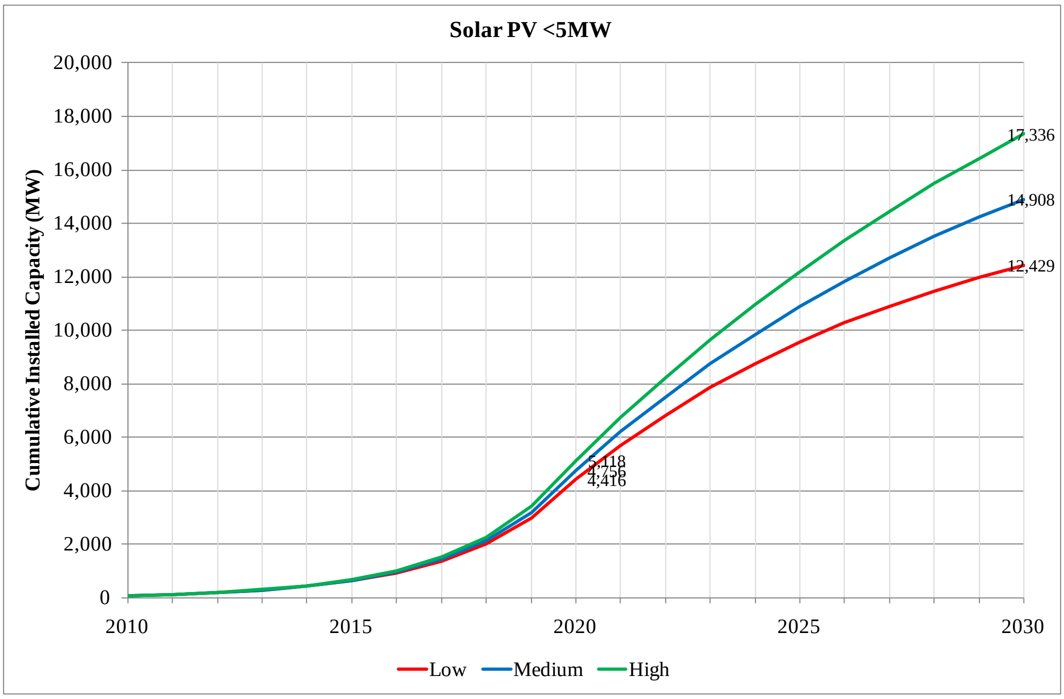


Figure 61: UK PV Cumulative Installed Capacity <5MW (MW)

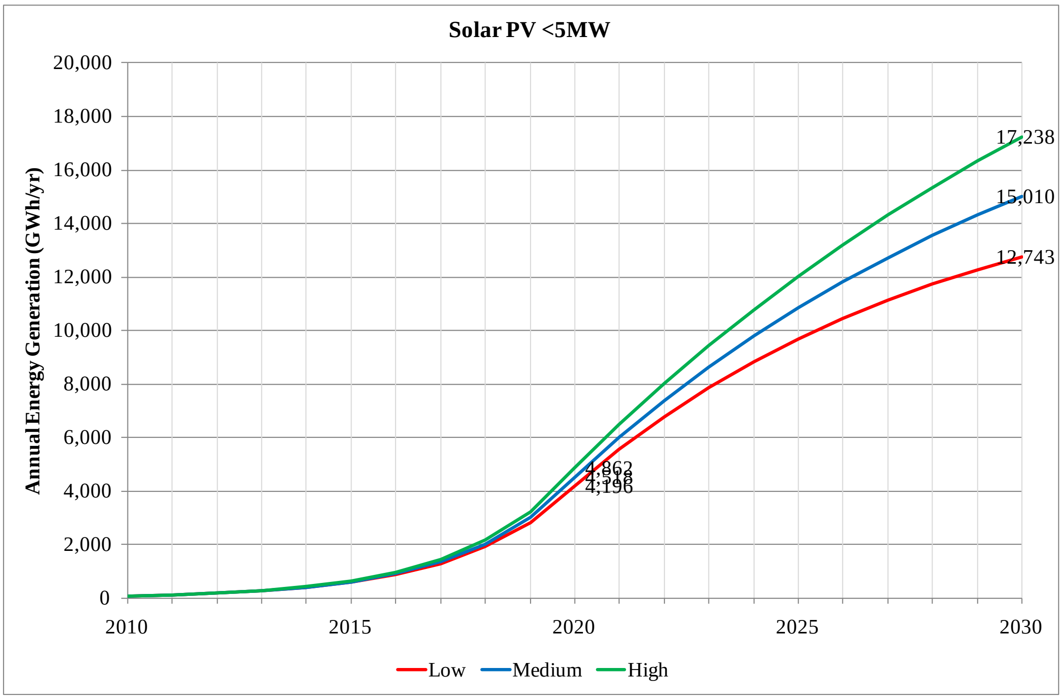


Figure 62: UK PV Annual Energy Generation <5MW (GWh/yr)

9.7 Beyond 2030

It is assumed that the UK can recreate similar growth rates to Germany over the next 20 years. Beyond 2030 annual growth is expected to level off.

9.8 Project Cost

9.8.1 Approach and Key Assumptions

DECC requested that current cost data should be collected for solar power for the following ranges:

<50kW

50kW – 5MW

5MW – 10MW

>10MW

A review of the variation in the collected data suggested that there were two clear size categories as regards units (above and below 50 kW), and the data has therefore been presented on this basis. This is primarily due to a lack of UK specific data at the larger scales, given that no projects of this size have been developed domestically.

The data collected include a variety of solar project types spanning domestic rooftop, portfolios of domestic rooftop, commercial rooftop and ground-mounted, and covers both crystalline and thin film solar PV.

Data for solar PV costs has been collected from publicly available industry reports and questionnaire responses from a number of manufacturers and project developers. Given that the solar industry is not well established in the UK, the sample size of data is small in comparison to mature technologies such as onshore wind.

Stakeholders indicated that solar schemes in the UK have post-tax, nominal project hurdle rates in the region of 7.5-9%. Typically it was assumed that the equipment would be operational for 25 years, although some stakeholders state that they expect the life of the solar panels to exceed this.

9.8.2 Capital Expenditure

Module costs, inverters and mounting systems are the most significant elements of capital expenditure. Grid connection, where applicable, makes up the majority of the remaining costs.

Pre-development costs for projects greater than 50kW varied between £14,000/MW and £27,000/MW, with a median cost of £20,000/MW. These costs include pre-licensing, planning (for ground mounted solar) and site surveys. The variation in costs is due to the specifics of the project and the selected site, with planning issues typically causing higher pre-development costs. At the <50kW scale prices per MW are significantly higher, predominantly due to the smaller scale of the installations. The costs are approximately £500 for a typical 2.5kW domestic rooftop solar installation.

The capital costs of solar PV at the <50 kW scale vary between £2.7m/MW and £5.1m/MW, with a median of £3.3m/MW. The characteristics of specific projects at the micro-scale can have a sizeable impact on costs. The type of technology used is a major cause of the price variation; thin film PV is cheaper than the more efficient crystalline technologies.

The price per MW for installing a single domestic rooftop solar PV system is larger than the cost of installing larger units on commercial rooftops, or a widespread roll out across numerous domestic houses. On average 97% of capital costs at this scale are construction and installation costs, of which a large percentage is due to the price of the modules and inverters. Developers of larger projects are therefore better positioned to negotiate with equipment suppliers and achieve lower costs per unit.

These economies of scale are also represented in the difference between costs at the <50 kW and >50 kW ranges. Costs for the >50kW category ranges from £1.9m/MW to £3.7m/MW, with a median price of £2.7m/MW. For this scale, prices again differ on technology type and site characteristics. The >50kW range incorporates both industrial scale roof mounted and ground mounted projects which entail different costs.

Whilst unable to collect data for UK projects of a greater scale than 5MW, it is expected that prices would not vary significantly from the >50kW range due to the modular nature of solar PV and the equipment-heavy nature of capital expenditure. This is broadly in line with recent costings for 5-20MW projects in Germany, Spain and Italy.

Table 33: Solar – capital costs (financial close 2010)

£'000/MW	<50kW	50kW>
High	5,080	3,736
Median	3,339	2,710
Low	2,732	1,873

Figure 63: Solar – capital costs (financial close 2010)

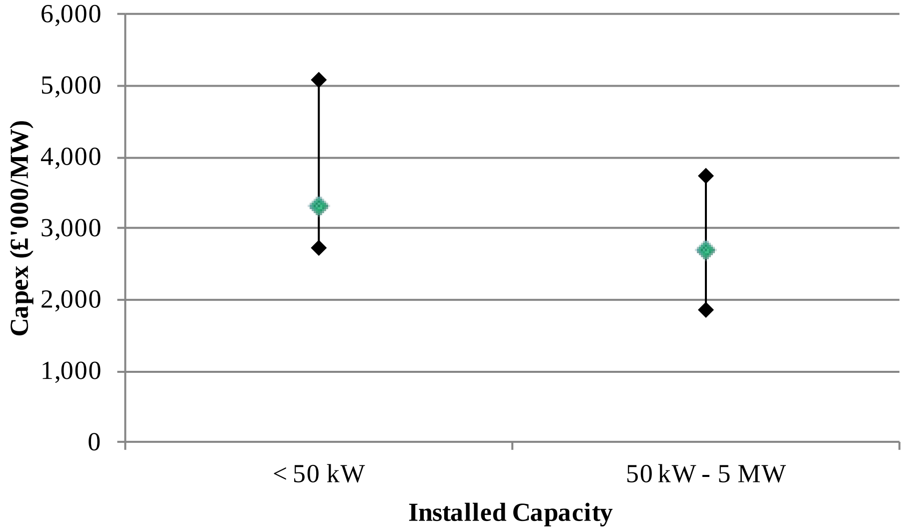


Table 34: Solar – capital cost breakdown*

Capital cost item	%
Pre-development	6%
Construction	92%
Grid costs	2%
Other	0% **

* The breakdown provided is not applicable for micro-scale solar
** Other costs for solar PV are typically covered in the EPC contract

Stakeholders considered the key cost drivers to be module costs, labour rates and exchange rates. It is expected that module costs will largely be impacted the rate of industry as below. DECC asked that the cost projection not include exclude any appreciation or depreciation of sterling due to the uncertainty of such movements.

Industry learning is the primary cause of the decline in prices forecast over the next 20 years. IEA's learning rate of 17% was applied to the Blue Map global deployment prediction, which anticipates an increase in capacity from 43GW to 794GW between 2010 and 2030. Global deployment rates have been used for industry learning effects to reflect the global supply chain.

It is anticipated that labour costs would increase at a rate of 0.1% per annum, which is a minor counter to the decrease in costs from learning.

The most significant decline in costs is forecast to happen between 2010 and 2020 as global deployment rapidly scales up. During this period, costs are anticipated to fall by 37%, compared with an overall 51% decline in capital expenditure expected by 2030.

Table 35: Solar – capital cost projections at financial close (real) (<50kW)

Capital cost (£000s/MW)	2010	2015	2020	2025	2030
High	5,080	4,027	3,218	2,759	2,487
Median	3,339	2,647	2,115	1,814	1,634
Low	2,732	2,166	1,731	1,484	1,337

Table 36: Solar – capital cost projections at financial close dates (real) (50kW>)

Capital cost (£000s/MW)	2010	2015	2020	2025	2030
High	3,736	2,961	2,367	2,029	1,829
Median	2,710	2,148	1,717	1,472	1,326
Low	1,873	1,485	1,187	1,017	0,917

9.8.3 Operating Costs

Operating costs for solar PV include operating labour costs, maintenance, inverter replacement, land rental, insurance and grid charges where applicable.

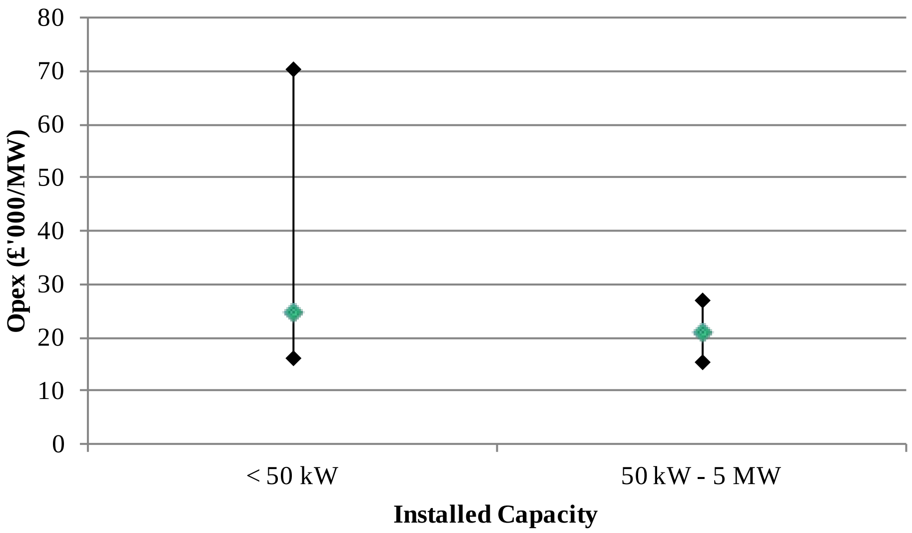
For micro-scale solar projects (<50kW), there is a significant variation in operating expenditure, ranging from £17,000/MW/year to £71,000/MW/year, with a median of £25,000/MW/year. This sizeable range suggests that there is uncertainty over operating expenditure for micro-scale projects in the UK as the domestic market develops. This study highlighted the differing views of developers and previous studies, with the median operating cost quoted by developers of £58,000/MW/year.

Larger solar PV projects (>50kW) have a narrower range of O&M costs with annual fees of between £16,000/MW/year and £27,000/MW/year, and a median of £21,000/MW/year. The variation in costs is thought to be due to the specifics of the project, with O&M fees being lower, on a per MW basis, for large-scale ground mounted solar installations than for geographically dispersed roof mounted installations. Given the lack of operational large-scale solar projects in the UK, the costs provided by stakeholders are based on European averages and liable to change.

Table 37: Solar – operating cost projections (financial close 2010)

£'000/MW	<50kW	50kW>
High	70.7	27.3
Median	24.8	21.1
Low	16.5	15.8

Figure 64: Solar – operating cost (financial close 2010)



Stakeholders identified labour costs as being the key future cost driver of operating expenditure. Labour costs in the manufacturing industry are expected to increase by 0.1% per annum; however as they are only a small portion of the total operating expenditure, projections appear flat between 2010 and 2030. Industry learning has not been included in the cost projections but could potentially occur through the emergence of remote monitoring and other O&M developments. The provision of manufacturer warranties for solar panels means that the future cost of spare parts is not expected to substantially impact on overall operating costs.

Table 38: Solar - operating cost projections at financial close dates (real) (<50kW)

Operating cost / MW per year (£000)	2010	2015	2020	2025	2030
High	71	71	71	71	71
Median	25	25	25	25	25
Low	17	17	17	17	17

Table 39: Solar – operating cost projections at financial close dates (real) (50 kW >)

Operating cost / MW per year (£000)	2010	2015	2020	2025	2030
High	27	27	27	27	27
Median	21	21	21	21	21
Low	16	16	16	16	16

9.8.4 Levelised costs

Using the Arup and E&Y capital and operating cost profiles[40] for solar PV installations greater than 50kW, DECC has calculated levelised costs of a reference installation at financial close in 2010, 2015, 2020, 2025 and 2030. The levelised cost ranges are based on Arup's low, medium and high capital cost estimates. The levelised costs have been calculated by assuming a pre-tax real hurdle rate of 7.5%, based on the Oxera report[41] for the CCC. The levelised costs assume a load factor of 11% and a installation lifetime of 25 years.

[40]. To note that the levelised costs are based on a separate set of capital and operating costs provided by Arup and E&Y that assume constant steel prices over time; capex includes infrastructure costs are incurred in the core facility, but do not include 'other' infrastructure costs that relate to costs incurred outside the site, such as water, roads, waste disposal and land costs. Levelised costs use different size categories for some technologies.

[41] www.oxera.com/main.aspx?id=9514

£ / MWh		**2010**	**2015**	**2020**	**2025**	**2030**
Solar PV	low	202	165	136	120	111
	medium	282	228	187	164	150
	high	380	306	250	218	199

Note: Dates refer to financial close.

9.9 Regions

The best sites for PV in the UK are concentrated in the South West of England. In Cornwall over 20 sites are currently at the planning stages of development. Met Office sunshine mapping data also indicates that the SE, Cambridgeshire and Lincolnshire could also be potential hotspots.

10 Dedicated Biomass (Solid)

10.1 Summary

New dedicated solid UK sourced biomass plants are likely to be less than 50MW in capacity and located in proximity to the available sustainable biomass and related transport infrastructure. New imported biomass plants are likely to be larger (50-300MW) and located close to the port of importation.

There is significant potential for generating electricity from sustainable solid biomass in dedicated new plants, even if significant quantities of solid biomass are used in co-firing or in converted fossil fired generating units. Because of the constraints on existing fossil fuelled generation imposed by the LCPD and IED, the potential for significant growth in new dedicated solid biomass capacity is strong after 2015 and even more so beyond 2020, although the equipment supply chain may then start to pose a limiting constraint. New dedicated biomass plants may be able to be located on sites conveniently close to significant heat loads, enhancing the possibility of adopting CHP with resultant improved energy conversion efficiency.

10.2 Introduction

The approach adopted has been to assess both the available resource and also the existing and potential users of the resource (for the generation of renewable electricity). In order to formulate generation scenarios, a starting point was the available sustainable solid biomass scenarios (essentially DECC numbers derived from AEA Technology (2011) expressed in energy terms). The AEA Technology study took account of demand for biomass from non-energy sectors in the UK in its analysis of feedstocks available for energy. This data covers both UK produced solid biomass and imported solid biomass, with both excluding biomass nominally allocated (by DECC/AEA) to transport and heat, according to projections of future heat and transport demand for solid biomass. DECC also reduced the solid biomass resource levels so as to include only sustainable sources (according to Renewables Obligation definitions). This yielded low medium and high solid biomass energy estimates out to 2030. Based on typical solid biomass fuel (heat) energy to electricity conversion efficiencies, the approximate electrical energy that could be produced from this solid biomass was then estimated. This provided a theoretical maximum annual energy production under each scenario.

Net sustainable DECC/AEA import data is based on a nominal limit that no more than 10% of the global biomass resource available for export can be acquired for UK use. Note also that it was assumed that biomass for export was based on the surplus potentially available after in-country use had been taken care of.

The technologies considered for the conversion of solid biomass into electricity in dedicated plants comprised two classes. New plants with an electrical capacity of up to 50MW were considered (similar to the existing Stephens Croft facility) to use mainly UK –sourced biomass. For new dedicated plants using mainly imported solid biomass, larger plants in the range 150-300MW, were considered.

The technology for converting solid biomass to electricity are reasonably well established. There are considerable parallels with some waste to energy technologies and there is considerable international experience with the combustion of solid biomass.

It should be noted that all forecast produced in this report are not financially constrained. There is no consideration of current or future financial support mechanisms.

10.3 Literature Review

In addition to the generic renewables literature in section 2.2, the reports by E4tech (2009) and AEA (2010) on biomass supply were considered. Various IEA Clean Coal Centre documents also provided generic background.

10.4 Limitations & Assumptions

10.4.1 Limitations

No significant limitations were identified.

10.4.2 Assumptions

Clearly the solid biomass available for electricity generation could be converted to electricity via a number of competing routes, namely co-firing stations (up to 10% biomass), enhanced co-firing (up to 50% biomass) in existing generation, conversion to 100% biomass of in existing capacity, existing dedicated biomass generation and new dedicated biomass generation.

Therefore the next stage of the analysis was to consider the potential types of facility where this solid biomass could potentially be converted to electricity. Five technology options were considered:

- Existing coal fired generation units with the ability to co-fire solid biomass;
- Existing coal fired generation units that could be converted to 100% biomass;
- Existing smaller (<50MWe) dedicated biomass generation units;
- New smaller (<50MWe) generally located inland and using UK sourced biomass transported by road; and
- New large (50-300MWe) mainly located adjacent to potential biomass import locations.

In translating biomass availability to potential new capacity, it has been assumed that larger plants, predominantly located conveniently to import facilities would be sourced with 10% UK biomass and 90% imports. However, the outturn percentage shares will differ from this, depending on the ability of individual sites to access competitive UK biomass sources. As smaller plant sizes would focus on local biomass, it has been assumed that these use UK biomass domestically sourced with no imports. This is based on the logistics of large biomass bulk transport vessels requiring a significant demand to be practically viable.

To avoid double counting and hence misrepresenting the potential, the approach adopted was to allocate the available biomass to each of these competing technologies on an economic prioritisation basis. Scenarios were developed for co-firing (see Chapter 11) and conversion (see Chapter 12). For both co-firing and conversion it has been assumed that 10% of the solid biomass will be sourced from the UK and 90% from imports.

The design life of new dedicated solid biomass was assumed to be at least 30 years. The load factor for new dedicated plants was assumed to be at least 80%.

10.4.3 Biomass Availability Assumptions

The low medium and high solid biomass availability scenarios are based on data from the report by AEA[42] to DECC which estimates the available sustainable solid biomass out to 2030. These scenarios are expressed in energy terms and include both UK produced biomass and imported biomass, with both excluding biomass nominally allocated (by DECC/AEA) to transport and heat.

The AEA report contains a summary of the main assumptions made for each UK solid biomass feedstock and any constraints. Feedstocks for clean wood fuels in the UK could be supplied from forestry residues, small round wood, sawmill residues, arboricultural arisings and short rotation forestry. Waste wood is also a significant wood resource, included by AEA in the waste feedstock results. AEA note that when considering international solid biomass, not all agricultural residues are relevant to UK because a large proportion are either too dispersed or too wet to be brought to the UK. The focus is therefore on specific residues that can be aggregated and traded internationally, particularly those that are already traded for energy or as feed components. It should be remembered that AEA warn that there is considerable uncertainty in the source data used. Production of agricultural residues varies considerably with time, depending on harvest conditions, for example the olive harvest can vary by over 30% from year to year. Therefore imported agricultural residues may be unreliable fuels on which to base energy strategies and AEA recommend adopting a flexible approach to these feedstocks. In AEA’s scenario analysis it was assumed that high investment enables investment in infrastructure for processing, storage and transport of agricultural residues for trade, however, in the low investment scenario this was not assumed. Products assumed available for bioenergy include saw log off cuts (including slab wood), small round wood and branch wood, but AEA assume that bark is not exported for energy.

The specific solid biomass energy data scenarios extracted from the AEA work and used as a starting point for Arup’s analysis is as follows:-

[42] UK and Global Bioenergy resource – Annex 1 report: details of analysis – prepared by AEA and Oxford Economics, Biomass Energy Centre and Forest Research. (Issue 2 – December 2010)

Table 40 Biomass Energy Data

TWh per year	Scenario	2010	2015	2020	2025	2030
UK Solid Biomass	Low	20.6	13.7	17.4	21.0	32.2
	Medium	44.0	23.7	26.9	32.7	59.6
	High	58.0	31.1	34.6	50.1	86.6
Import Solid Biomass	Low	23.3	17.6	40.9	106.8	254.1
	Medium	23.3	44.0	109.9	254.6	593.8
	High	23.3	59.9	169.7	422.5	1000.2

10.5 Constraints

The next phase of analysis involved a comparison of the available biomass (UK and imported treated separately) with the biomass requirement for the co-firing and converted units, plus any existing dedicated UK biomass units (Stephen's Croft etc). Where more biomass than required is available, this is assumed to be available for new dedicated biomass plants. However, before undertaking this analysis, an estimate was made of the potential constraints to new dedicated biomass plants (both smaller UK inland projects and larger port side mainly import projects). This yielded a nominal maximum commissioning rate per year, plus a cap on the total number of sites that might be developed.

10.5.1 Supply Chain

For smaller dedicated biomass plants it is estimated that the equipment supply chain would be able to service a maximum commissioning rate of approximately 100MW per year.

For larger dedicated biomass plants the supply chain may be a more critical factor. Assuming that imported dedicated biomass plants are of the order of 50-300MWe and assuming that active construction (i.e. ignoring planning and preliminary works) is approx 2-3 years per project, it is estimated that the supply chain could initially struggle to exceed ~6 projects in parallel (assuming that other smaller UK biomass plants (treated separately) are also in construction), so this would suggest a maximum annual commissioning rate of ~600MW

10.5.2 Planning

Planning aspects were included in the consideration of available sites. For inland biomass plants, transportation impacts may have more significance than other environmental concerns. This might constrain site acceptability in major conurbations and encourage peripheral development, closer to major transport routes. If so, this might limit the practicality of CHP developments, as heat demands tend to be concentrated around major conurbations.

For larger dedicated biomass plants reliant on imported biomass, prime sites would have direct access to ports that would permit unloading of bulk materials from large vessels capable of ocean voyages (e.g. Panamax). This may conflict with other land use planning at large ports.

It was further recognised that the size and location of these plants would be influenced by the proximity of sites to available UK biomass and/or the practicalities (and economics) of transporting imported biomass to potential sites.

10.5.3 UK Grid

The availability of connections to the UK Grid is not likely to pose a significant constraint to new build development, although clearly some additional investment will be required. New build on existing generation sites could benefit from existing transmission entry capacity.

10.5.4 Technical

The combustion of solid biomass is a reasonably well developed technology and so a lack of technical development or innovation is unlikely to pose a significant constraint. The technology is well established internationally.

10.5.5 Other Constraints

Regarding site availability for smaller (<50MWe) UK sourced biomass plants, ostensibly it should be possible to find inland sites for 50-60 projects in the tens of MWs (i.e. three projects per year for 20 years) so siting is not likely to pose a major constraint. This is slightly less than the number of UK counties (~70), although some counties close to larger imported biomass plants could see local biomass going to them rather than a local smaller dedicated biomass plant.

Regarding site availability for larger dedicated solid biomass plants, chiefly using imported biomass, a preliminary assessment based simply on the number of major UK ports, capable of handling larger bulk cargo vessels (and recognising that some port sites may be unsuitable, but also that other sites, not designated as ports, e.g. Tilbury PS might compensate), suggests that approximately 40 sites should be available. Based on an average size of 200MW per site this would suggest a cap of ~ 8000MW.

Note, it should be recognised that some ports will also be importing biomass for co-firing (up to ~2023) and full unit conversions to biomass.

10.6 Maximum Build Rate Scenarios

10.6.1 Available Resource

The nominal surplus of biomass in each year and the nominal capacity increase from year to year were derived for each scenario and then, recognising that unit sizes are modular, estimates of actual MW build and energy produced were made. This approach also ensured that capacity increases were never negative and that the maximum build rate and number of site limit constraints were met. This was undertaken separately for smaller inland dedicated biomass plants and the larger import dependent biomass plants.

The resulting data were then used to create plots of biomass energy per year, by different technology, capacity additions (or decreases) per year for dedicated small, dedicated large, co-fire and conversion and cumulative capacity increases (or decreases).

In order to provide a sense check of the predicted build rates before 2015, a comparison was made with data on existing and planned biomass plants from DECC RESTATS. This confirms that the potential capacity of projects currently in the planning phase is reasonably compatible with the predicted deployment of new dedicated biomass plants over the next few years.

The low medium and high solid biomass availability scenarios are based on data from the report by AEA Technology which estimates the available sustainable solid biomass out to 2030. These scenarios are expressed in energy terms and include both UK produced biomass and imported biomass, with both excluding biomass nominally allocated (by DECC/AEA) to transport and heat.

10.6.2 Low Scenario

The low scenario is based on the low solid biomass availability scenario, after the fuel needs for co-firing and possible full conversion of some existing generating units has been removed.

10.6.3 Medium Scenario

The medium scenario is based on the medium solid biomass availability scenario, after the fuel needs for co-firing and possible full conversion of some existing generating units has been removed.

10.6.4 High Scenario

The high scenario is based on the high solid biomass availability scenario, after the fuel needs for co-firing and possible full conversion of some existing generating units has been removed

10.6.5 Maximum Build Rate Plots

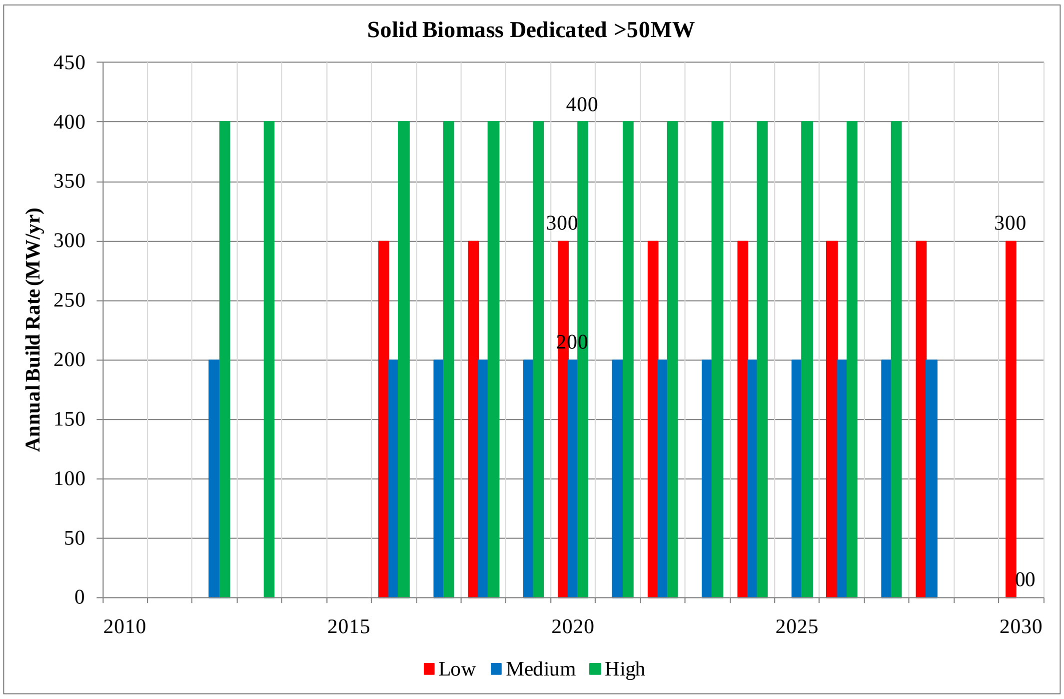


Figure 65: UK Annual Build Rate Dedicated Biomass (Solid) >50MW (MW/yr)

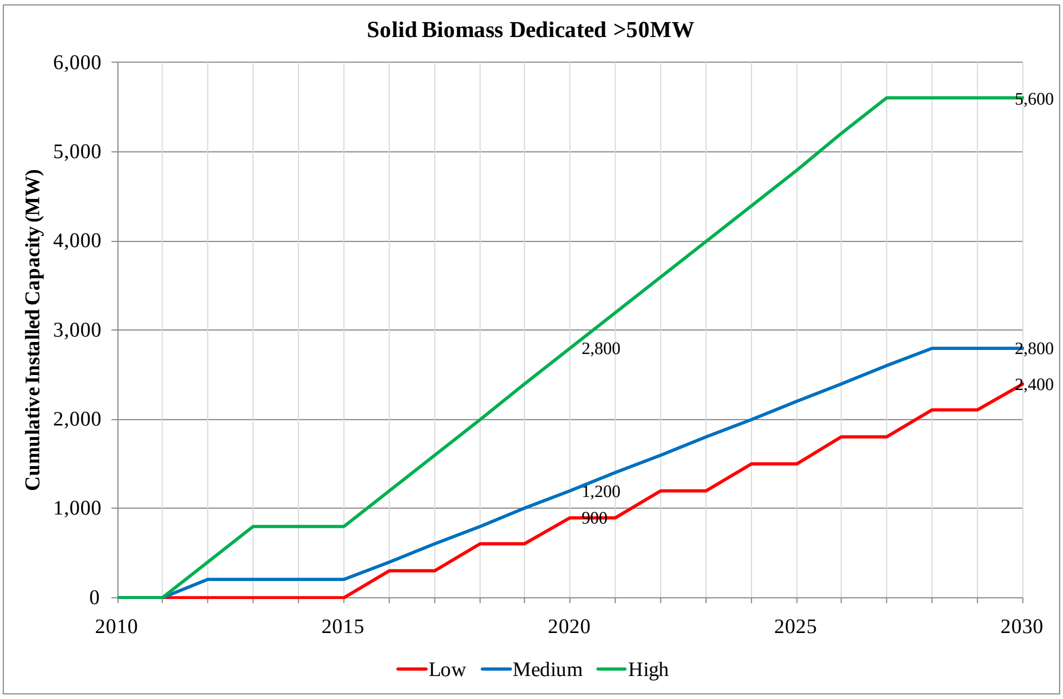


Figure 66: UK Cumulative Installed Capacity Dedicated Biomass (Solid) >50MW (MW)

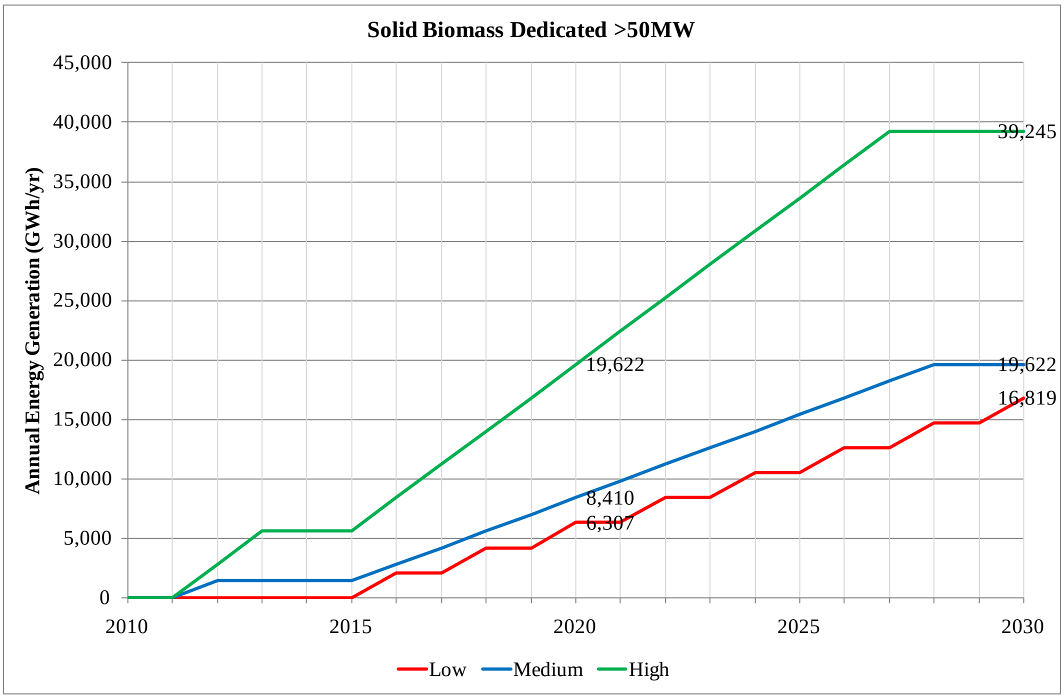


Figure 67: UK Annual Energy Generation Dedicated Biomass (Solid) >50MW (GWh/yr)

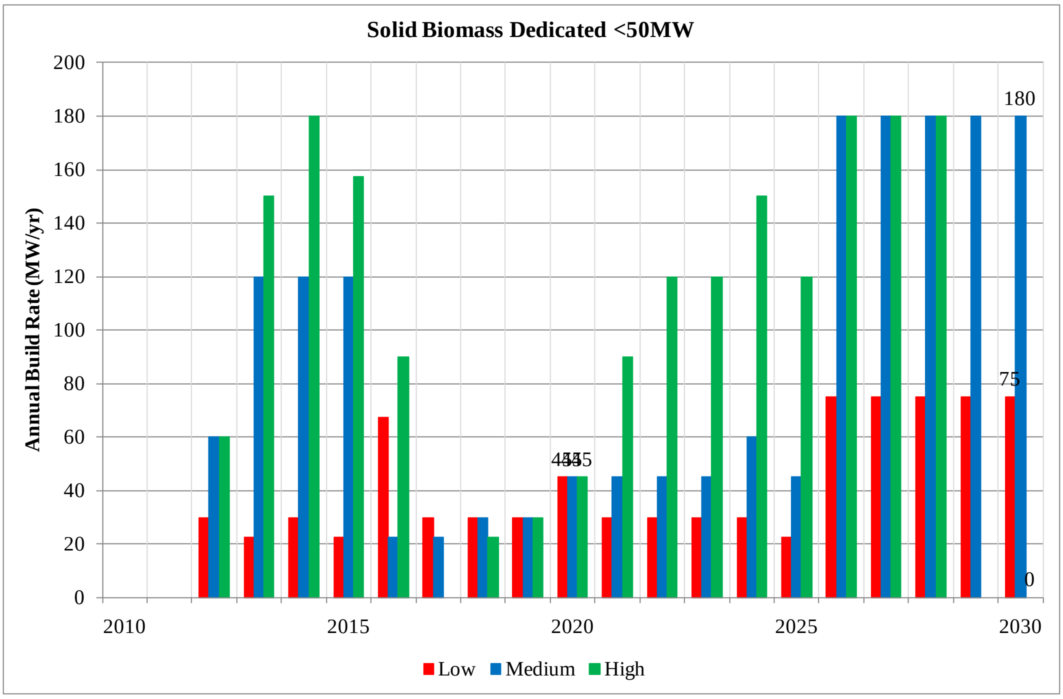


Figure 68: UK Annual Build Rate Dedicated Biomass (Solid) >50MW (MW/yr)

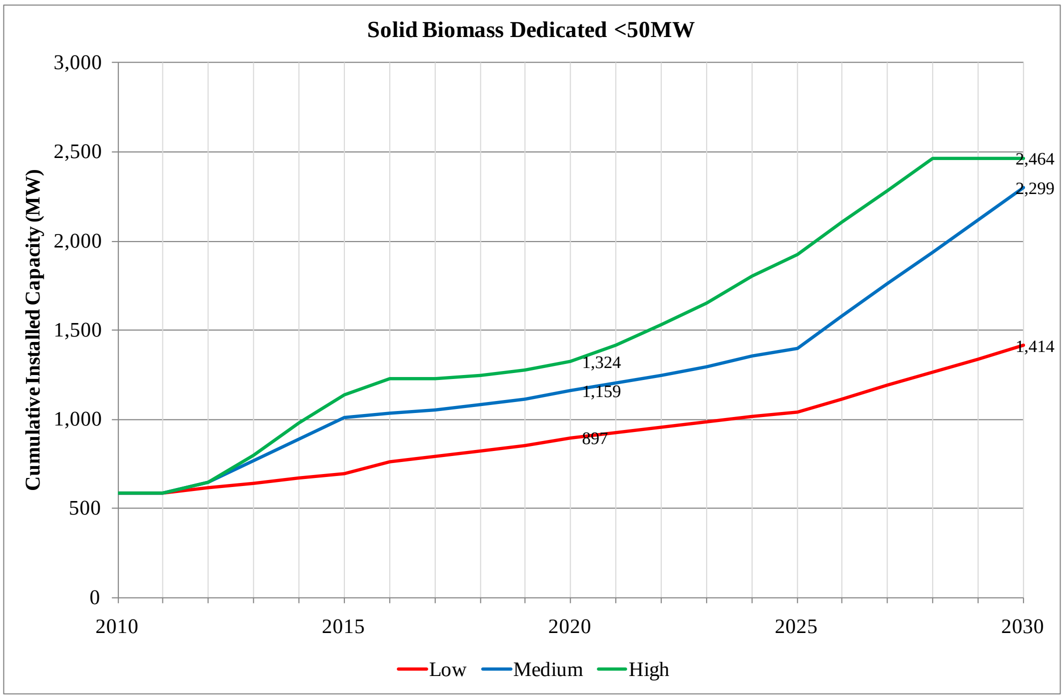


Figure 69: UK Cumulative Installed Capacity Dedicated Biomass (Solid) <50MW (MW)

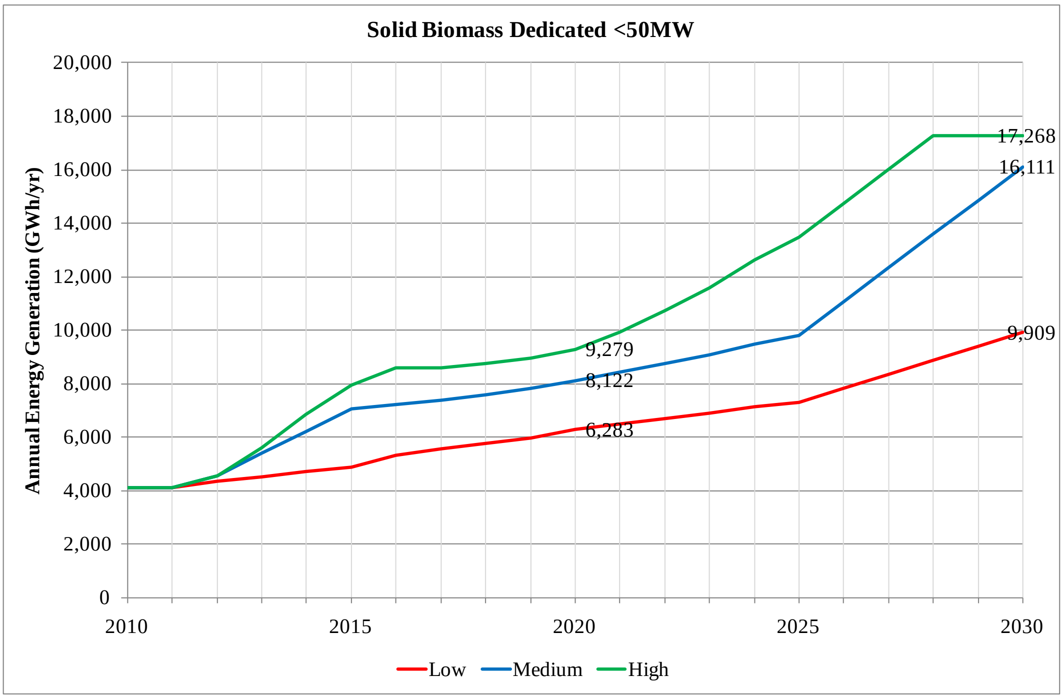


Figure 70: UK Annual Energy Generation Dedicated Biomass (Solid) <50MW (GWh/yr)

10.7 Project Cost

10.7.1 Key assumptions

DECC requested a review of the cost of biomass plants in relation to the following categories:

- < 50kW
- 50kW – 5MW
- 5MW – 50MW
- 50MW – 100MW
- 100MW +

Data has been collected from publicly available industry reports and questionnaire responses from stakeholders, mainly spanning developers and utilities.

Consultation with stakeholders suggests smaller sized plants would usually be configured as CHP or heat-only and therefore fall outside the scope of the dedicated biomass category. Therefore the sub-50kW category has been excluded from this study.

Data analysed splits largely into two categories, mainly in relation to UK sourced and globally sourced feedstock plants.

The UK sourced plants tend to be sub-50MW and have lower efficiencies (30% and below) than the larger scale plants. However this lower efficiency is countered by their ability to use a broader spectrum of feedstock which is generally non-virgin and therefore cheaper.

The globally sourced plants tend to be above 50MW and located on port-side sites. The technology used in the large scale plants requires high quality feedstock, which is typically imported at a premium. These facilities have far higher efficiencies (35% and above) which counters the additional fuel costs.

The data-set shown has therefore been split into a sub-50MW category and above 50MW category.

Overall the technology for burning biomass is relatively mature with technology mirroring that used for conventional power, with the overall expectation of an investment period of 20-25 years for the plants.

Stakeholders noted that nominal post tax project hurdle rates were in the range of 12-15%.

10.7.2 Capital Expenditure

The key cost items within biomass relate to boiler costs, turbine costs, fuel handling infrastructure, civils, grid infrastructure and civil works.

Pre-development costs for biomass vary on the success rate received by different parties. The mid-range for a sub-50MW plant is at £92,000/MW, whilst for an over-50MW plant is £27,000/MW suggesting substantial economies of scale in the permitting process.

Capital costs for a sub-50MW plant range from £2.6m/MW to £3.9m/MW with a median of £3.3m/MW. This range reflects the variations in fuel type and configuration. As with other biomass technologies the variation in capital cost often reflects a lower cost fuel/operating expenditure.

Capital costs for an above 50MW plant range from £2.3m/MW to £2.8m/MW with a median of £2.4m/MW. The smaller range reflects the more similar technologies and fuel that is being proposed for the larger plants.

The dataset suggests a strong relationship between the size of the asset and its cost per MW. This is not considered to be an effect which solely relates to the economies of scale of the plant. The lower grade fuel type normally used in the smaller plants (e.g. waste wood) also drives up cost per MW through requiring different technology solutions which are potentially more costly e.g. Waste Incineration Directive (WID) compliance, wider firing windows.

Figure 71: Dedicated Biomass – capital costs (financial close 2010)

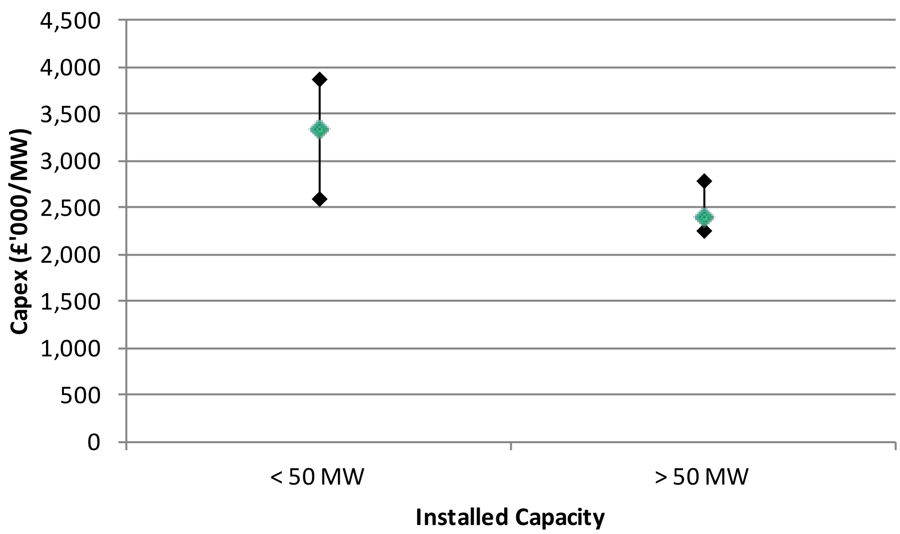


Table 41: Dedicated Biomass – capital costs (financial close 2010)

£'000/MW	<50MW	>50MW
High	3,871	2,801
Median	3,342	2,417
Low	2,607	2,258

Table 42: Dedicated Biomass – capital cost breakdown

Capital cost item	%
Pre-development	1%
Construction	95%
Grid costs	2%
Other infrastructure	2%

Stakeholders considered the key cost drivers to be exchange rates and steel. The expected increase in steel prices would provide costs increasing steadily through to 2030. DECC asked that the cost projections exclude exchange rate movements due to the uncertainty surrounding these movements.

However, this increase is largely negated by the effect of the minimal learning expected. The Blue Map deployment study expects an increase in global deployment from 80GW in 2010 to 268GW by 2030. Given the global nature of the biomass equipment supply chain this data has been used together with an IEA learning rate of 5%.

Capital costs for biomass are therefore expected to remain largely flat over time with a 2% overall increase expected from 2010 to 2030.

The higher rates of global deployment expected in early years give a small expected decrease in costing between 2010 and 2015, with subsequent increases due to increasing steel prices post-2015.

Table 43: Dedicated Biomass – capital cost projections at financial close dates (real) (>50MW)

Capital cost (£000s/ MW)	2010	2015	2020	2025	2030
High	2,801	2,787	2,794	2,832	2,870
Median	2,417	2,405	2,411	2,443	2,476
Low	2,258	2,247	2,252	2,283	2,313

Table 44: Dedicated Biomass – capital cost projections at financial close dates (real) (<50MW)

Capital cost (£000s/ MW)	2010	2015	2020	2025	2030
High	3,871	3,852	3,861	3,913	3,966
Median	3,342	3,326	3,334	3,378	3,424
Low	2,607	2,594	2,600	2,635	2,671

10.7.3 Operating Costs

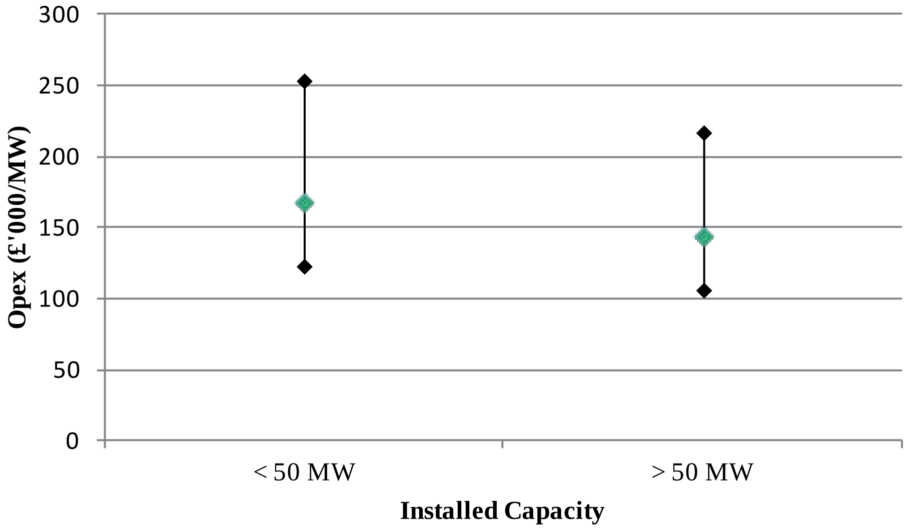
The key cost items within biomass relate to the O&M contract, grid costs, rent, and insurance. Fuel costs have been excluded from this study at the request of DECC.

A relatively large range is seen between the high and low relating to the variation discussed in capital costs and site specific factors (e.g. rental agreements). There are some scale effects noticeable between the sub-50MW and above 50MW scales with a 14% decrease between small and large scales. Overall operating costs equate to between 5% and 6% of the capital cost of the assets.

Table 45: Dedicated Biomass – operating costs (financial close 2010)

£’000/MW	<50MW	>50MW
High	253.5	217.6
Median	168.1	144.3
Low	123.2	105.7

Figure 72: Dedicated Biomass – operating costs (financial close 2010)



Operating costs are also expected to remain largely flat over time, reflecting the limited learning likely to be available. It is expected that labour will be the largest driver of these costs going forward, however the historic labour index used does not suggest substantial rises. Learning effects used are consistent with the capital costs as there is an expectation that the small learning effects through the UK roll-out will decrease the pricing of O&M contracts.

Table 46: Dedicated Biomass – operating cost projection at financial close dates (real) (<50MW)

Operating cost / MW per year (£000)	2010	2015	2020	2025	2030
High	254	250	247	247	248
Median	168	165	163	164	164
Low	123	121	120	120	120

Table 47: Dedicated Biomass – operating cost projection at financial close dates (real) (> 50 MW)

Operating cost / MW per year (£000)	2010	2015	2020	2025	2030
High	218	214	212	212	212
Median	144	142	140	140	140
Low	106	104	103	103	103

10.7.4 Levelised Costs

Using the Arup and E&Y capital and operating cost profiles[43] for dedicated solid biomass plants smaller and greater than 50MW, DECC has calculated levelised costs of a smaller and greater than 50MW reference installation at financial close in 2010, 2015, 2020, 2025 and 2030, respectively. The levelised cost ranges are based on Arup's respective low, medium and high capital cost estimates. Feedstock costs for large-scale dedicated biomass are based on 90% imported and 10% domestic biomass feedstock prices from AEA (2011)[44]. Small-scale biomass is based on 10% imported and 90% domestic feedstock prices. The levelised costs have been calculated by assuming a pre-tax real hurdle rate of 12.7% going down to 11.6% post 2020. These hurdle rates are based on Arup stakeholder information, the Oxera report[45] for the CCC and DECC assumptions on the hurdle rate profile over time. The levelised costs assume a load factor of 90% and a plant lifetime of 25 years.

£ / MWh		2010	2015	2020	2025	2030
Dedicated biomass (solid) 5-50MW	low	127	125	120	119	118
	medium	143	141	134	133	133
	high	154	152	144	143	142
Dedicated biomass (solid) >50MW	low	152	151	146	145	145
	medium	156	154	149	148	148
	high	165	163	156	156	155

Note: Dates refer to financial close.

[43][43] To note that the levelised costs are based on a separate set of capital and operating costs provided by Arup and E&Y that assume constant steel prices over time; capex includes infrastructure costs are incurred in the core facility, but do not include 'other' infrastructure costs that relate to costs incurred outside the site, such as water, roads, waste disposal and land costs. Levelised costs use different size categories for some technologies.

[44] www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/energy_mix/renewable/policy/incentive/incentive.aspx

[45] www.oxera.com/main.aspx?id=9514

10.8 Beyond 2030

Continued use of solid biomass in dedicated electricity generation plants should be possible beyond 2030, assuming that the use of solid biomass to produce electricity remains politically acceptable and that alternative competing demands for the resource (such as woodchip for furniture etc) remain similar to today. There may be some slight increases in the conversion efficiency, and the possibility for greater use of the residual heat of combustion in forms of CHP.

10.9 Regions

Dedicated new solid biomass plants for UK biomass are likely to be constructed in areas of proximity to sufficient concentrations of biomass, especially Scotland and the other upland areas of the UK.

11 Biomass Co-firing

11.1 Summary

Biomass co-firing is inherently linked to the future of coal fired generation in the UK. New environmental requirements, such as LCPD and IED, combined with increasing carbon prices, plus competition from subsidised renewable generation, are likely to greatly reduce the energy from existing coal fired power stations. Therefore whilst co-firing has been a significant contributor to renewable generation, it may reduce to almost zero by the mid 2020s.

11.2 Introduction

Solid biomass co-firing has made a significant contribution to renewable energy generation in the UK to date. The principal fuels are wood pellets and imported food processing residues. Co-firing is essentially provided by the existing coal fired capacity. Whilst there has been a cap on the share of co-firing in the ROCs presented by suppliers meeting their obligation under the RO, which increased from 10% to 12.5% in 2010, the banding of ROCs to give only 0.5 ROCs per MWh has effectively doubled the amount of biomass that can be co-fired within this cap.

Looking to the future, therefore, the amount of biomass co-firing is likely to be constrained by the extent to which the existing coal fired generation continues to operate, unless new coal generation is constructed and the relative coal-biomass prices. The key factors influencing this are environmental emission requirements (LCPD and IED[46]) and potentially new emission performance standards, plus the role of coal in the UK energy market, which may depend on the outcomes of the recent consultation on Electricity Market Reform.

Plants that have opted out of the LCPD must cease operation by 31 December 2015. These include:

- Cockenzie;
- Didcot A;
- Eggborough (1 & 2);
- Ferrybridge C (3&4);
- Ironbridge;
- Kingsnorth; and
- Tilbury.

Opted in coal generation fitted with FGD will be subject to the Industrial Emissions Directive (IED) from 2016. Whilst some of these will invest in further environmental controls (principally Selective Catalytic Reduction (SCR) to reduce NOx), most will probably make use of either the delayed compliance options (nominally compliance by 2020) or the IED opt out provisions which allow continued, but limited, operation until 2023, then closure.

[46] LCPD is the Large Combustion Plant Directive and IED is the Industrial Emission Directive

Plants currently LCPD compliant include:

- Aberthaw B;
- Cottam;
- Drax;
- Eggborough (3&4);
- Ferrybridge C (1&2);
- Fiddlers Ferry;
- Longannet;
- Ratcliffe;
- Rugeley B;
- West Burton;
- Kilroot; and
- Uskmouth.

Therefore, by 2030 no more than a few of the existing coal generation units (and perhaps none) will remain in service, significantly reducing the potential for biomass co-firing. In addition, the load factor on this remaining coal generation beyond 2015 is predicted to reduce, further limiting the energy produced from biomass co-firing.

The plants that do retrofit SCR to achieve the tighter IED NOx emission requirements may constrain or cease biomass co-firing as the SCR catalytic membranes can be highly sensitive to contaminants in the combustion flue gases, which may be exacerbated by the combustion products associated with biomass.

In addition, some of the above existing coal generation units are candidates for full conversion to biomass (as discussed in Chapter 12). Therefore the analysis for solid biomass co-firing takes the above constraints into account.

For all co-firing and conversion calculations it has been assumed that 90% of the biomass will be imported with 10% from local UK sources (nominally based on Drax experience).

When considering the biomass potential from existing coal stations within the UK, the current locations and environmental status of such stations are also a factor.

The assumed annual load factors post 2015 are based on both the nominal LCPD and IED status, plus the general trend of reducing fossil generation load factors to accommodate new wind generation (as predicted by Ofgem, Poyry and others). Note that under the low conversion scenario, co-firing levels remain high as the analysis indicates that no units may be converted to 100% biomass use (see Chapter 12).

It should be noted that all forecast produced in this report are not financially constrained. There is no consideration of current or future financial support mechanisms.

11.3 Literature Review

Literature detailed in the relevant section of the technical bibliography was drawn upon for this section of the report, in addition to reports in Section 2.2 above. Other generic information (for example by the IEA Clean Coal Centre, Poyry and Ofgem) has been used to inform this study of biomass co-firing.

11.4 Limitations & Assumptions

11.4.1 Limitations

The exact impact of the IED on the future operation of co-firing of solid biomass has not been fully investigated. It is perceived that SCR technology may be sensitive to some chemicals produced by the combustion of solid biomass and, therefore, a cautious approach has been adopted when considering co-firing of solid biomass beyond 2020.

11.4.2 Assumptions

For co-firing, the load factor is determined by the relative economics of the primary fuel. Reduced load factors are predicted for fossil generation in the future. Most of the existing coal fired generating units are already more than 40 years old and are encountering life limiting conditions such as boiler creep.[47] Some stations (e.g. Drax) are replacing life expired items of plant to allow continued future operation, but this will always require an economic evaluation of the benefits of such investment.

Our analysis focuses on co-firing biomass with coal at 10-15% biomass ratios. Greater percentages of biomass (so called enhanced co-firing) may be possible but with greater capital investment costs. More coal units adopting enhanced biomass co-firing may be offset by earlier closures or reduced operation of ‘standard’ co-firing units.

It is unlikely that significant CHP will feature in co-firing on existing coal fired generation. These generation units are sited some distance away from viable heat demand. The deployment of renewable CHP is discussed further in Chapter 19.

11.5 Constraints

The key constraint to solid biomass co-firing is the uncertain future economics of coal fired generation, especially with potentially reduced load factors, higher carbon prices and the need for plant upgrades, for example to comply with the IED.

11.5.1 Supply Chain

Co-firing is already established and is likely to reduce in future, as existing coal

[47] A problem akin to metal fatigue experienced after prolonged operation at high temperature and pressure.

fired generation closes. The supply chain is therefore unlikely to pose a constraint.

11.5.2 Planning

Co-firing is already an established technology and additional planning consents would generally not be required.

11.5.3 UK Grid

Co-firing occurs in existing generation which already has grid connections.

11.5.4 Technical

Co-firing is typically limited to around 10% at current fossil fired units, although it is possible to increase this.

11.5.5 Other Constraints

The key other constraint is the availability and access to sufficient solid biomass.

11.6 Maximum Build Rate Scenarios

11.6.1 Available Resource

The nominal requirement of biomass in each year for co-firing and the anticipated decrease in operating capacity over time were derived for each scenario. Note, these decreases in capacity are due to the closure of existing aged fossil fuelled generation, due to the LCPD, plus potential inability to continue co-firing if constrained by the measures needed to comply with tighter IED environmental performance requirements in future. Estimates were made of MW capacity and energy produced.

11.6.2 Low Scenario

The low scenario is based on the low solid biomass availability scenario. (See section 10.4.3)

11.6.3 Medium Scenario

The medium scenario is based on the medium solid biomass availability scenario. (See section 10.4.3)

11.6.4 High Scenario

The high scenario is based on the high solid biomass availability scenario. (See section 10.4.3)

11.6.5 Maximum Build Rate Plots

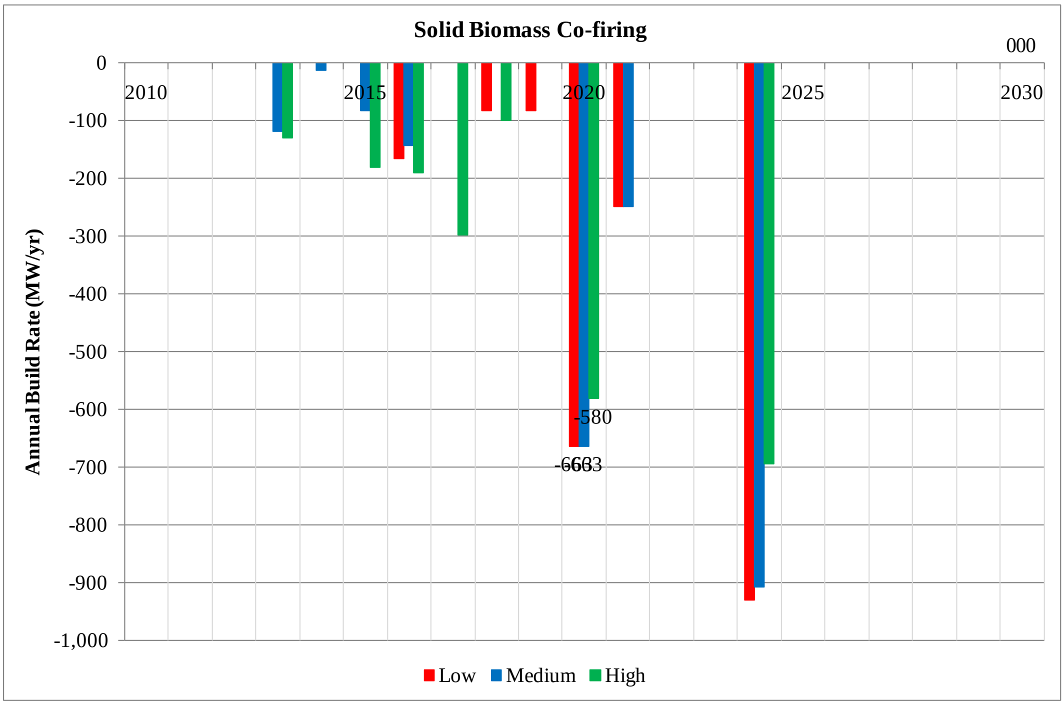


Figure 73: UK Solid Biomass Co-firing Annual Build Rate (MW/yr)

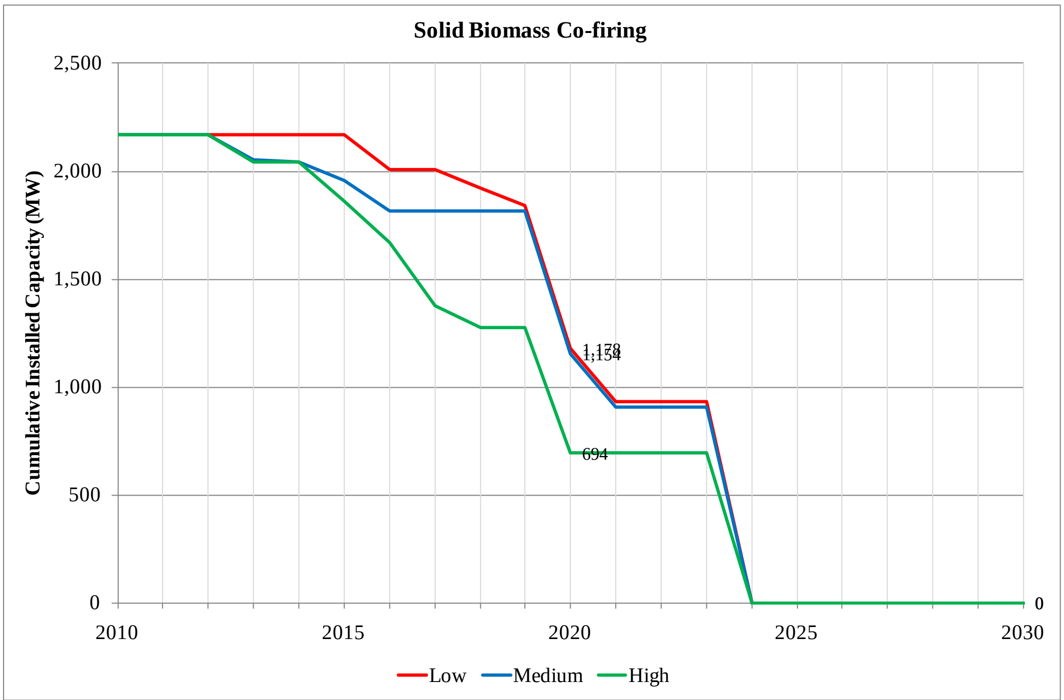


Figure 74: UK Solid Biomass Co-firing Cumulative Installed Capacity (MW)

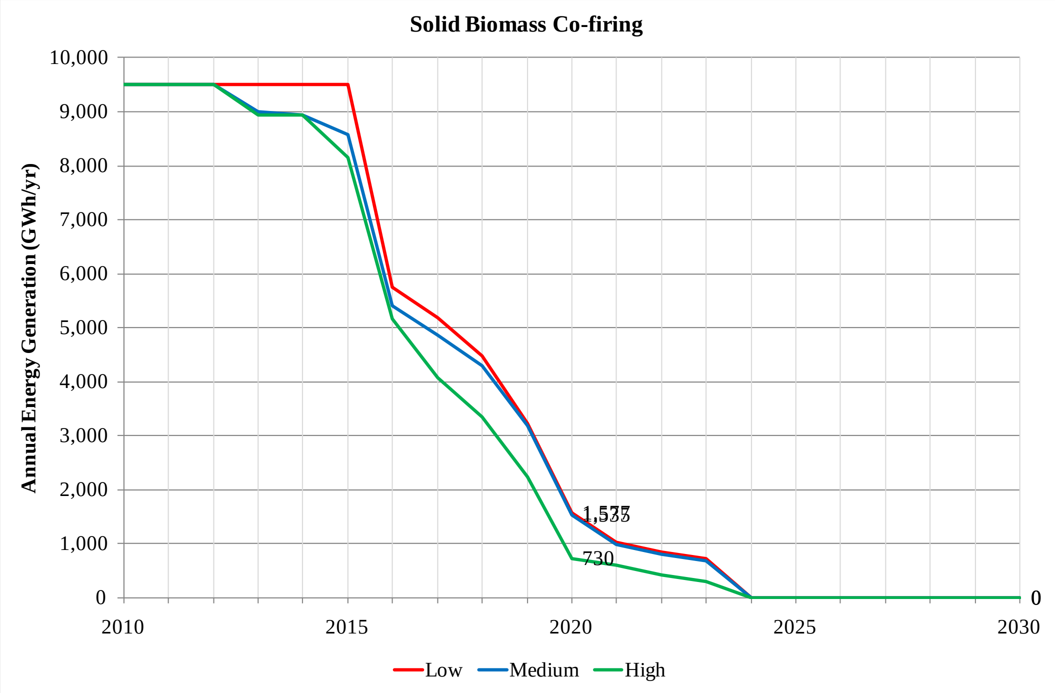


Figure 75: UK Solid Biomass Co-firing Annual Energy Generation (GWh/yr)

11.7 Project Cost

11.7.1 Key Assumptions

Project costs for biomass co-firing are based on consultations with industry stakeholders and relate to projects that have recently started operation, or are in construction or development. Additional information has also been collected from industry literature.

Co-firing cost represents the incremental cost of partially fuelling an existing coal fired power station with biomass. Conventional and enhanced co-firing is considered in this section. Conventional co-firing uses up to 10% biomass whilst enhanced co-firing uses a share of biomass of up to 50%. The full conversion of a coal fired power station into a dedicated biomass plant is considered separately.

11.7.2 Capital Expenditure

Capital expenditure for co-firing is based on project data provided by industry stakeholders and two industry reports. It is defined as the additional expenditure required to install biomass capacity on top of original capital expenditure requirement at a coal plant.

Pre-development costs vary from £39,000/MW to £72,000/MW. This principally relates to technical development. Planning and pre-licensing costs are limited since co-firing requires the adaptation of an existing facility rather than a newly built plant.

Capital expenditure varies widely depending on the type of co-firing employed:

- Conventional co-firing mixes biomass with coal prior to the pre-combustion process. Biomass is processed with the coal and requires relatively limited additional equipment.

- Enhanced co-firing mixes the coal and biomass after their respective pre-combustion processing. The technique requires significant plant adaptation, leading to increased capital cost.

Conventional co-firing represents the lower end of the cost range, whilst the capital expenditure for enhanced co-firing could range up to £880,000/MW. 48 below presents capital cost ranges. Pre-development is not included in the capital cost range.

Table 48: Co-firing – Capital Costs (financial close 2010)

£000s/MW	>20MW
High	880
Median	167
Low	86

Table 49 presents how capital costs are broken down in the average plant.

Table 49: Co-firing – Capital Cost Breakdown

Capital Cost Item	%
Pre-development	8%
Construction	50%
Grid Connection	0%
Other Infrastructure	42%

The grid connection is part of the existing coal fired plant, so no additional costs are typically incurred for co-firing. Other infrastructure costs are high as there is a relatively small requirement for new construction in co-firing projects.

Exchange rate movements and labour cost are the main drivers of project cost. Conventional co-firing is a mature technology, so there is limited potential for additional learning effects. Enhanced co-firing is less established, and there are a limited number of stakeholders currently looking into this technique, so learning effects could still be realised.

Table 50 presents the range of current capital costs and how they are expected to change over time.

Table 50: Co-firing – Capital Cost Projections at Financial Close Dates (Real)

£'000/MW	2010	2015	2020	2025	2030
High	880	855	840	838	836
Median	167	162	159	159	159
Low	86	84	82	82	82

11.7.3 Operating Cost

The operating cost of co-firing relates to the additional biomass fuel processing and handling cost and maintenance of additional equipment.

The differences between conventional and enhanced co-firing drive variations in the operating costs of plants. Enhanced co-firing incurs a higher incremental operating cost. Operating costs have a relatively small range compared to capital costs, illustrating the difference in operational requirements between conventional and enhanced co-firing.

Table 51 below presents operational cost ranges for co-firing.

Table 51: Co-firing – Operating Costs (Financial Close 2010)

£000s/MW	>20MW
High	35
Median	33
Low	20

Operating cost projections assume labour is the principal cost driver. Exchange rates are also significant as spare parts are partly manufactured abroad. Stakeholders have significant experience in operating the existing plants, so do generally not anticipate future learning effects that might reduce operating costs.

Table 52 shows the range of current operational costs and how they are expected to change over time to 2020.

Table 52: Co-firing – Operating Costs Projections at Financial Close Dates (Real)

£'000 / MW	2010	2015	2020	2025	2030
High	35	36	36	37	37
Median	33	33	34	34	35
Low	20	20	21	21	21

11.7.4 Levelised Costs

Using the Arup and E&Y capital and operating cost profiles48 for biomass co-firing plants, DECC has calculated levelised costs of a reference installation at financial close in 2010, 2015, 2020, 2025 and 2030. The levelised cost ranges represent at the high end Arup's high enhanced co-firing estimate, for medium Arup's high conventional co-firing estimate and for low Arup's low conventional co-firing capital cost estimate. Feedstock costs are based on 90% imported and 10% domestic biomass feedstock prices from AEA (2011)[49]. The levelised costs have been calculated using a pre-tax real hurdle rate of 12.7% going down to 11.6% post 2020. These hurdle rates are based on Arup stakeholder information, the Oxera report50 for the CCC and DECC assumptions on the hurdle rate profile over time. The levelised costs assume a load factor of 51% and a plant lifetime of 9 years for conventional co-firing and a plant lifetime of 22 years and a load factor of 64% for enhanced co-firing.

£ / MWh		2010	2015	2020	2025	2030
Co-firing	low	94	94	93	93	93
	medium	100	100	99	99	99
	high	110	111	110	110	110

Note: Dates refer to financial close.

11.8 Beyond 2030

Beyond 2030 it is likely that most, if not all, remaining coal fired generation will be fitted with carbon capture and storage (CCS). Any new coal fired generation built in the future is also likely to move to full CCS after 2030. It has been assumed that the initial demonstration CCS plants will initially minimise biomass co-firing, but over time, once the technology and operational experience has been developed, biomass co-firing will be introduced. The carbon emissions performance standard proposed as part of the Electricity Market Reforms only applies to new fossil fired generation and therefore has no bearing on the co-firing potential of any existing coal generation units that remain in service beyond 2030. However, biomass co-firing may help new coal fired generation with partial CCS to comply with any progressive reduction in the emissions performance standard.

11.9 Regions

Co-firing is focussed on the existing location of the large coal fired generation. As plants in the South East of England (Kingsnorth and Tilbury) and other home counties (Didcot) close due to LCPD requirements, biomass co-firing will be clustered around the East Midlands and Yorkshire, plus South Wales, Merseyside and the Scottish belt.

[48] To note that the levelised costs are based on a separate set of capital and operating costs provided by Arup and E&Y that assume constant steel prices over time; capex includes infrastructure costs are incurred in the core facility, but do not include 'other' infrastructure costs that relate to costs incurred outside the site, such as water, roads, waste disposal and land costs. Levelised costs different size categories for some technologies.

[49] www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/energy_mix/renewable/policy/incentive/incentive.aspx

[50] www.oxera.com/main.aspx?id=9514

12 Biomass Conversion

12.1 Summary

When considering potential candidate coal generating units for full conversion to biomass, it has been assumed that the majority of solid biomass would be imported and that candidate sites would need to have practical transport access to import facilities. This would tend to favour sites in Yorkshire, the Thames Estuary, South Wales and the North West. Up to 11 existing units could be converted under the high scenario and this would yield a significant contribution to UK renewable energy production. Crucially this might offset the reduction in energy production foreseen from co-firing and provide a key fraction of renewable energy to meet the 2020 obligations.

12.2 Introduction

It would be technically possible to convert some existing coal fired generation to 100% biomass. The economics would depend on the existing plant status, access to sufficient biomass and costs for new fuel handling equipment.

It should be noted that all forecast produced in this report are not financially constrained. There is no consideration of current or future financial support mechanisms.

12.3 Literature Review

This chapter was informed by reference to documents listed in the relevant part of the technical bibliography in addition to various reports in Section 2.2.Generic information (for example by the IEA Clean Coal Centre) has also been used to inform this study on biomass conversion.

12.4 Limitations & Assumptions

12.4.1 Limitations

The economic and technical feasibility of full conversion is highly site dependent and this section is more generic in nature, although specific candidate units for full conversion are considered.

12.4.2 Assumptions

When considering potential candidate coal generating units for full conversion to biomass, a key assumption was that the majority of their solid biomass would be imported and that candidate sites would need to have practical transport access to import facilities. Representative sites in Yorkshire, the Thames Estuary, South Wales and the North West have been used, although it is possible that actual site locations could differ. For the purpose of this analysis the nominal (exemplar) units considered for 100% conversion to biomass were up to three units at each of Drax, Tilbury and Uskmouth and two units at Fiddlers Ferry. However Arup is aware of other existing generation sites that are considering full conversion to biomass.

As with two other existing coal fired generation units, the future operation depends in part on their status with respect to the Large Combustion Plant Directive (LCPD) and with the Industrial Emissions Directive (IED) that applies from January 2016, albeit with some transitional arrangements. Therefore some estimation has been made on when units might close due to LCPD or cease co-firing due to retrofit of SCR to comply with IED (assuming that risk of biomass combustion gases damaging the SCR membranes will make biomass co-firing with SCR unattractive).

The assumed annual load factors were based on both the nominal LCPD and IED status, plus the general trend of reducing fossil generation load factors to accommodate new wind generation (as predicted by Ofgem, Poyry and others). Note that under the low conversion scenario, no units are in fact 100% converted. It is assumed that some units will adopt the compliance with IED by 2020 route and others will adopt the opt out and hence close by 2023. Assumed load factors post 2015 reflect this.

This has yielded the equivalent electrical energy from biomass use by 100% conversion of coal units for each year and each scenario. For all full conversion calculations it has been assumed that 90% of the biomass will be imported with 10% from local UK sources (nominally based on Drax experience).

It has been assumed that once fully converted, the load factor would exceed 80% (subject to biomass availability). The operating life as a 100% biomass unit would vary from unit to unit, depending on past operating and investment history etc. Some units may have many years operation on full biomass, others may only have a few.

12.5 Constraints

The prime constraint on the full conversion to solid biomass of existing coal fired generation is the finite number of existing generating units and their geographic location in relation to potential fuel import facilities.

12.5.1 Supply Chain

The equipment supply chain is unlikely to pose a constraint.

12.5.2 Planning

As the coal plants are already consented, the key planning issue relates to biomass transportation and storage, which will intrinsically be site dependent.

12.5.3 UK Grid

The existing generating units already have transmission entry capacity.

12.5.4 Technical

The key technical development that may ease the development of conversion to solid biomass is torrefaction of the biomass, as this would reduce the need for changes to the fuel milling and handling systems.

12.5.5 Other Constraints

It is likely that some existing coal fired generation sites may be considered for new CCS build in the future. Future land requirements both for the new build plant plus associated construction lay down and fuel and other operational material storage areas may impact on the scope and timing for converting existing units to solid biomass.

12.6 Maximum Build Rate Scenarios

12.6.1 Low Scenario

Under the low scenario, it is assessed that the attractiveness of full conversion and the lower availability of solid biomass makes full conversion unattractive. Therefore no existing units are converted to 100% biomass under this scenario.

12.6.2 Medium Scenario

Increasing availability of imported solid biomass allows for the potential conversion of up to five units to 100% solid biomass under the medium scenario (see section 10.4.3).

12.6.3 High Scenario

Further availability of imported solid biomass allows for the potential conversion of up to 11 units to 100% solid biomass under the high scenario (see section 10.4.3).

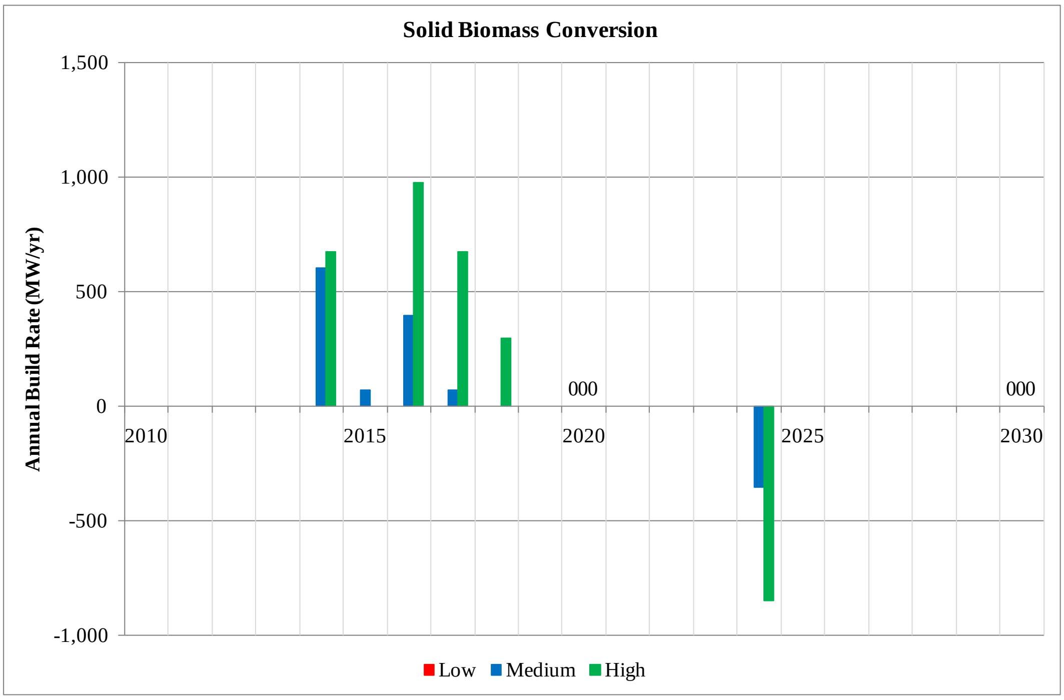


Figure 76: UK Solid Biomass Conversion Annual Build Rate (MW/yr)

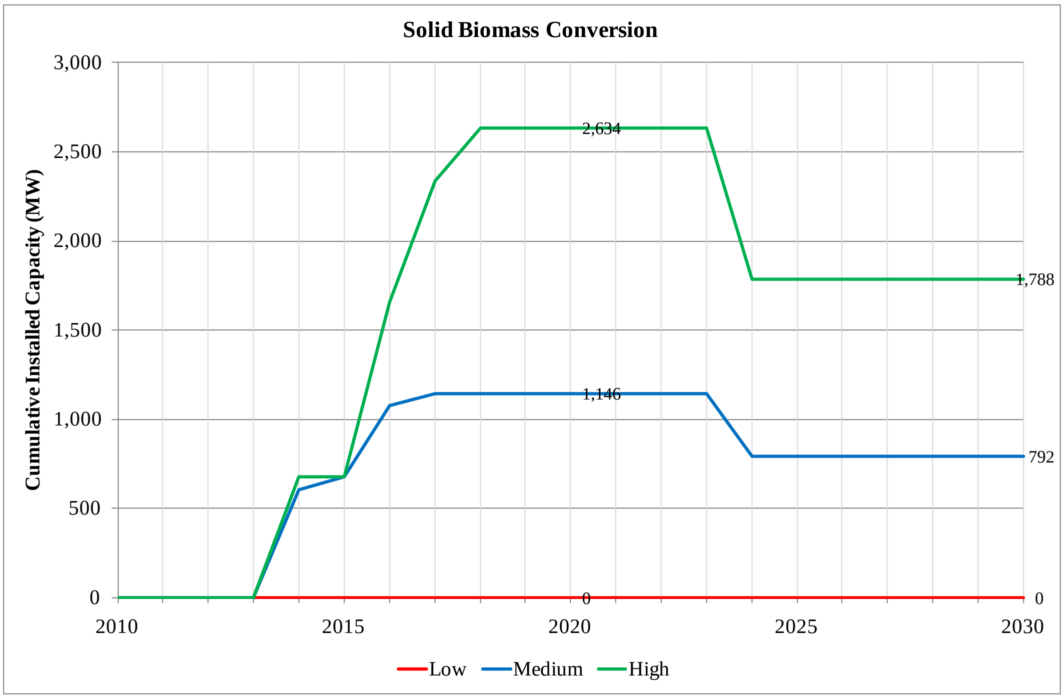


Figure 77: UK Solid Biomass Conversion Cumulative Installed Capacity (MW)

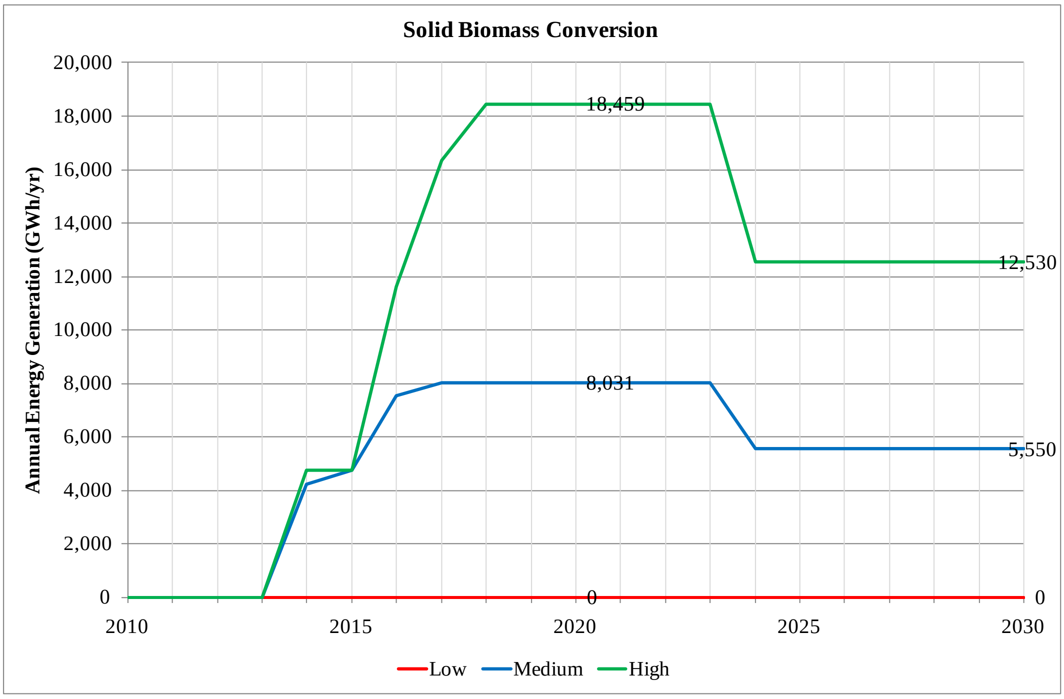


Figure 78: UK Solid Biomass Conversion Annual Energy Generation (GWh/yr)

12.7 Project Costs

12.7.1 Key Assumptions

Co-firing conversion cost represents the expenditure required to convert an existing coal fired power station into a dedicated biomass plant. The information collected on the project cost is based on consultations with industry stakeholders and relates to projects in development.

12.7.2 Capital Expenditure

Capital expenditure for co-firing is based on project data provided by four industry stakeholders.

Pre-development costs vary from £2,000 to £47,000/MW. As conversion requires adaptation of an existing coal fired plant, limited pre-development may be required unless planning issues arise in relation to biomass transportation and storage.

The unit capital cost range for conversion projects is large. Cost variations are caused by length of plant operation post-conversion and how stakeholders interpret the environmental regulations.

- Many coal fired power stations have opted out of the LCPD or are approaching the end of their operational lives. Operators can either convert the plants for the remainder of their planned life, i.e. close no later than 2015, or convert the plant to be compliant with environmental standards. Stakeholders suggest that short term conversion until 2015 is possible with relatively low capital investments.
- To allow for full conversion and to run the plant to the end of its operational life, more comprehensive alterations are required for sustainable plant operation and to comply with European environmental standards for large combustion plants. The capital cost associated with these projects can vary due to interpretation of the environmental legislation. It is not clear to stakeholders exactly which technologies will be required to establish compliance with the EU IED, leading to variations in expected capital cost.

Table 53 below presents the capital cost range for conversion. Pre-development is not included in the capital cost range.

Table 53: Conversion – Capital Costs (financial close 2010)

£'000/MW	100 – 1,500MW
High	1,190
Median	627
Low	167

Table 54 presents how capital costs are typically broken down for a conversion project.

Table 54: Conversion – Capital Cost Breakdown

Capital Cost Item	%
Pre-development	3%
Construction	68%
Grid Connection	0%
Other Infrastructure	29%

The majority of capital costs relate to construction. Construction work includes boiler replacement, construction of biomass storage facilities and modifications to the material handling systems. The existing facility will contain a grid connection, so no additional expenditure is required. Other infrastructure may include rail network upgrades or port infrastructure improvements.

Exchange rate movements and labour costs are the principal drivers of future project cost. The importance of labour is due to labour intensive equipment manufacturing processes. Exchange rates are significant as some equipment is imported.

Stakeholders noted that due to the limited remaining life of power stations and European environmental legislation, there is only a limited period of time during which conversion appears economically viable. As a result, there is limited medium to long term opportunity for learning effects.

Table 55 below presents the range of current capital costs and how they are expected to change over time.

Table 55: Conversion – Capital Cost Projections at Financial Close Dates (Real)

£'000/MW	2010	2015	2020
High	1,190	1,177	1,171
Median	627	620	617
Low	167	165	164

12.7.3 Operating Costs

Operating costs relate to the running of the entire facility. It is not anticipated that the operational requirements of a plant will change significantly post conversion. However, the de-rating of the plant (i.e. reduction in installed capacity), a result of the lower energy density of biomass, leads to increased unit cost. Table 56 presents operational cost ranges for conversion.

Table 56: Conversion – Operating Costs (Financial Close 2010)

£'000/MW	100 – 1,500 MW
High	49
Median	48
Low	45

The labour cost as part of O&M contracts is a main driver of plant operating cost. Stakeholders have significant experience in running plants and do not anticipate significant learning effects in operation. Table 57 below shows the range of current operational costs and how they are expected to change over time to 2020.

Table 57: Conversion – Operating Costs Projections at Financial Close Dates (Real)

£'000/MW	2010	2015	2020
High	49	50	50
Median	48	48	49
Low	45	46	46

12.7.4 Levelised Costs

Using the Arup and E&Y capital and operating cost profiles[51] for biomass conversion plants, DECC has calculated levelised costs of a reference installation at financial close in 2010, 2015, 2020, 2025 and 2030. The levelised cost ranges are based on Arup's low, medium and high capital costs. Feedstock costs are based on 90% imported and 10% domestic biomass feedstock prices from AEA (2011)[52]. The levelised costs have been calculated using a pre-tax real hurdle rate of 12.7% going down to 11.6% post 2020. These hurdle rates are based on Arup stakeholder information, the Oxera report[53] for the CCC and DECC assumptions on the hurdle rate profile over time. The levelised costs assume a load factor of 63% and a plant lifetime of 15 years.

£ / MWh		2010	2015	2020	2025	2030
Biomass conversion	low	106	106	106	106	106
	medium	116	116	115	115	115
	high	128	129	127	127	126

[51] To note that the levelised costs are based on a separate set of capital and operating costs provided by Arup and E&Y that assume constant steel prices over time; capex includes infrastructure costs are incurred in the core facility, but do not include 'other' infrastructure costs that relate to costs incurred outside the site, such as water, roads, waste disposal and land costs. Levelised costs different size categories for some technologies.

[52] www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/energy_mix/renewable/policy/incentive/incentive.aspx

[53] www.oxera.com/main.aspx?id=9514

Note: Dates refer to financial close.

12.8 Beyond 2030

It is unlikely that many (if any) of the existing coal fired generating units will be economic to retain in service beyond 2030. Most are already over 40 years old. Any new plants built to replace this capacity and using 100% biomass are considered under the new dedicated biomass section (Chapter 10).

12.9 Regions

Full conversion of existing coal units to biomass is likely to be concentrated in the North East, the North West, the Thames Estuary and South Wales.

13 Bioliquids

13.1 Summary

Forecasts of bioliquid deployment have been developed up to 2030. These are based on a number of assumptions and constraining factors including, but not limited to, the following:

- Supply chain constraints – the availability of bioliquid resource could be a potential constraint on construction of new generation. Equipment supply and skilled labour are less likely to be a significant constraint on deployment;
- Grid constraints – grid access is unlikely to cause a significant constraint;
- Planning – Planning is assumed not to constrain the construction of new dedicated bioliquid generating capacity. When considering the possible conversion of existing oil fired generation units to bioliquids, planning constraints have been assumed to be minimal, however environmental licences are likely to constrain future operation. If bioliquids were substituted for distillate fuel at some of the existing CCGT plants, we have assumed that existing planning limitations on the number of operating hours that distillate fuel can be use would also be applied to dedicated bioliquid facilities, therefore putting a constraint on the amount of bioliquid generation per annum; and
- Technical – key issues surround the technical performance of new dedicated bioliquid generation, conversion of existing units and fuel substitution in CCGTs. For example, if the emission controls and operating hours differ significantly compared with distillate, the economic feasibility of bioliquids in CCGT plants may impair deployment.

Under the low scenario it is assumed that no dedicated plants are constructed, and all co-firing and conversion plants are closed before 2020. The medium scenario results in approximately 1000MW of dedicated bioliquids capacity by 2030. The high scenario results in approximately 2,500MW by 2020 and 3,500MW by 2030.

13.2 Introduction

The available bioliquid resource was derived from data initially prepared by E4tech (as recommended by DECC). Bio-ethanol was considered less suitable for electricity generation and therefore biodiesel remaining after transport use was the principal bioliquid considered. Pyrolysis oil has only been included in the high scenario, and is assumed to be insignificant in the low and medium scenarios. It is produced from the thermal decomposition of biomass under reduced or zero oxygen conditions. Tall oil is already used for some electricity generation (mainly via co-firing) and has similarly been included in the high scenario. Data on tall oil and pyrolysis oil was derived from the NNFCC study (0.5 Mt tall oil and 0.26 Mt pyrolysis oil). Tall oil, also called liquid rosin or tallol, is a viscous yellow-black liquid obtained as a co-product of the process of pulp and paper manufacturing. Tall oil is a difficult product to handle and needs processing if it is to be used in internal combustion engines, although it can be blended with other bioliquids to make it suitable for electricity generation in either dedicated units or for co-firing. The bioliquid resource available for electricity generation is considerably smaller than the solid biomass resource. This analysis is based on net sustainable bioliquids available for power generation derived from E4tech/DECC work and assumes that competition from other users of bioliquids was considered in the derivation of that data. Regarding the source of the biodiesel, the specific fuel categories and calorific values included within the assessment in Table 58 were not used as estimates were based on the energy available from bioliquids under each scenario and not on the respective volumes.

Table 58: Biodiesel Calorific Value Fuel[54]

Fuel source	Type	Assumed GJ/Te
Microalgae oil	2G diesel	11.20
OSR - RED	1G biodiesel	14.64
Soy - RED	1G biodiesel	14.64
Jatropha - RED	1G biodiesel	14.64
Palm - RED	1G biodiesel	14.64
UCO	1G biodiesel	36.46
Tallow	1G biodiesel	32.74

Table 59: Global Assumed Feedstock Supply

Supply of feedstock per year (t)		2010	2015	2020	2025	2030
Oil(Low)	Rapeseed	4877335	5148825	2072562	2275842	2502948
	Soybean	694884	1473108	1667734	1512251	1607075
	Palm oil	90285	244853	204349	281154	321953
	Jatropha	13403	53031	210209	211765	210600
	Tallow	43292	77735	95107	102716	115632
	Used oil	91394	98286	92158	96078	105120
	Microalgae	0	0	0	0	0
Oil (Medium)	Rapeseed	6085055	7402679	3141403	4086640	3587955
	Soybean	2720970	6728971	4551489	6395880	10527210
	Palm oil	203955	338384	133156	278971	382473
	Jatropha	127855	438327	1098113	2298067	4177007
	Tallow	263750	255887	231004	244855	252376
	Used oil	117222	125574	124058	154168	182272
	Microalgae	0	0	1350	16125	115100
Oil (High)	Rapeseed	6283062	7550594	3159613	4150251	4065330
	Soybean	2630405	6671328	4570023	6601311	11350576
	Palm oil	233195	462638	195630	509811	973653
	Jatropha	130008	734348	1716263	2899664	5019448
	Tallow	292676	280639	248619	268837	280903
	Used oil	146338	152013	145028	168023	187269
	Microalgae	0	0	3854	280441	4638252

While domestic rapeseed accounts for a significant part of the UK biodiesel

[54] Note: not used in Arup analysis.

feedstock, contributions from soya, palm oil and in the medium and high scenarios Tallow are also significant.

Most existing biodiesel generating plants are relatively small, typically using reciprocating internal combustion engines up to ~5MWe capacity. Existing capacity (2010) together with potential new build by 2012 is estimated to be <50MWe.

Please note that all forecasts produced in this report are not financially constrained. There is no consideration of current or future financial support mechanisms.

13.3 Literature Review

Key references include the E4tech report plus the recent NNFCC report on future of bioliquid feedstock and technologies, as well as the reports in Section 2.2.

13.4 Limitations & Assumptions

13.4.1 Limitations

The exact impact of the LCPD and IED on future operation of bioliquid combustion technologies has not been fully investigated.

13.4.2 Assumptions

Deployment of bioliquids electricity generation is dependent upon there being an accessible and economically viable supply of feedstocks. Only sustainable bioliquids have been considered, based on the 2009 EU Renewable Energy Directive (RED) (2009/28/EC) that stipulates that only bioenergy, derived from sustainable sources can be eligible to count towards Member States contributions to their renewable energy targets and therefore as eligible for financial support.

It is possible to use bioliquids blended with normal diesel in existing engines (up to approx 30%), but data on the size of the existing diesel generation fleet and operating factors was not available. No additional information on such use was submitted in response to our call for data. It has therefore been assumed that bioliquid use will initially be at dedicated plants. Build rates have accordingly been estimated based on the availability of bioliquid, subject to any supply chain or siting constraints. In years where available bioliquid supply may exceed demand from our estimated fleet of new dedicated bioliquid electricity generation plants, two options have been considered. One is the full conversion of one or more units at existing large oil fired generation (e.g. Grain, Littlebrook and Kilroot[55]). The other is the substitution of bioliquid for distillate oil in those Combined Cycle Gas Turbine (CCGTs) with distillate capability, although Arup does not have specific intelligence indicating that either bioliquid combustion option is under active consideration.

Although some bioliquid may be used to replace oil used for flame stabilisation at coal fired generation, this modest usage has been ignored for the purpose of this analysis. Similarly, the limited amount of bioliquid currently used in existing

[55] Kilroot has dual fuel capability – coal and oil.

dedicated generation plants and CHP facilities (approx 100kT/yr) has been treated as marginal for the purposes of this analysis.

It has been assumed that available bioliquid for electricity generation is first allocated to new dedicated plants, with any residual amounts then considered for use in existing generating units. It should be noted that generation capacity etc is calculated from the fuel availability starting point. However, future fuel availability is not fully known and will depend in part of the cost/subsidy arrangements available, which could be highly sensitive to price.

The bioliquid fuel used in existing generation of electricity (based on the Renewable Obligation 2009/2010 data) is as follows:

Table 60: Historic bioliquid use information

Feedstock	Tonnes
Vegetable Oil	109
Used Cooking Oil	1,074
Waste liquids not used in the transport sector[56]	115,242

13.4.3 Short Term Conversion of Existing Oil Fired Generation

The resource level projections we are using derived in part from E4tech information indicate a dip in bioliquid availability around 2020. Therefore, we have limited new dedicated plant build prior to 2020 to a level commensurate with bioliquid availability in 2020. Because of this, there is a nominal surplus of bioliquid resource available around 2015. Arup appreciates that these estimates have large uncertainties and therefore the results of this analysis should be treated with appropriate caution. Future resource availability is highly sensitive to price. In principle, it may be possible to use bioliquid (perhaps for only a few years) in existing oil fired generation capacity. Other alternatives, such as use in blended fuels, may also be possible. The existing oil fired units at Littlebrook and Grain are opted out of the LCPD and are expected to close by 2016, however the coal/oil fired generation at Kilroot in Northern Ireland has had FGD fitted to comply with the LCPD requirements. All three sites have ship unloading facilities that may be capable of handling imported (sustainable) bioliquid.

Littlebrook (3x660MW) and Grain (4x660MW) are on the Thames Estuary; one unit at Littlebrook and two at Grain are mothballed. For the purposes of this assessment it has been assumed that no more than three of these 660MW units are converted under the high scenario. It should be noted that palm oil was trialled in one unit around 2006, but plans were dropped due to sustainability concerns. No new plans for use of palm oil in existing large oil fired units featured in discussions with industry as part of this study.

Kilroot has 2x300MW units and it has been assumed that both units could be fully converted to bioliquid if required. As Kilroot has both oil and coal capability it should not be double counted as both a solid biomass conversion candidate and a bioliquid conversion candidate. Care should therefore be taken if combining data

[56] Including Tall oil

from Chapters 11, 12 and 13.

It has been assumed that LCPD issues prompt the closure of Grain and Littlebrook after 2015 and that subsequent IED requirements will prevent any significant use of bioliquid at Kilroot after 2020. These restrictions on future operation apply both to full conversion plus the use of bioliquid blends.

13.4.4 Potential for Use of Bioliquids in Existing CCGT Generation

Due to the assumed build rate constraints (for new build), plus LCPD closures, there may be nominal surpluses of bioliquid after 2020 under the high scenario beyond 2026. One option considered was the potential to use bioliquid in place of distillate at some of the existing CCGT generation stations, although stakeholder contacts did not indicate any specific plans by industry to explore this. Not all of the UK CCGTs have the option to burn distillate, many are purely gas fired with no standby distillate capability. In addition, many of the CCGTs with distillate capability have oil storage or delivery constraints, plus consent conditions (Section 36 or IPPC) that may limit the number of hours that distillate can be used in any one year. This rules out many, if not all, for continuous operation on bioliquid and therefore bioliquid use has typically been assumed not to exceed 30 days per year in our analysis.

From Arup's knowledge (based on previous DECC/JESS[57] analysis), nearly 3GW of CCGT capacity has the option to use distillate, including Barking Power (1,000MW), Brigg (266 MW), Fawley Cogen (150MW), Medway (700MW) and Immingham (760MW).

13.5 Constraints

The available bioliquid resource available for electricity generation exhibits a dip around 2020, therefore it is assumed that the construction of new dedicated bioliquid generating capacity in the period to 2020 will not exceed the available resource in 2020. Thereafter, it is assumed that no more than 500 MW of dedicated new build bioliquid generating capacity can be commissioned each year, due to equipment supply chain constraints. This build rate constraint only affects the high bioliquid scenario. Therefore, as a result of this analysis, it is possible to estimate the new build capacity added in each year, the cumulative capacity and the growth in annual energy produced from dedicated bioliquid generation.

13.5.1 Supply Chain

The supply chain is not considered to be a constraint in this instance. Equipment suppliers, fabrication capacity and skilled labour force are unlikely to pose a constraint to bioliquid development.

[57] JESS – former Joint Energy Security Supply group comprising of government, industry and regulator representatives.

13.5.2 Planning

Existing large oil fired generation in England is expected to close by 2016, due to LCPD requirements. Existing CCGT stations generally have planning limitations on the number of hours that distillate fuel can be used. It has been assumed that these constraints would continue to apply for bioliquid, especially where the planning concern related to the delivery of fuel via road tanker.

It is not foreseen that planning consents would pose a major constraint on the construction of dedicated bioliquid generation plants, particularly if these are CHP plants linked to local industry or service provision, or are only a few MW in size.

The planning aspects of full conversion of existing oil fired generation to bioliquids is uncertain. Previous trials have taken place without requiring major planning applications. One key issue would be if such conversions were considered as “new build” in terms of the requirement for full environmental impact assessments and compliance with new plant standards. The time and cost to achieve this might make full conversion economically unattractive.

13.5.3 UK Grid

Grid connection and access is unlikely to pose a significant constraint.

13.5.4 Technical

The key technical issue for dedicated bioliquid generation is the technical performance of the plant and whether equipment suppliers provide appropriate performance guarantees for such fuel. Contaminants and higher viscosity are potential areas of concern.

It is not clear how CCGT combustors will operate with bioliquids. If emissions controls and equivalent operating hours differ significantly compared to distillate, the feasibility and economic rationale for use of bioliquids in CCGTs may be impaired.

CHP arrangements offer significant carbon reduction benefits, but operation of the bioliquid fuelled generation may then have to match associated heat demand and quality/reliability requirements.

13.5.5 Other Constraints

A key issue with bioliquids is the perception of the sustainability of the fuel held by key stakeholders. The large generators are currently also part of major electricity retail groups and therefore they may be loathe to risk impairing their reputation with customers and shareholders, plus important NGOs.

13.6 Maximum Build Rate Scenarios

13.6.1 Available Resource

For new build of dedicated bioliquid generating capacity it has been assumed that no more than 500MW could be commissioned in any one year, comprising a number of smaller (<10MW) plants plus a few larger (mainly imported fuel) plants. Larger plants are more likely under the high scenario, but these may be less suitable for CHP, due to the lack of sufficient nearby heat demand.

13.6.2 Low Scenario

In this scenario, limited sustainable bioliquid availability would result in insignificant build rates. No use of bioliquid in existing CCGTs (in place of distillate oil) is foreseen nor use in existing oil fired generating units.

13.6.3 Medium Scenario

Under the medium scenario, the construction of new bioliquid generation capacity is not constrained by the equipment and construction supply chain beyond 2020. Residual bioliquid resource not used in dedicated plants may be used in some CCGTs post-2020, but no use in existing large oil fired generating units is foreseen.

13.6.4 High Scenario

The high scenario is significantly larger than the medium scenario, even though the amount of electricity is constrained by construction constraints.

Figure 79 indicates a step change in bioliquid conversion to energy in existing CCGTs around 2026, triggered by the unavailability of sufficient dedicated bioliquid generation caused by equipment supply constraints starting to become significant.

13.6.5 Maximum Build Rate Plots

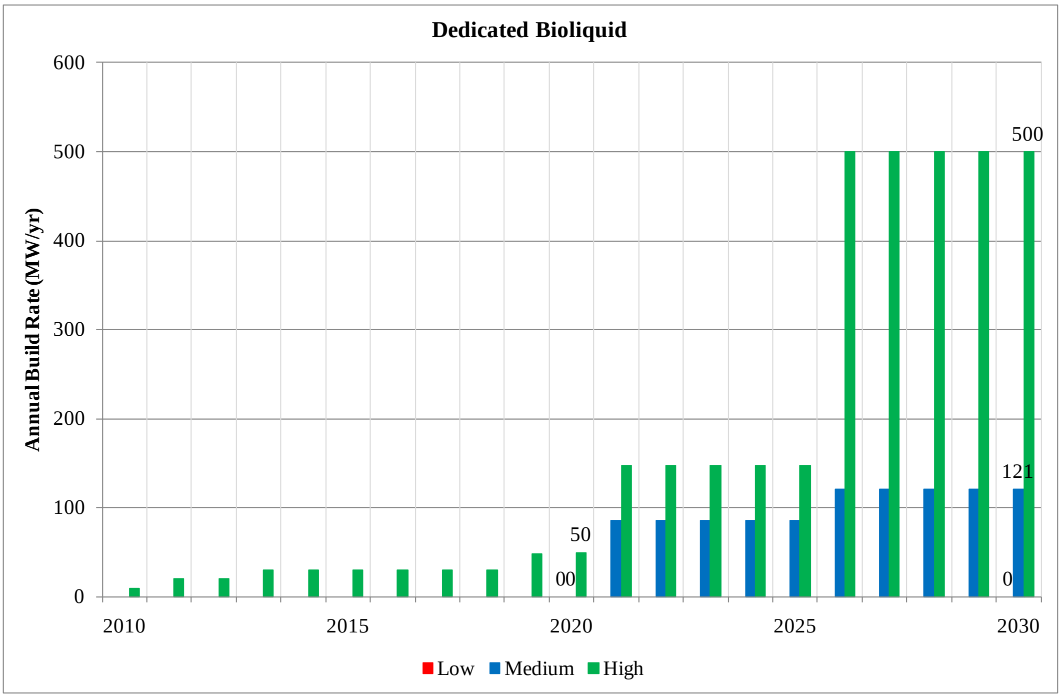


Figure 79: UK Dedicated Bioliquids Annual Build Rate (MW/yr)

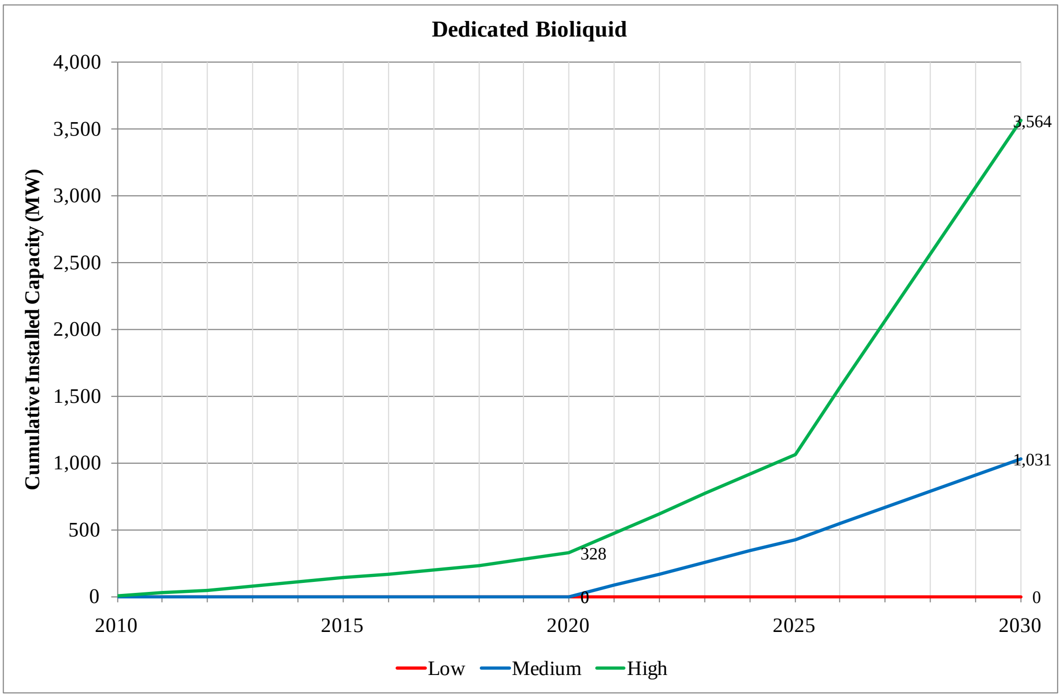


Figure 80: UK Dedicated Bioliquids Cumulative Installed Capacity (MW)

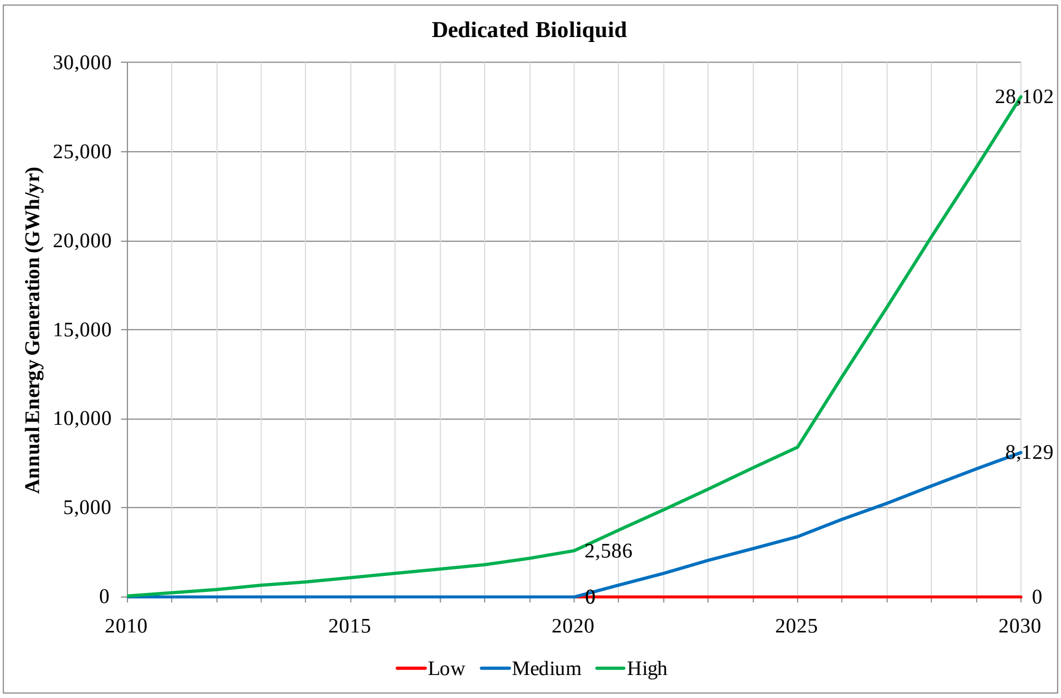


Figure 81: UK Dedicated Bioliquids Annual Energy Generation (GWh/yr)

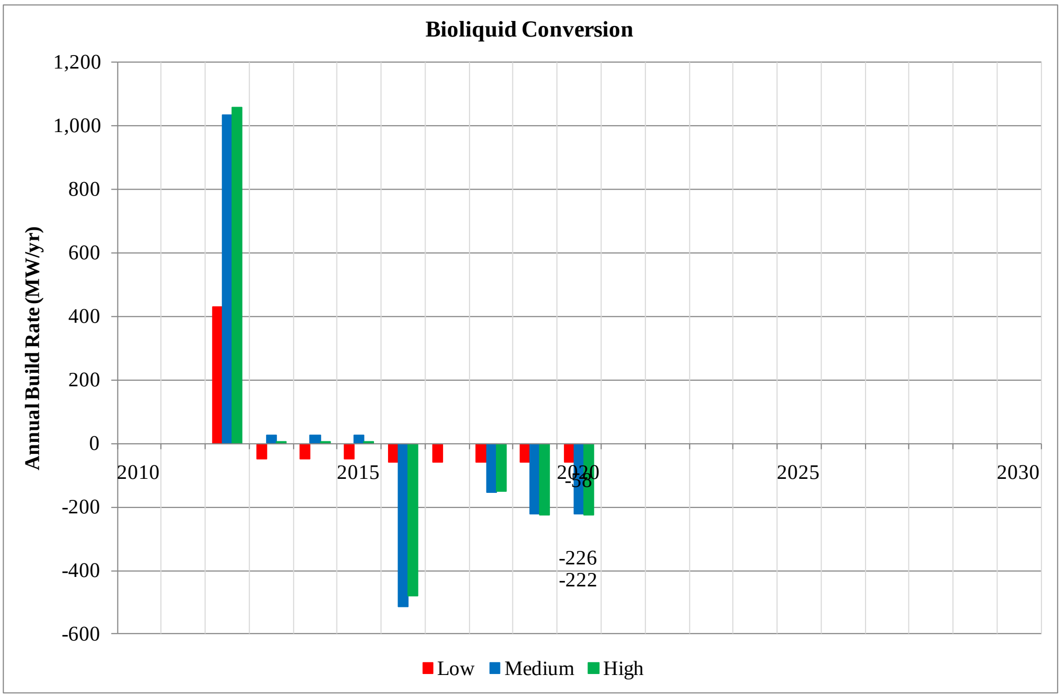


Figure 82: UK Bioliquid Conversion Annual Build Rate (MW/yr)

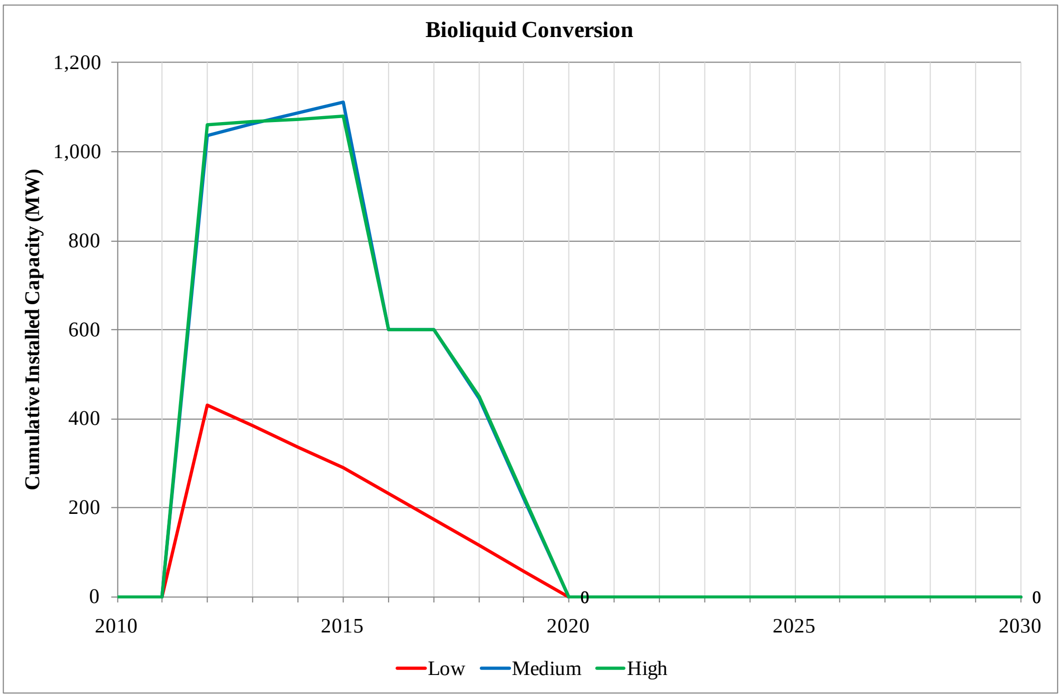


Figure 83: UK Bioliquid Conversion Installed Capacity (MW)

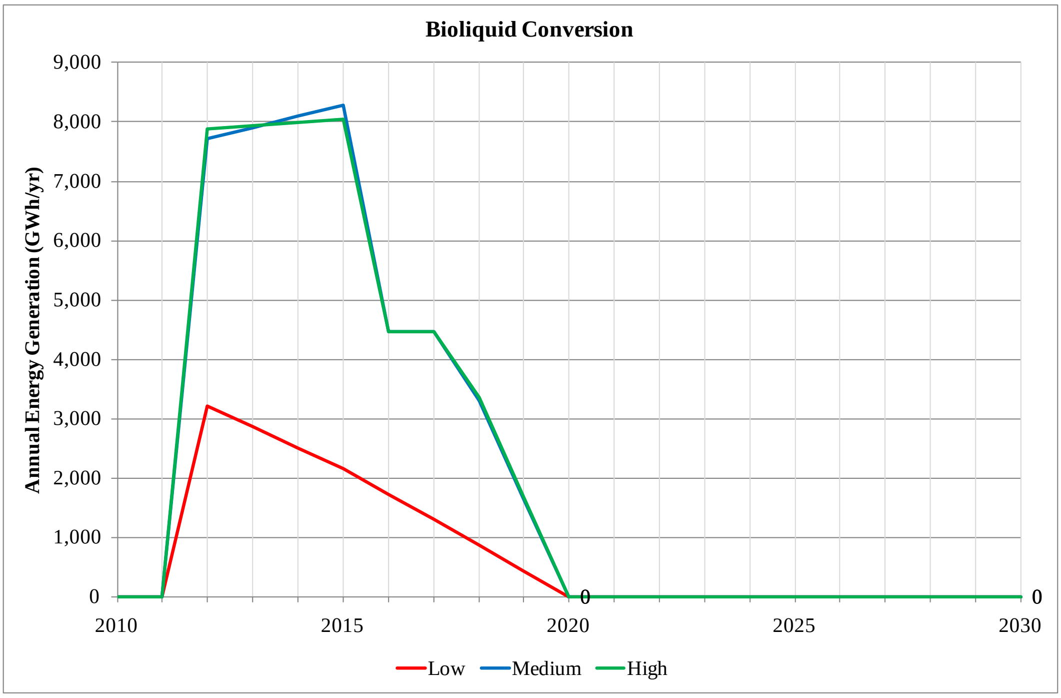


Figure 84: UK Bioliquid Conversion Annual Energy Generation (GWh/yr)

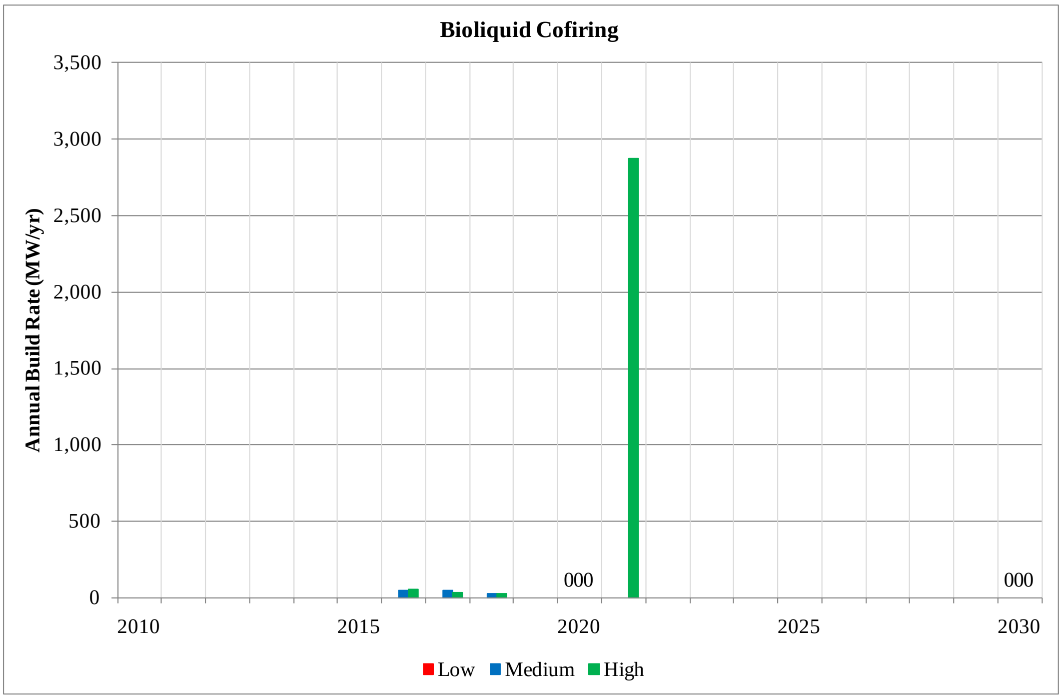


Figure 85: UK Bioliquid Co-firing Annual Build (MW/yr)

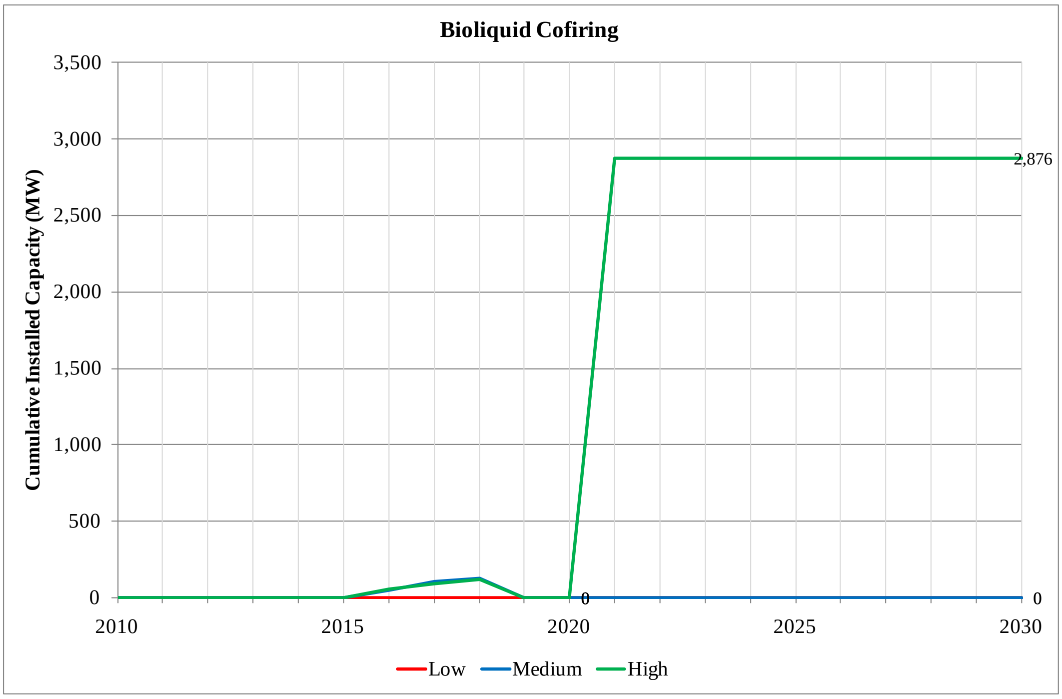


Figure 86: UK Bioliquid Co-firing Cumulative Installed Capacity (MW)

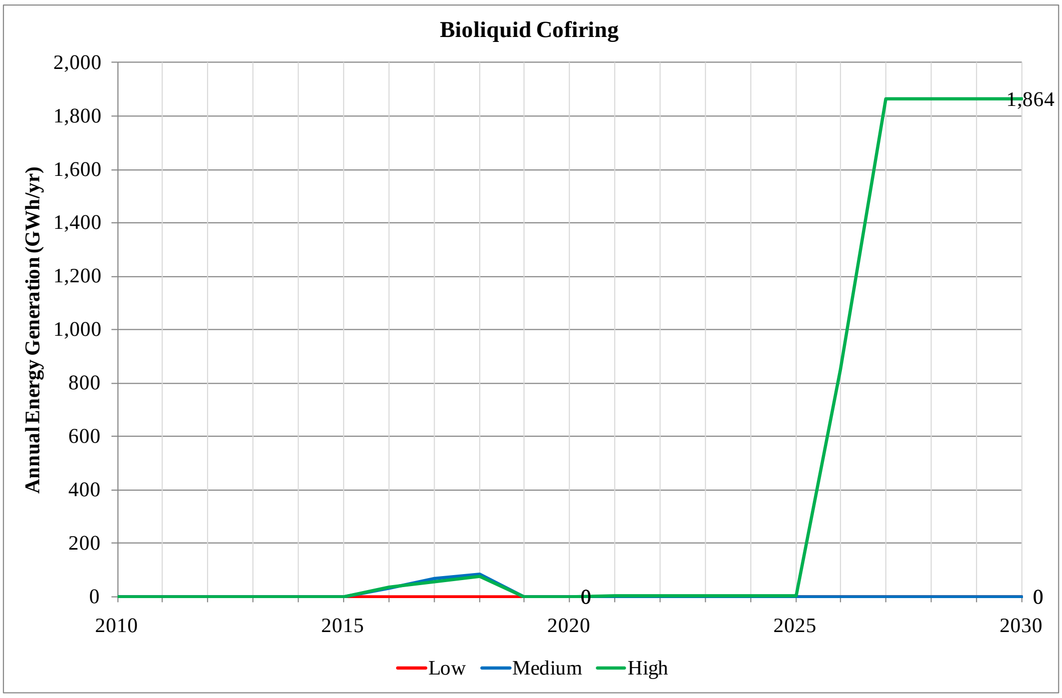


Figure 87: UK Bioliquid Co-firing Annual Energy Generation (GWh/yr)

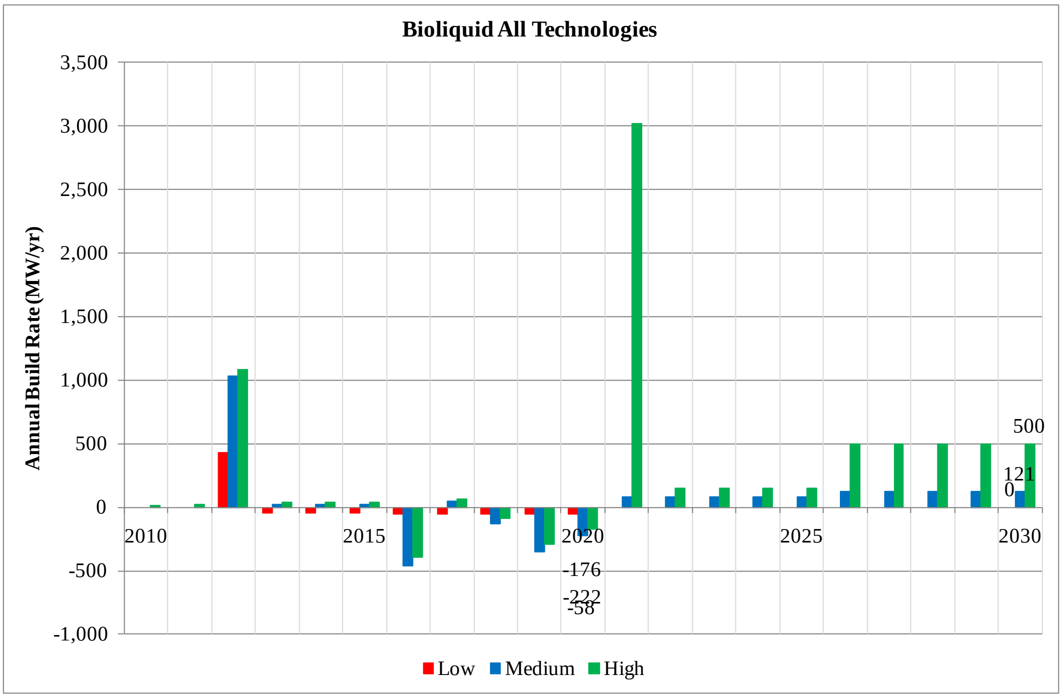


Figure 88: All UK Bioliquid Annual Build (MW/yr)

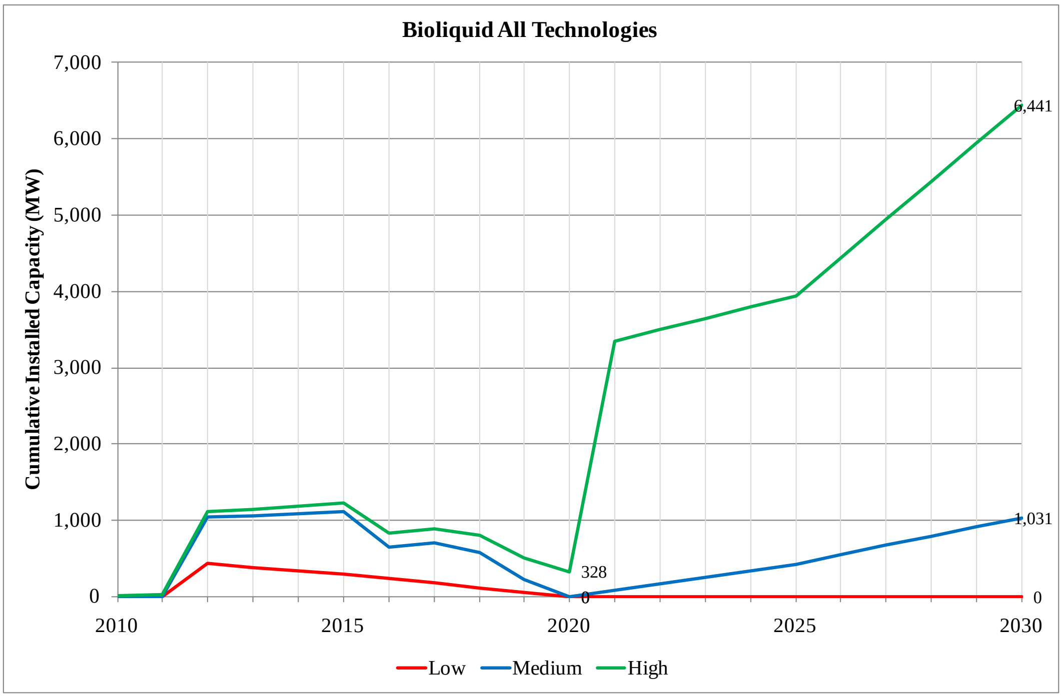


Figure 89: All UK Bioliquid Cumulative Installed Capacity (MW)

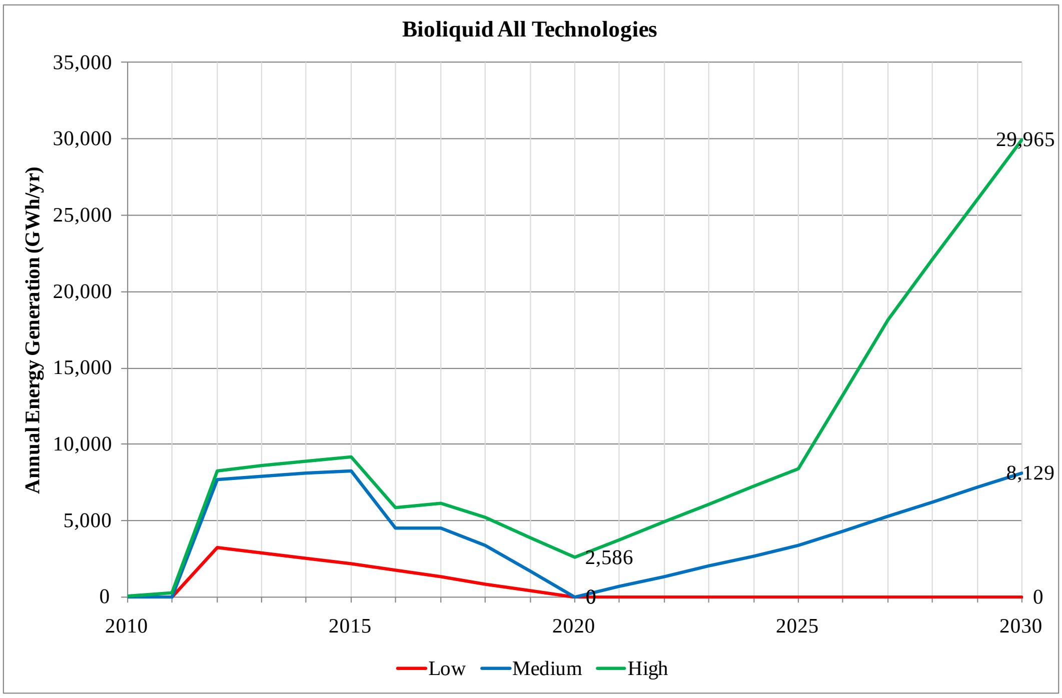


Figure 90: All UK Bioliquid Annual Energy Generation (GWh/yr)

13.7 Project Costs

13.7.1 Key Assumptions

The information collected on the project cost for bioliquids is based on consultations with industry stakeholders. It relates to projects that have recently started operation, or are in construction or development. Additional information has been collected from industry literature.

The majority of projects use similar generation equipment to convert bioliquids into electricity. However, the fuel handling and processing requirements vary with fuel type. Information has been collected for plants using biodiesel, pure plant oil (PPO), used cooking oil (UCO), tall oil, tallow and pyrolysis oil.

Stakeholders have indicated that bioliquid project hurdle rates vary between 11% and 12% (post-tax nominal).

13.7.2 Capital Expenditure

The capital expenditure assessment for bioliquids is based on project information provided by eight industry stakeholders[58]. The main capital expenditure items for bioliquid projects are generation equipment (e.g. diesel engine), ancillary fuel handling equipment, fuel processing facilities and the civil and structural aspects of the projects. The fuel processing facilities convert the raw oils into a suitable fuel. The ancillary fuel handling equipment ensures the fuel is in the correct state prior to combustion.

Stakeholders have found that pre-development costs can vary widely, from

[58] Also covered in NNFCC report

£31,000 to £1,006,000/MW. The largest proportion of pre-development cost is generally due to technical requirements. Plant scale has a significant impact on unit development cost.

In terms of capital expenditure, a number of drivers explain the existing cost ranges:

- Micro-scale projects (<50kW) experience significant diseconomies of scale. Above this range the effect is less prevalent, as plants increase capacity by using larger engines then deploying a larger number of engines, which reduces the share of site related fixed costs per unit.
- Capital costs generally increase as the properties of the fuel type used depart from diesel. It leads to a greater requirement for ancillary equipment to handle and filter the fuel prior to use in the generation equipment. These fuels will also have a greater fuel processing requirement, to convert the oil into a suitable fuel, increasing capital cost.
- Engine manufacturers will generally not provide performance guarantees for plants using fuels other than PPO. Even when available, the performance guarantees increase capital cost as they expose the manufacturer to greater risk. However guarantees can reduce future operating costs.
- It is possible for bioliquid plants to productively utilise the heat produced by generation equipment and CHP applications would be expected to form the majority of installations. One example utilises the heat requirement as natural gas is reduced in pressure as it enters local gas distribution networks. Rather than use natural gas to offset the adiabatic temperature fall, waste heat can be used to heat the natural gas. The average capital for >10MW has a larger average than the 0.05 – 10MW range. Pre-development is not included in the capital cost ranges.

Table 61: Bioliquids – Capital Costs (Financial Close 2010)

£’000/MW	<50kW	50kW – 10MW	>10MW
High	7,551	1,680	1,610
Median	3,933	875	1,250
Low	2,719	605	768

Figure 91: Bioliquids – Capital Costs (Financial Close 2010)

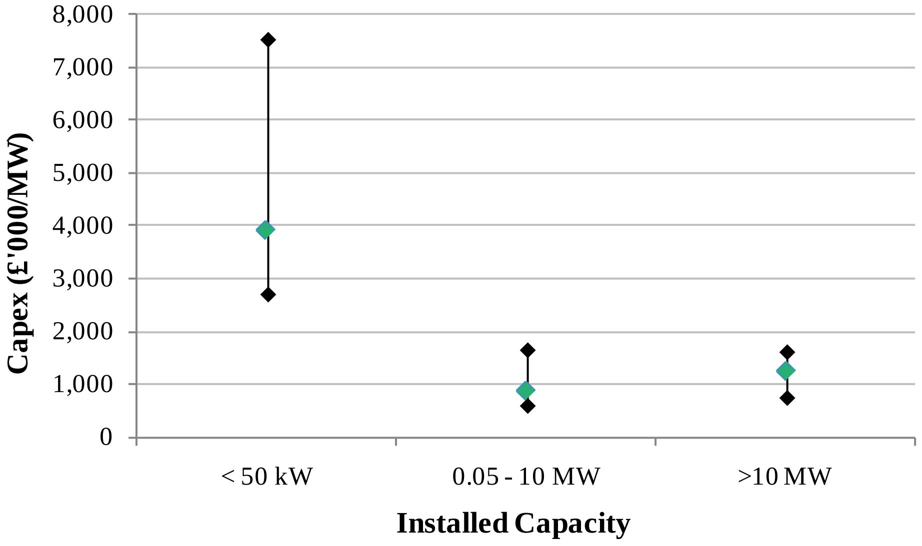


Table 62 below illustrates how capital costs are broken down in the average plant.

Table 62: Bioliquids – Capital Cost Breakdown

Capital cost item	%
Pre-development	23%
Construction	71%
Grid Connection	3%
Other Infrastructure	3%

The majority of capital costs relates to construction. Other infrastructure costs generally relate to site-specific requirements.

For future cost projections, exchange rate movements and labour cost are considered to be the most significant cost drivers. The impact of exchange rates is significant as much of the equipment is imported. The high manufacturing requirement in the equipment production process also makes labour a key cost driver.

The technology used in bioliquid projects is well established, having been used extensively for conventional energy production with diesel, so no learning effects are expected through further technological advances. However, bioliquid plants have not been widely deployed in the UK. As a result, there may be future cost reductions through supply chain development as deployment increases. In addition, reduced performance insurance costs (via guarantees) may develop, especially for newer fuels such as pyrolysis oil.

Table 63 below presents the range of current capital costs and how they are expected to change over time. These costs represent the 50kW to 10MW installed capacity range.

Table 63: Bioliquids – Capital Cost Projections at Financial Close Date (Real)

£000s/MW	2010	2015	2020	2025	2030
High	1,680	1,650	1,633	1,637	1,640
Median	875	859	851	852	854
Low	605	594	588	589	591

13.7.3 Operating Costs

Fuel costs are explicitly treated separately to other operating costs which are mainly driven by the processing and handling requirements of different fuel types. The key points in relation to operating cost ranges are as follows:

- Plants that process raw oils, such as tallow or tall oil, have greater operating costs, but reduced fuel costs.
- More viscous oils require heating before they can be used in the generation equipment. Fuel heating requirements increase operating costs.
- The generation equipment utilised in bioliquids projects is generally designed for diesel. As the properties of the different fuels depart from those of diesel, equipment maintenance and replacement costs increase.

Table 64 below presents operating cost ranges for the 50kW – 10MW installed capacity band. Stakeholders did not provide information for projects outside of this range. Fuel costs have been excluded from operating cost as they are outside the scope of this study.

Table 64: Bioliquids – Operating Costs (Financial Close 2010)

£'000/MW	50kW – 10MW
High	373
Median	169
Low	68

Labour is the principal cost driver for future O&M project costs. Labour is required for the fuel processing and the operation and maintenance of the generation and ancillary equipment. Exchange rates are also significant as many spare parts are procured from abroad.

The components that make up a bioliquid plant are well established and there is significant operating experience in other industries that employ the same type of generation equipment. Stakeholders, do not therefore expect long term learning effects in plant operation. Table 65 below shows the range of current operating costs and how they are expected to change over time. Costs represent the 50kW to 10MW installed capacity range.

Table 65: Bioliquids – Operating Costs Projections at Financial Close Dates (Real)

£'000/MW	2010	2015	2020	2025	2030
High	373	373	374	378	381
Median	169	169	170	172	173
Low	68	68	68	69	70

13.7.4 Levelised Costs

Using the Arup and E&Y capital and operating cost profiles[59] for bioliquid plants, DECC has calculated levelised costs of a reference installation at financial close in 2010, 2015, 2020, 2025 and 2030. The levelised cost ranges are based on Arup's low, medium and high capital costs. Feedstock costs are based on biodiesel price projections from AEA (2011)[60]. The levelised costs have been calculated using a pre-tax real hurdle rate of 11.9%, based on Arup stakeholder information. The levelised costs assume a load factor of 73% and a plant lifetime of 10 years.

£ / MWh		2010	2015	2020	2025	2030
Bioliquids (Biodiesel)	low	288	302	303	299	298
	medium	301	315	316	312	310
	high	357	370	371	366	364

Note: Dates refer to financial close.

13.8 Regions

Dedicated bioliquid plants for domestically sourced biomass are likely to be constructed in areas in proximity to sufficient concentrations of biomass, especially arable areas of the UK. Larger plants reliant on imported bioliquids could be located nearer to ports, however, pipeline, rail tanker and road tanker are all established transport routes for liquid fuels and therefore there is more flexibility in siting. This may particularly assist with locating plants near potential heat loads so as to maximise CHP potential.

[59] To note that the levelised costs are based on a separate set of capital and operating costs provided by Arup and E&Y that assume constant steel prices over time; do not consider other infrastructure costs that mainly relate to land purchase/ rent costs which the RO is not aiming to subsidise; and uses different size categories for some technologies.

[60] www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/energy_mix/renewable/policy/incentive/incentive.aspx

14 Energy from Waste

14.1 Summary

EfW is still relatively underdeveloped in the UK compared to other EU member states such as Denmark, Belgium, the Netherlands, France, Austria and Germany.

It is considered that there is a good potential to significantly increase the current electricity generation from waste biomass fuel of about 150MWe (i.e. 3.9Mt in 2009/10) to about double that in 2020 and almost trebling it by 2030. This correlates well with the predicted renewable electricity generation of 415MWe and associated overall waste biomass fuel resource of 12.5Mt still expected to be available in 2030 Following government reduction initiatives.

The renewable energy generation is to a large extent dependent on the biogenic carbon in the waste. It has been conservatively assumed that the waste contains 50% biogenic carbon. However, the EU Renewable Energy Directive states 62.5%, and recent research by DEFRA[61], indicates that this might be as high as 68%. Using the higher biogenic carbon values, this would increase the potential renewable electricity generation by about 25% to 30% respectively.

The main barriers to achieving the high deployment rates are associated with the long lead times for projects and the risk of planning permission delays and refusal for EfW plants.

The electricity generation is also constrained by the maximum availability of waste biomass fuel under the high scenario, and it has been assumed that no waste fuel such as SRF is being imported to the UK.

14.2 Introduction

Energy from Waste (EfW) is the term usually used to describe the process of direct and controlled combustion (or incineration) of residual municipal solid waste (MSW) to reduce its mass and volume, and to generate energy in the form of electricity and heat.

The Renewables Obligation (RO) currently only supports EfW plants that operate in combined heat and power (CHP) mode.

Arup identified a total of 26 EfW plants operating in the UK in 2009 treating almost four million tonnes of residual MSW and solid recovered fuel (SRF). Most of these plants use moving grate incineration technology, generating electricity only with about 13% operating in CHP mode. These plants have a combined renewable electricity generation capacity of about 150MWe assuming a

61 http://archive.defra.gov.uk/environment/waste/localauth/funding/pfi/documents/pfi-supporting-analysis-waste101206.pdf). The analysis assumed a biodegradable content of 68% for all municipal waste. It is supported by existing research and is considered the best available proxy for all municipal waste, including the proportion of C&I waste now classified as municipal waste (see the following) - Municipal Waste Composition – Review of Municipal Waste Component Analyses: http://randd.defra.gov.uk/Default.aspx?Menu=Menu&Module=More&Location=None&Completed=0&ProjectID=15133; and Environment Agency 2007 analysis of the biodegradable content of mixed C&I waste landfilled in Wales- *http://www.environment-agency.gov.uk/research/library/publications/33977.aspx*

load factor of 85%, an electrical efficiency of 23% and a 50% content of biogenic carbon in the waste.

EfW plants are still relatively underdeveloped in the UK compared to other EU member states such as Denmark, Belgium, the Netherlands, France, Austria and Germany. For example, there was a total of 66 EfW plants in Germany in 2005 treating about 16 million tonnes of MSW (including both renewable and non-renewable fuel) and generating about 787.5MWe (or 6.3TWh) of net electricity, and 2,150MWth (or 17.2TWh) of heat. More recent figures show that approximately 18 million tonnes of MSW are thermally treated in Germany in just under 70 incinerators. More than half of all German waste incinerators meet the proposed EU "energy efficiency threshold" of 0.6 to be classed as a recovery operation (for plants operational or permitted before 1 January 2009).[62]

It should be noted that all forecast produced in this report are not financially constrained. There is no consideration of current or future financial support mechanisms.

14.3 Limitations and Assumptions

14.3.1 Limitations

Limitations of the EfW literature review include:

- Information on planned EfW plants (i.e. those that have planning permissions granted, those that have submitted planning applications but which have not yet been determined, and those in the planning process) is not readily available.
- The renewable energy generation is to a large extent dependent on the biogenic carbon in the waste. For the purpose of this report, it has been conservatively assumed that the waste contains 50% biogenic carbon as this ties in with the percentage used for energy from municipal solid waste under the Renewables Obligation Order 2009. However, the Renewable Energy Directive states 62.5% (for the purposes of reporting against renewable energy targets) and research undertaken by the Department for Environment, Food and Rural Affairs (DEFRA) in 2008, indicates that this might be as high as 68%.[63]
- The deployment scenarios developed for EfW do not include electricity loss for operating a proportion of the plants in CHP mode. However, the overall maximum potential capacity from waste biomass fuel has been constrained at 467MWe for EfW and advanced conversion technologies (ACT) by 2030, including a provision of 25% of EfW plants operating in CHP mode by that time.
- Solid recovered fuel has not been considered separately in the AEA 2010 report but is included in the overall quantity of MSW assumed to be available for EfW.

[62] Annex II of the EU Waste Framework Directive specifies that the incineration of municipal waste may be classed as a recovery operation ('R1: Use principally as a fuel or other means to generate energy').
[63] See footnote 60

14.3.2 Assumptions

The predicted waste biomass fuel availability and associated energy conversion potential was based on the AEA UK Global Bioenergy Resource report (i.e. AEA 2010 report). Certain information and assumptions contained in the AEA 2010 report were changed after discussion with DECC and DEFRA to reflect latest policy developments and analysis on availability of waste[64]. The key technology assumptions for EfW are as follows:

- Fuel for EfW plants is assumed to be mixed residual MSW and part of the mixed Commercial and Industrial Waste (CIW), which is collectively termed in this report as 'waste biomass fuel'.
- Net calorific value (NCV) of waste biomass fuel is 9GJ/t.
- Biogenic carbon content of waste biomass fuel is 50%.
- Design life of EfW plants is 25 years.
- Load factor of EfW plants is 85% (or 7,446hours/annum).
- Electrical conversion efficiency of EfW plants is 23% in electricity only mode.
- 90% of the waste biomass fuel is predicted to be treated in 2030 using EfW plants (high scenario) with 10% being treated using advanced conversion technologies (i.e. gasification or pyrolysis).
- It has been assumed that 25% of the total waste biomass fuel available for EfW will be converted using plants operating in CHP mode with an energy efficiency of 65% (i.e. electrical efficiency of 20% and thermal efficiency of 45%).
- Available waste biomass fuel was approximately 5.1Mt in 2010, of which 3.9Mt was treated using EfW.[65] AEA has predicted that the total available waste biomass fuel resource for thermal waste treatment will be 12.5Mt in 2030.[66]

14.4 Constraints

14.4.1 Supply Chain

The supply chain for the development and deployment of EfW plants is not considered to be a main constraint. There are many experienced EfW technology providers with the ability to provide turnkey plants or plant components such as combustion grates, boilers, steam turbine generators and flue gas treatment systems etc.

Central and local Government, through the waste Private Finance Initiative (PFI),

---

[64] http://archive.defra.gov.uk/corporate/consult/waste-review/100729-waste-review-call-for-evidence.pdf

[65] This is based on an unconstrained feedstock potential estimated by AEA of 58.7Mt and competing feedstock use of 53.6Mt. The competing feedstock uses include, for example, recycling and landfill disposal of waste.

[66] DEFRA are currently undertaking some further analysis on the availability of waste biomass fuel for thermal treatment. The AEA estimate is considered to be at the upper end of the available resource.

has been successful in attracting considerable interest in EfW projects in the UK with a good level of competition and new entrants to the market.[67] Joint ventures have also been formed with, for example, energy companies to be able to best respond to the market opportunities and apply the required technical knowledge.

In total, seven waste PFI projects had their funding withdrawn by the Government in 2010. Based on our information, only two out of the seven procurement processes appear to have been affected in a detrimental way (i.e. Cheshire West and Chester/Cheshire East and Leicestershire have no clear plans announced on whether or how procurement will proceed). It is likely that most of the local authorities will continue with the procurement of their projects given that there is a need for new waste treatment infrastructure to meet, for example, EU targets for diversion of biodegradable municipal waste from landfill, and potential fines if these targets cannot be met, as well as other benefits, such as better environmental performance.

Based on our experience and discussion with representatives from the waste management industry, one of the constraints that could slow down the delivery of new EfW plants is that the project development costs (e.g. civil construction works etc) are considered to be higher in the UK compared to other parts of Europe.

14.4.2 Planning

Based on information obtained from Department of Community and Local Government comprising 2009 and 2010 planning decision statistics for waste planning applications in England, the success rate is high for major waste planning applications – 90% and 88% respectively out of a total of over 400 applications each year. However, obtaining planning permission for EfW plants is a challenge for local authorities and project developers.

There is often concern by residents about potential adverse health effects associated with EfW plants, resulting in objections which can cause substantial delays to the procurement process or termination of projects. There are several recent cases where waste PFI projects were rejected by the local planning authority (e.g. Surrey and Cornwall) or where developers have withdrawn their applications.

It has been reported by the National Audit Office (NAO), that there are often long lead times for developing projects and that it takes five to nine years to develop projects and bring assets into operation. The NAO report also states that: *"Prior to contract award, PFI projects have been delayed by an average of 19 months compared to the original timetables"*.

The deployment scenarios developed by Arup for EfW plants not currently under construction have considered the number of plants which have planning permissions granted, those that have submitted a planning application but which have not yet been determined, and those which are in the planning process. In addition, the lead times for developing projects have also been considered based on 2010 data. It has been assumed that the construction and commissioning

[67] As part of the Government's Spending Review, it was concluded in October 2010 to withdraw the provisional allocation of PFI credits from seven projects. (see http://www.defra.gov.uk/news/2010/10/20/changes-to-pfi-programme/)

periods for the four EfW plants identified as being under construction is four (low scenario), three (medium scenario) and two years (high scenario) respectively. In comparison to the plants under construction, for plants not yet under construction, the deployment period has been assumed to be constrained by the capacity of the market to respond to an increase in the deployment rate of EfW plants due to limited resources of project developers, technology providers and other support services to deliver plants under a high deployment scenario. The deployment scenarios developed for EfW plants are as follows:

Planning Permission Granted

- Low deployment – 50% of plants that have planning permission are being built assuming a construction and commissioning period of four years;
- Medium deployment – 70% of plants that have planning permission are being built assuming a construction and commissioning period of five years; and
- High deployment – 90% of plants that have planning permission are being built assuming a construction and commissioning period of six years.

Planning Permission Submitted but No Decision

- Low deployment – 40% of plants that have planning permission submitted but no decision are being built assuming a construction and commissioning period of four years;

Medium deployment – 60% of plants that have planning permission submitted but no decision are being built assuming a construction and commissioning period of five years; and

High deployment – 80% of plants that have planning permission submitted but no decision are being built assuming a construction and commissioning period of six years.

In the Planning Process

- Low deployment – 40% of plants that are in the planning process are being built assuming a construction and commissioning period of six years;
- Medium deployment – 60% of plants that are in the planning process are being built assuming a construction and commissioning period of seven years; and
- High deployment – 80% of plants that are in the planning process are being built assuming a construction and commissioning period of eight years.

14.4.3 UK Grid

The average EfW plant size is about 200,000 to 250,000 tonnes/annum generating about 15MWe to 20MWe of net electricity. Based on this plant size, electricity off-take to the UK national grid is not expected to represent a significant constraint. Where larger plants (e.g. >50MWe) are being developed, it is likely that these would be constructed in industrial areas or where there is good existing off-take infrastructure. The number of large EfW plants likely to be developed is considered to be relatively small.

14.4.4 Technical

EfW plants are one of the most proven technologies for the thermal treatment of mixed waste biomass fuel. There is a range of technology providers and project developers established in the market, and they have demonstrated their ability to successfully deliver EfW plants.

No particular innovation is expected regarding EfW technology given that it is a well established and researched technology. The main challenge will be to make better use of the heat generated to improve the overall energy efficiency of EfW plants resulting in better environmental performance (e.g. reduced greenhouse gas emissions). Efficient EfW plants can also be classified as energy recovery operations (R1 facilities) rather than waste disposal.

Currently, only about 13% of EfW plants (i.e. five plants) treating waste biomass fuel operate in CHP mode in the UK. The Confederation of European Waste to Energy Plants states: "*Taking the reference year 2006, the total amount of WtE plants in Europe (EU27+ Switzerland+Norway) was 420. From this number 252 WtE plants in Europe are below the R1 factor 0.60 or did not participate. In other words - so far only 40% of plants are proven to reach R1.*"

Developing heat transmission networks is challenging because there is a number of barriers to their deployment, for example, availability of heat customers (e.g. food and drink industry, homes, hospitals, universities etc) located in close proximity to the EfW plants, and affordability (e.g. capital costs of the heat network and connections).

14.4.5 Other Constraints

The main incentive for developing EfW plants in the UK is the rising cost for landfill disposal of waste driven by the increasing landfill tax. Landfill gate fees will soon be higher for MSW than typical gate fees for the treatment of waste using EfW. However, if this fiscal incentive is stopped or reversed than this would have an adverse effect on the deployment of EfW treatment capacity. DECC requirements were that financial constraints/incentives not be taken into account in the maximum build rates scenarios.

14.5 Maximum Build Rate Scenarios

14.5.1 Available Resource

The renewable fraction of solid waste includes MSW and the mixed waste stream of CIW (i.e. waste biomass fuel). As stated above, the available potential for waste biomass fuel has been taken from the AEA 2010 report, and is estimated by AEA to amount to 12.5Mt in 2030. This estimate is based on a 'paired scenario' with landfill gas to avoid double counting of the waste biomass fuel used to calculate renewable electricity generation.

AEA also assumes that UK recycling targets take precedence and are achieved, and that uptake of EfW accelerates in line with MSW 'recovery' targets to 2020 (75% in 2020, rising to 80% in 2025). AEA has assumed that the share of the residual waste going to EfW after recycling rises from their values in 2009 (16% MSW and 1% CIW respectively) to reach 50% in 2025, with the remainder going to landfill.

AEA has stated that anaerobic digestion of the wet fraction of MSW and CIW are counted as part of the recycling fraction.

14.5.2 Low Scenario

The following assumptions have been made: 100% of EfW plants currently under construction will be constructed and commissioned over a period of four years. Subsequently, 50% of EfW plants that have planning permission will be constructed and commissioned over a period of four years. Thereafter, 40% of EfW plants that have submitted a planning application but no decision has been made will be constructed and commissioned over a period of five years, and 40% EfW plants that are in the planning process will be deployed over a period of six years. Thereafter, the build rate has been assumed to be constant until 2030.

14.5.3 Medium Scenario

The following assumptions have been made: 100% of EfW plants currently under construction will be constructed and commissioned over a period of three years. Subsequently, 70% of EfW plants that have planning permission will be constructed and commissioned over a period of five years. Thereafter, 60% of EfW plants that have submitted a planning application but no decision has been made will be constructed and commissioned over a period of five years, and 60% of EfW plants in the planning process will be deployed over a period of seven years. Thereafter, the build rate has been assumed to be constant until 2030.

14.5.4 High Scenario

The following assumptions have been made: 100% of waste to energy plants currently under construction will be constructed and commissioned over a period of two years. Subsequently, 90% of EfW plants that have planning permission will be constructed and commissioned over a period of six years. Thereafter, 80% of EfW plants that have submitted a planning application but no has been made decision will be constructed and commissioned over a period of six years, and 80% of EfW plants that are in the planning process will be deployed over a period of eight years. Thereafter, the build rate has been assumed to be constant until 2030.

14.5.5 Maximum Build Rate Plots

Figures 92, 93 and 94 represent annual deployment rates in MW/yr (see Figure 92), cumulative installed capacity in MW (see Figure 93), and cumulative renewable electricity generation per year in GWh/yr (see Figure 94) for EfW until 2030.

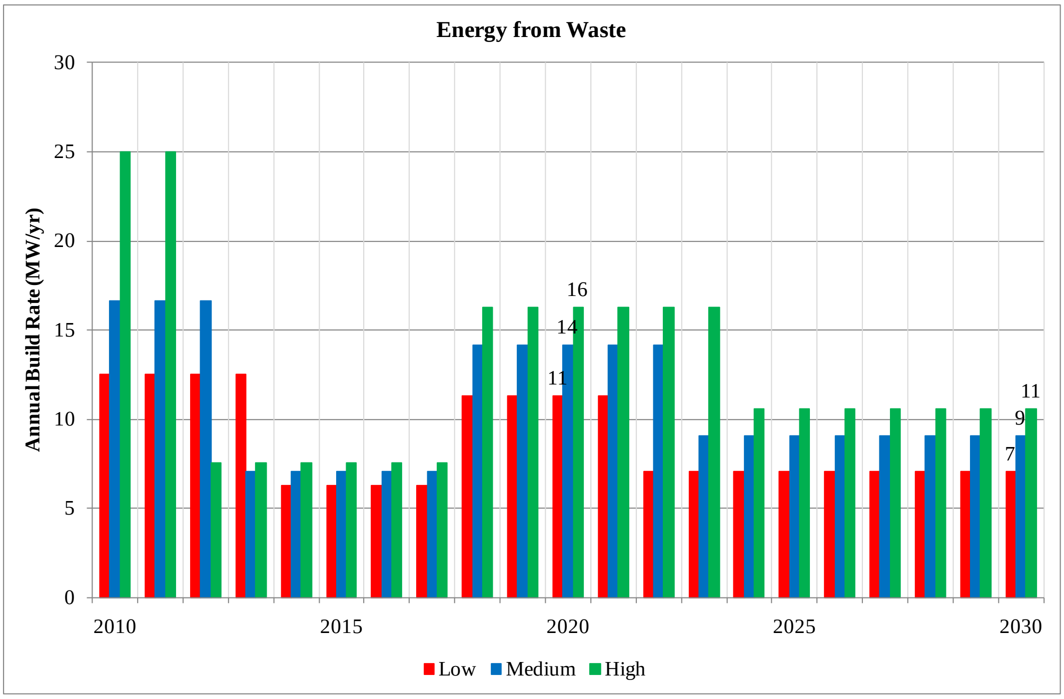


Figure 92: UK Energy from Waste Annual Build Rate (MW/yr)

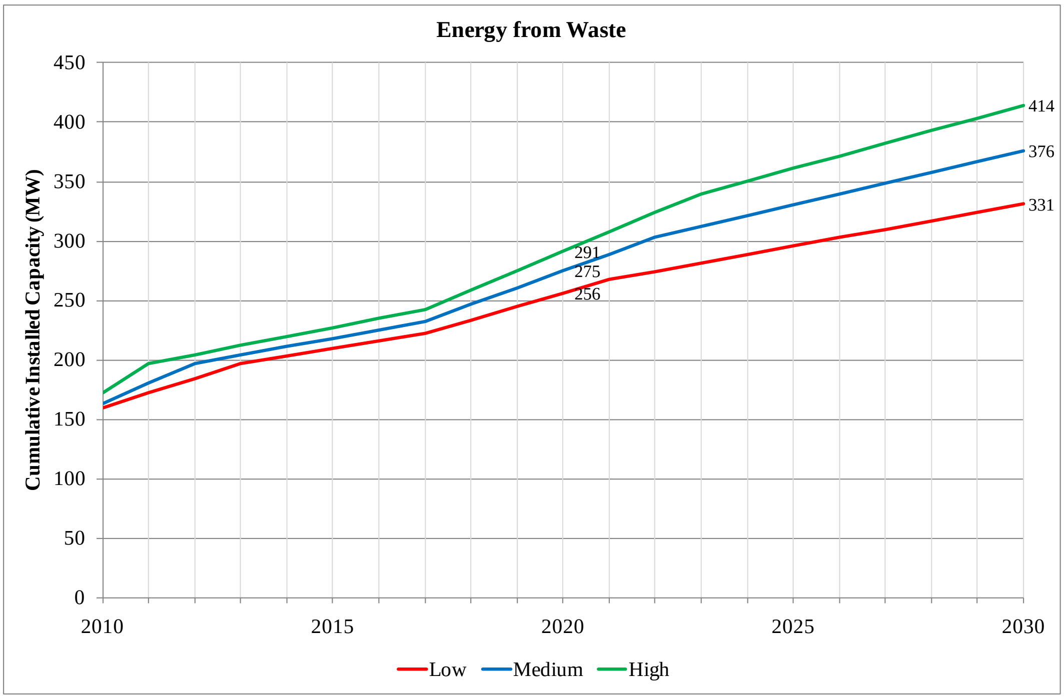


Figure 93: UK Energy from Waste Cumulative Installed Capacity (MW)

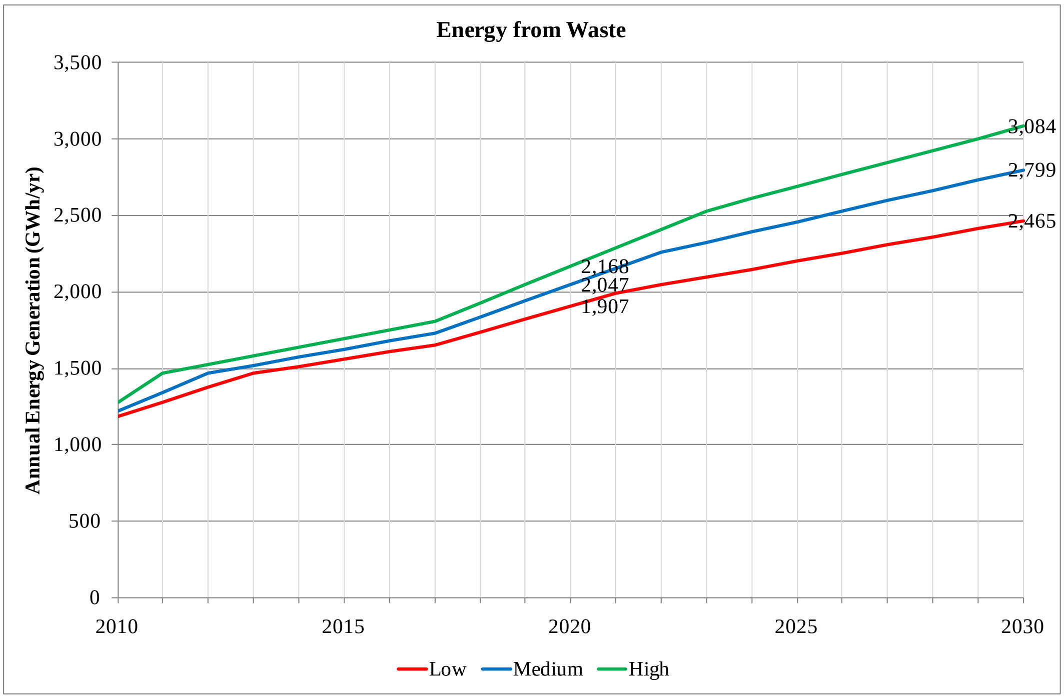


Figure 94: UK Energy from Waste Annual Energy Generation (GWh/yr)

14.6 Beyond 2030

The deployment rate of EfW plants after 2030 is expected to be relatively low if sufficient EfW plants are built between now and 2030 to treat the quantity of waste biomass fuel expected to be available. It is assumed that the UK would not import large quantities of SRF for treatment using EfW.

14.7 Cost and Pricing

14.7.1 Key Assumptions

The project cost information for Energy from Waste Combined Heat and Power (EfW CHP) has been provided by three industry stakeholders.

Stakeholders have indicated that project hurdle rates vary from 11% to 12% (post-tax nominal).

14.7.2 Capital Expenditure

Pre-development costs range from £95,000/MW to £216,000/MW, the majority of which relates to pre-licensing and planning. Stakeholders have experienced significant variations in pre-development costs which are created by project specific characteristics, not scale. These include tender cost, environmental permitting and the pre-development timescale.

The variation in capital cost between projects generally relates to economies of scale, site specific requirements, waste processing equipment and fuel type, for example:

- The standard of equipment required varies between plants. This is due to differences in planning conditions and client specification.

- Plants can include Mechanical Biological Treatment (MBT) facilities. This allows for removal of recyclable elements of waste, but increases the capital cost.
- Projects may use SRF, which is derived from MSW. SRF has a higher energy density than untreated MSW, so a smaller volume is required to produce the same quantity of electricity output. As less fuel is required per unit of installed capacity, the equipment requirements are reduced, leading to lower unit capital cost.

Table 66 below presents the capital cost range for EfW CHP. Predevelopment is not included in the capital cost range.

Table 66: EfW CHP – Capital Costs (Financial Close 2010)

£000s/MW	5 - 50MW
High	7,134
Median	5,062
Low	3,941

Table 67 below illustrates the breakdown of capital costs for EfW CHP projects.

Table 67: EfW CHP – Capital Cost Breakdown

Capital Cost Item	%
Pre-development	3%
Construction	84%
Grid Connection	3%
Other Infrastructure	10%

Labour and exchange rates are the main drivers of capital cost. The contribution of labour costs relates to its requirement in manufacturing equipment. The impact of exchange rate movements is significant as much of the equipment required is imported.

Limited learning effects are anticipated since the technology is relatively mature and stakeholders see limited potential for technological improvements. Table 68 presents the range of current capital costs and how they are expected to change over time.

Table 68: EfW CHP – Capital Cost Projections at Financial Close Dates (Real)

£000s/MW	2010	2015	2020	2025	2030
High	7,134	7,058	7,023	7,050	7,077
Median	5,062	5,008	4,983	5,002	5,022
Low	3,941	3,899	3,880	3,895	3,910

14.7.3 Operating Cost

Operating costs show a relatively small range. This indicates that operating requirements of EfW CHP plants are relatively standardised. Table 69 below presents the operating cost range for EfW CHP.

Table 69: EfW CHP – Operating Costs (Financial Close 2010)

£000s/MW	5-50MW
High	539
Median	482
Low	368

Labour is the most significant variable of future operating cost. Exchange rates also have a material impact as many spare parts are manufactured abroad.

The technology is well established and stakeholders have gained significant experience in running plants. No learning effects are anticipated in plant operation. Table 70 below shows the range of current operating costs and how they will change over time.

Table 70: EfW CHP – Operating Costs Projections at Financial Close Dates (Real)

£000s/MW	2010	2015	2020	2025	2030
High	539	546	552	559	566
Median	482	488	494	500	506
Low	368	372	377	382	386

14.7.4 Levelised Costs

Using the Arup and E&Y capital and operating cost profiles[68] for EfW CHP,

[68] To note that the levelised costs are based on a separate set of capital and operating costs provided by Arup and E&Y that assume constant steel prices over time; capex includes infrastructure costs are incurred in the core facility, but do not include 'other' infrastructure costs that relate to costs incurred outside the site, such as water, roads, waste disposal and land costs. Levelised costs use different size categories for some technologies.

DECC has calculated levelised costs of a reference installation at financial close in 2010, 2015, 2020, 2025 and 2030, respectively. The levelised cost ranges are based on Arup's respective low, medium and high capital cost estimates. Gate fee assumptions for EfW CHP are based on the lower end of the gate fee range in the WRAP Gate Fee Report (2010)[69]. It should be noted that there is a large range of possible gate fees and the choice of gate fee strongly impacts on levelised costs. In addition the levelised costs take into account a heat revenue, based on an avoided gas boiler cost approach. Avoided capex/opex are based on AEA/NERA (2009)[70]; avoided gas fuel and carbon costs are based on DECC gas and carbon price projections. The levelised costs of EfW CHP do not take into account the cost of delivery of the heat to the customer.

The levelised costs have been calculated by assuming a pre-tax real hurdle rate of 12.9% for EfW CHP. Hurdle rates are based on Arup stakeholder information, the Oxera report[71] for the CCC and DECC assumptions. CHP technologies are assumed to be more risky than power only technologies, which is reflected in a 1 percentage point uplift in hurdle rate for CHP technologies. The levelised costs assume an 83% load factor and 29 years lifetime for EfW CHP.

£ / MWh		2010	2015	2020	2025	2030
EfW CHP	low	-52	-54	-63	-73	-82
	medium	-30	-33	-42	-52	-61
	high	11	8	-3	-12	-22

Note: Dates refer to financial close.

14.8 Regions

England is likely to have the highest concentration of EfW plants given that it generates about 80% of the total MSW in the UK. The geographic distribution of EfW plants is driven by the cost for transporting the waste to the nearest waste treatment plant. An average transportation distance is about 40km (i.e. 25 miles). Transporting waste over greater distances is generally uneconomical and therefore plants are likely to be located relatively close to the production of the waste. This is also in line with national waste policy to manage waste as close as possible to the point of production (the 'Proximity Principle'). However, there may be opportunities to transport waste by rail or water over longer distances to a centralised waste treatment plant.

[69] www.wrap.org.uk/downloads/2010_Gate_Fees_Report.53e7e3d7.9523.pdf
[70] www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/energy_mix/renewable/policy/incentive/incentive.aspx
[71] www.oxera.com/main.aspx?id=9514

15 Anaerobic Digestion

15.1 Summary

Electricity generation using anaerobic digestion (AD) technology has been considered for food waste and farm manures.

The installed capacity for the treatment of food waste and farm manures in 2010 is about 28MWe.

The available energy from AD is 5,661GWh per year, which is equivalent to 708MWe of installed generation capacity at 2030.

For the low scenario the installed capacity would reach 60.5% of the maximum resource available by 2030.

For the medium scenario, the maximum generation capacity is predicted to be reached by 2030.

For the high scenario the maximum generation capacity is predicted to be reached by 2020.

15.2 Introduction

Anaerobic digestion (AD) is the biological conversion of biodegradable organic material by micro-organisms in the absence of oxygen, which results in a reduction in the quantity of organic material and the production of biogas, consisting of approximately 55-70% methane, 30-45% Carbon Dioxide and approximately 1% nitrogen, with trace elements of hydrogen sulphide. The process also produces a nutrient-rich liquid and solid bio-fertiliser (i.e. digestate).

The process is widely employed by the water industry within the UK for the stabilisation of sewage sludge. In addition to the water industry, there is a growing interest in the digestion of alternative feedstock including food waste, farmyard waste materials and crops grown specifically for AD. However, AD plant development in the UK has been slow compared to some other EU member states (e.g. Austria, Denmark, Germany and Sweden).

There is a number of AD technologies available and their technical complexity and associated capital and operational costs depend on the feedstock to be treated. Typically, food waste AD plants are technically more complex requiring, for example, a greater degree of pre- or post-processing of the feedstock to remove certain contaminants such as plastic packaging, metals, glass etc, and pasteurisation units to meet the strict Animal By-Products Regulations etc.

The AD process operates under mesophilic (25-45°C) or thermophilic (50-60°C) conditions. Furthermore, the process may operate as either a dry digestion process, with material at a dry solids content of greater than 15%, or a wet process, operating below 15% dry solids, more suited to materials such as animal slurry.

Biogas is typically collected and used to heat the digester, to optimise the digestion process, and at larger plants where it is economical, biogas is collected and used for in combined heat and power (CHP) plants. Current advances are also being made in the injecting of biomethane (processed biogas) into the national gas grid and the use of biomethane as biofuel for transport.

Digestion of food waste and of manures may be carried out separately or in a combined treatment process. As stated above, the former can require significant pre-treatment processing, to remove contaminants such as packaging, and may therefore entail a greater capital and operating cost depending on the food waste being processed.

While there are both cost and legislative differences in the treatment of farm and food waste, digestion of these two waste streams is sometimes carried out together. A small number of the existing anaerobic digestion plants in the UK, both on-farm and off-farm, both on-farm and off-farm, treat a mixture of food waste and manures, and depending on their environmental permits may vary the feedstock to some degree, based on the availability and the increase in income associated with treating food waste from both a gate fee and increased biogas potential.

In addition, to the benefits provided by energy production, the digestion of food waste provides the benefit of a sustainable waste treatment process for the diversion of biodegradable material away from landfill, in line with UK regional waste strategies. The digestion of farmyard manures improves the fertilising properties and reduces the environmental effects of spreading undigested manure and slurry (Environment Agency, 2010).

It should be noted that all forecast produced in this report are not financially constrained. There is no consideration of current or future financial support mechanisms.

15.3 Literature Review

Primary conclusions and findings from this review were:

The AEA technology biomass predictions were used to inform the waste resource available for AD. The report identified total and available quantities for the three suitable waste types, consisting of food waste and farmyard manures.

15.4 Limitations & Assumptions

15.4.1 Limitations

Due to the interrelationship between the digestion of food waste and farmyard manures, it has not been possible to separate the build rate scenarios for these two feedstocks. The existing number of both on-farm and off-farm digestion facilities has been identified. However, as both type of facilities do treat either, or both, food waste and farmyard manures build rates scenarios reflect the combined capacity for both.

15.4.2 Assumptions

The AD Feedstock Resource Availability:

The quantity of available food waste and farmyard manures is based on the estimates from AEA Technology (2010) report.

The energy yield for the combined on-farm and off-farm facilities is based separately on the quantity of food waste and farmyard manures available.

Electrical Energy Yield per Wet Tonne of Feedstock:

The net electrical yield of farmyard manures is assumed as 40kWh/tonne, based on:

- A calorific value of 0.38GJ/tonne (AEA Technology 2010);
- A CHP electrical generation efficiency of 38%; and
- Negligible parasitic load, based on minimal pre- and post-treatment requirements.

The calorific value of the manure is based on an average manure of 7% dry solids (DS), 50% of which are volatile solids (VS). Fifty four percent of the VS are digested, giving 18.9Nm^3/tonne of biogas with a calorific value of 20MJ/Nm^3. The calculations assume that manure has a specific gravity of one tonne per norm cubic metre.

The net electrical yield of food waste is assumed to be 200kWh/tonne.

The calorific value of food waste is assumed to be 3.26GJ/tonne. This is based on an average DS of 27.7% of which 87.9% are VS. Sixty seven percent of the VS are digested during the digestion, giving 163Nm^3 of biogas.

Assuming a CV of 20MJ/m^3 for the biogas gives an energy yield of 3.26GJ/tonne of food waste, which is equivalent to 906kWh/tonne. Assuming an electrical efficiency of CHP unit of 38%, this equates to electrical output of 344kWh/tonne food waste, not including parasitic load.

However, the typical net electrical output from food waste AD of 200kWh/tonne has been used, based on Arup's experience and consultation with AD technology providers.

Current Installed Capacity:

It is assumed that the UK has a current installed capacity of 28MWe for both on-farm and off-farm units (www.biogas-info.co.uk/).

The forecast for installed capacity is based on the available energy resource, biogas, being combusted in CHP engines operating for 8,000 hours per year (i.e. 91.3% load factor).

In deriving the maximum electrical generation from AD, it has been assumed that the use of biogas for transport fuel and for injection into the national gas grid is insignificant.

15.5 Constraints

15.5.1 Supply Chain

The supply chain for the development of AD facilities is not considered to represent a significant constraint. Many of the individual components of a facility are readily available. This includes CHP engines, pumps and tanks.

The key cost drivers are steel, labour, commodities, civils costs, concrete and exchange rate fluctuations. The exchange rate risk is high with the majority of technology providers based in Europe.

The feedstock supply chain is not currently able to provide sufficient material to allow the estimated increase in capacity. Further development of the waste recycling industry, including an increase in the collection of source segregated food waste etc is required to enable the predicted capacity to be reached. As landfill tax increases and proposed changes to municipal food waste collections are implemented, it is expected that municipal food waste collections will increase, as local authorities are required to meet recycling targets set out in their waste strategies and this will support the increase in treatment capacity. However, there is a risk that many local authorities may postpone the implementation of separate food and green waste collection schemes for a period of time (likely to be two to three years) due to recent local authority budget cuts.

15.5.2 Planning

Planning is not considered to represent a key issue for AD facilities compared to other waste treatment technologies such as incineration. For example, farm scale AD facilities would generally be expected to be relatively small, with the activities appropriate to a farm setting. However, obtaining planning permission is still a critical step in the development of an AD plant requiring due attention.

Larger scale off-farm or food waste facilities may be considered as ‘bad neighbour’ waste treatment sites by the general public and are therefore at risk of experiencing local opposition and subsequent planning delays, particularly if developed as part of an integrated waste management facility. However, the current experience suggests that where located, for example, on existing industrial sites, the barriers to obtaining planning permission can be managed to reduce the risk of planning permission refusal.

15.5.3 UK Grid

Small scale on-farm facilities tend to use the biogas for on-site use. For small-scale off-farm sites, the cost of connection to the national grid is a constraint. For larger plants, connection costs represents a smaller proportion of total costs and so are not a significant issue in the development of AD capacity.

15.5.4 Technical

AD is a relatively established technology in the UK for sewage sludge and the basics of the process are therefore relatively well understood. However, its application to food and farm waste feedstock is relatively new and the deployment of AD plants used is currently going through a period of refining the technology to suit the feedstock.

Current innovation includes development and optimisation of the pre-processing waste handling technologies, such as food waste de-packaging, and pre-treatment and development of advanced digestion processes for food wastes, similar to those used for sewage sludge.

Optimisation of the processes is unlikely to offer significant improvements in terms of maintenance, reliability and some limited improvement in gas yield.

Development of alternative energy use options such as upgrading of the biogas for injection into the gas grid or for use as a transport fuel, through the development of more financially viable gas upgrading technologies, would reduce the capacity available for electricity generation.

15.5.5 Other Constraints

A key constraint to the initial development of on-farm AD capacity is the perception of the cost benefit and operational issues of AD by the farming community. This constraint would be reduced through education reflecting on successful case studies and by positive word of mouth.

15.6 Maximum Build Rate Scenarios

15.6.1 Available Resource

The maximum potential for energy generation from AD is based on an unconstrained supply of the suitable UK resources.

The available quantity of food waste in the UK is 15.8 million tonnes per annum (AEA Technology 2010). Based on an electrical generation of 200kWh/tonne there is the potential for 3,160GWh electricity per year to be produced from food waste and green waste. Assuming that all biogas is used for electrical generation via CHP this is equivalent to an installed generating capacity of 395MWe.

The available quantity of farmyard manures in the UK is 62.6 million tonnes per annum (AEA Technology 2010). Based on an electrical generation of 40kWh/tonne there is the potential for 2,504GWh electricity per year. This is equivalent to an installed generating capacity of 313MWe.

The total available resource for electricity generation from AD is therefore 5,661GWh/year from 2020 onwards, with an installed generation capacity of 0.708GWe (or 708MWe).

Import of waste material for AD has not been included in the forecast of electricity generation as this would be in conflict with the ‘proximity principle’ that states that waste should be treated as close as possible to the source of generation, and the restrictions of transfrontier shipment of waste.

15.6.2 Low Scenario

The low scenario assumes a constant increase in on-farm and off-farm generation capacity in line with 2010 deployment rates of 20MWe/yr.

By 2030, AD would be generating 3,421GWh per year of electricity from an installed capacity of 428MWe.

15.6.3 Medium Scenario

The medium scenario assumes the deployment increases from a current deployment rate of 20MWe/yr in 2010 up to 40MWe/yr, by 2015, due to a faster uptake of the technology by potential operators.

The scenario predicts that AD would be generating the maximum available electricity of 5,661GWh from an installed capacity of 708MWe by 2030.

15.6.4 High Scenario

The high scenario assumes deployment increases from the current deployment rate (20MWe/yr in 2010) up to 100MWe/yr, by 2016, due to a faster uptake of the technology resulting from other successful projects and good communication across the industry. The rate of increase predicted would still be less than the maximum increase experienced in Germany, of approximately 310MWe/yr installed. However, it should be recognised that in Germany the development of energy crop plant rather than waste plant was encouraged.

The scenario predicts that AD would be generating the maximum available electricity of 5,661GWh from an installed capacity of 708MWe by 2020.

15.6.5 Maximum Build Rate Plots

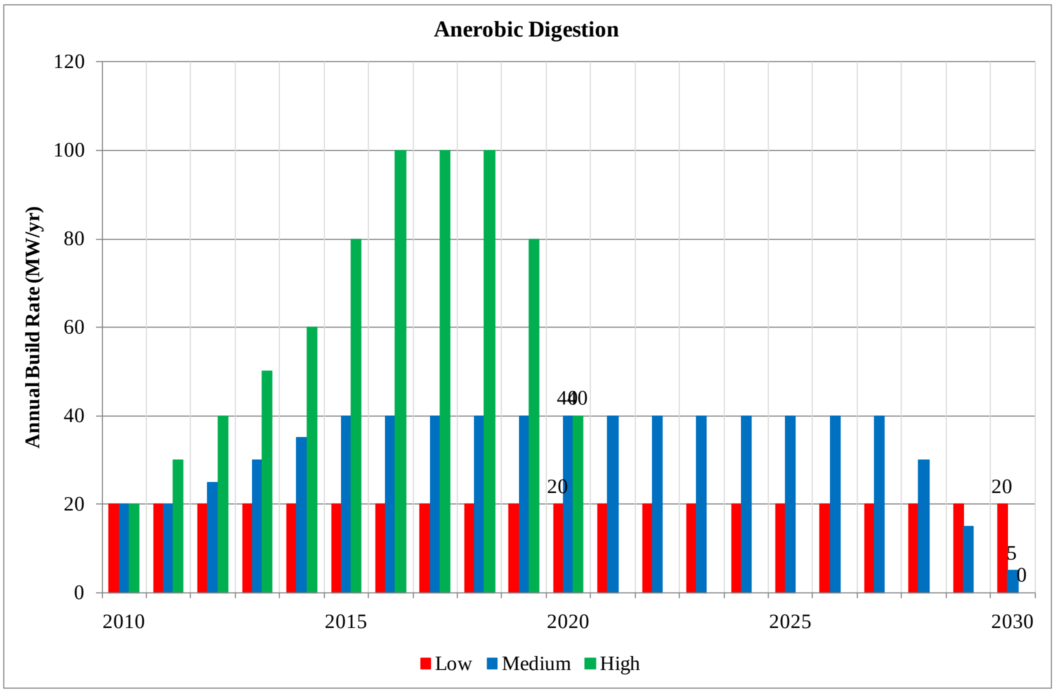


Figure 95: UK Anaerobic Digestion Annual Build Rate (MW/yr)

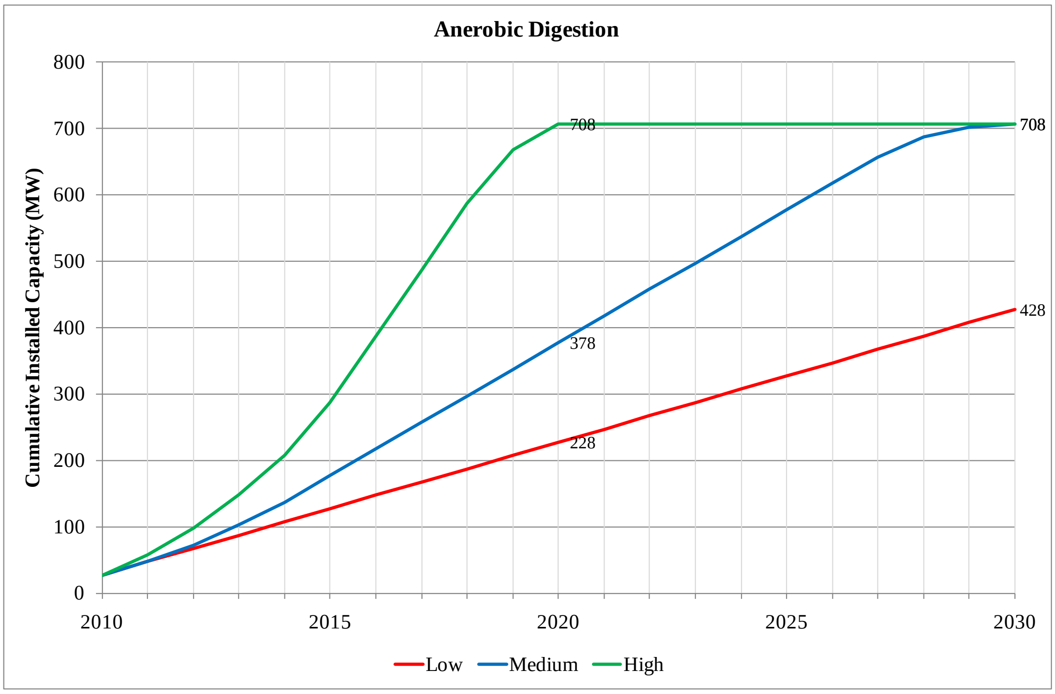


Figure 96: UK Anaerobic Digestion Cumulative Installed Capacity (MW)

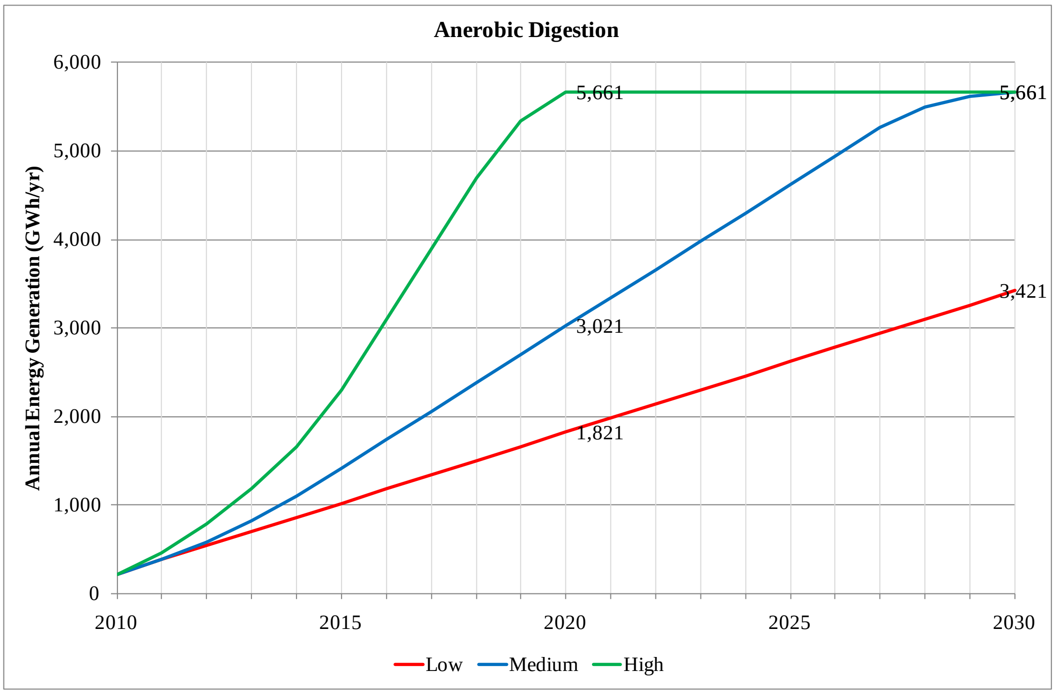


Figure 97: UK Anaerobic Digestion Annual Energy Generation (GWh/yr)

15.7 Beyond 2030

Based on the availability of waste feedstock the growth rates could not be sustained above the total installed capacity predicted.

However, additional deployment, either post 2030, or additional to that predicted up to 2030, may come from crop feedstock being used to increase generation, depending on price paid for electricity (market demand and incentivisation).

15.8 Cost and Pricing

15.8.1 Key Assumptions

The majority of information collected on the project cost for AD technologies is based on consultation with industry stakeholders and relates to projects that have recently started operation, or are in construction or development. Additional information has also been collected from industry literature.

For this analysis AD has been split by feedstock types, as suggested by DECC. This Chapter relates to AD technologies that use farm manure, purpose grown crops and food waste. AD using sewage as a feedstock is covered in Chapter 18. The information collected reflects wet AD as the stakeholders consulted are exclusively involved with this process.

The AD process does vary significantly with different feedstock. For example, the type of feedstock used affects pre-digestion processing requirements, as well as the facility's ability to charge a gate fee.

Stakeholders have indicated that project hurdle rates are between 12% to 16% (post-tax nominal).

15.8.2 Capital Expenditure

Capital expenditure for AD is based on project data provided by 11 industry stakeholders and four industry reports. The main capital expenditure items for AD projects are feedstock processing and handling equipment, digestion equipment, civil and structural works and power generation equipment.

Pre-development costs vary from £58,000/MW to £817,000/MW. This is generally shared equally between pre-licensing, planning and technical development. Stakeholders have found that pre-development costs vary widely and are site specific, whilst not directly related to project size. The principal pre-development cost driver is timescale, which varies significantly between projects.

Capital costs show a large range. Variation between projects is principally driven by three factors: feedstock types, economies of scale and process configuration.

- Food waste plants require more capital intensive pre-processing equipment than those using farm manure or purpose grown crops, leading to increased unit capital cost.
- Larger plants experience economies of scale. Equipment requirements and costs do not increase linearly with installed capacity, resulting in smaller plants having greater unit capital cost for a specific feedstock.
- The digestion process does not vary significantly between projects, however there are differences in their configuration. The number of digestion vessels used at a plant creates trade-offs between capital cost and plant efficiency. Also, greater expenditure on automated material handling equipment reduces operational cost.

Table 71 below presents capital cost ranges for different installed capacity bands. These ranges are illustrated graphically below. Pre-development costs are excluded from the cost ranges shown in Table 71.

Table 71: Anaerobic Digestion – Capital Costs (Financial Close 2010)

£'000/MW	<1MW	1 to 6MW
High	6,985	6,260
Median	4,463	4,000
Low	2,396	2,147

Figure 98: Anaerobic Digestion – Capital Costs (Financial Close 2010)

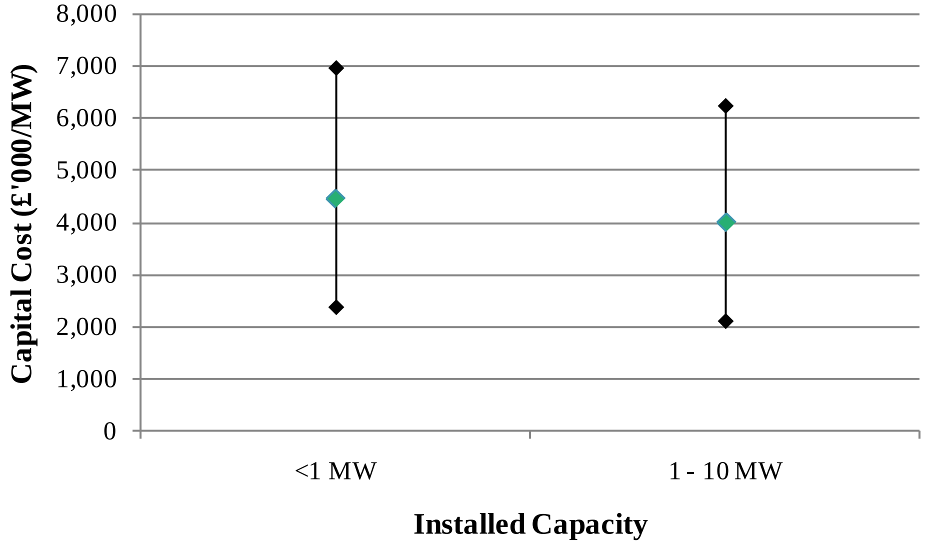


Table 72 below illustrates how capital costs are broken down in the average plant.

Table 72: Anaerobic Digestion – Capital Cost Breakdown

Capital Cost Item	%
Pre-development	8%
Construction	82%
Grid Connection	6%
Other Infrastructure	4%

The majority of capital cost relates to construction. Other infrastructure costs include access roads and other site specific requirements.

Exchange rate movements and labour cost are the most significant cost drivers for future project cost. Historically, continental Europe has lead on the development of AD. As a result, much of the technology and equipment is imported. Labour cost has a material impact as both the manufacturing of equipment, and the construction of civil structures, are labour intensive.

AD is a relatively well established technology and has been extensively deployed in Western Europe. Significant advances in the technology are therefore not anticipated. The main opportunity for learning is expected through the development of a specialised and efficient local supply chain as deployment increases. Deployment of AD in the UK is relatively limited; as it increases, the supply chain will develop and more industry participants will specialise in the technology, increasing efficiency and reducing costs.

Table 73 below presents the range of current capital costs and how they are expected to change over time. These costs represent the 1 – 10MW installed capacity range.

Table 73: Anaerobic Digestion – Capital Cost Projections at Financial Close Dates (Real)

£'000/MW	2010	2015	2020	2025	2030
High	6,260	6,121	6,056	6,100	6,144
Median	4,000	3,911	3,870	3,898	3,926
Low	2,147	2,099	2,077	2,092	2,107

DECC has also requested a further breakdown of current cost data between food waste and farm waste. A review of the collated data suggested that the presentation of two cost ranges is possible.

Table 74 below present the available range of capital costs.

Table 74: Anaerobic Digestion – capital costs (2010)

£'000/MW	Food Waste	Farm Waste
High	6,915	6,711
Median	5,241	3,906
Low	3,740	1,673

15.8.3 Operating Cost

The operating costs of an AD plant are principally driven by the labour required to operate and maintain feedstock processing, digestion and generation equipment.

Variations in cost between projects are driven by the same key variables as capital cost: feedstock type, economies of scale and process configuration.

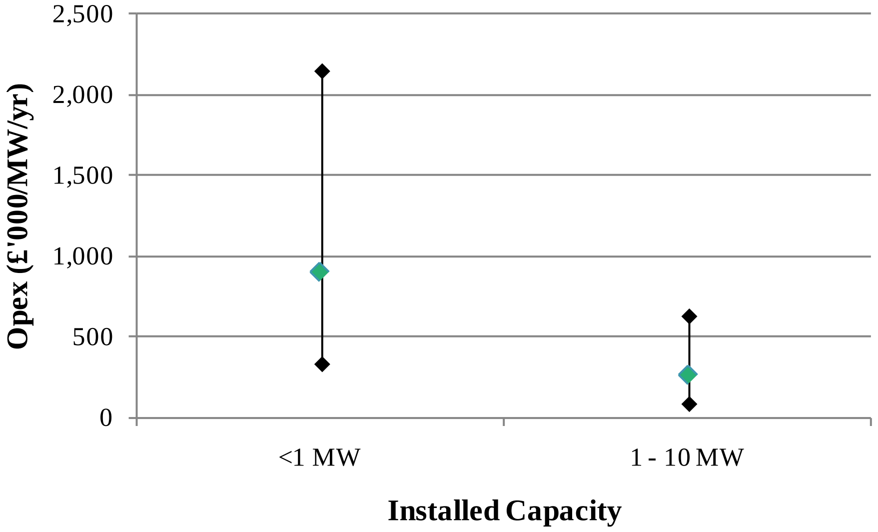
- The feedstock processing requirements of food waste plants are labour intensive, leading to high operational cost compared to plants of a similar installed capacity, using alternative feedstocks.
- Larger plants experience significant economies of scales. Labour requirements do not increase proportionally. Similar labour requirements lead to significantly higher unit operating costs for small scale plants.
- The degree of automation in material handling systems varies between projects. Where there is a high degree of automation operational labour costs are reduced.

Table 75 below presents operational cost ranges for different installed capacity bands. Feedstock costs have been excluded from the operating costs as they are outside the scope of this study. A gate fee is received for food waste feedstocks, but not included as an offsetting item in operating costs.

Table 75: Anaerobic Digestion – Operating Costs (Financial Close 2010)

£'000/MW	<1MW	1 - 6MW
High	2,156	630
Median	900	263
Low	335	98

Figure 99: Anaerobic Digestion – Operating Costs (Financial Close 2010)



Future operating cost projections assume labour costs are the principal cost driver. Exchange rates are also significant as many spare parts are manufactured abroad.

With a wealth of industry experience in operating AD plants, stakeholders do not anticipate learning effects and hence cost reduction, in operating plants. Table 76 shows the range of current operational costs and how they will change over time. These costs represent the 1–10MW installed capacity range.

Table 76: Anaerobic Digestion – Operating Costs Projections at Financial Close (Real)

£'000/MW	2010	2015	2020	2025	2030
High	630	639	649	658	668
Median	263	267	271	275	279
Low	98	99	101	102	104

A breakdown of operating cost data between food waste and farm waste AD is presented below.

Table 77: Anaerobic Digestion – Operating Costs (2010)

£'000/MW	Food Waste	Farm Waste
High	728	1006
Median	481	839
Low	219	394

15.8.4 Levelised Costs

Using the Arup and E&Y capital and operating cost profiles[72] for AD plants, DECC has calculated levelised costs of a reference installation at financial close in 2010, 2015, 2020, 2025 and 2030. The levelised cost ranges are based on Arup's low, medium and high capital costs. Gate fee assumptions are based on AEA (2011)[73]. Note that if the AD plant is on-farm or on a factory site, there will be no gate fee. This case has not been considered in the levelised costs below. The levelised costs have been calculated by assuming a pre-tax real hurdle rate of 13.2% going down to 11.9% by 2020. The initial hurdle rate has been set at the rate of R3 offshore wind due to an assumed similar risk initially, going down to the same rate as for EfW by 2020. The assumed load factor is 84% and the assumed plant lifetime is 21 years.

£ / MWh		2010	2015	2020	2025	2030
AD	low	75	74	70	70	70
<5MW	medium	122	119	110	110	109
	high	194	188	173	171	170

Note: Dates refer to financial close.

15.9 Regions

There is no regional influence on feedstock resource or development of technology capacity. There may be some localised impacts on resource availability, where longer term waste contracts reduce the quantity of food waste available for digestion. It should be noted that the Scottish Government has identified the separate collection of food waste as one of the key areas of action, in order to recover its material and energy value and avoid contamination of other waste materials.

[72] To note that the levelised costs are based on a separate set of capital and operating costs provided by Arup and E&Y that assume constant steel prices over time; capex includes infrastructure costs are incurred in the core facility, but do not include 'other' infrastructure costs that relate to costs incurred outside the site, such as water, roads, waste disposal and land costs. Levelised costs use different size categories for some technologies.

[73] Available at: www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/energy_mix/renewable/policy/incentive/incentive.aspx

16 Advanced Conversion Technologies

16.1 Summary

Gasification and pyrolysis are still considered to be emerging and unproven technologies for the treatment of waste biomass fuel. To our knowledge, there are very few commercial scale gasification and pyrolysis plants operating in Europe and world-wide. In particular, there are very few large-scale commercial plants (i.e. >150,000tonnes/annum) in operation. However, there has been some significant interest in the UK in developing ACT plants.

ACT plants face, or have faced, significant technical challenges in terms of treating heterogeneous waste streams, and there are several cases where plants failed to achieve their design throughput or air emission standards. The two UK gasification plants (i.e. Scotgen, Dumfries and Energos, Isle of Wight) have both encountered technical problems during plant commissioning resulting in significant programme delays.

Based on the two existing gasification and pyrolysis plants in the UK and other examples of gasification and pyrolysis plants world-wide, UK project developers are likely to encounter technical problems in commissioning and operating these types of plants. This has already adversely affected the bankability and deployment rate of these technologies. It is considered that there is a low potential of significantly increasing the current electricity generation from waste biomass fuel in the short-term (i.e. 5 to 10 years) using gasification and pyrolysis technologies. The key innovation required is to develop enough technical knowledge and expertise to address some of the technical challenges and demonstrate successful commercial operation of these plants, which would help to establish these plants as proven technology and increase deployment rates to 2030.

There is relatively little information available on the actual overall energy conversion efficiency of gasification and pyrolysis plants. Based on our research and experience, the overall efficiency (i.e. net electrical efficiency) is often not higher than that achieved via a conventional Rankin steam cycle energy conversion system where steam is used to drive a turbine generator to produce electricity.

The renewable energy generation is to a large extent dependent on the biogenic carbon in the waste. It has been conservatively assumed that the waste contains 50% biogenic carbon. However, the EU Renewable Energy Directive states 62.5%, and research undertaken by DEFRA, indicates that this might be as high as 68%[74]. Using the higher biogenic carbon values, this would increase the potential electricity generation from ACT by about 25% to 30%.

The electricity generation is also constrained by the availability of waste biomass fuel. It has been assumed for this study that no waste fuel such as SRF is being imported to the UK.

[74] See footnote 60.

16.2 Introduction

The term Advanced Conversion Technologies (ACT) describes gasification and pyrolysis technologies used to reduce the mass and volume of municipal solid waste (MSW) or solid recovered fuel (SRF), and to generate energy in the form of electricity and heat.

Gasification is the thermal degradation of waste in a closed system with limited air or oxygen supply (i.e. sub-stoichiometric air-fuel ratio conditions) at temperatures typically between 750°C and 1,600°C. The gasification process generates a synthetic gas (i.e. syngas) mainly comprising carbon monoxide, hydrogen and methane, which can be combusted to raise steam and drive a turbine or be converted using gas engines or gas turbines to produce electricity and heat.

Pyrolysis is the thermal degradation of waste in a closed system in the absence of air, at temperatures typically between 400°C and 800°C. The pyrolysis process generates a hydrogen rich syngas which can be used to produce heat and electricity in the same way as described for gasification.

A total of two gasification plants were operating in the UK in 2009/10 with a combined permitted treatment capacity of almost 100,000tonnes/annum. One of these plants (Scotgen, Dumfries) is a merchant facility operating a batch gasification process and the other is considered to be a two stage combustion technology (Energos, Isle of Wight). However, both plants have encountered significant problems during commissioning, and it is believed that the Scotgen plant is still not fully operational (see Section 16.5.4 for further details). Therefore, the actual waste throughput (i.e. about 60,000 tonnes) was lower compared to the design throughput capacity of these plants. In February 2011, construction work started on the UK's first large-scale (i.e. 100,000 tonnes/annum) gasification plant in Dagenham, London. The plant is being developed by Biossence using Enerkem (www.enerkem.com) technology.

It is understood that neither the Scotgen nor the Energos plants are expected to operate in combined heat and power (CHP) mode. These two plants have a combined electricity generation capacity of about 2.7MWe assuming a load factor of 85%, an electrical efficiency of 23% and a 50% biogenic carbon content in the waste. It is understood that the Scotgen plant is still being commissioned and the Energos plant initially failed to meet dioxin air emission standards and operation was suspended by the Environment Agency for several months. However, it has been reported (e.g. letsrecyle.com, April 2011) that the Energos plant has passed emission tests since the end of October 2010 when it was re-opened. It should be noted that the Isle of Wight plant was a retrofit solution of an existing energy from waste plant, which is likely to have contributed to the difficulties in meeting air emissions standards. Energos states that: *"…the Isle of Wight facility was "not typical" of the seven facilities the firm operates throughout Europe"*. However, the Energos gasification process is very similar to energy from waste technology (i.e. moving grate incineration) and is often referred to as a two stage combustion process.

Based on 2010 data, the favoured ACT technology is gasification with a further eight plants having received planning permission, and a further seven applications awaiting decision. All but two of these planned gasification plants will operate as merchant facilities. In contrast, there is a single pyrolysis plant currently under construction. Assuming all these facilities become operational, their combined treatment capacity will be almost three million tonnes of waste biomass fuel. However, these plants face significant technical challenges in terms of treating heterogeneous waste biomass fuel. It is believed that these technical challenges will adversely affect the deployment rate of these plants over the next 10 to 20 years in the UK, unless project developers overcome these technical hurdles.

The renewable electricity forecast provided in this report is not financially constrained. There is no consideration of current or future financial support mechanisms.

16.3 Literature Review

There is limited data available regarding the performance of gasification and pyrolysis plants due to the lack of commercial scale plants with sufficient operational hours. Therefore, there is considerable uncertainty regarding the technical viability of gasification and pyrolysis plants and their future deployment.

16.4 Limitations & Assumptions

16.4.1 Limitations

Limitations of the gasification and pyrolysis review include:

- Information on planned gasification and pyrolysis plants (i.e. those that have planning permissions granted, those that have submitted planning application but which have not yet been determined, and those in the planning process) is not readily available.
- There is a lack of reliable information on the actual electrical efficiency of gasification and pyrolysis plants due to very few commercial scale plants having been in operation for several years.
- The deployment scenarios developed for gasification and pyrolysis do not directly include an electricity loss for operating some of the plants in CHP mode. However, the overall maximum total power capacity from waste biomass fuel has been constrained at 467MWe for both ACT and EfW technologies by 2030, which includes a provision of 25% of ACT plants operating in CHP mode in that year.
- Typically, ACT plants use SRF derived from, for example, mixed MSW and commercial and industrial waste (CIW) as a feedstock. However, the preparation of SRF has not been considered separately in the AEA 2010 report. To avoid double counting of the energy embodied in the waste biomass fuel and to simplify the modelling, the same assumption regarding calorific value of the waste used for EfW were also applied to ACT (see Section 16.4.2).
- There is not enough data available to robustly assess the deployment of advanced and standard gasification and pyrolysis technologies. Currently less established technologies such as advanced gasification and pyrolysis are eligible for two ROCs per MWh. The definition of advanced gasification and pyrolysis is included in the Renewables Obligation Order 2009 (England and

Wales),[75] and is defined by the calorific value of the syngas (i.e. gross calorific value when measured at 25ºC and 0.1MPa at the inlet to the generating station of at least 4MJ/Nm^3). In addition, for advanced pyrolysis, in the case of a liquid fuel, has a gross calorific value when measured at 25ºC and 0.1MPa at the inlet to the generating station of at least 10MJ/kg. Arup believes that rather than taking into account the calorific value of the syngas or pyrolysis oil generated, the overall energy conversion efficiency of the plant should be considered including, for example, energy losses due to production of oxygen needed for generating a high calorific syngas and the quenching of high temperature syngas etc.

16.4.2 Assumptions

The overall predicted waste biomass fuel resource availability and associated energy conversion potential was based on the AEA UK Global Bioenergy Resource report (i.e. the AEA 2010 report). Certain information and assumptions contained in the AEA 2010 report were changed after discussion with DECC and DEFRA to reflect latest government waste policy[76]. The key technology assumptions for gasification and pyrolysis are as follows:

- Fuel for gasification and pyrolysis plants is assumed to be mixed residual MSW and part of the mixed CIW, which is collectively termed in this report as ‘waste biomass fuel’.
- Net calorific value (NCV) of waste biomass fuel is 9GJ/t.
- Biogenic carbon content of waste biomass fuel is 50%.
- Design life of gasification and pyrolysis plants is 25 years.
- Load factor of gasification and pyrolysis plants is 85% (or 7,446hours/ annum).
- Electrical conversion efficiency of gasification and pyrolysis plants is 23% in electricity only mode.
- 10% of waste biomass fuel is predicted to be treated in 2030 using gasification and pyrolysis plants (high scenario), with 90% being treated using EfW (i.e. incineration).
- It has been assumed that 25% of the total waste biomass fuel available for ACT will be converted using plants operating in CHP mode with an energy efficiency of 65% (i.e. electrical efficiency of 20% and thermal efficiency of 45%).
- Available waste biomass fuel was approximately 5.1Mt in 2010 and about 0.06Mt was treated using ACT plants.[77] The total available waste biomass fuel resource is predicted by AEA to be 12.5Mt in 2030.

[75] The Renewables Obligation Order 2009 (England and Wales), Part 1 Introductory Provisions. (http://www.legislation.gov.uk/uksi/2009/785/made?view=plain)
[76] http://archive.defra.gov.uk/corporate/consult/waste-review/100729-waste-review-call-for-evidence.pdf
[77] This is based on an unconstrained feedstock potential estimated by AEA of 58.7Mt and competing feedstock use of 53.6Mt. The competing feedstock uses include, for example, recycling and landfill disposal of waste.

16.5 Constraints

16.5.1 Supply Chain

The supply chain for the development and deployment of gasification and pyrolysis plants is considered to be a constraint. There are many companies that offer gasification and pyrolysis technologies, but very view have a proven track record of commercial scale plants performing as reliably as, for example, EfW plants (i.e. moving grate incinerators).

The lack of a proven track record means that the bankability of these projects is low, attracting significantly less support from financing institutions compared to projects using proven EfW technology solutions.

16.5.2 Planning

Based on information obtained from Department of Community and Local Government comprising 2009 and 2010 planning decision statistics for waste planning applications in England, the success rate is high for major waste planning applications – 90% and 88%, respectively, out of a total of over 400 applications each year. Based on the available planning information in 2010, more than half of the granted planning permissions for the thermal treatment of waste were gasification technologies (i.e. mainly Energos and Biossence technologies).

It is assumed that the gasification and pyrolysis plants currently under construction will all be built. For the low, medium and high deployment scenarios, the construction and commissioning period is assumed to be four (low scenario), three (medium scenario) and two years (high scenario). The deployment scenarios developed by Arup for gasification and pyrolysis plants not currently under construction have considered the number of plants which have granted planning permissions, those that have submitted a planning application but which have not yet been determined, and those which are in the planning process. In addition, the lead times for developing projects has been considered. In comparison to the plants under construction, for plants not yet under construction, the deployment period has been assumed to be constrained by the capacity of the market to respond to an increase in the deployment rate of EfW plants due to limited resources of project developers, technology providers and other support services to deliver plants under a high deployment scenario. The deployment scenarios developed for these gasification and pyrolysis plants are as follows:

Planning Permission Granted

- Low deployment – 20% of plants that have planning permission are being built assuming a construction and commissioning period of four years;
- Medium deployment – 30% of plants that have planning permission are being built assuming a construction and commissioning period of five years; and
- High deployment – 40% of plants that have planning permission are being built assuming a construction and commissioning period of six years.

Planning Permission Submitted but No Decision

- Low deployment – 20% of plants that have planning permission submitted but no decision are being built assuming a construction and commissioning period of four years;
- Medium deployment – 30% of plants that have planning permission submitted but no decision are being built assuming a construction and commissioning period of five years; and
- High deployment – 40% of plants that have planning permission submitted but no decision are being built assuming a construction and commissioning period of six years.

In the Planning Process

- Low deployment – 20% of plants that are in the planning process are being built assuming a construction and commissioning period of six years;
- Medium deployment – 30% of plants that are in the planning process are being built assuming a construction and commissioning period of seven years; and
- High deployment – 40% of plants that are in the planning process are being built assuming a construction and commissioning period of eight years.

16.5.3 UK Grid

Most gasification and pyrolysis plants have a waste design throughput of less than 150,000tonnes/annum and are expected to generate less than 15MWe of net electricity. Based on this plant size, electricity off-take to the UK national grid is not expected to represent a significant constraint. Where larger plants are being developed, it is likely that these would be constructed in industrial areas or where there is good existing power off-take infrastructure.

16.5.4 Technical

Gasification and pyrolysis are still considered to be emerging and unproven technologies for the treatment of waste biomass fuel. To our knowledge, there are very few commercial scale gasification and pyrolysis plants operating in the EU and worldwide. In particular, there are very few large scale plants (i.e. >150,000tonnes/annum) in operation.

These plants face significant technical challenges in terms of treating heterogeneous waste streams. For example, lower cost gasification systems are typically air-blown and produce a low calorific value syngas. Cleaning of the syngas to make it suitable for use in gas engines or gas turbines is challenging and requires a high level of process engineering expertise.

For example, a Thermoselect gasification plant in Karlsruhe (Germany) did not meet the plant performance requirements, such as waste throughput and air emission standards. In the UK, the operation of the Isle of Wight gasification plant was suspended by the Environment Agency in May 2010 due to problems with elevated dioxin emissions since the plant was first commissioned in November 2008. However, the plant re-opened at the end of October 2010 and has passed the air emission tests. Commissioning of the Scotgen plant commenced in July 2009 but problems were encountered in December 2009 with the boiler superheater tubes attributed to fouling, high temperature and corrosion when the plant progressed from burning clean wood to MSW. The plant was shut down and commissioning re-started in March 2010. However, the Scottish Environment Protection Agency has reported (November 2010) that the plant is still in the commissioning phase, and that the steam turbine has not yet been connected (i.e. the plant is not generating any energy).

Several gasification and pyrolysis plants have been reported to operate successfully in Japan (e.g. JFE Thermoselect). JFE's first Thermoselect plant in Chiba was the company's test plant and lessons learnt were adopted in six other plants built by JFE. JFE is a major engineering company with an annual turnover in 2010 of almost £18 billion pounds, having the process engineering expertise and financial resources to overcome technical challenges.

There is relatively little information available on the actual overall efficiency of gasification and pyrolysis plants. Based on our research and experience, the overall efficiency (i.e. net electrical efficiency) is often not higher than that achieved via conventional steam cycle energy conversion systems. For example, it has been reported by the New Technologies Demonstrator Programme that, on average, the Energos Isle of Wight plant generated 354kWh of electricity per tonne of SRF treated over approximately a 11 months demonstration period, with a cycle efficiency of 15%. In addition, the Advanced Plasma Power pilot plant in Swindon produces a syngas which is being converted into electricity via an internal combustion engine and it has been reported that it has a net electrical efficiency of 23.3%.

Based on the two existing gasification and pyrolysis plants in the UK, and other examples of gasification and pyrolysis plants worldwide, UK project developers are likely to encounter technical problems in commissioning and operating these types of plants. This has already adversely affected the bankability and deployment rate of these technologies. The key innovation required is to develop enough technical knowledge and expertise to address some of the technical challenges and demonstrate successful commercial operation of these plants.

Several Japanese engineering companies (e.g. Mitsubishi Environmental Engineering, Nippon Steel Engineering, JFE Engineering, Kawasaki Giken and Kobelco Eco-Solutions) have gained experience in developing gasification plants for more than 10 years. These companies may decide to enter the European market and transfer some of their knowledge and expertise.

16.5.5 Other Constraints

The main incentive for developing gasification and pyrolysis plants in the UK is the rising cost for landfill disposal of waste driven by the increasing landfill tax. Landfill gate fees will soon be higher for MSW than typical gate fees for the treatment of waste using gasification and pyrolysis. However, if this fiscal incentive is stopped or reversed than this would have an adverse effect on the deployment of gasification and pyrolysis treatment capacity.

16.6 Maximum Build Rate Scenarios

16.6.1 Available Resource

The renewable fraction of solid waste includes MSW and the mixed waste stream of CIW (i.e. waste biomass fuel). As stated above, the available potential waste biomass fuel has been taken from the AEA 2010 report, and is estimated by AEA to amount to 12.5Mt in 2030 with a biogenic carbon content of 50%. This estimate is based on a 'paired scenario' with landfill gas to avoid double counting of the waste biomass fuel used to calculate renewable electricity generation.

AEA also assumed that UK recycling targets take precedence and are achieved, and that uptake of waste to energy accelerates in line with MSW 'recovery' targets to 2020 (75% in 2020, rising to 80% in 2025). AEA has assumed that the share of the residual waste going to waste to energy after recycling rises from their values in 2009 (16% MSW and 1% CIW respectively) to reach 50% in 2025, with the remainder going to landfill.

AEA has stated that anaerobic digestion of the wet fraction of MSW and CIW is counted as part of the recycling fraction.

Based on the deployment assumptions of gasification and pyrolysis plants, it is estimated that 10% of total available waste biomass fuel will be treated in 2030 using ACT plants.

16.6.2 Low Scenario

The following assumptions have been made: 100% of gasification and pyrolysis plants currently under construction will be constructed and commissioned over a period of four years. Subsequently, 20% of gasification and pyrolysis plants that have planning permission will be constructed and commissioned over a period of four years. Thereafter, 20% of gasification and pyrolysis plants that have submitted a planning application but no decision has been made will be constructed and commissioned over a period of four years, and 20% of gasification and pyrolysis plants that are in the planning process will be deployed over a period of six years. From then on, the build rate has been assumed to be constant until 2030.

16.6.3 Medium Scenario

The following assumptions have been made: 100% of gasification and pyrolysis plants currently under construction will be constructed and commissioned over a period of three years. Subsequently, 30% of gasification and pyrolysis plants that have planning permission will be constructed and commissioned over a period of five years. Thereafter, 30% of gasification and pyrolysis plants that have submitted a planning application but no decision has been made will be constructed and commissioned over a period of five years, and 20% of gasification and pyrolysis plants in the planning process will be deployed over a period of seven years. From then on, the build rate has been assumed to be constant until 2030.

16.6.4 High Scenario

The following assumptions have been made: 100% of gasification and pyrolysis plants currently under construction will be constructed and commissioned over a period of two years. Subsequently, 40% of gasification and pyrolysis plants that have planning permission will be constructed and commissioned over a period of six years. Thereafter, 40% of gasification and pyrolysis plants that have submitted a planning application but no decision has been made will be constructed and commissioned over a period of six years, and 40% of gasification and pyrolysis plants in the planning process will be deployed over a period of eight years. From then on, the build rate has been assumed to be constant until 2030.

16.6.5 Maximum Build Rate Plots

Figures 100, 101 and 102 below represent annual deployment rates in MWe/yr (see Figure 100), cumulative installed capacity in MWe (see Figure 101), and cumulative renewable electricity generation per year in GWhe (see Figure 102) for gasification and pyrolysis plants until 2030.

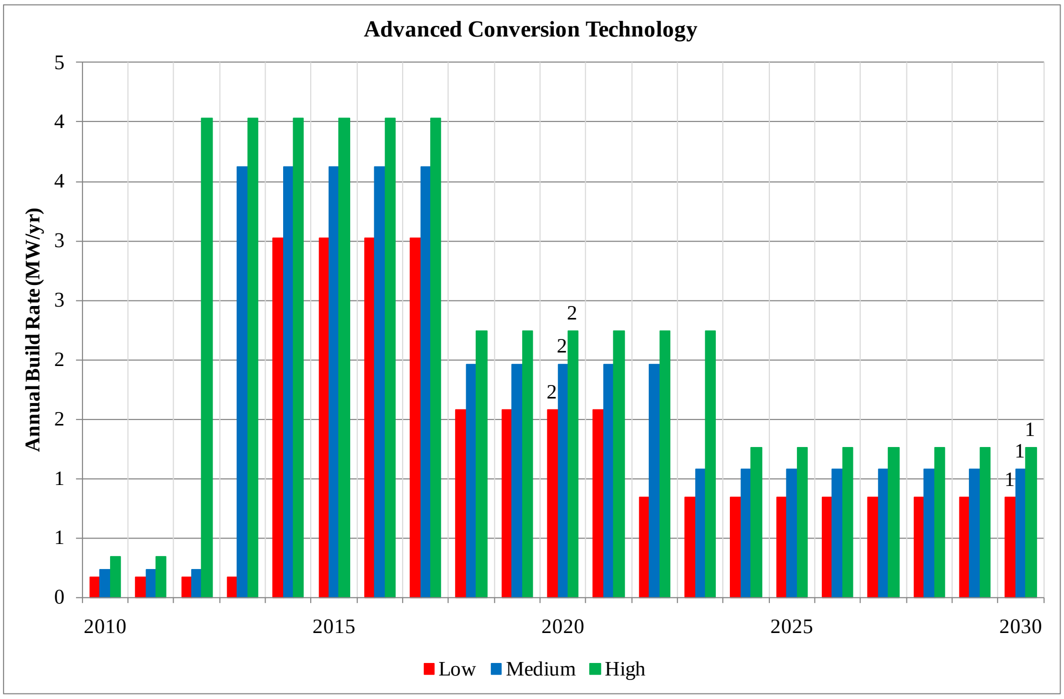


Figure 100: UK Advanced Conversion Technology Annual Installed Capacity (MW/yr)

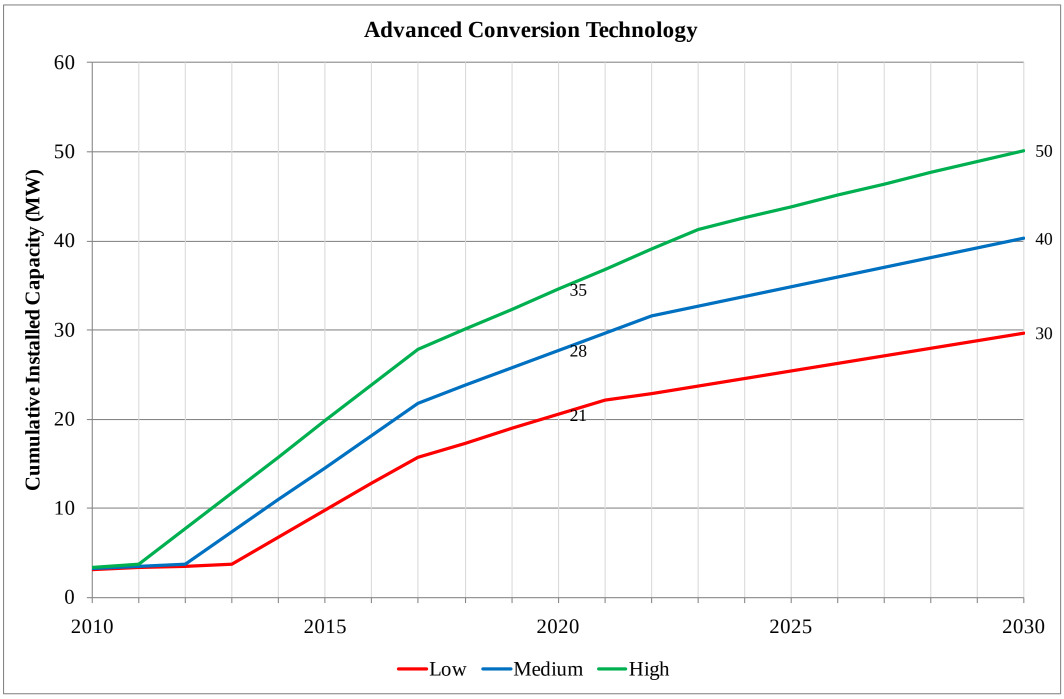


Figure 101: UK Advanced Conversion Technology Cumulative Installed Capacity (MW)

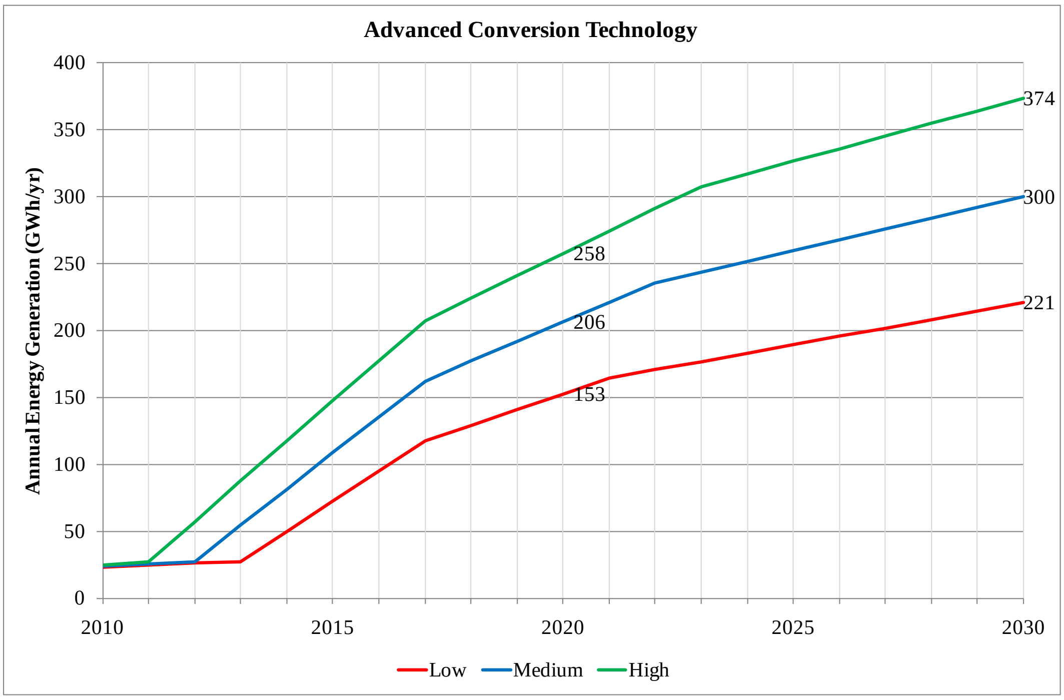


Figure 102: UK Advanced Conversion Technology Annual Electricity Generation (GWh/yr)

16.7 Beyond 2030

The deployment rate of gasification and pyrolysis plants after 2030 is expected to be relatively low if sufficient gasification and pyrolysis plants, as well as EfW plants, are being built between now and 2030 to treat the quantity of waste biomass fuel expected to be available. It is assumed that the UK waste industry would not import large quantities of SRF for treatment using gasification and pyrolysis. However, some EU member states have started to import SRF such as the Netherlands and Germany, making best use of existing thermal treatment overcapacities.

16.8 Project Costs

16.8.1 Key Assumptions

The information collected on the project cost for ACT is based on consultations with industry stakeholders and industry literature. Stakeholder information relates to projects that have recently started operation, or are in construction or development.

ACT is assumed to be advanced or standard gasification or pyrolysis, the difference of which is defined by the technique used to convert fuel into syngas. However, there are examples of both techniques being incorporated into one plant. The main differentiation between advanced and standard versions of the technology is the quality of syngas that is produced.

The majority of stakeholders consulted are involved with advanced gasification projects. However, the difference between these sub-classifications is unclear within the industry.

Stakeholders have indicated that project hurdle rates are between 13% and 15% (post-tax nominal).

Please note that all forecast produced in this report are not financially constrained. There is no consideration of current or future financial support mechanisms.

16.8.2 Capital Expenditure

Capital expenditure for ACT is based on project data provided by six industry stakeholders and four industry reports. The main capital expenditure items for ACT projects are the conversion equipment, civil and structural works and generation equipment.

Pre-development costs vary from £17,000 to £255,000/MW. Costs are heavily weighted towards pre-licensing and planning, rather than the technical design aspects of pre-development. Stakeholders have found that pre-development costs vary widely and are site specific. The principal driver for variation is pre-development timescale. Stakeholders have realised significant cost efficiencies where permit application material and designs can be shared between standardised plants.

Capital costs show a large range. This is mainly due to variations in ACT processes that exist in a market of evolving technology providers. It affects project capital cost through the following mechanisms:

- Industry participants with repeatable designs and opportunities for the deployment of multiple plants can achieve lower unit capital costs; and
- The ACT process, and its efficiency, varies between technology providers. Less efficient processes may produce a lower quality of syngas, require more gas clean-up equipment and have greater parasitic loads.

Procurement methods also lead to variations in capital costs. As ACT is not well established, Engineering Procurement Construction (EPC) contractors price significant levels of risk into their quotes, which can be avoided using a multi-contract approach. Additionally, sites which are developed directly by the technology provider will incur lower capital cost than those where independent developers are involved.

The Table below presents capital cost ranges for different installed capacity bands. These ranges are also illustrated graphically. Pre-development cost is not included in the capital cost ranges.

Table 78: Advanced Conversion Technology – Capital Costs (Financial Close 2010)

£000s/MW	<10 MW	10 - 30MW
High	8,915	6,272
Median	6,300	5,473
Low	2,825	2,525

Figure 103: Advanced Conversion Technology – Capital Costs (Financial Close 2010)

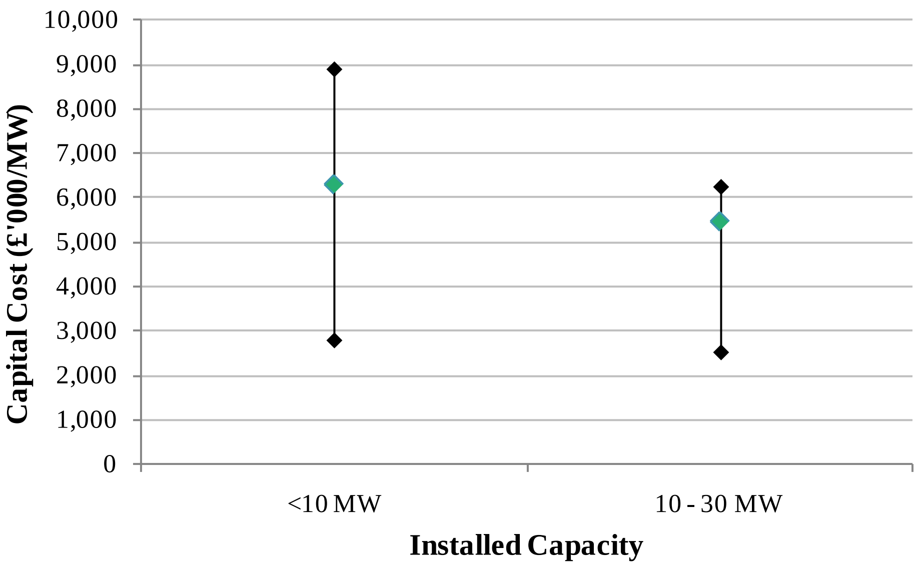


Table 79 below illustrates how capital costs are broken down in the average plant.

Table 79: Advanced Conversion Technology – capital cost breakdown

Capital cost item	%
Pre-development	2%
Construction	92%
Grid Connection	1%
Other Infrastructure	5%

The majority of capital cost relates to construction. Other infrastructure cost includes access roads and site specific requirements.

Labour cost is assumed to be the most significant cost driver of future project cost. ACT processes require labour intensive processes to produce equipment and implement the civil and structural aspects of projects. Exchange rates also have a material effect on cost because plant equipment can be imported. There are, however, significant variations in the foreign exchange component of different projects.

ACT is still in its initial stages of development, which provides significant scope for learning effects. These are considered to take the form of technological improvements and the development of a specialised and efficient supply chain as deployment increases.

Table 80 below presents the range of current capital costs and how they are expected to change over time. These costs represent the <10MW installed capacity range.

Table 80: Advanced Conversion Technology – Capital Cost Projections at Financial Close Dates (real)

£000s / MW	2010	2015	2020	2025	2030
High	8,915	8,246	7,895	7,962	8,029
Median	6,300	5,827	5,580	5,627	5,674
Low	2,825	2,613	2,502	2,523	2,545

16.8.3 Operating Costs

Operating costs of ACT plants are mainly driven by the labour required to operate and maintain gas production and generation equipment. Operational cost shows a relatively small range compared to capital cost, indicating that the operational requirements do not vary considerably with the process employed.

Operation and maintenance contracts for generation equipment can be provided by the manufacturer. These contracts can make up a large proportion of total operating cost. The contract price will be largely driven by the quality of gas produced by conversion equipment. Consequently, more efficient plants will have reduced operational costs.

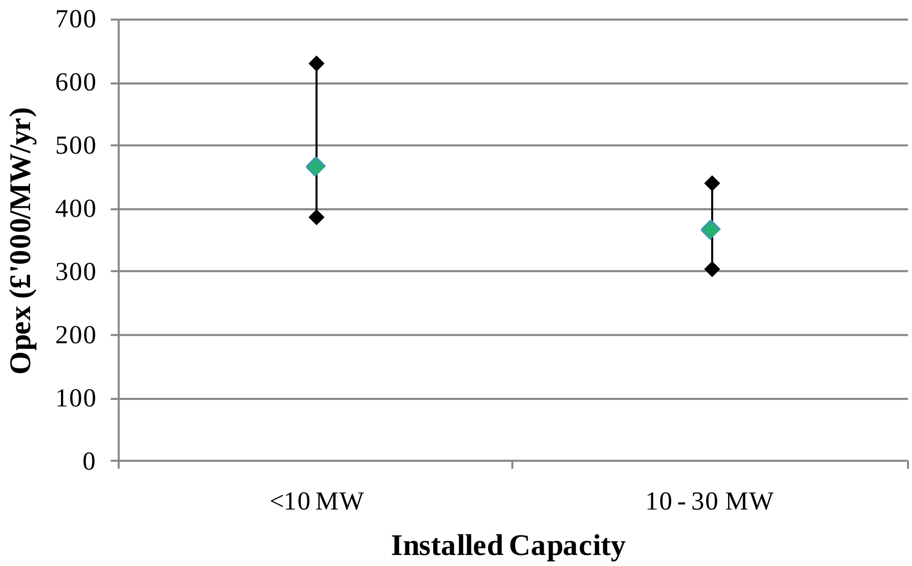
The method of procuring operational services can affect the cost. Operational services from the technology provider are typically less expensive as they are more able to manage performance and availability risk.

Table 81 below presents operational cost ranges for different installed capacity bands. The majority of plants receive gate fees for their fuels; these are not included as an offsetting item in operating costs.

Table 81: Advanced Conversion Technology – Operating Costs (Financial Close 2010)

£000s / MW	< 10 MW	10 - 30 MW
High	632	441
Median	466	367
Low	389	305

Figure 104: Advanced Conversion Technology – Operating Costs (Financial Close 2010)



The principal driver of future cost is assumed to be labour prices. Exchange rates will also contribute to future costs as spare parts can be manufactured abroad.

There is potential for learning effects in the operation of ACT plants. It relates to development of a market to provide ACT operational services, caused by increased demand, and operators learning to run plants more efficiently.

Table below shows the range of current operational costs and how they are expected to change over time. These costs represent the 10-30MW installed capacity range.

Table 82: Advanced Conversion Technology – Operating Costs Projections at Financial Close Dates (real)

£000s / MW	2010	2015	2020	2025	2030
High	441	426	405	396	382
Median	367	354	337	330	318
Low	305	294	284	274	264

16.8.4 Levelised Costs

Using the Arup and E&Y capital and operating cost profiles[78] for ACT plants, DECC has calculated levelised costs of a reference installation at financial close in 2010, 2015, 2020, 2025 and 2030. The levelised cost ranges are based on Arup's low, medium and high capital cost estimates. Gate fees are based on the lower end of the gate fee range in the WRAP Gate Fee Report (2010)[79]. If plants experience difficulty in obtaining waste, gate fees might also be below the WRAP range, which would result in higher levelised costs. It should be noted that there is a large range of possible gate fees and the choice of gate fee strongly impacts on levelised costs. The levelised costs have been calculated by assuming a pre-tax real hurdle rate of 13.2% going down to 11.9% by 2020. The initial hurdle rate has been set at the rate of R3 offshore wind due to an assumed similar risk initially, going down to the same rate as for Energy from Waste by 2020. The assumed load factor is 84% and the assumed plant lifetime is 23 years..

£ / MWh		2010	2015	2020	2025	2030
ACT	low	-35	-39	-47	-50	-52
	medium	34	26	11	7	4
	high	80	71	50	46	43

16.9 Regions

England is likely to have the highest concentration of gasification and pyrolysis plants given that it generates about 80% of the total MSW in the UK. The geographic distribution of gasification and pyrolysis plants is driven by the cost for transporting the waste to the nearest treatment plant. An average transporting distance is about 40km (i.e. 25 miles). Transporting waste over greater distances is generally uneconomical and therefore plants are likely to be located relatively close to the production of the waste. This is also in line with national waste policy to manage waste as close as possible to the point of production (the 'Proximity Principle'). However, there may be opportunities to transport waste by rail or water over longer distances to a centralised waste treatment plant.

---

[78] To note that the levelised costs are based on a separate set of capital and operating costs provided by Arup and E&Y that assume constant steel prices over time; capex includes infrastructure costs are incurred in the core facility, but do not include 'other' infrastructure costs that relate to costs incurred outside the site, such as water, roads, waste disposal and land costs. Levelised costs use different size categories for some technologies.

[79] www.wrap.org.uk/downloads/2010_Gate_Fees_Report.53e7e3d7.9523.pdf

17 Landfill Gas

17.1 Summary

This report has considered the future contribution of renewable energy from landfill gas by assessing the resource potential and whether the existing infrastructure requires further development to exploit the potential resource.

The review of previous assessments of the resource potential, together with the experience of developers in the industry and the removal of organic waste from landfill, indicates that the potential resource has been overstated and that the sector is at, or close to, peak energy contribution. This in 2009/10 amounted to 4,834GWh based upon the quantity of ROCs issued to the sector.

Short-term LFG will continue to contribute significant quantities of renewable power. However predicting the declining contribution as the organic fraction is removed from landfill is very difficult.

The medium- to long-term assessment indicates a reduction in generation capacity by at least half over the next 10 to 15 years. This is supported by the effect of the EU Landfill Directive and associated increases in treatment technologies (e.g. anaerobic digestion) being used to divert, for example, biodegradable municipal waste from landfill, thus removing the feedstock which produces landfill gas.

An alternative optimistic assessment using AEA gas reserve potential indicates that a further 100-200MWe of capacity could be deployed in 2020 and a further 40-100MWe from 2020 to 2030. However, this deployment will include the replacement of some existing capacity. Beyond 2030 the contribution to renewable electricity from LFG will be minimal.

17.2 Introduction

Landfill gas (LFG) generation technology can be considered mature given the experience of operators and technology suppliers over the last 20 years. Most of the schemes in operation utilise spark ignited reciprocating gas engines modified to operate on low calorific gas down to 35% methane by volume in the fuel gas. The range of output capacity is typically 3MWe down to 0.1MWe (100kWe). There has been some development of micro-turbines in the UK but in discussion with the developer, this technology although reliable, does not offer significant cost savings or efficiencies compared to small gas engines.

In discussion with a number of operators, the market is now mature with few sites being developed further. The sites without generating capacity are either sterilised via the non-fossil fuel obligation (NFFO) saving arrangements or the gas volumes do not warrant commercial development.

Operators are seeing a declining gas resource mainly due to biodegradable municipal waste (BMW) and other organic waste being diverted from landfill and treated using, for example, composting and anaerobic digestion. This trend is likely to continue in the future due to increasing landfill tax and local authority targets for reducing the quantity of BMW going to landfill.

The industry has been very successful in developing capacity. However, there are limited sites for development opportunities and the market has consolidated in recent years with much of the capacity being held by a small number of operators. The market has reached a level of maturity whereby any new capacity will only replace existing generation that is in decline as the LFG reserves on a particular site decline. Therefore future exploitation of the LFG resource will see developers relocating generator sets rather than deploying new capacity.

17.3 Literature Review

The predicted resource availability of biodegradable municipal waste and similar commercial and industrial waste going to landfill has been based on the AEA UK Global Bioenergy Resource report (i.e. the AEA 2010 report). The key finding from the review was that the gas yield and calorific values were based on theoretical modelling or laboratory tests and this over states the quantum of resource available to generate energy. When compared with those figures used by developers for assessing LFG potential for power generation, the figures are overstated by as much as 50%. The gas profile developers use is also shorter in duration than those indicated in the studies reviewed. Certain information and assumptions contained in the AEA 2010 report were changed, which is discussed in more detail in Section 17.4 below.

Based on information obtained by Arup from the Office of the Gas and Electricity Markets (Ofgem), there were 410 accredited LFG generation stations in the UK in 2010 with a combined capacity of 956MWe of electricity. From the Ofgem Renewables Obligation: Annual Report 2009-2010 the energy generated by Landfill gas equates to 4,844GWh/annum or about 17PJ, and based on the accredited capacity, a load factor of 58% (i.e. 5,080hours/annum) can be calculated. This equates to about 11% of the available capacity estimated by AEA for 2010 of 157PJ.

This is only a crude approximation as the Ofgem reports do not state whether the generating capacity was in operation, merely the capacity ‘accredited’.

The reports were also used to determine whether further development would take place in each of the markets (i.e. England, Wales, Scotland and Northern Ireland).

17.4 Limitations & Assumptions

17.4.1 Limitations

Detailed analysis to verify which of the sites accredited under RO is contributing energy was not possible due to lack of detailed data (and time). Some broad assumptions were therefore made in relation to whether generating stations were still operating and the likely useful life of a generating asset before replacement would be necessary.

The AEA assumptions on gas potential appears to overstate the quantum of the LFG resource available for exploitation, therefore adjustments were made to reflect the likely available gas based on the experience of developers and operators. Typically developers use a conversion factor of 2GJ/tonne or less, rather than the 4GJ/tonne in the report. Developers are more conservative on the quantum of gas generated per tonne of waste, using figures that range from 90-150m^3/tonne rather than the 200m^3/tonne and use a calorific value of 17MJ/m^3 or less compared to 20MJ/m^3 quoted in the AEA Future Energy Solutions report on renewable heat. These figures would suggest that the gas potential could be overstated by as much as 50% in the AEA analysis.

However, comparing the theoretical gas potential to the actual quantity of LFG captured for use is not easy to assess. The factors that influence gas production at a particular site (such as organic waste infill rates, whether the waste is dry or wet, leachate levels, air ingress to the site, and efficiency of the gas collection system) cannot be rationalised to a simple model. In addition, changes to site management techniques in recent years (such as restricting leachate recirculation) limit or reduce the gas yields, but extend the production life. Therefore, the data on future energy production is at best difficult to predict and, with reducing organic inputs to landfill, almost unpredictable.

An alternate view is that LFG reserves will not deplete as rapidly as predicted. The organic fraction will continue to generate gas in line with the AEA assessment. This predicts a decline from 40Mt to 18.5Mt of organic waste being landfill in 2020. Although there is sufficient existing installed capacity to exploit a higher potential reserve, by 2020 a further 100-200MWe installed capacity may be required to replace generators that have reached the end of their economic life.

This scenario has not been modelled. However the higher levels of gas could be exploited by increasing the load factor from 58-85%, which could generate a further 2,000GWh/annum without increasing the installed capacity. The scenario is feasible with large operators re-deploying existing assets to match generating capacity to the gas reserves at a particular site.

At the higher levels of gas potential in the AEA assessment consideration must be given to the current experience seen in the actual LFG reserve available for generation (which is much lower than the theoretical models) and the duration that the gas potential will exist. This indicates a further 100-200MWe of installed capacity may be deployed up to 2020 and then a further 40-100MWe from 2020 to 2030. However, some of this capacity will be replacement generation. These numbers have not been verified through assessing specific site data and they should be viewed as an optimistic scenario.

17.4.2 Assumptions

LFG generator sets have a typical economic life of 10-15 years provided they have been well maintained. This fits well to the industry and stakeholder models that useable quantities of gas are generated up to 10 years after the landfill site is closed.

In assessing the future capacity therefore, consideration must be given to replacing of the generating asset or re-deploying assets that are underutilised through lack of gas.

From Ofgem's data, the load factor on average is 50-60%, which is low for the technology deployed. With this type of technology it should be possible to achieve a load factor of 90-95% if there is sufficient gas of a suitable calorific value.

The assessment has therefore assumed that assets will be re-deployed rather than replaced, and that there is sufficient capacity currently installed to be relocated to exploit the declining gas reserve and allow for assets to reach the end of their economic life without being replaced.

This scenario has been confirmed by a number of operators as part of the analysis work.

17.5 Constraints

17.5.1 Supply Chain

The technology risks and resource requirements for effective commercial exploitation of LFG are well known and therefore this is not viewed as a constraint to development.

17.5.2 Planning

The planning guidance supports the development of power generation from landfill gas and therefore this is not viewed as a constraint.

17.5.3 UK Grid

In general the issues around LFG development are well understood and the connection costs still remain a constraint for sites of smaller capacity in areas where the infrastructure must be reinforced to accept the output. However, given the maturity of the market, it is unlikely that significant new capacity will be constrained between now and 2030.

17.5.4 Technical

LFG utilisation is a mature market, not constrained by lack of technical innovation.

17.5.5 Other

The largest determining factor on future energy generation from LFG is the maturity of the gas reserve, how quickly it will deplete and the continuation of gas with a calorific value that can be utilised by the available technology at an attractive commercial rate.

The use of micro-turbines has been limited in the UK as the current total life cycle cost is similar to a small reciprocating spark ignited gas engine. However, the deployment of micro-turbines may become feasible as the methane level in LFG declines below 30% by volume. However, this will merely fill in capacity between the high and low models, rather than increase the overall installed generating capacity.

What is clear from the Ofgem RO reports is that there is little or no development activity in the sector and that the load factor is low compared to base load generation. This indicates that the gas reserve is at, or close to, the peak production and, with the reduction of biogenic waste deposited in landfills, will decline from current levels within 10-15 years.

If the AEA assessment of LFG reserves continues and, accepting that installed capacity will reduce as generators reach the end of their economic life, then without some form of support, the deployment potential of 100-200MWe of new capacity is likely to remain constrained.

17.6 Maximum Build Rate Scenarios

17.6.1 Available Resource

A more conservative approach to the available resource has been taken when compared to the AEA assessment. This reflects the industry view of future development that the amount of gas generated is heavily influenced by factors within the landfill site, the efficiency of gas capture and utilisation.

Therefore, the starting point reflects the current resource level of 4,844GWh achieved in 2009/10, and that the gas potential, although it may continue in the short-term, is in decline as sites are closed or generator sets reach the end of their useful life.

It assumes no further development of new capacity, as there is already over capacity in the market and development will be constrained.

The low, medium and high scenarios have been modelled using the Ofgem accreditation data based upon the commissioning start date of the generating station as the point in time when landfill gas levels are sufficient to support energy generation. It is acknowledged that landfill sites may generate quantities of landfill gas that could be commercially viable before the commissioning of a landfill gas fuelled power station, but in the absence of other data, the Ofgem registered commissioning date was deemed to be an appropriate starting point for modelling.

The low, medium and high scenario models were calculated based upon an operating life of 10, 15 and 20 years from the commissioning date. Again this is a crude assessment based upon the generic nature of the data rather than a site-by-site specific review.

Sensitivity analysis for the low, medium and high scenario models were undertaken by calculating the renewable electricity generation from LFG based on altering the gas energy content, gas yield, and load factors based upon industry experience. These sensitivities were then compared to Ofgem Renewables Obligation: Annual Reports for the last three years by way of historical performance data and to the three models generated using the generic operating life of 10, 15, and 20 years respectively.

In all three scenarios, which modelled different gas qualities, gas yields and a reducing load factor, the results were more pessimistic, when compared to the operating life models. This more pessimistic outlook does not correlate well to the actual output performance evidence in the most recent Ofgem reports and therefore these scenarios were not used (i.e. discounted).

17.6.2 Low Scenario

This scenario assumes that the useable gas generation is 10 years from commissioning of the generating station and it will then cease to contribute further output. In addition, the remaining active sites would continue to contribute at a load factor of 58% utilisation (comparable to the industry average). This was then used to generate the energy contribution curve.

A further sensitivity to assess the gas potential using a conversion value of 2GJ/tonne and gas potential of 100m^3/tonne of waste was modelled, as was the reduction in load factor from 60% to 30%, reflecting the reducing calorific value of LFG as the gas potential depletes after site closure. However, the rapid rate of decline shown by these sensitivities was considered to be very pessimistic in the light of recent trends in the market and was not used in the final assessment.

17.6.3 Medium Scenario

This scenario assumes that the useable gas generation is 15 years from commissioning of the generating station and it will then cease to contribute further output. The generating capacity is replenished by transferring generating sets from unproductive sites. In addition, the remaining active sites would continue to contribute at 58% load factor (comparable to the industry average). This was then used to generate the energy contribution curve.

A further sensitivity to assess the gas potential using a conversion value of 2GJ/tonne and gas potential of 150m^3/tonne of waste was modelled, as was the reduction in load factor from 60% to 30% reflecting the reducing calorific value of LFG as the gas potential depletes after site closure. However, the rapid rate of decline shown by these sensitivities was considered to be very pessimistic in the light of recent trends in the market and was not used in the final assessment.

17.6.4 High Scenario

This scenario assumes that the useable gas generation is 20 years from commissioning of the generating station and it will then cease to contribute further output. The generating capacity is replenished by transferring generating sets from unproductive sites. In addition, the remaining active sites would continue to contribute at a load factor of 58% (comparable to the industry average). This was then used to generate the energy contribution curve.

A further sensitivity to assess the gas potential using a conversion value of 2GJ/tonne and gas potential of 200m^3/tonne of waste was modelled, as was the reduction in load factor from 60% to 30% reflecting the reducing calorific value of LFG as the gas potential depletes after site closure. However, the rapid rate of decline shown by these sensitivities was considered to be very pessimistic in the light of recent trends in the market and was not used in the final assessment.

17.6.5 Maximum Build Rate Plots

The three figures below represent cumulative installed capacity in MWe (Figure 106), and cumulative electricity generation per year in GWh for landfill gas generation sets until 2030.

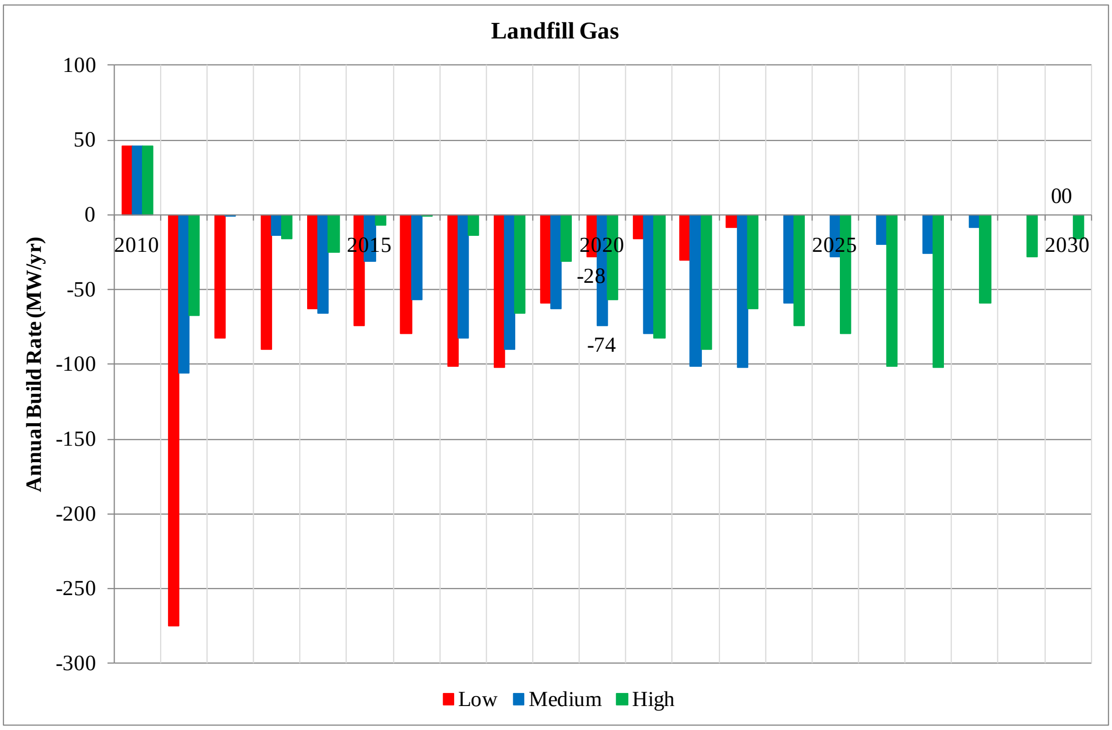


Figure 105: UK Landfill Gas Annual Installed Capacity (MW/yr)

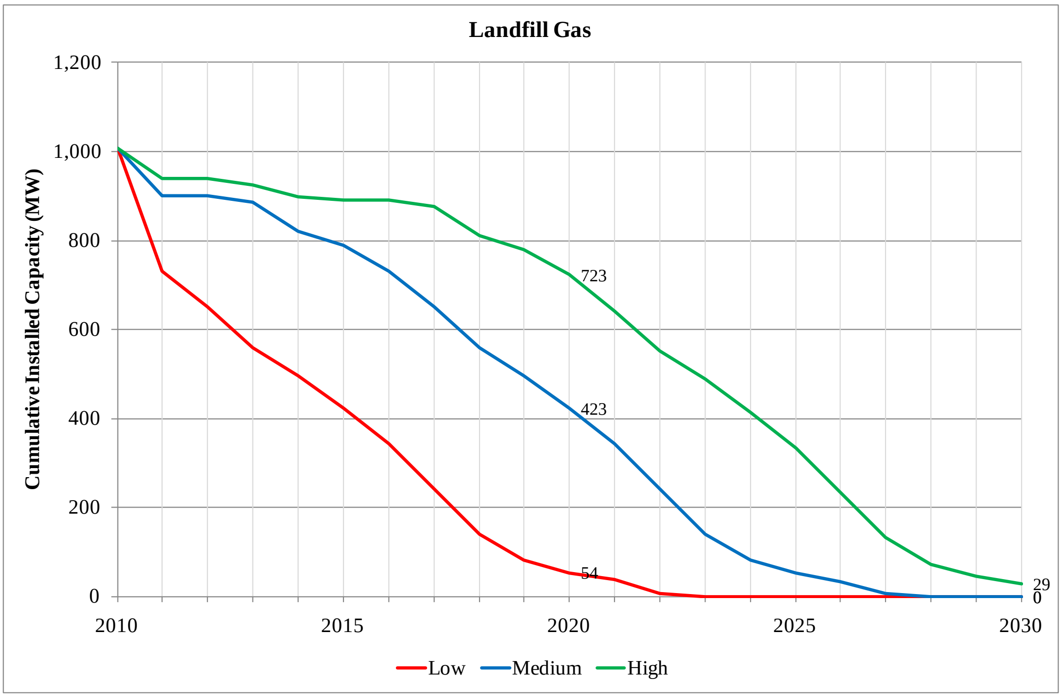


Figure 106: UK Landfill Gas Cumulative Installed Capacity (MWe)

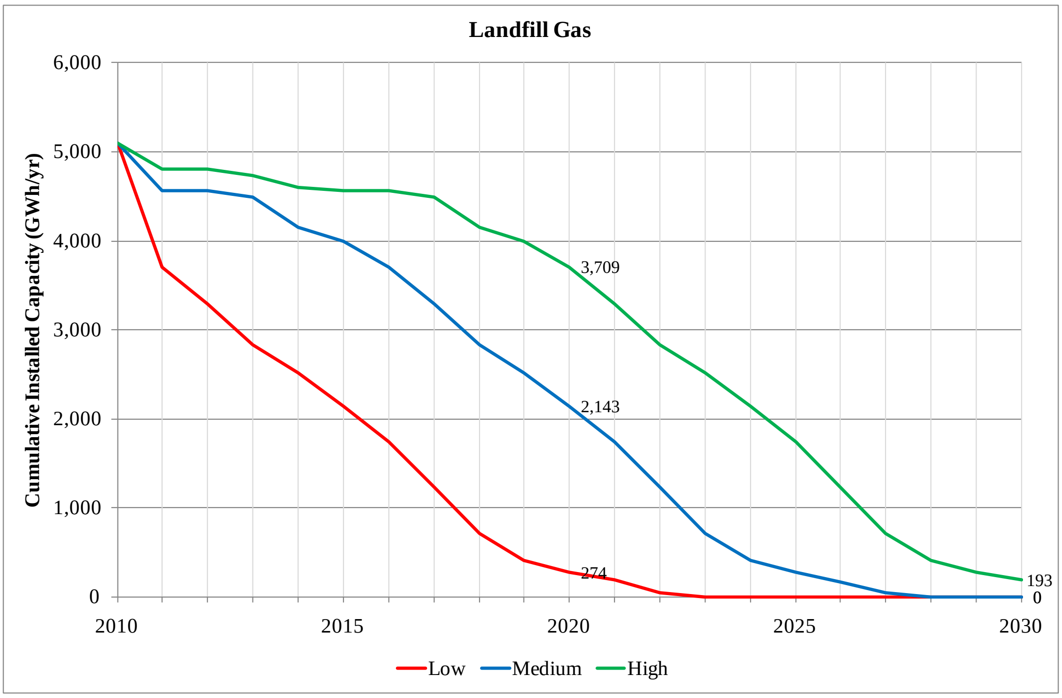


Figure 107: Landfill Gas UK Annual Electricity Generation (GWhe/yr)

The scenarios modelled for LFG assume that there is excess capacity to exploit the potential and this is evidenced by the total numbers of ROCs issued by Ofgem and the relatively low load factor for this technology. In addition, only 14 new sites were registered in 2009, compared with a total of 410. Therefore, the assumed installation rate per year is zero.

17.7 Beyond 2030

Given the changes in waste disposal in the UK and the current views of developers and operators, the renewable energy generated from LFG is likely to be minimal from 2030 to 2050. The removal of organic materials from landfill will curtail LFG production gas and the existing generating capacity will deplete the existing resource.

17.8 Project Cost

17.9 Key Assumptions

Landfill gas costs are considered to be the incremental costs of generating electricity at a landfill site. This is principally the investment for, and operation of, gas collection and generation equipment.

The information collected on project cost for landfill gas is based on consultation with industry stakeholders and relates to projects that have recently started operation, or are in development. The majority of large landfill gas sites have been developed. As a result, the data collected for this study reflects relatively smaller scale projects below 2MWe of installed capacity.

Stakeholders have indicated that project hurdle rates vary from 13-15% (post-tax nominal).

17.9.1 Capital Expenditure

Pre-development costs vary from £26,000/MWe to £170,000/MWe, the most significant element of which is pre-licensing cost.

Capital costs for LFG are based on project data provided by three industry stakeholders. The main capital expenditure items are for gas collection and processing and generation equipment. Unit costs show a relatively small range, illustrating that equipment installed at the different sites is relatively similar.

Stakeholders believe that there is a decreasing number of opportunities to develop landfill gas projects due to changes in waste streams and the level of deployment that has already been achieved. Stakeholders have also experienced a reduction in the quantity of biodegradable waste deposited in landfill. This leads to falling gas yields with a commensurate impact on plant capacity.

Table 83 below presents capital cost ranges for projects generating <2MWe. Pre-development costs are not included in capital cost ranges.

Table 83: Landfill Gas – Capital Costs (Financial Close 2010)

£’000/MW	<2MW
High	1,550
Median	1,403
Low	1,164

Table 84 below illustrates how capital costs are broken down in the average plant.

Table 84: Landfill Gas – Capital Cost Breakdown

Capital Cost Items	%
Pre-development	6%
Construction	67%
Grid Connection	14%
Other Infrastructure	13%

The majority of capital cost relates to construction and installation, i.e. of processing equipment and engines. Other infrastructure costs relate to site-specific requirements.

Labour costs and, to a lesser extent, steel prices are the main drivers of capital cost, as a result of their requirement in the manufacturing of equipment. The technology used in landfill gas projects is mature and has been used extensively for other applications. Consequently, limited learning effects and cost reductions are expected.

Table 85 presents the range of current capital costs and how they are expected to change over time.

Table 85: Landfill Gas – Capital Cost Projections at Financial Close Dates (Real)

£'000/MW	2010	2015	2020	2025	2030
High	1,550	1,542	1,541	1,551	1,560
Median	1,403	1,396	1,395	1,404	1,412
Low	1,164	1,158	1,158	1,164	1,171

17.9.2 Operating Costs

The range of unit operating costs varies significantly by project. This is due to scale effects and variations in the maintenance requirements of engines and gas clean-up at different sites.

Differences in the waste composition at each site can impact on the required operation and maintenance (O&M) regime and its cost. As landfill waste streams have changed, the concentration of contaminants has generally increased. The contaminants can increase wear in generation equipment, resulting in lower efficiencies and additional plant maintenance requirements.

Table 86 presents operational cost ranges.

Table 86: Landfill Gas – Operating Costs (Financial Close 2010)

£'000/MW	<2MW
High	212
Mean	125
Low	70

Labour costs for operation and maintenance of the gas collection and generation equipment is the main driver of future operating costs.

No learning effects are anticipated. This is due the maturity of the technology and a high level of operational experience that already exists in the industry.

Table 87 shows the range of current operational costs and how they are expected to change over time. The removal of organic waste, such as biodegradable municipal waste from landfill, will lead to reduced future landfill gas yields, which would lead to increased unit operational costs. This scenario has not been considered in the operational cost projections.

Table 87: Landfill Gas – Operating Costs Projections at Financial Close Dates (Real)

£'000/MW	2010	2015	2020	2025	2030
High	212	215	217	220	222
Median	108	109	111	112	113
Low	70	71	72	73	73

17.9.3 Levelised Costs

Using the Arup and E&Y capital and operating cost profiles[80] for Landfill Gas plants, DECC has calculated levelised costs of a reference installation at financial close in 2010, 2015, 2020, 2025 and 2030. The levelised cost ranges are based on Arup's low, medium and high capital costs. The levelised costs have been calculated by assuming a pre-tax real hurdle rate of 9.6%, assuming a similar risk profile as for onshore wind. The assumed load factor is 81% and the assumed plant lifetime is 11 years.

£ / MWh		2010	2015	2020	2025	2030
Landfill gas	low	39	39	39	38	38
	medium	45	45	45	45	45
	high	50	50	50	50	49

Note: Dates refer to financial close.

17.10 Regions

Landfill will continue to contribute to renewable electricity generation but with declining gas volumes, it is expected that there will be little or no future increase in capacity. This is verified by the number of new sites accredited under RO in 14 sites in 2009/10 and 14 sites in 2008/09, compared with 202 sites registered in 2002.

England and Wales are mature markets, which will see generator sets relocated to exploit the gas potential.

Scotland has very few sites remaining to be exploited and proposed changes to the rateable value of LFG generation may further constrain or reduce the contribution.

Northern Ireland may see some activity but with few sites any development would not have an impact on the overall technology band.

[80] To note that the levelised costs are based on a separate set of capital and operating costs provided by Arup and E&Y that assume constant steel prices over time; do not consider other infrastructure costs that mainly relate to land purchase/ rent costs which the RO is not aiming to subsidise; and uses different size categories for some technologies.

18 Sewage Gas

18.1 Summary

Energy production through the combustion of biogas has been considered for the anaerobic digestion of sewage sludge.

The currently installed capacity from the treatment of sewage sludge is estimated at 94.5 MWe.

The available energy from sewage gas is 1,381 GWh per year, which is equivalent to 175 MWe of installed generation capacity.

For the low build scenario, the installed capacity will reach the maximum resource available by 2030.

For the medium build scenario, the maximum generation capacity is predicted to be reached by 2027.

For the high build scenario the generation capacity reached by 2020 is predicted to be over 96% of the maximum available capacity available, with 1,005 of the available capacity being reached by 2023.

18.2 Introduction

The majority of sewage sludge is recycled to farmland, providing organic and nutrients to soils, the second largest disposal route is incineration. The treatment and disposal of sewage sludge is governed by various legislation. The two of most significance to the anaerobic digestion and the recycling of sewage sludge to land are the Urban Waste Water Treatment Directive, which directs both the treatment and disposal (and banned the disposal at sea of sewage sludge from the end of 1998) and the Sludge (used in agriculture) Regulations 1989 (as amended) which regulate the land spreading of sewage sludge. There is also a voluntary agreement known as the 'Safe Sludge Matrix' which ensures that sludge is only recycled to certain crops and vegetation.

Prior to its use as a soil improver, sewage sludge must be treated to stabilise it, reducing odour and pollution risks from its use, and to reduce the level of pathogens within the material to make it safe for use on farmland. This can be achieved via a number of different, and sometimes complimentary, treatment processes, including anaerobic digestion.

Anaerobic digestion (AD) is the biological conversion of putrescible material in the absence of oxygen, which results in a reduction in the quantity of solid material and the production of biogas, consisting of approximately 55-70% methane, 30-45% carbon dioxide and approximately 1% nitrogen, with trace elements of hydrogen sulphide. The process operates under mesophilic (approximately 36°C) or thermophilic (approximately 55°C) conditions.

The process is widely employed by the water industry within the UK for the stabilisation of sewage sludge to reduce the quantity of material going to disposal, to improve its aesthetic nature before it is recycled to farmland or similar and to reduce the level of pathogens in the digestate to a safe level, prior to its use on farmland.

Biogas is typically collected and used to heat the digester, to optimise the digestion process, and at larger plants, where it is economical, biogas is collected and used in combined heat and power (CHP) plants. Current advances are also being made in the injection of biomethane (processed biogas) into the national gas grid and the use of biogas as biofuel for transport.

Please note that all forecast produced in this report are not financially constrained. There is no consideration of current or future financial support mechanisms.

18.3 Limitations and Assumptions

18.3.1 Assumptions

- Electrical energy yield per wet tonne Sewage sludge at 4% dry solids 42kWh/t.
- CHP engines operate for 8,000 hours per year.
- AD feedstock resource: feedstock resource availability estimate from AEA report. Figures reviewed by Arup.
- Sewage Gas – Current feed stock 1.37Mt dry solids (Water UK) at 4% solids giving 34.25Mt sludge, rising to 39.33Mt in 2030.
- 66% currently treated (18% of this incinerated and small quantity composted and lime treated) with approximately 18Mt currently being digested.
- Incineration to be reduced to 50% of current capacity by 2020 and total sludge treated to increase to 90% of total produced by 2030, giving 24.5Mt sewage sludge digested by 2020 and 29.82Mt digested by 2030.
- Installed capacity in 2008 identified by DECC Restats is 137MWe. However, the current generation is stated as 582GWh/yr. Based on 8,000 operational hours per year this is equivalent to 72.76MWe installed, indicating that there is inefficiency in the currently installed generation capacity, due to older inefficient CHP motors.
- The current installed capacity is therefore assumed to be 94.5MWe based on 18Mt sludge being digested, the electrical yield of 42kWh/t per tonne and CHP engine being 90% available. It is assumed that a key part of the build out rate is the increase in availability of existing generation capacity to 90%, through replacement of older CHP engines.
- The future predictions for installed capacity are based on the available energy resource, biogas, being combusted in CHP engines operation 8,000 hours per year.
- In deriving the maximum electrical generation from sewage gas it has been assumed that the use of biogas for transport fuel and for injection into the gas grid is insignificant.

18.4 Constraints

18.4.1 Supply Chain

The supply chain for the development of AD facilities is not considered to represent a significant problem. The industry is fairly mature, particularly in the wastewater sector. Many of the individual components of a facility are readily available. This includes CHP engines, pumps and tanks.

The key cost drivers are steel, labour, commodities, civil costs, concrete and exchange rates. The exchange rate impact is significant with the majority of technology providers based in Europe.

The availability of feedstock and, sewage sludge will be influenced by future legislation regarding effluent discharge standard, and the consequential need for further wastewater treatment, resulting in increases in sludge production. In addition, improved logistics will make existing feedstock more economical to transport to treatment facilities and therefore increase the overall resource available for treatment.

18.4.2 Planning

Planning is not considered to represent a key issue. Development of sewage gas facilities is generally on existing sewage treatment sites and, where planning permissions are required, it would usually be considered an appropriate location.

18.4.3 UK Grid

At sewage gas sites the local electricity networks the electricity generated is usually used locally, often at the wastewater treatment works (WwTW). Furthermore, the capacity of the local electricity supply network is sufficient for the supply of electricity to the WwTW and is therefore of sufficient capacity to receive the power generated by the sewage gas facility. Connection to the national grid is therefore not considered to represent a significant issue in the development of sewage gas AD capacity.

18.4.4 Technical

Sewage gas AD is a relatively established technology in the UK for sewage sludge and the basics of the process are therefore relatively well understood.

Current innovation includes development and optimisation of pre-treatment technologies, such as various hydrolysis processes, to improve the rate and level of treatment and therefore increase biogas yields.

Further optimisation of the processes is likely to focus on improvements in terms of maintenance and reliability, of both the digestion process and CHP plant, and some limited improvement in gas yield; however these are unlikely to lead to a significant increase in energy generation.

Development of alternative energy use options, such as the upgrading of the biogas for injection into the gas grid or for use as a transport fuel, through to the development of more financially viable gas upgrading technologies, would improve the overall efficiency of the biogas use, however these would reduce the capacity available for electricity generation.

18.5 Maximum Build Rate Scenarios

18.5.1 Available Resource

The unconstrained quantity of sewage sludge in the UK is 35.4Mt. Based on an electrical generation of 42kW/tonne, there is the potential for 1,487GWh electricity per year to be produced from sewage sludge. This is equivalent to an installed generating capacity of 186MWe.

18.5.2 Low Scenario

The total available energy from sewage gas, up to which capacity might grow, is 1,381GWh, which is equivalent to an installed capacity of 175MWe.

The low build rate scenario assumes a constant increase in generation capacity up to the maximum available capacity by 2030 (3.84MWe/yr).

This lower increase in capacity represents a low increase in capacity than the average between 1987 and 2010. The low but constant increase in capacity represents the increasing inaccessibility of the resource from smaller treatment works, together with a general increase in the sewage sludge produced, due to the requirement for increased wastewater treatment to meet tightening discharge standards.

By 2030 sewage gas would therefore be generating 1,381GWh per year from an installed capacity of 175MWe.

18.5.3 Medium Scenario

The medium build rate scenario assumes a deployment rate equivalent to the historic deployment rate between 1987 and 2010 (4.65MWe/yr).

The scenario predicts that by 2020 sewage gas would be generating 1,148GWh, from an installed capacity of 146MW. By 2027, sewage gas would be generating the maximum available energy generation of 1,381GWh from an installed capacity of 175MWe.

18.5.4 High Scenario

The high build rate scenario assumes deployment rate equivalent to the historic deployment rate between 2000 and 2010 (6.09MWe/yr). This is considered to be high and includes the period when many sludge treatment facilities were rationalised to larger regional sludge treatment facilities double ROCs were available for energy from sewage gas, making increases in the generation capacity more attractive.

The scenario predicts that by 2020 sewage gas would be generating 1,273GWh, from an installed capacity of 161MWe. Sewage gas would be producing the maximum available energy generation of 1,381GWh from an installed capacity of 175MWe by 2023.

18.5.5 Maximum Build Rate Plots

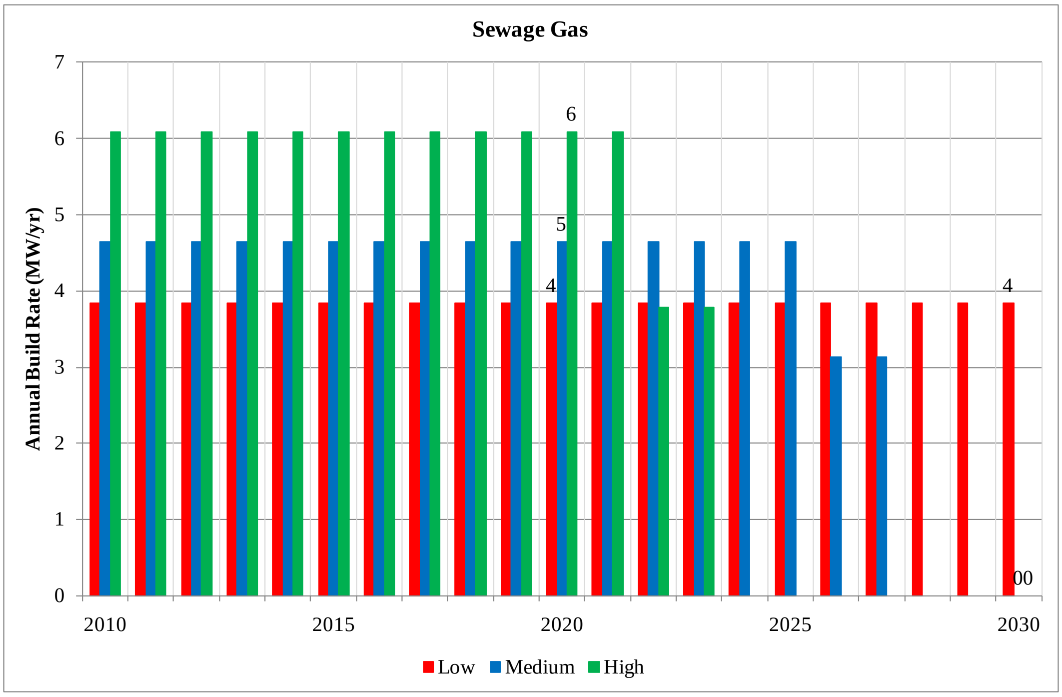


Figure 108: UK Annual Installed Capacity (MW/yr)

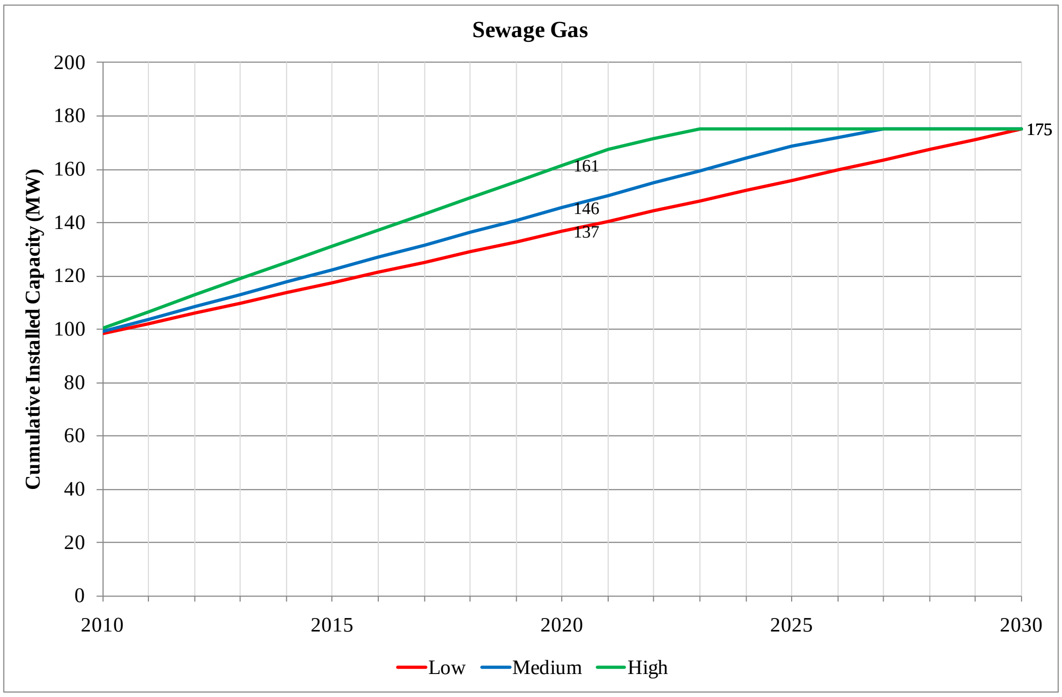


Figure 109: UK Cumulative Installed Capacity (MW)

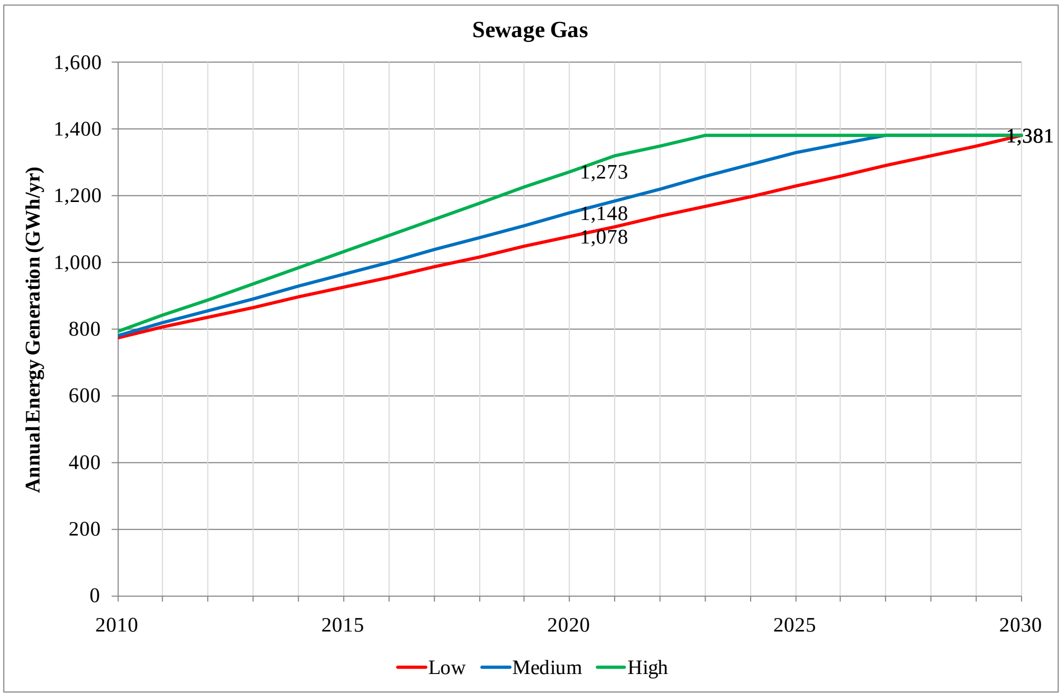


Figure 110: UK Annual Energy Generation (GWh/yr)

18.6 Beyond 2030

Based on the availability of waste feedstock the growth rates could not be sustained above the total installed capacity predicted.

18.7 Project Costs

18.7.1 Key Assumptions

The sewage gas cost analysis has been created from industry benchmarks relating to six projects. The costs shown are the incremental expenditure required for electricity generation at a wastewater treatment plant. This is principally generation and sewage treatment equipment. It does not include the anaerobic digestion equipment that would be required if electricity was not generated.

18.7.2 Capital Expenditure

Capital expenditure on a unit cost basis varies due to economies of scale and differences between conventional and advanced sewage gas projects. For conventional plants, the main capital item is the generation equipment. Advanced sewage gas projects have additional equipment that treats the waste prior to the digestion process. Installing advanced pre-treatment facilities increases capital costs, but the gas yield and plant efficiency increases.

Table 88 presents capital cost ranges for sewage gas.

Table 88: Sewage Gas – Capital Costs (Financial Close 2010)

£000s / MW	< 5 MW
High	5,914
Median	3,618
Low	2,287

Labour and exchange rates are the main drivers of future project cost. The contribution of labour costs relates to the high level of manufacturing input required to construct equipment. Exchange rates are also relevant as equipment is partly imported.

The components used in conventional sewage gas projects are mature and have been used extensively for other applications. However, the advanced pre-treatment equipment is less established and learning effects and cost reductions are expected as the technology is more widely deployed.

Table 89 presents the range of current capital costs and how they are expected to change over time.

Table 89: Sewage Gas – Capital Cost Projections at Financial Close Dates (real)

£000s / MW	2010	2015	2020	2025	2030
High	5,914	5,837	5,822	5,897	5,973
Median	3,618	3,571	3,562	3,608	3,654
Low	2,287	2,257	2,251	2,280	2,310

18.7.3 Operating Costs

The operating costs for conventional sewage gas plants relate largely to handling and maintaining generation equipment. For advanced sewage gas plants, additional labour is required to operate the pre-treatment facility. Also, the pre-treatment may use thermal techniques which will have additional operating costs to heat the sewage.

Table 90 presents the operating cost range for sewage gas projects.

Table 90: Sewage gas – operating costs (2010)

£000s / MW	< 5 MW
High	134
Median	105
Low	74

The cost of labour and exchange rates are key drivers of future operating cost. The exchange rate impacts on operating costs because of imported spare parts.

There are expected to be limited opportunities for learning effects in operating costs. Table 91 shows the range of current costs and how they are expected to change over time.

Table 91: Sewage gas – Operating Costs Projections at Financial Close Dates (real)

£000s / MW	2010	2015	2020	2025	2030
High	134	136	138	140	142
Median	105	107	108	110	112
Low	74	75	76	77	78

18.8 Levelised Costs

Using the Arup and E&Y capital and operating cost profiles[81] for Sewage Gas plants, DECC has calculated levelised costs of a reference installation at financial close in 2010, 2015, 2020, 2025 and 2030. The levelised cost ranges are based on Arup's low, medium and high capital costs. The levelised costs have been calculated using a pre-tax real hurdle rate of 9.6%, assuming a similar risk profile as for onshore wind. The assumed load factor is 68% and the assumed plant lifetime 28 years.

£ / MWh		2010	2015	2020	2025	2030
Sewage gas	low	57	56	55	54	54
	medium	81	79	77	76	76
	high	122	118	115	114	113

Note: Dates refer to financial close.

18.9 Regions

There is no regional influence on feedstock resource or development of technology capacity. There may be some local impacts based on local water company strategy. These influences include locally increased generation capacity at regional sewage sludge treatment centres and reduced regional generation capacity, due to the incineration of sludge in certain regions.

[81] To note that the levelised costs are based on a separate set of capital and operating costs provided by Arup and E&Y that assume constant steel prices over time; capex includes infrastructure costs are incurred in the core facility, but do not include 'other' infrastructure costs that relate to costs incurred outside the site, such as water, roads, waste disposal and land costs. Levelised costs use different size categories for some technologies..

19 Renewable Combined Heat and Power

19.1 Summary

The UK is approaching deployment of renewable CHP from a relatively low base. If current growth is maintained and support is in place, growth towards the upper end of the forecast is not unrealistic.

Heat production through renewable CHP is considered for: anaerobic digestion; dedicated biomass; waste to energy; bioliquids; sewage gas; and geothermal. Under the medium scenario, total installed capacity is estimated to be 1,060MW by 2020 and 2,842MW by 2030.

The annually available heat from this is 18,679GWh by 2020 and 53,266GWh by 2030.

19.2 Introduction

CHP is the simultaneous generation of electricity and heat as part of the same fuel efficient process. The generation of electricity produces heat as a by-product, which is normally released into the atmosphere. A CHP will capture this by-product and use it for space and hot water heating, and in other processes, for example steam for industrial processes. At the same time, heat can also be used in absorption chillers for cooling. A plant which has been designed to utilise all three outputs is sometimes referred to as a trigeneration system.

Gas fired CHP is a highly robust and reliable technology, and with regular maintenance a CHP engine will normally last between 15 and 20 years. A variety of renewable fuels can be used in a CHP generator, including: solid biomass; municipal solid waste (MSW); and refuse derived fuels (RDF).

CHP schemes are typically characterised by their willingness to serve a specific development within a defined urban area. In the UK its use is widespread but far from commonplace. The current market predominantly serves schemes with reliable continuous heat demands, such as an industrial customer, hospital or university campus. However, there is also a lot of opportunity for the development of wider schemes, focused around urban regeneration in London and other metropolitan centres across the UK.

The vast majority of CHP currently use fossil fuels, the majority running on natural gas[82]. There is however signs that a growing proportion of installations are starting to use renewable fuel sources, particularly beyond city/urban context. Continuing government support and policy will provide additional incentives to install renewable CHP generation.

Based on the earlier deployment forecast for dedicated biomass, waste to energy, geothermal, and anaerobic digestion. An estimate of CHP deployment has been prepared. Our approach has been to assume that deployment is a subset of forecast capacity. It is also Arup's opinion that there will be no CHP deployment associated with: landfill gas; ACT; biomass co-firing; and the conversion of

[82] DUKES (2010), Chapter 6, Chart 6.2 indicates the following fuel mix in UK CHP: 71% natural gas; other fuels 11%; refinery gas 6%; renewables 4%; coal 4%; blast furnace gas 2%; and fuel oil 2%.

existing generation.

There are a large number of opportunities to deliver renewable CHP operations. Compared to gas CHP, the high cost and low electrical efficiency associated with renewable CHP means that there have been limited deployment opportunities to date.

19.3 Limitations and Assumptions

19.3.1 Limitations

There is a limited literature on the potential renewable CHP resource in the UK. AEA (2010) has attempted to quantify future deployment whilst taking into account changes in RO and RHI financial incentives. As stated elsewhere, this report has focused on estimating deployment exclusive of any financial constraints. Assumptions of future delivery are based on our earlier deployment forecasts for dedicated biomass, AD, EfW, and geothermal.

19.3.2 Assumptions

There are significant opportunities to deliver large numbers of renewable CHP units. To deliver a large number, DECC's current strategy will need to provide the correct incentives to stimulate investment. For the analysis it has been assumed that there is no limit on the financial incentives a CHP operator may receive.

No assumption about replacement of existing schemes has been made. It can be assumed that most renewable CHP units will have asset lives of between 15 to 20 years. A typical district energy scheme will have a long asset life of 40 years or more.

The contribution of biomass related electricity will depend on four ongoing factors: technical innovation and improvement in bankability and technology track record: economic viability and development scales; biomass resources and costs; and transportation costs. The key driver for renewable fuel will be its direct substitution for other fossil fuels and support from the agricultural sector.

To generate an estimate of heat generation the following assumptions have been made:

- There is only CHP deployment alongside the roll-out of: dedicated biomass; AD; energy from waste; bioliquids; sewage gas; and geothermal. These calculations are based on the earlier deployment forecasts in the preceding chapters.
- The percentage of waste to energy plants that can operate in CHP mode has been assumed to be: 15% (2015); 20% (2017); and 25% (2019). For the CHP technology associated with the delivery of: biomass; bioliquids; AD/sewage gas; and geothermal, the assumed percentages are: 30%; 77%; 37%; and 10% respectively.
- For the forecast it has been assumed that all waste to energy; geothermal; and dedicated biomass CHP plants will operate on a steam cycle basis, with an annual utilisation factor of 70%.

- The deployment of AD CHP has been assumed to be severely restricted. CHP of this kind is only likely to occur when heat demand is local to generation and there is a heat customer commercially involved, for example a horticultural enterprise could provide an AD plant with the raw material and take heat. The opportunity to sell heat onto a third party via a heat network is therefore slim. Due to the likely remote location of such facilities, it has been estimated that only 37% of AD deployment will include a CHP. However, this estimate is likely to be affected by the introduction of the Renewable Heat Incentive.

- The deployment of landfill gas CHP has been discounted from the analysis. Roll-out would be severely restricted because of its remote location.

- Table 92 below provides a summary of the assumptions used to estimate the heat generation forecast.

Table 92: Deployment Forecast Generation Assumptions[83]

CHP Technology	Cumulative Installed CHP Capacity MW (2009)	Utilisation Factor	Annual Hours	CHP Electricity to Heat Ratio
Waste to Energy	56.6MW	85%	7,446	1:3.0
Geothermal	-	90%	7,884	1:3.0
Dedicated Biomass	98.7MW	75%	6,570	1:3.0
Anaerobic Digestion	-	50%	4,380	1:1.2
Sewage Gas	43.6MW	91%	7,998	1:1.2
Dedicated Bioliquids	-	80%	7,008	1:3.0

19.4 Constraints

19.4.1 Supply Chain

Development of renewable CHP is highly dependent on how developers and investors perceive the risks and benefits associated with this technology. Focussed policy support will stimulate demand for renewable CHP, a strengthened planning regime that favours the delivery of CHP to new developments would also support future delivery. There is however a lack of regulatory capacity, especially around the sale price of heat. Regulators will need to take into account measures to simplify the planning process and speed up deployment and guidance on the standards required. This should help facilitate delivery and reduce future response times.

[83] These are Arup's own assumptions on utilisation and electricity to heat ratio. Using the deployment forecast for each CHP technology, it has been possible to generate an estimate of potential heat output.

19.4.2 UK Grid

For medium and large sites, reinforcement of the local distribution network grid may be required. For some schemes, the high upfront cost of grid connection, particularly in rural areas, could have a major impact on delivery.

19.4.3 Technical

It has been shown above that renewable CHP suffers from a series of specific constraints. The following is a list of technical barriers which have been identified when compared to gas CHP:

- Biomass CHP has poor electrical efficiency compared to gas CHP, with the exception of biogas/bioliquid used in an engine cycle;
- Heat to power ratio in more proven technologies is poor and results in schemes that are small in electrical terms;
- Plant emissions in relation to achieving planning permission in an urban setting;
- Space in relation to energy centre, plant and fuel storage footprint; and
- There is a long-term requirement to deal with the residue from the combustion process.

19.4.4 Other Constraints

Deployment of Renewable CHP in the UK will remain highly dependent on support from Government. If support for renewable CHP continues, it is reasonable to expect that constraints on the supply of renewable sustainable fuel will cause an increase in operating costs for CHP operators. Costs will increase until investment responds and renewable sustainable fuel can become more widely available.

19.5 Maximum Build Rate Scenarios

19.5.1 Available Resource

Under an assumption of no financial constraint our forecast indicates that the maximum capacity installed by 2030 will be 6,209MW. The forecast assumes that the right mix of housing and commercial development will be ready to receive heat. The analysis has used our deployment forecast to form the basis of the high, medium and low scenarios.

All scenarios (low to high) assume a general upward trend in deployment will continue, as investors gain confidence and the technology becomes more reliable. The forecast indicates that by 2030 the range of deployment will be 1,470MW (low scenario) to 5,991MW (high scenario). The medium scenario indicates deployment of 2,842MW of capacity will be installed.

19.5.2 All Renewable CHP Maximum Build Rate Plots

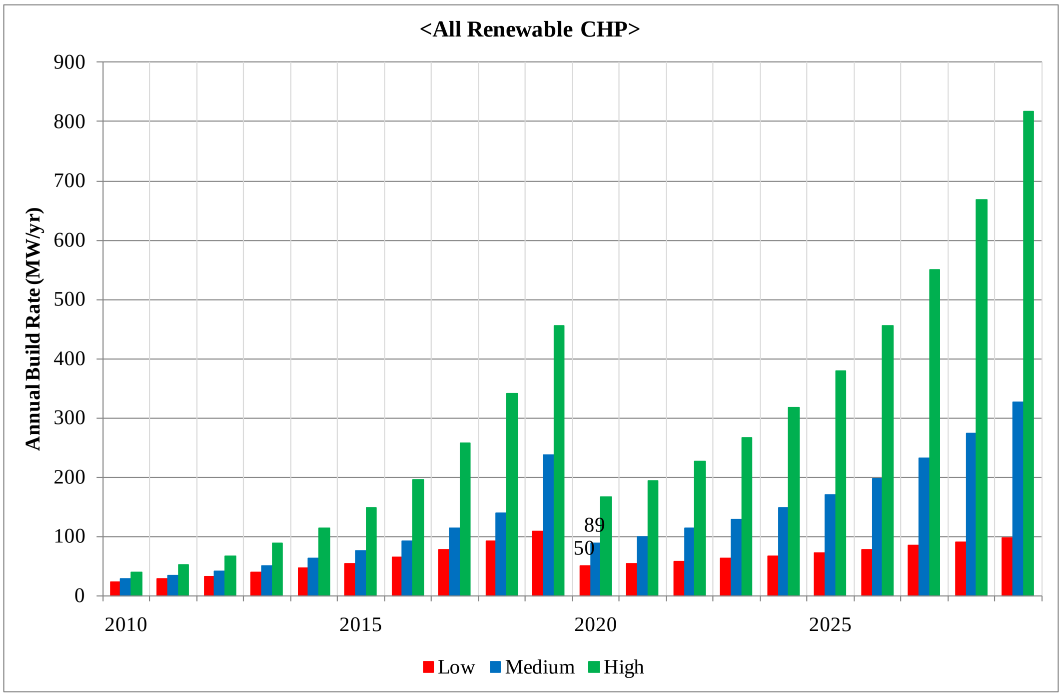


Figure 111: Renewable CHP Annual Build Rate

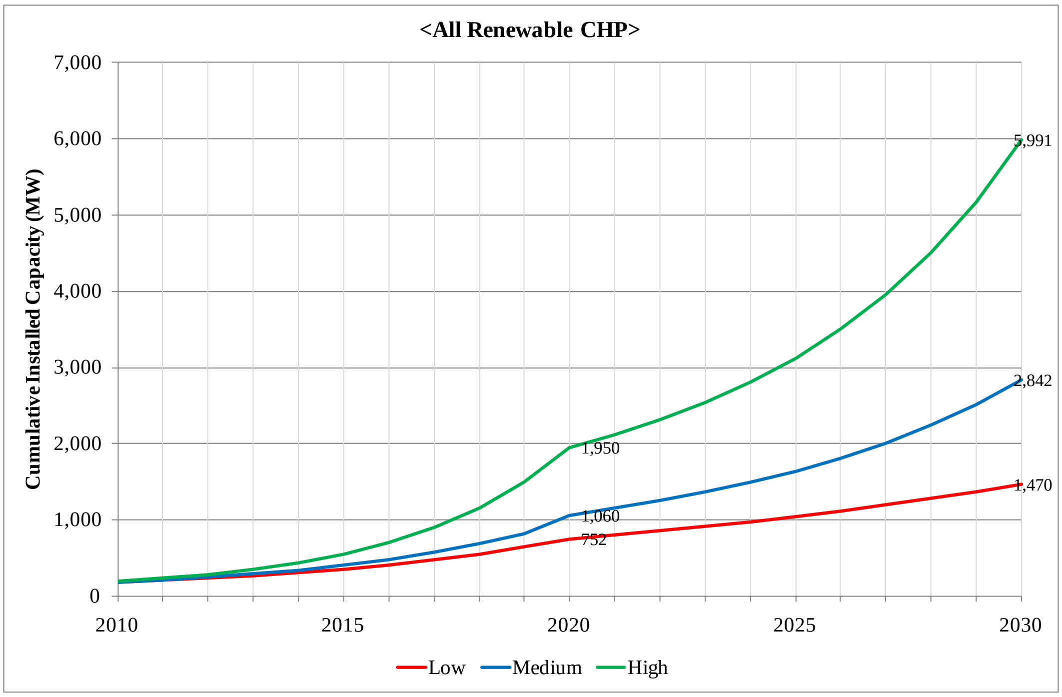


Figure 112: Renewable CHP Cumulative Installed Capacity

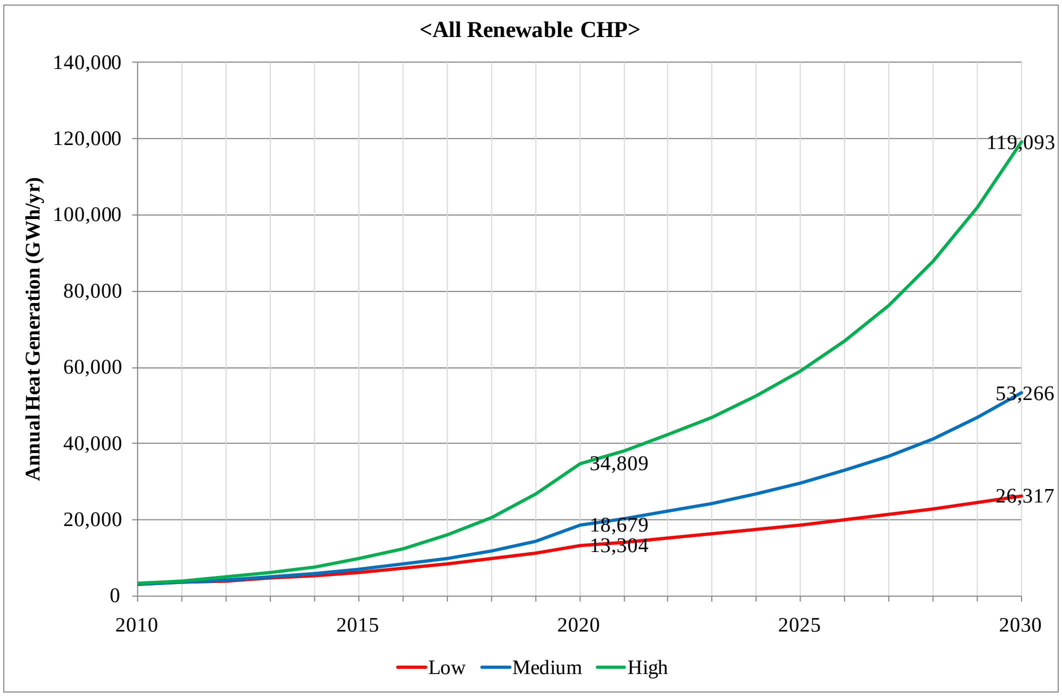


Figure 113: Renewable CHP Annual Energy Generation

19.5.3 Waste to Energy CHP Maximum Build Rate Plots

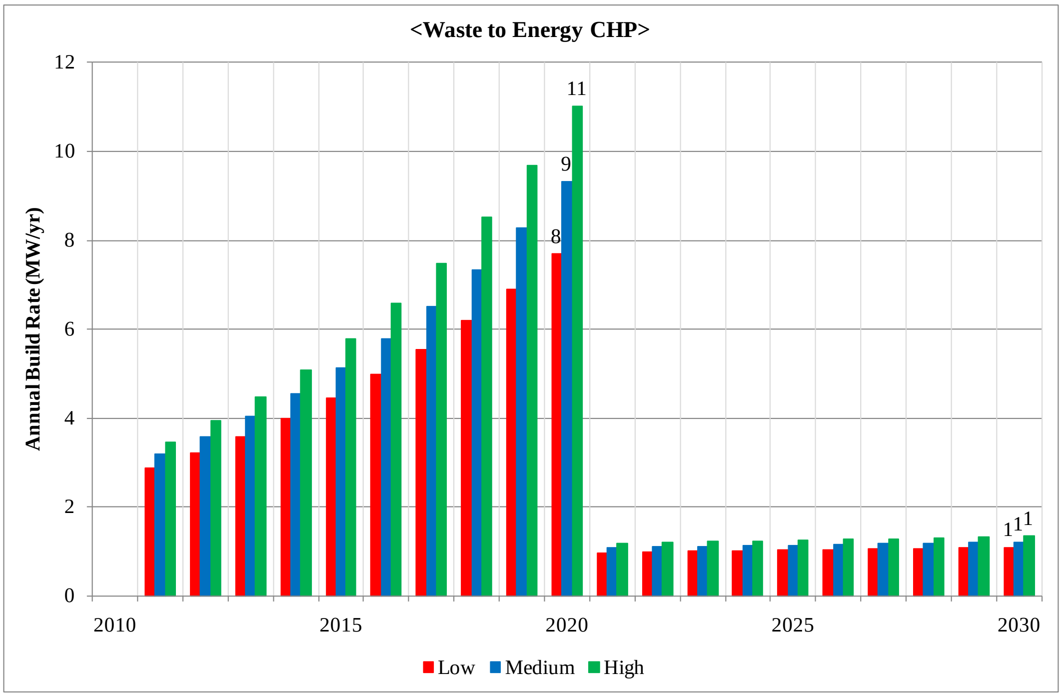


Figure 114: Waste to Energy CHP Annual Build Rate

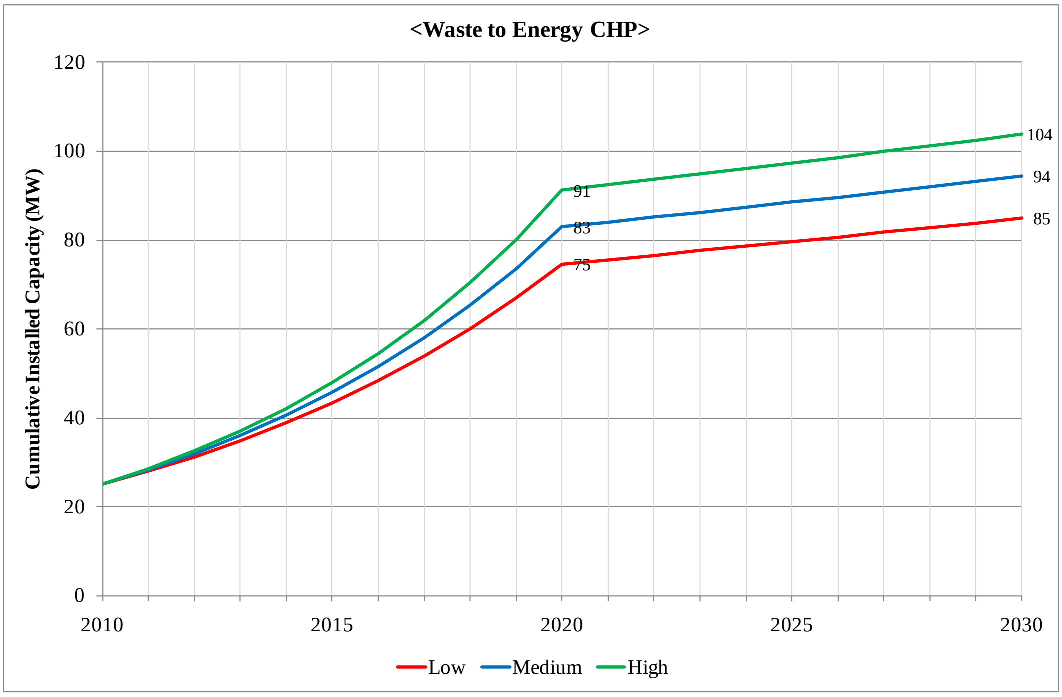


Figure 115: Waste to Energy CHP Cumulative Installed Capacity

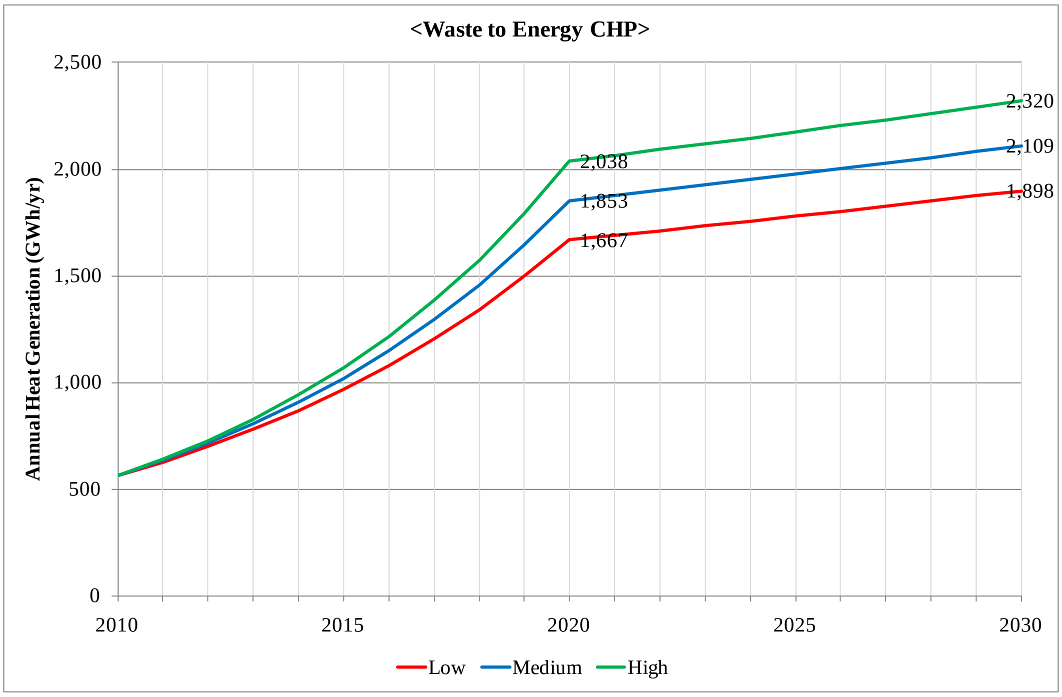


Figure 116: Waste to Energy CHP Annual Energy Generation

19.5.4 Geothermal CHP Maximum Build Rate Plots

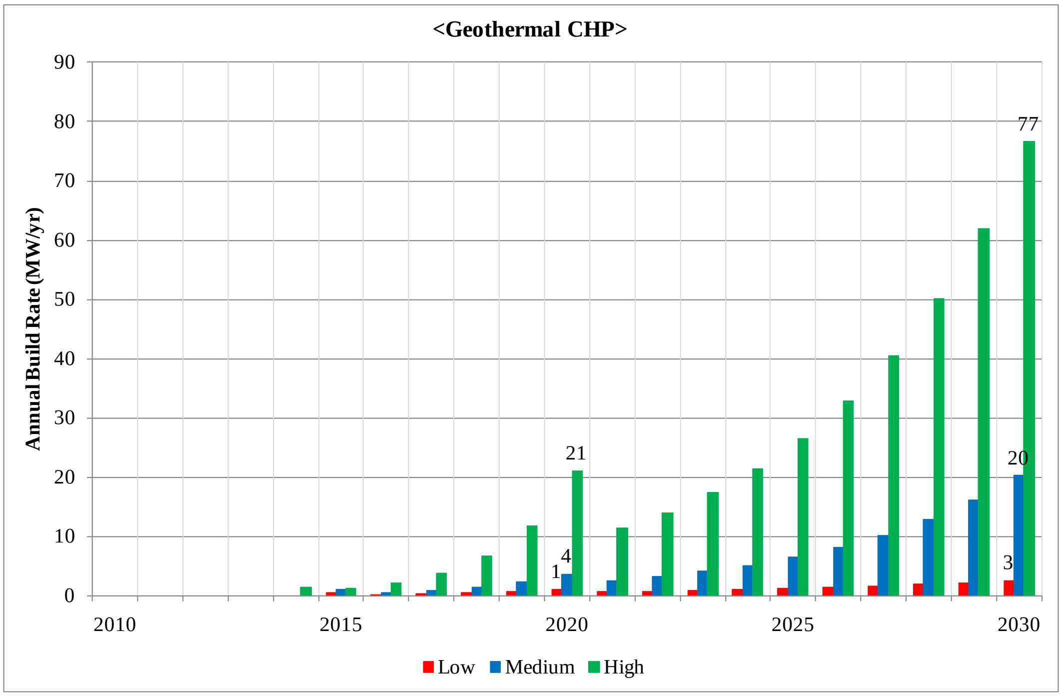


Figure 117: Geothermal CHP Annual Build Rate

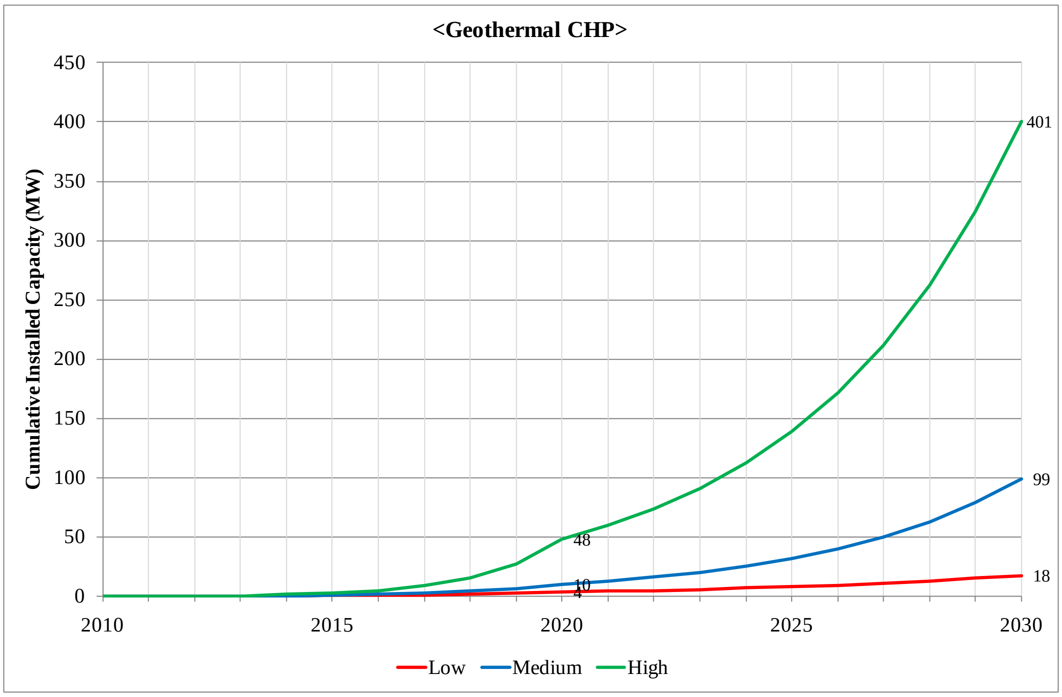


Figure 118: Geothermal CHP Cumulative Installed Capacity

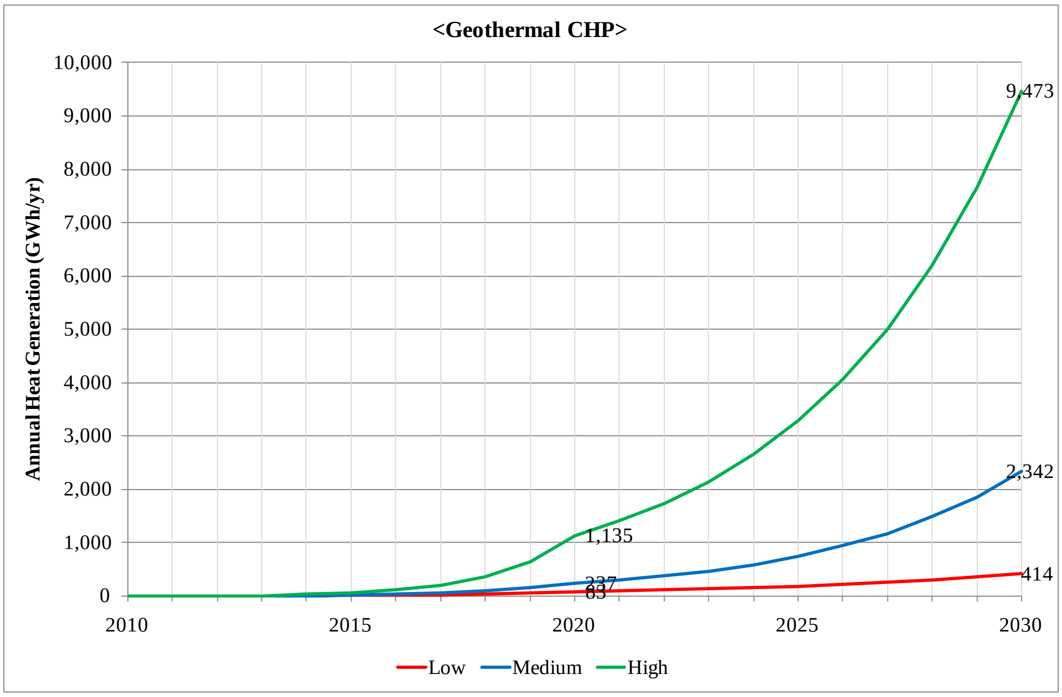


Figure 119: Geothermal CHP Annual Energy Generation

19.5.5 Anaerobic Digestion CHP Maximum Build Rate Plots

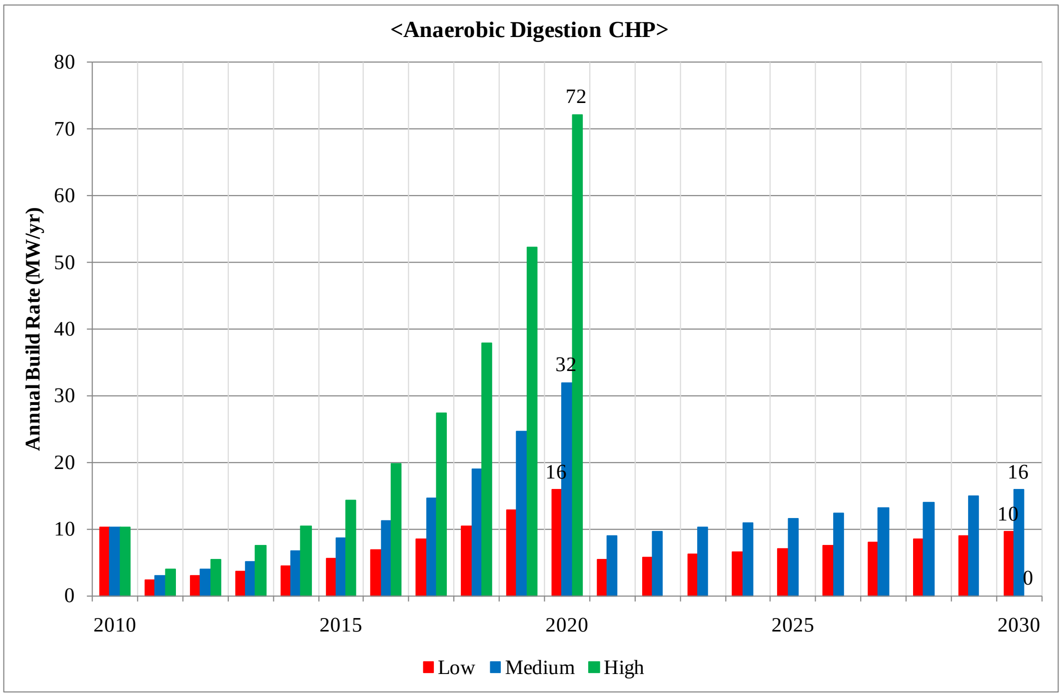


Figure 120: Anaerobic Digestion CHP Annual Build Rate

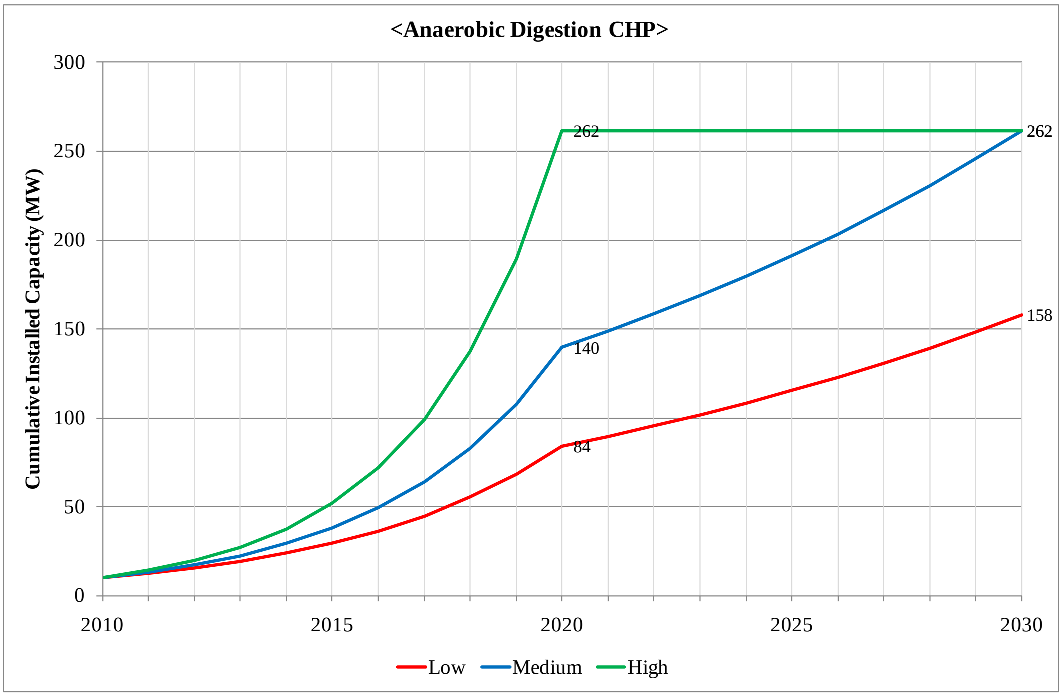


Figure 121: Anaerobic Digestion CHP Cumulative Installed Capacity

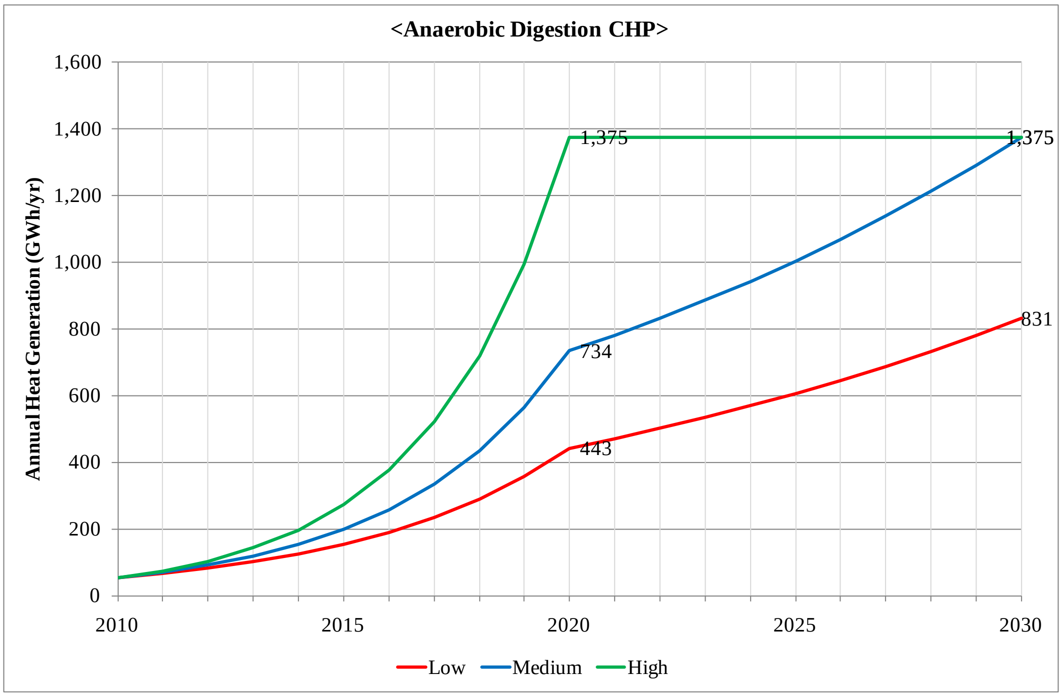


Figure 122: Anaerobic Digestion CHP Annual Energy Generation

19.5.6 Dedicated Biomass CHP Maximum Build Rate Plots

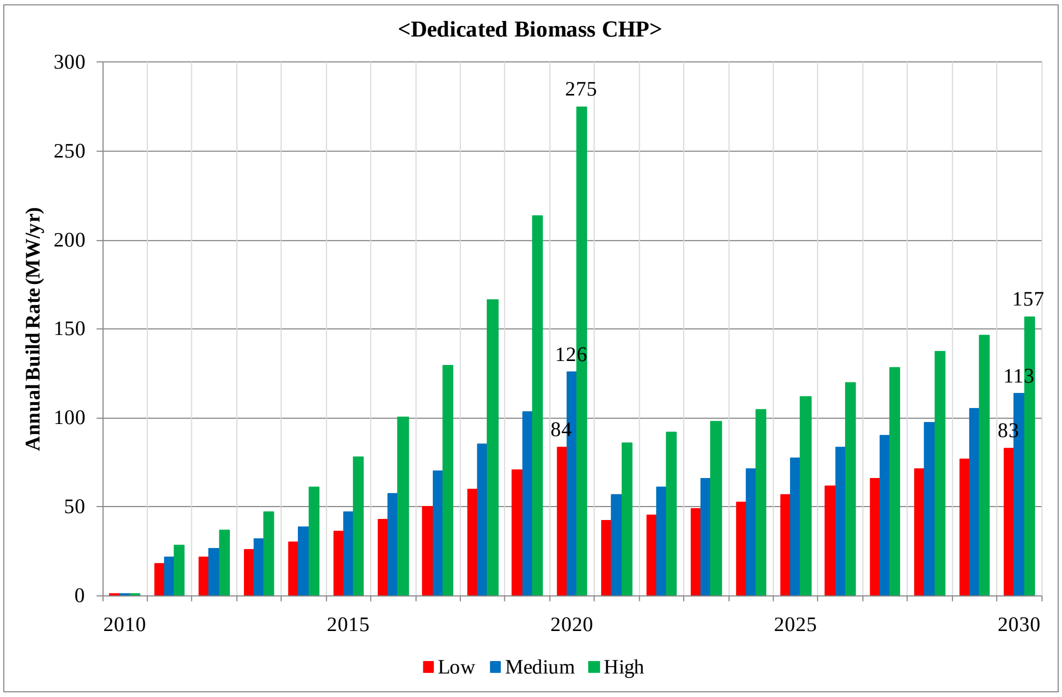


Figure 123: Dedicated Biomass CHP Annual Build Rate

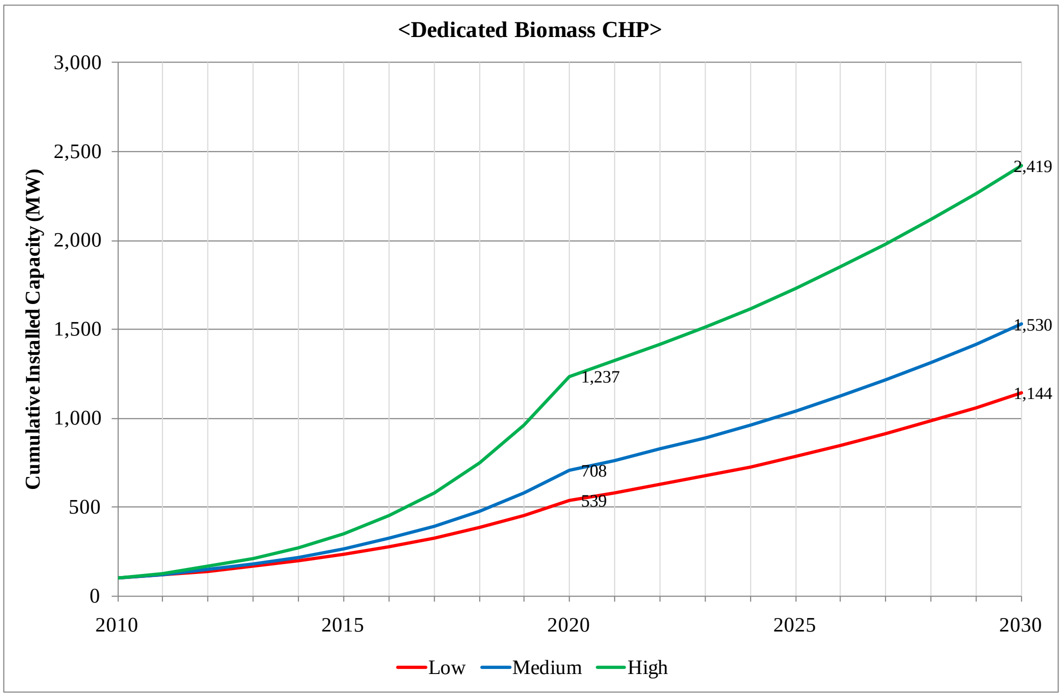


Figure 124: Dedicated Biomass CHP Cumulative Installed Capacity

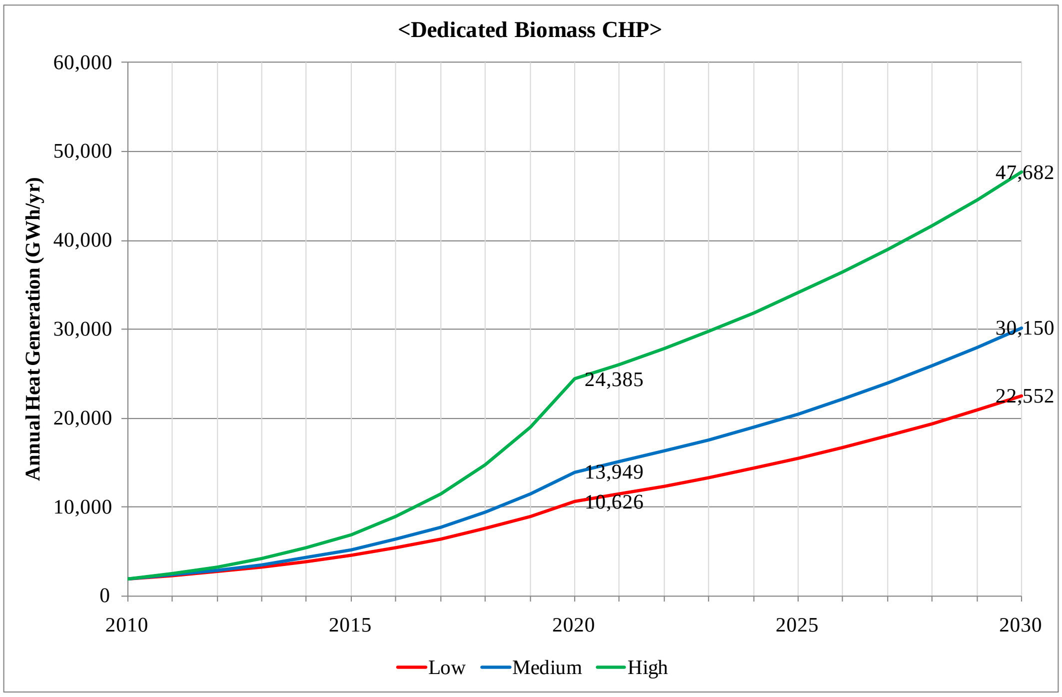


Figure 125: Dedicated Biomass CHP Annual Energy Generation

19.5.7 Dedicated Bioliquids CHP Maximum Build Rate Plots

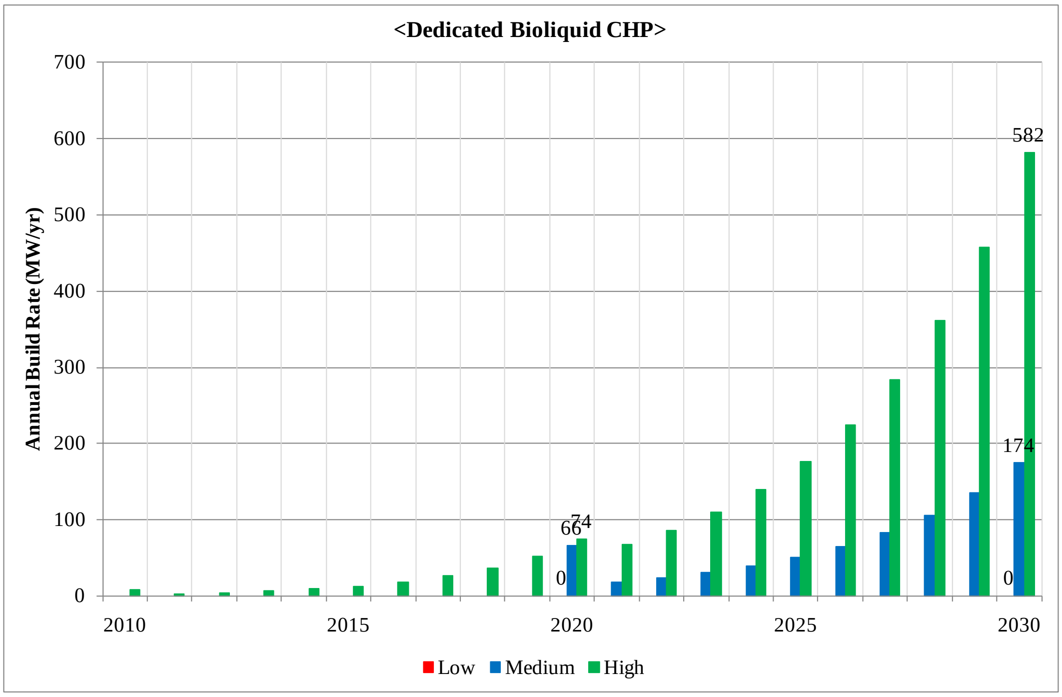


Figure 126: Dedicated Bioliquids CHP Annual Build Rate

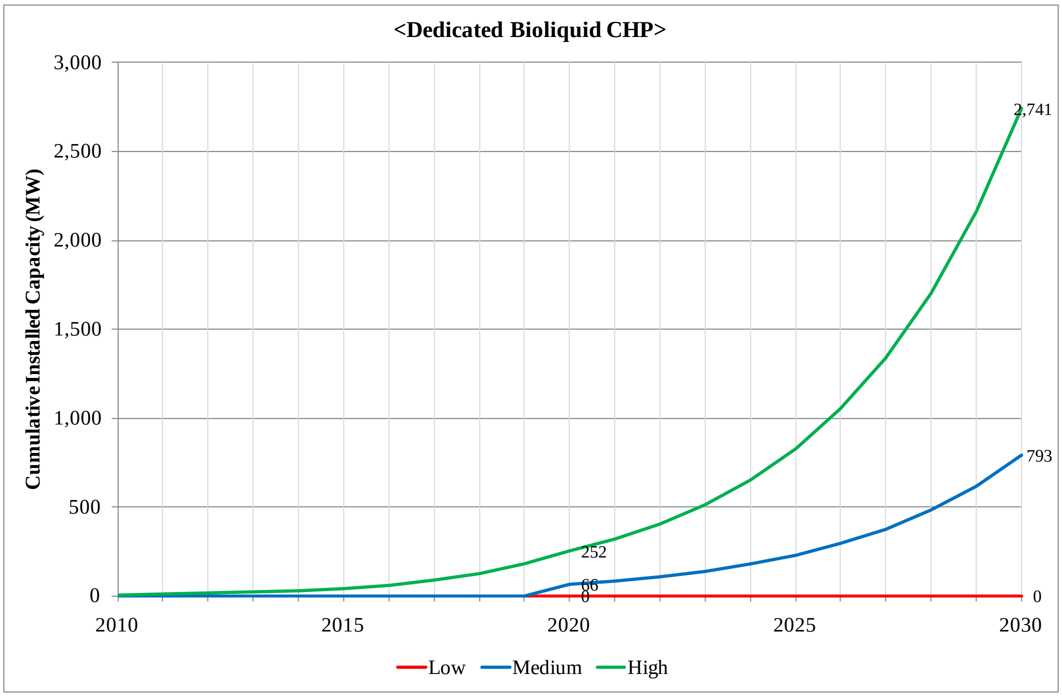


Figure 127: Dedicated Bioliquids CHP Cumulative Installed Capacity

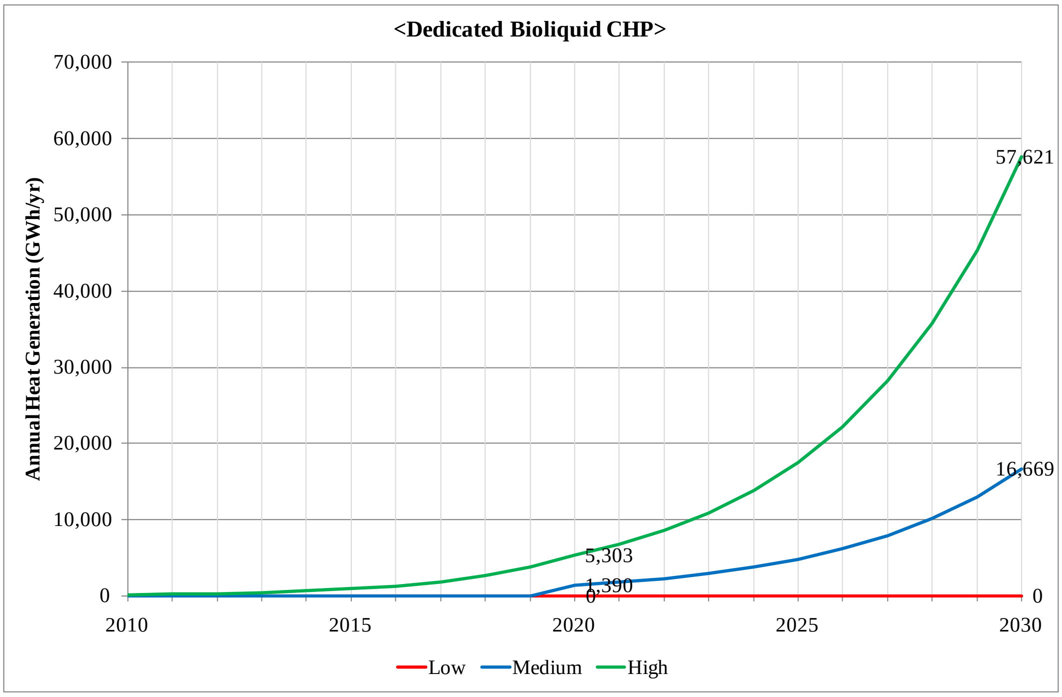


Figure 128: Dedicated Bioliquids CHP Annual Energy Generation

19.5.8 Sewage Gas CHP Maximum Build Rate Plots

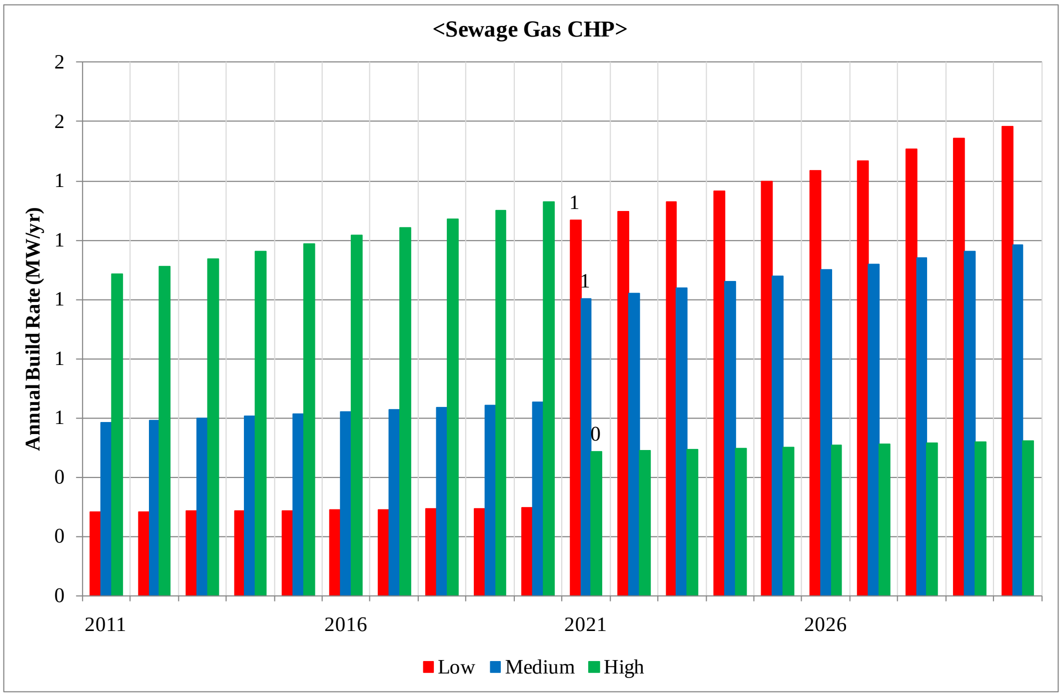


Figure 129: Sewage Gas CHP Annual Build Rate

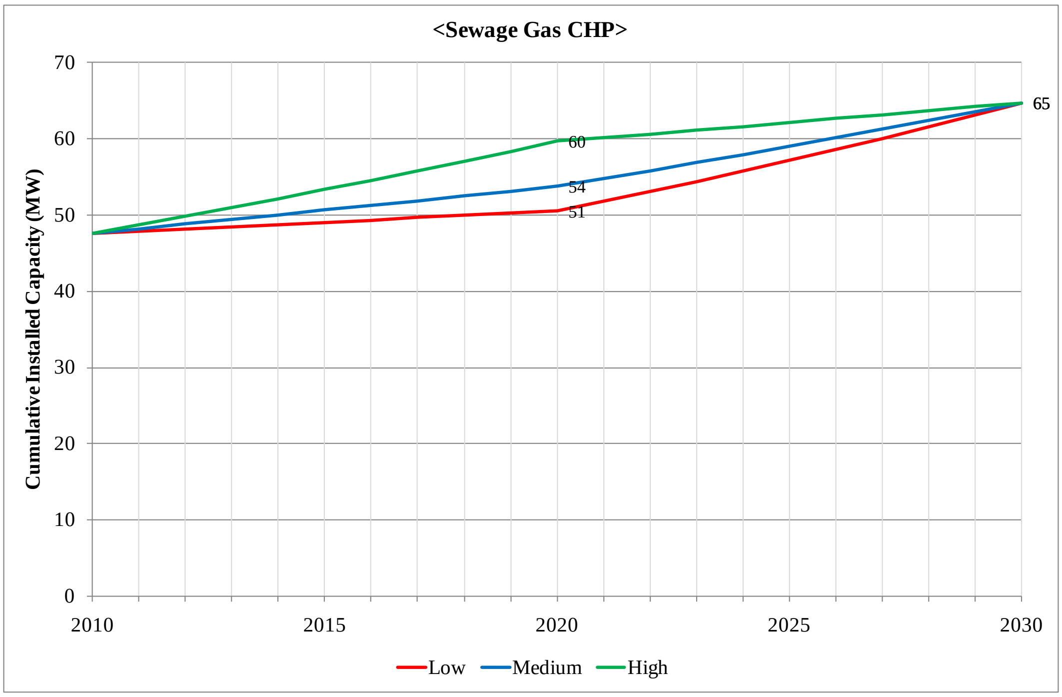


Figure 130: Sewage Gas CHP Cumulative Installed Capacity

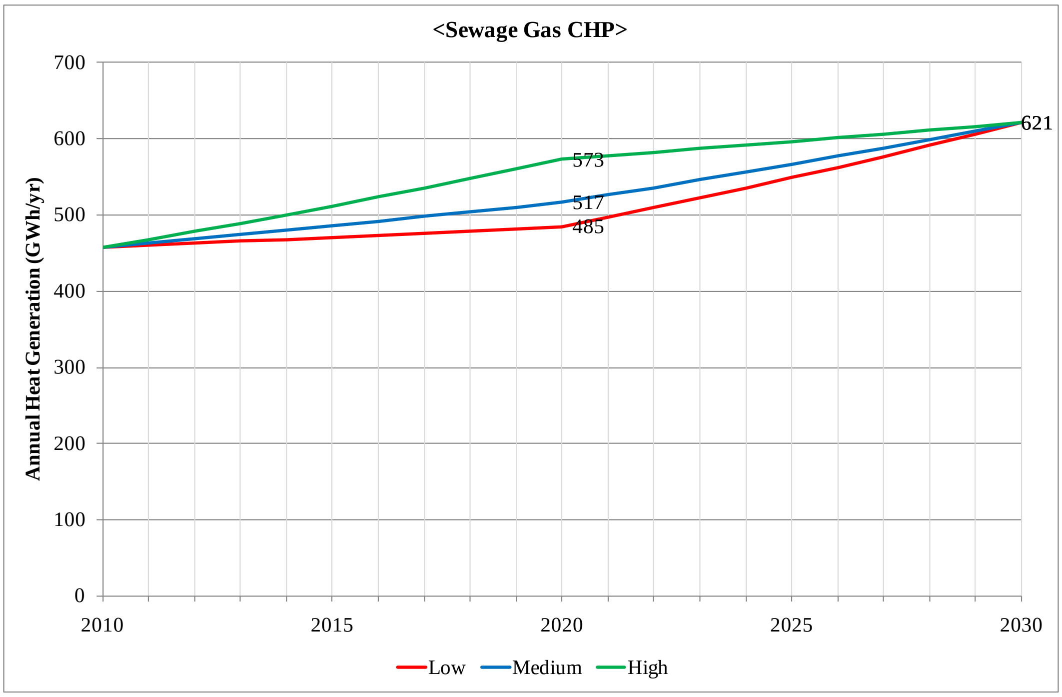


Figure 131: Sewage Gas CHP Annual Energy Generation

19.6 Beyond 2030

It is assumed that the UK can continue to encourage the deployment of renewable CHP over the next 20 years. Beyond 2030 growth is expected to level off, with renewable CHP systems eventually replacing gas and other fuels, no forecast to 2050 has been provided at this stage.

19.7 Cost and Pricing[84]

DECC has requested that cost data be estimated for renewable CHP technology. Analysis of the data indicates that a breakdown was possible, based on stakeholder data for existing generation plant. Current capital and operating costs for different CHP technologies are presented on tables 93 to 102.

It should be noted that for bioliquid, EfW and ACT CHP there has not been sufficient deployment data to allow a comprehensive collation of costs. Respondents were asked to indicate the additional expenditure required to install CHP equipment at their plants. Where actual project cost data has not been available, the suggested additional cost has been used to generate an estimate of CHP capex. For this analysis it has been assumed that plant operating costs for CHP are not materially different from power only plants.

To calculate the cost of exporting heat from a geothermal plant, the additional expenditure required was added to the power only costs. This was estimated by using the expenditure required for other technologies that have comparable generation equipment. It has also been assumed that Opex for plants with CHP is

[84] Due to a lack of data it should be noted that costs for Co-firing CHP have not been used in this analysis. The best available data is available within the following report: Mott Macdonald, UK Electricity Generation Cost Update: June 2010.

not materially different from power only plants

Table 93: Bioliquid CHP – capital costs (2010)

£’000/MW	
Low	563
Median	942
High	2,320

Table 94: Bioliquid CHP – capital cost projections (real)

£’000/MW	2010	2015	2020	2025	2030
High	2,320	2,278	2,255	2,260	2,265
Median	942	925	916	918	920
Low	563	553	547	548	550

Table 95: ACT CHP – capital costs (2010)

£’000/MW	
Low	2,680
Median	6,316
High	8,601

Table 96: ACT CHP – capital cost projections (real)

£’000/MW	2010	2015	2020	2025	2030
High	8,601	7,956	7,618	7,682	7,747
Median	6,316	5,842	5,594	5,641	5,689
Low	2,680	2,479	2,374	2,394	2,414

Table 97: Biomass CHP – capital costs (2010)

£'000/MW	
Low	3,561
Median	4,188
High	5,100

Table 98: Biomass CHP – capital cost projections (real)

£'000/MW	2010	2015	2020	2025	2030
High	5,100	5,016	4,970	4,978	4,987
Median	4,188	4,119	4,081	4,088	4,095
Low	3,561	3,502	3,470	3,476	3,482

Table 99: EfW CHP – capital costs (2010)

£'000/MW	
Low	3,968
Median	5,097
High	7,183

Table 100: EfW CHP – Capital Cost Projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	7,134	7,058	7,023	7,050	7,077
Median	5,062	5,008	4,983	5,002	5,022
Low	3,941	3,899	3,880	3,895	3,910

Table 101: Geothermal CHP – capital costs (2010)

£'000/MW	
Low	3,100
Median	6,062
High	8,570

Table 102: Geothermal CHP – Capital Cost Projections (real)

£'000 / MW	2010	2015	2020	2025	2030
High	8,570	6,442	6,362	6,237	6,120
Median	6,062	4,557	4,500	4,411	4,329
Low	3,100	2,330	2,301	2,256	2,214

19.7.1 Operating Cost

Depending on the CHP technology, operating costs can show large variation. A smaller cost range indicates that the operating requirements are relatively standardised. Table 103 to 112 present the operating cost range for all renewable CHP technology.

For all renewable CHP technology labour is a significant variable of future operating costs. Because most of the technology is manufactured abroad, exchange rates also have a significant impact.

As discussed in earlier chapters each technology is variable in terms of how well it is established and how stakeholders gain experience in running plants. For example, EfW, AD, sewage gas are well established technologies, therefore the opportunity to increase learning effects are limited. However, with a new technology such as ACT, there is large potential for learning effects in the operation of these plants.

Table 103: Bioliquid CHP – operating costs (2010)

£'000/MW	
Low	68
Median	169
High	373

Table 104: Bioliquid CHP – operating costs projections (real)

£'000/MW	2010	2015	2020	2025	2030
High	373	373	374	378	381
Median	169	169	170	172	173
Low	68	68	68	69	70

Table 105: ACT CHP – operating costs (2010)

£'000/MW	
Low	312
Median	418
High	516

Table 106: ACT CHP – operating costs projections (real)

£'000/MW	2010	2015	2020	2025	2030
High	516	498	481	464	447
Median	418	403	389	376	362
Low	312	301	291	280	271

Table 107: Biomass CHP – operating costs (2010)

£'000/MW	
Low	138
Median	189
High	269

Table 108: Biomass CHP – operating costs projections (real)

£'000/MW	2010	2015	2020	2025	2030
High	269	273	277	281	285
Median	189	192	195	197	200
Low	138	140	142	144	146

Table 109: EfW CHP – operating costs (2010)

£'000/MW	
Low	368
Median	482
High	539

Table 110: EfW CHP – Operating Costs Projections (Real)

£000s/MW	2010	2015	2020	2025	2030
High	539	546	552	559	566
Median	482	488	494	500	506
Low	368	372	377	382	386

Table 111: Geothermal CHP – operating costs (2010)

£'000 / MW	
High	142
Median	190
Low	254

Table 112: Geothermal CHP – Operating Costs Projections (Real)

£000s/MW	2010	2015	2020	2025	2030
High	255	259	262	266	270
Median	190	193	196	198	201
Low	142	144	146	148	150

19.7.2 Levelised Costs

The table below shows the levelised costs that DECC has calculated for all CHP technologies that Arup and EY collected data for. The levelised costs are expressed in terms of £ per MWh electricity generated.

Using the Arup and E&Y capital and operating cost profiles[85] for Bioliquid CHP, ACT CHP, Biomass CHP, EfW CHP and Geothermal CHP plants, DECC has calculated levelised costs of a reference installation at financial close in 2010, 2015, 2020, 2025 and 2030, respectively. The levelised cost ranges are based on Arup's respective low, medium and high capital cost estimates. Gate fee assumptions for EfW and ACT are based on the lower end of the gate fee range in the WRAP Gate Fee Report (2010)[86]. If plants experience difficulty in obtaining waste, gate fees might also be below the WRAP range, which would result in higher levelised costs. It should be noted that there is a large range of possible gate fees and the choice of gate fee strongly impacts on levelised costs. Feedstock costs for Bioliquid CHP are based on biodiesel price projections from AEA (2011)[87]; Biomass feedstock costs are based on 90% imported and 10% domestic biomass feedstock prices from AEA (2011)[88]. In addition the renewable CHP technologies listed below take into account a heat revenue, based on an avoided gas boiler cost approach. Avoided capex/opex are based on AEA/NERA (2009)[89]; avoided gas fuel and carbon costs are based on DECC gas and carbon price projections. The levelised costs of CHP technologies may not take into account the cost of delivery of the heat to the customer. For biomass CHP it needs to be noted that the DECC levelised costs are based on electrical efficiency heat to power ratio information from the Combined Heat and Power Quality Assurance programme (CHPQA)[90].

The levelised costs have been calculated by assuming a pre-tax real hurdle rate of 12.9% for Bioliquid CHP; 14.2% for ACT CHP going down to 12.9% by 2020; 13.7% for Biomass CHP going down to 12.6% post 2020; 12.9% for EfW CHP; and 23.7% for Geothermal CHP going down to 13.7% by 2030. Hurdle rates are based on Arup stakeholder information, the Oxera report[91] for the CCC and DECC assumptions. CHP technologies are assumed to be more risky than power only technologies, which is reflected in a 1 percentage point uplift in hurdle rate for CHP technologies.

The respective load factors and plant lifetimes assumed are: 73% and 10 years for Bioliquids CHP; 84% and 23 years for ACT CHP; 77% and 23 years for Biomass CHP; 83% and 29 years for EfW CHP; and 91% and 25 years for Geothermal CHP.

£ / MWh		2010	2015	2020	2025	2030
Bioliquids CHP (Biodiesel)	Low	252	262	261	255	253
	medium	267	278	277	270	268

[85] To note that the levelised costs are based on a separate set of capital and operating costs provided by Arup and E&Y that assume constant steel prices over time; capex includes infrastructure costs are incurred in the core facility, but do not include 'other' infrastructure costs that relate to costs incurred outside the site, such as water, roads, waste disposal and land costs. Levelised costs use different size categories for some technologies.
[86] www.wrap.org.uk/downloads/2010_Gate_Fees_Report.53e7e3d7.9523.pdf
[87] www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/energy_mix/renewable/policy/incentive/incentive.aspx
[88] www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/energy_mix/renewable/policy/incentive/incentive.aspx
[89] www.decc.gov.uk/en/content/cms/what_we_do/uk_supply/energy_mix/renewable/policy/incentive/incentive.aspx
[90] http://chpqa.decc.gov.uk/
[91] www.oxera.com/main.aspx?id=9514

	High	332	341	339	332	329
ACT CHP	Low	-59	-66	-75	-79	-82
	medium	18	8	-10	-15	-19
	High	69	58	35	29	24
Biomass CHP	Low	210	202	185	174	163
	medium	226	218	200	189	178
	High	250	241	220	209	199
EfW CHP	Low	-52	-54	-63	-73	-82
	medium	-30	-33	-42	-52	-61
	High	11	8	-3	-12	-22
Geothermal CHP	Low	57	16	-27	-49	-74
	medium	183	113	37	13	-28
	High	293	200	94	69	14

Note: Dates refer to financial close.

19.8 Regions

The best sites for renewable CHP in the UK are close to sources of fuel, high heat and electricity demand. Through the planning process local authorities should continue to promote deployment at a local level.

Appendix A– Cost Projection Scenarios

DECC requested the production of an alternative scenario for their analysis. The differences to the capital and operating costs presented in the main report are that:

- Capital costs exclude 'other infrastructure' costs (such as water, roads, waste disposal and land costs)
- Future cost projections assume that steel prices remain constant in real terms.
- Future cost projections apply the central learning rates to the high, median low costs, rather than the low learning rates to the high costs and the high learning rates to the costs.

These are the same assumptions used as for the levelised costs, calculated by DECC presented in the main report.

Biomass

Table 113: Biomass >50MW – capital costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	2,801	2,724	2,668	2,642	2,617
Median	2,417	2,350	2,302	2,280	2,258
Low	2,258	2,196	2,151	2,130	2,110

Table 114: Biomass >50MW– operating costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	218	212	208	206	205
Median	145	141	138	137	136
Low	106	103	101	100	99

Table 115: Biomass <50MW – capital costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	3,871	3,764	3,687	3,652	3,617
Median	3,342	3,250	3,183	3,153	3,123
Low	2,607	2,535	2,483	2,459	2,436

Table 116: Biomass <50MW– operating costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	257	250	245	243	241
Median	170	166	162	161	160
Low	125	121	119	118	117

Onshore Wind

Table 117: Onshore >5MW – capital costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	1,820	1,739	1,681	1,638	1,595
Median	1,524	1,456	1,408	1,371	1,336
Low	1,184	1,132	1,094	1,066	1,038

Table 118: Onshore >5MW – operating costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	68	68	68	69	69
Median	53	53	53	53	53
Low	28	28	28	28	28

Table 119: Onshore 50kW-5MW – capital costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	1,858	1,776	1,716	1,672	1,629
Median	1,548	1,479	1,430	1,393	1,357
Low	1,174	1,122	1,085	1,057	1,029

Table 120: Onshore 50kW-5MW – operating costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	65	65	65	65	65
Median	44	44	44	44	45
Low	36	36	36	36	36

Offshore Wind

Table 121: Offshore R2 >100MW – capital costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	3,183	2,589	2,242	2,047	1,900
Median	2,722	2,214	1,917	1,750	1,625
Low	2,300	1,871	1,620	1,479	1,373

Table 122: Offshore R2 >100MW– operating costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	186	152	131	120	111
Median	163	132	115	105	97
Low	116	95	82	75	70

Offshore Wind Round 3

Table 123: Offshore Round 3 >50MW – capital costs projections (real)

£000s/MW	2015	2020	2025	2030
High	3,279	2,685	2,373	2,166
Median	2,699	2,211	1,954	1,784
Low	2,293	1,878	1,660	1,515

Table 124: Offshore Round 3 >50MW– operating costs projections (real)

£000s/MW	2015	2020	2025	2030
High	211	173	153	140
Median	161	132	117	107
Low	105	86	76	70

Solar

Table 125: Solar >50kW – capital costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	3,736	2,961	2,367	2,029	1,829
Median	2,710	2,148	1,717	1,472	1,326
Low	1,873	1,485	1,187	1,017	917

Table 126: Solar >50kW– operating costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	27	27	27	27	27
Median	21	21	21	21	21
Low	16	16	16	16	16

Anaerobic Digestion

Table 127: Anaerobic Digestion – capital costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	7,326	7,009	6,786	6,690	6,595
Median	4,013	3,839	3,717	3,664	3,612
Low	1,742	1,667	1,614	1,591	1,568

Table 128: Anaerobic Digestion – operating costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	981	984	987	990	993
Median	500	502	503	505	506
Low	99	99	99	100	100

Geothermal

Table 129: Geothermal – capital costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	7,680	5,723	5,606	5,450	5,304
Median	5,363	3,996	3,915	3,806	3,704
Low	2,681	1,998	1,957	1,903	1,852

Table 130: Geothermal – operating costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	255	255	256	257	258
Median	190	190	191	191	192
Low	142	142	143	143	144

Standard Cofiring

Table 131: Cofiring – capital costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	167	160	156	154	152
Median	121	116	113	112	110
Low	40	39	37	37	37

Table 132: Cofiring – operating costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	30	30	30	30	30
Median	25	25	25	25	25
Low	20	20	20	20	20

Biomass Conversion

Table 133: Biomass Conversion – capital costs projections (real)

£000s/MW	2010	2015	2020
High	869	837	814
Median	458	441	429
Low	122	117	114

Table 134: Biomass Conversion – operating costs projections (real)

£000s/MW	2010	2015	2020
High	51	51	51
Median	49	49	49
Low	46	47	47

Landfill Gas

Table 135: Landfill Gas – capital costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	1,332	1,313	1,299	1,295	1,290
Median	1,206	1,189	1,177	1,172	1,168
Low	1,000	986	976	972	968

Table 136: Landfill Gas – operating costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	212	213	213	214	214
Median	125	126	126	126	127
Low	70	70	70	71	71

Sewage Gas

Table 137: Sewage Gas – capital costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	5,914	5,694	5,541	5,476	5,412
Median	3,618	3,484	3,389	3,350	3,310
Low	2,287	2,202	2,143	2,118	2,093

Table 138: Sewage Gas – operating costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	134	134	135	135	136
Median	105	106	106	106	107
Low	74	74	74	75	75

Hydropower < 5MW

Table 139: Hydropower <5MW – capital costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	9,480	9,511	9,543	9,575	9,606
Median	4,429	4,444	4,459	4,473	4,488
Low	2,604	2,613	2,622	2,630	2,639

Table 140: Hydropower <5MW – operating costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	109	110	110	111	111
Median	66	66	67	67	67
Low	22	22	22	22	22

Hydropower > 5MW

Table 141: Hydropower >5MW – capital costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	2,858	2,867	2,877	2,887	2,896
Median	2,307	2,315	2,322	2,330	2,338
Low	1,448	1,453	1,458	1,462	1,467

Table 142: Hydropower >5MW – operating costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	66	67	67	67	67
Median	54	54	54	55	55
Low	24	24	24	25	25

EfW CHP

Table 143: EfW CHP – capital costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	6,446	6,316	6,225	6,189	6,154
Median	4,574	4,482	4,417	4,392	4,367
Low	3,561	3,489	3,439	3,419	3,400

Table 144: EfW CHP – operating costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	539	540	542	543	544
Median	482	483	484	486	487
Low	368	369	370	371	371

EfW power only

Table 145: EfW – capital costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	6,133	6,009	5,923	5,889	5,855
Median	3,534	3,463	3,413	3,393	3,374
Low	3,388	3,320	3,272	3,253	3,235

Table 146: EfW – operating costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	496	497	499	500	501
Median	443	444	445	446	447
Low	339	340	340	341	342

Bioliquids

Table 147: Bioliquids – capital costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	1,892	1,836	1,797	1,780	1,764
Median	794	771	755	747	740
Low	475	461	451	447	443

Table 148: Bioliquids – operating costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	373	368	366	365	364
Median	169	167	166	166	165
Low	68	67	67	67	67

Advance Conversion Technology (ACT)

Table 149: ACT – capital costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	7,757	7,421	7,186	7,084	6,983
Median	5,697	5,450	5,277	5,202	5,128
Low	2,417	2,313	2,239	2,208	2,176

Table 150: ACT – operating costs projections (real)

£000s/MW	2010	2015	2020	2025	2030
High	504	481	459	438	418
Median	408	389	372	354	338
Low	305	291	277	265	252

Renewable CHP

Table 151 ACT – capital costs projections (real)

£'000/MW	2010	2015	2020	2025	2030
High	8,138	7,786	7,539	7,431	7,326
Median	5,976	5,718	5,536	5,457	5,380
Low	2,536	2,426	2,349	2,316	2,283

Table 152 ACT – operating costs projections (real)

£'000/MW	2010	2015	2020	2025	2030
High	504	481	459	438	418
Median	408	389	372	354	338
Low	305	291	277	265	252

Table 153 Bioliquids CHP – capital costs projections (real)

£'000/MW	2010	2015	2020	2025	2030
High	2,244	2,179	2,132	2,112	2,092
Median	942	915	895	887	878
Low	563	547	535	530	525

Table 154 Bioliquids CHP – operating costs projections (real)

£'000/MW	2010	2015	2020	2025	2030
High	297	294	292	291	290
Median	135	133	132	132	132
Low	54	54	53	53	53

Table 155 Geothermal CHP – capital costs projections (real)

£'000/MW	2010	2015	2020	2025	2030
High	8,386	6,249	6,121	5,951	5,792
Median	5,932	4,421	4,330	4,210	4,097
Low	3,034	2,261	2,214	2,153	2,095

Table 156 Geothermal CHP – operating costs projections (real)

£'000/MW	2010	2015	2020	2025	2030
High	255	255	256	257	258
Median	190	190	191	191	192
Low	142	142	143	143	144

Table 157 Biomass CHP – capital costs projections (real)

£’000/MW	2010	2015	2020	2025	2030
High	4,966	4,829	4,731	4,685	4,650
Median	4,078	3,965	3,884	3,847	3,818
Low	3,467	3,372	3,303	3,271	3,246

Table 158 Biomass CHP – operating costs projections (real)

£’000/MW	2010	2015	2020	2025	2030
High	271	264	259	257	254
Median	191	186	182	181	179
Low	139	136	133	132	131

Appendix B –Wave and Tidal Stream Deployment (England, Wales and Scotland)

This appendix provides a forecast of wave and tidal stream deployment for England, Wales and Scotland only.

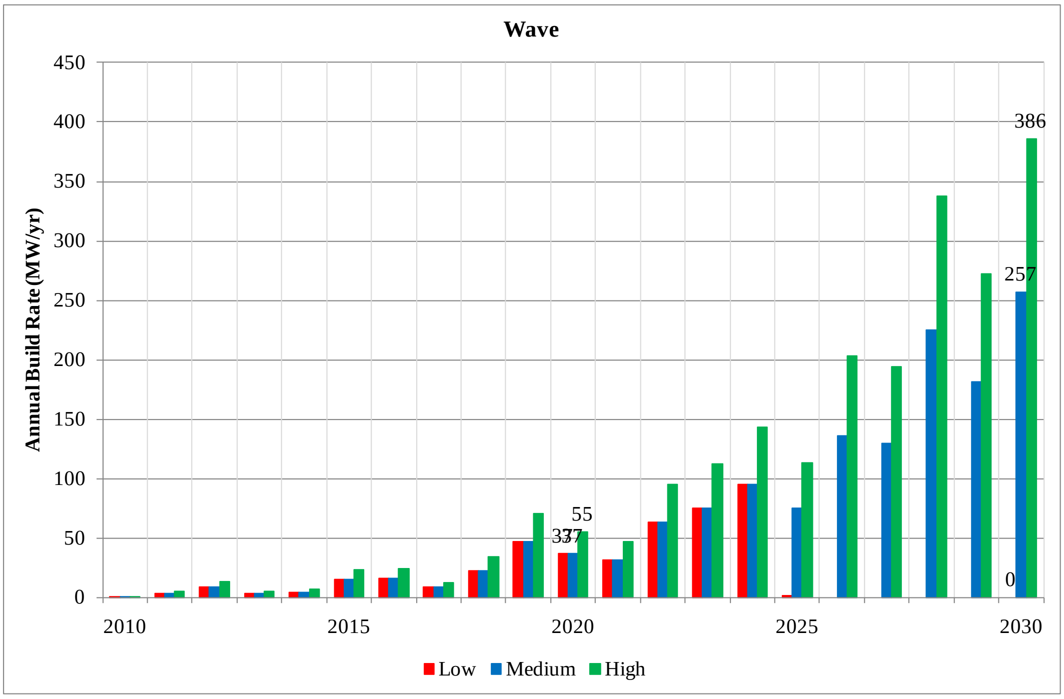


Figure 132: Wave Annual Build Rate: Scotland (MW/yr)

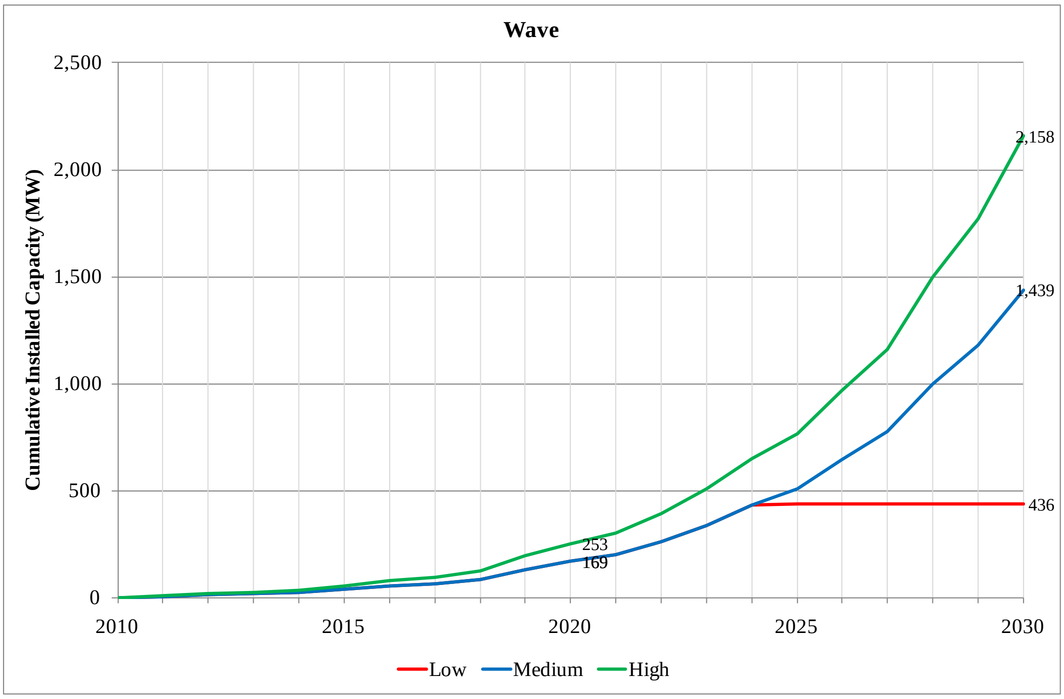


Figure 133: Wave Cumulative Installed Capacity: Scotland (MW)

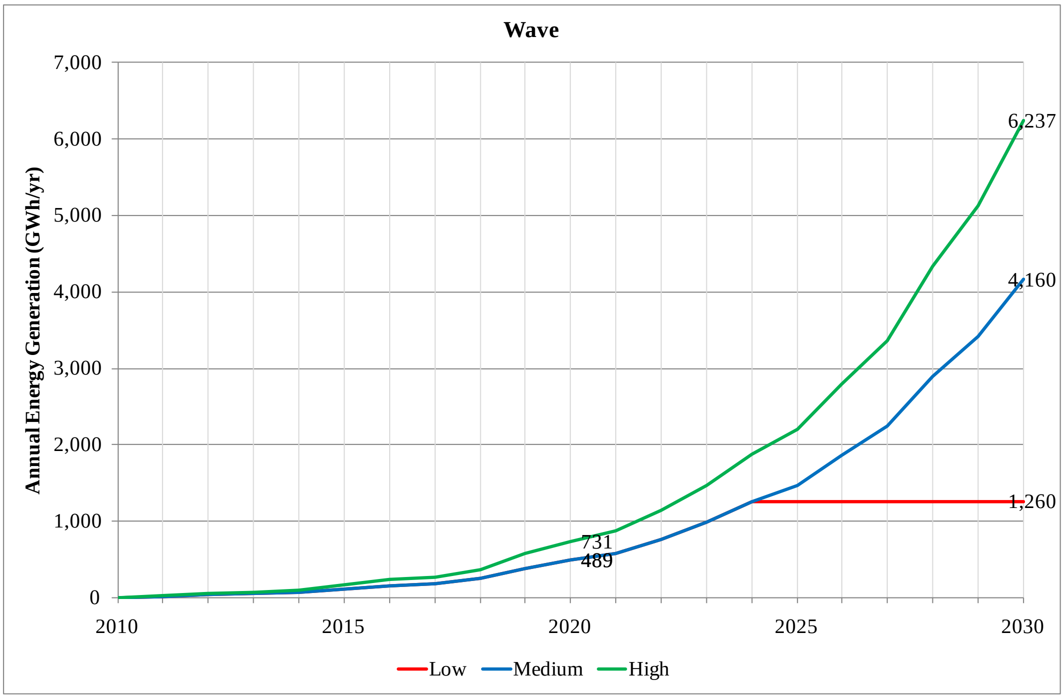


Figure 134: Wave Annual Energy Generation: Scotland (GWh/yr)

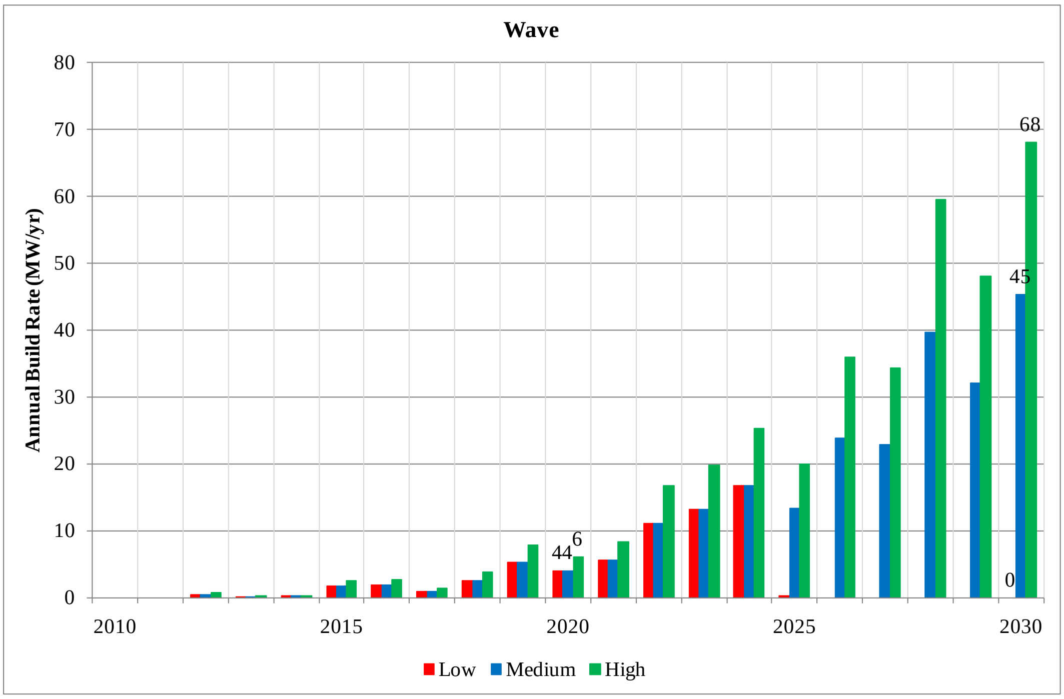


Figure 135: Wave Annual Build Rate: England & Wales (MW/yr)

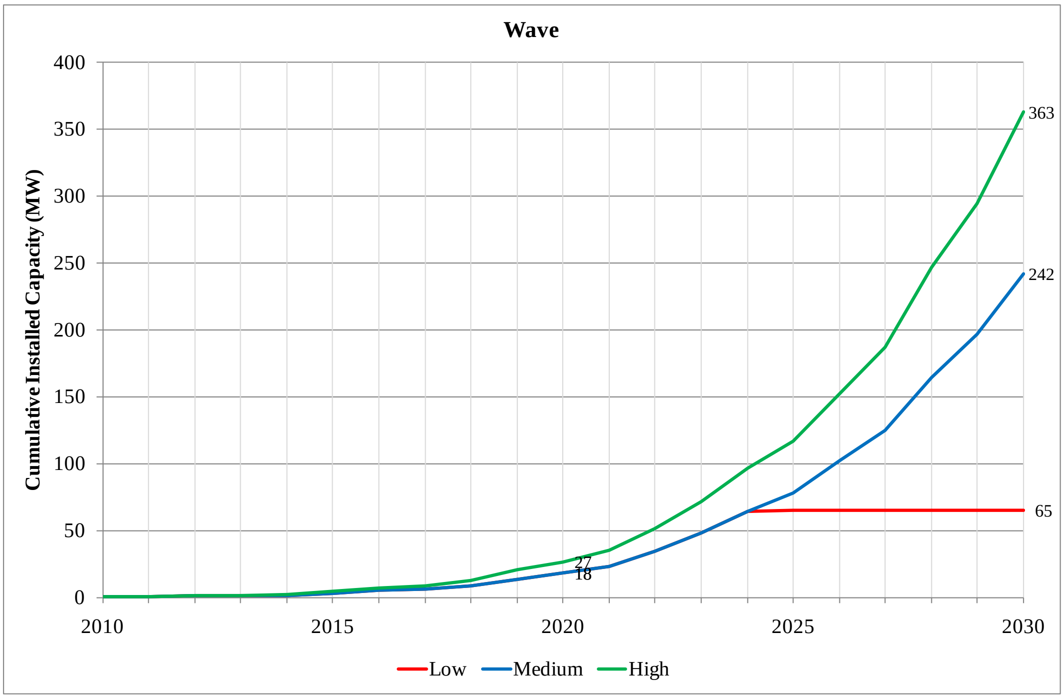


Figure 136: Wave Cumulative Installed Capacity: England & Wales (MW)

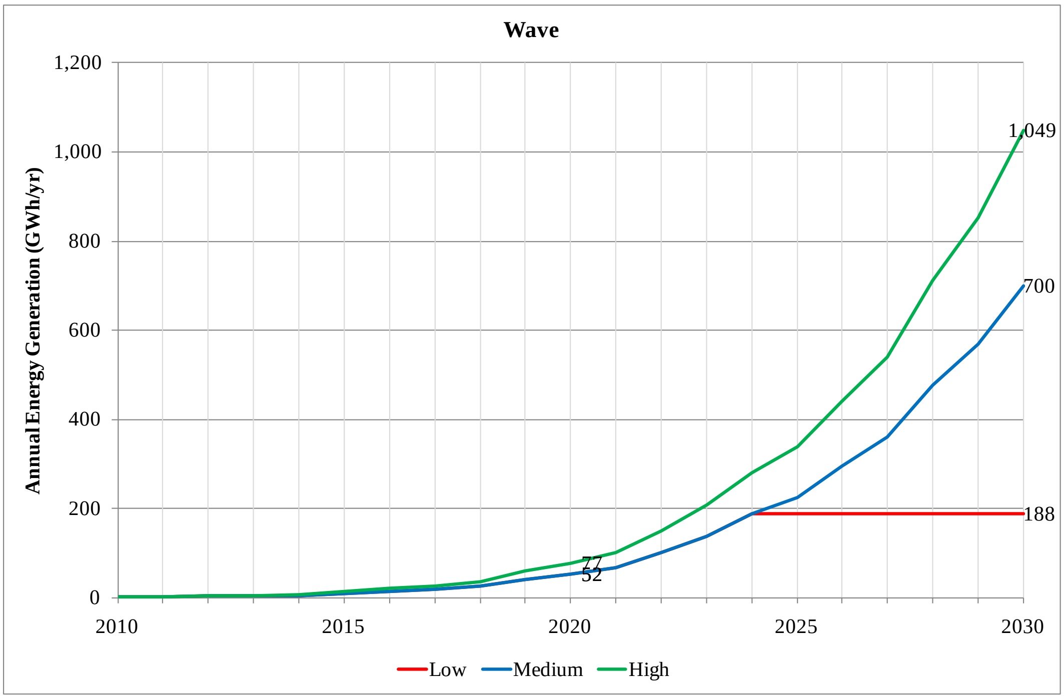


Figure 137: Wave Annual Energy Generation: England & Wales (GWh/yr)

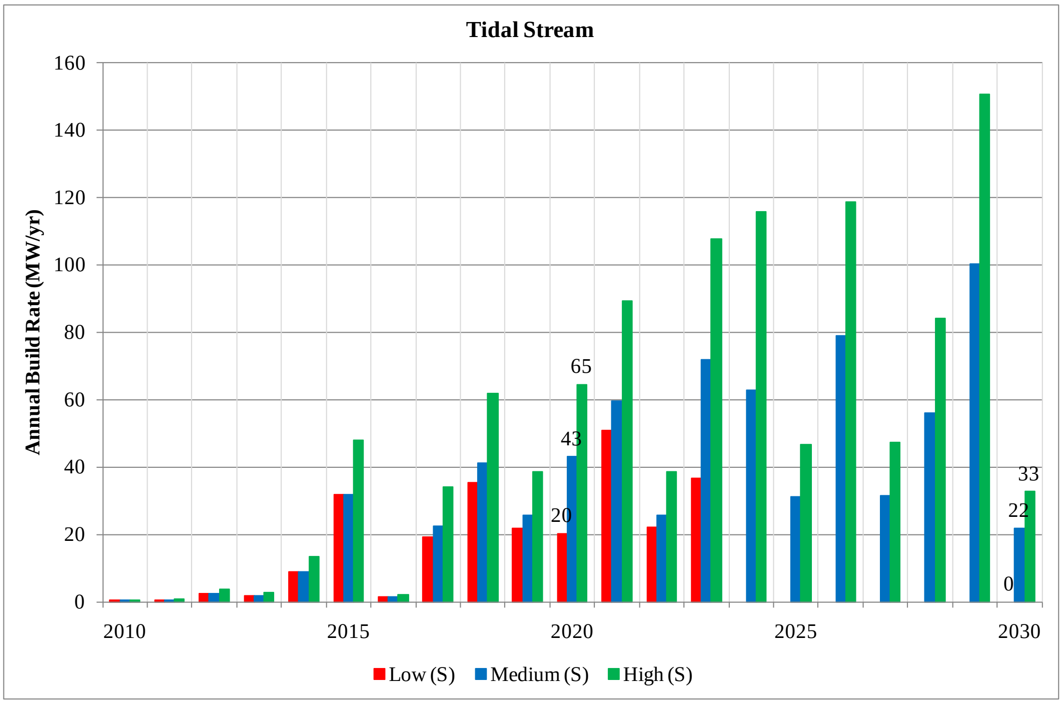


Figure 138: Tidal Stream Annual Build Rate: Scotland (MW/yr)

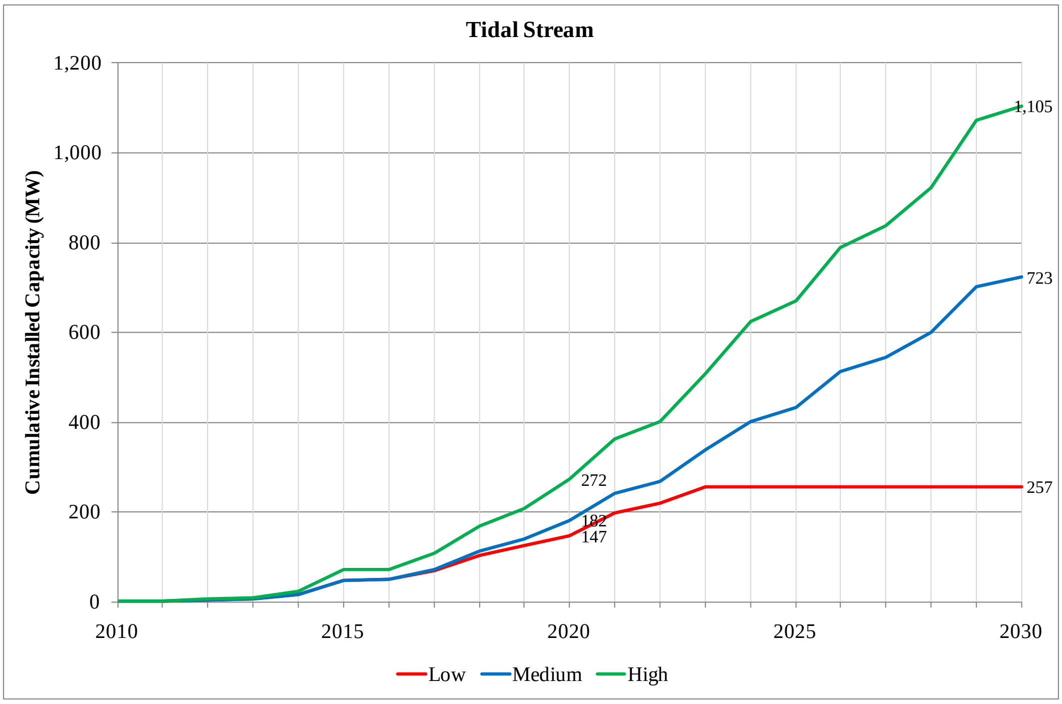


Figure 139: UK Tidal Stream Cumulative Installed Capacity: Scotland (MW)

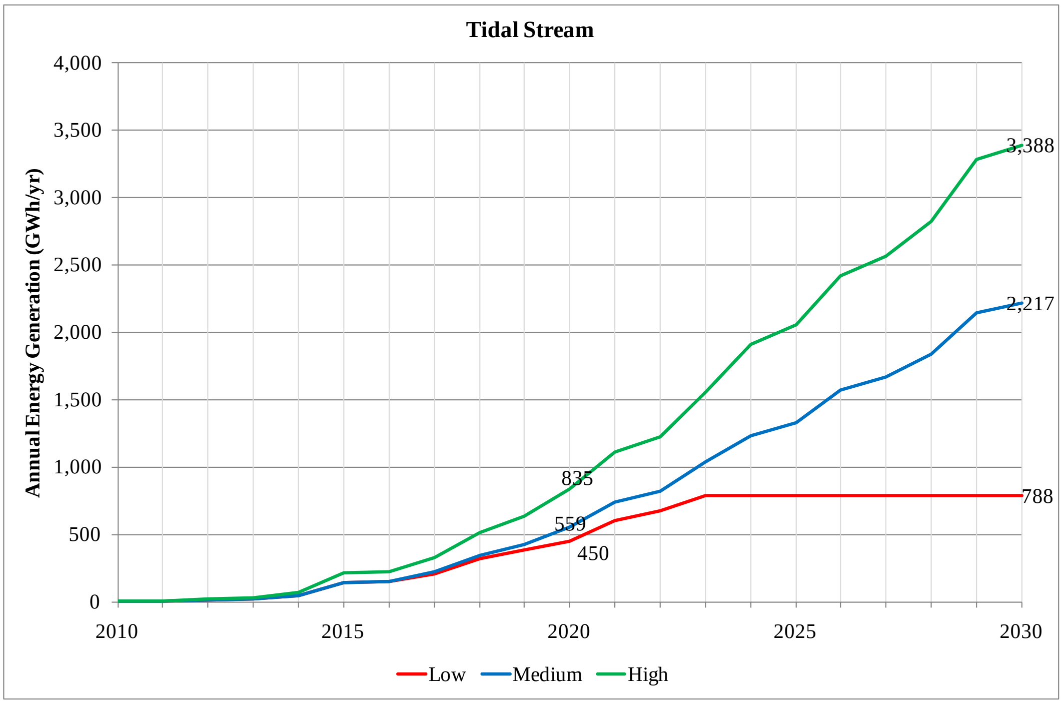


Figure 140: UK Tidal Stream Annual Energy Generation: Scotland (GWh/yr)

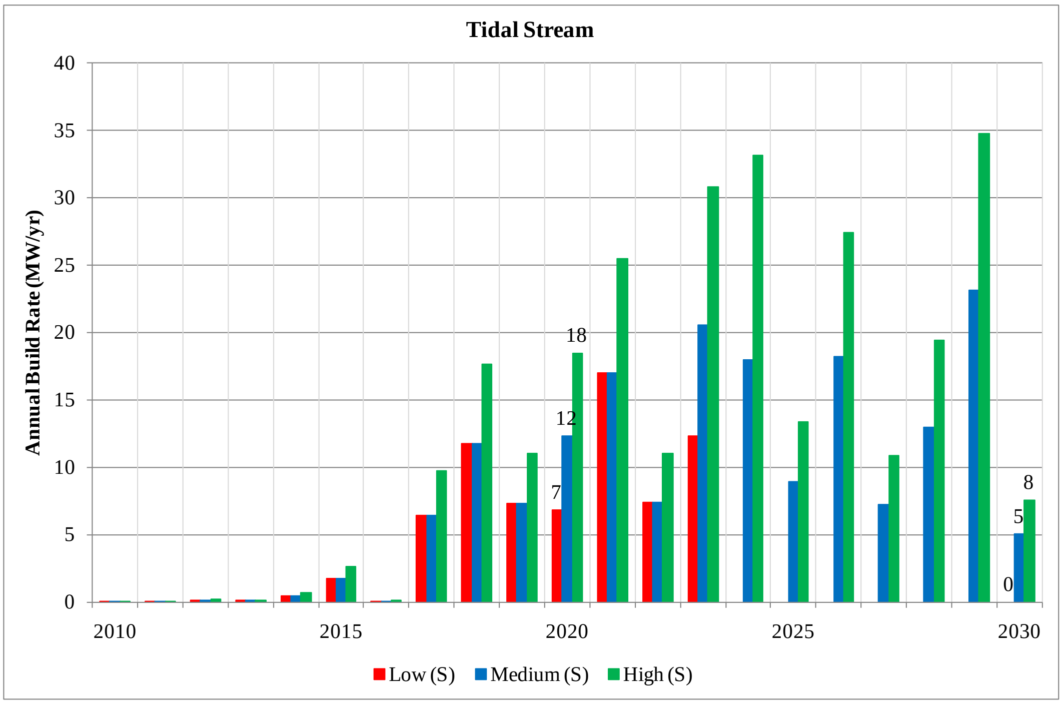


Figure 141: Tidal Stream Annual Build Rate: England & Wales (MW/yr)

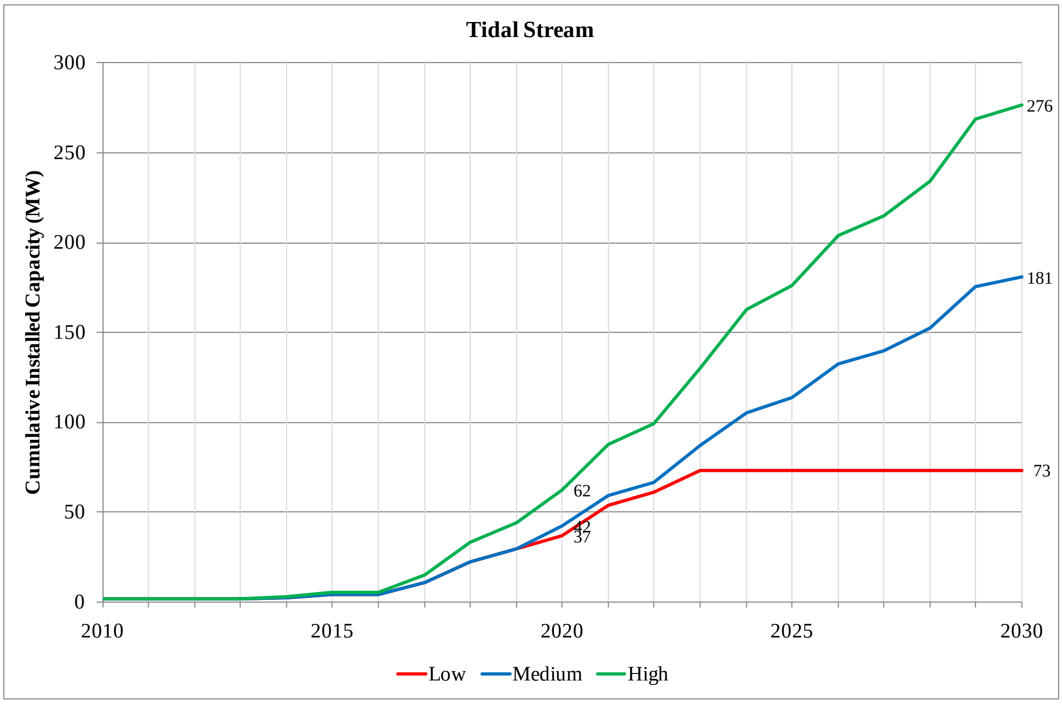


Figure 142: UK Tidal Stream Cumulative Installed Capacity: England & Wales (MW)

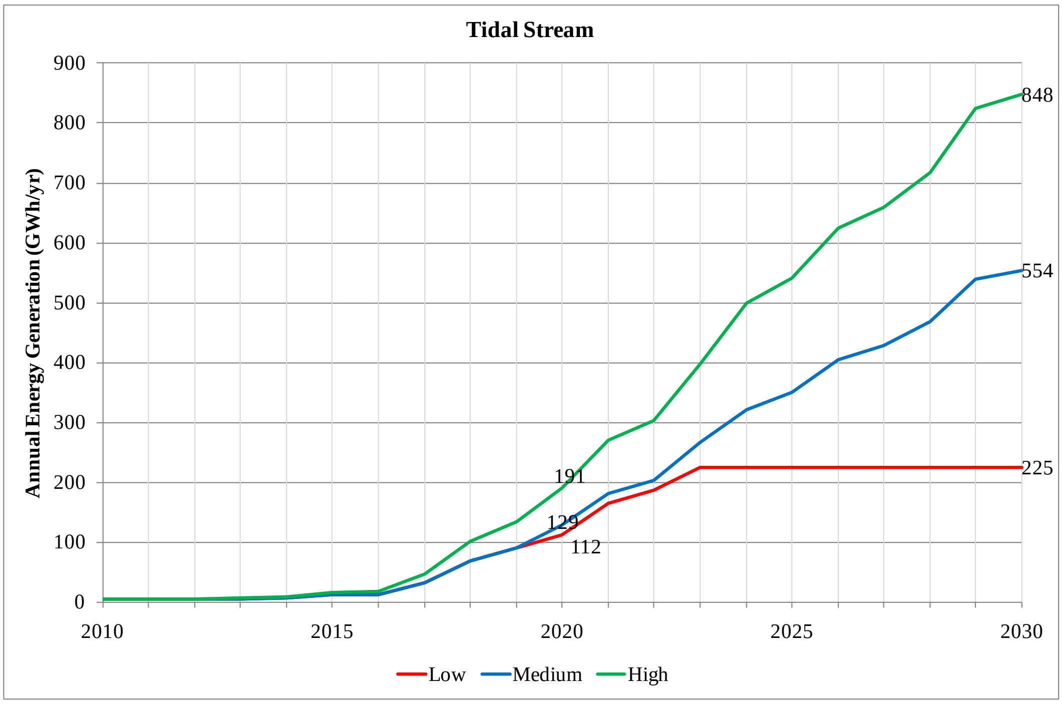


Figure 143: UK Tidal Stream Annual Energy Generation: England & Wales (GWh/yr)

Appendix C –Northern Ireland Data

This appendix provides a forecast of renewable technology roll-out in Northern Ireland only.

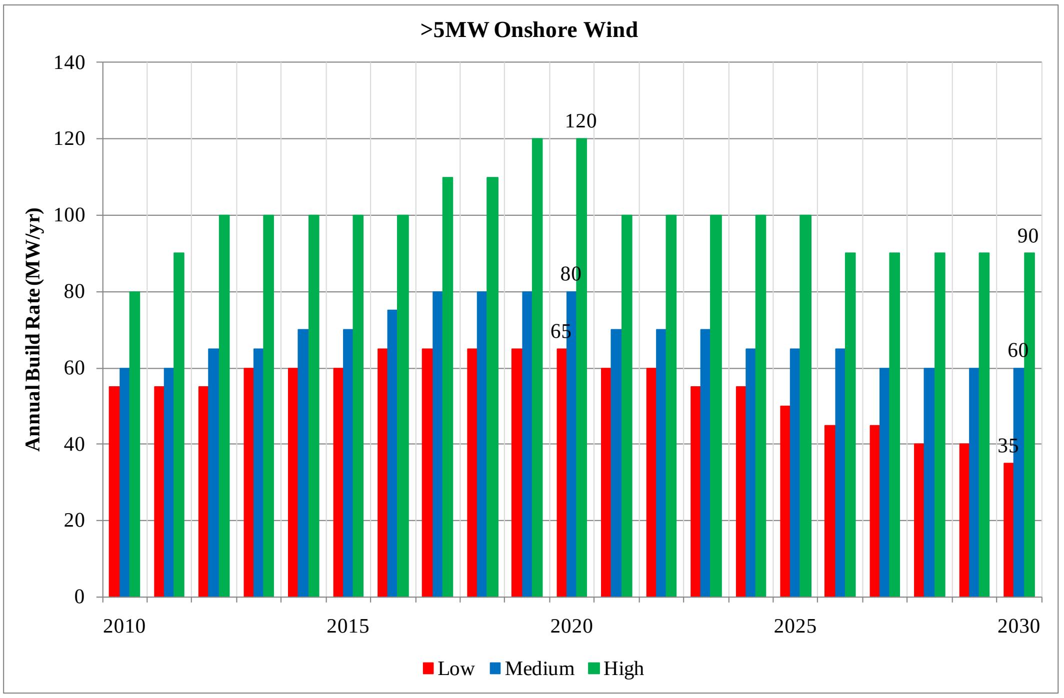


Figure 144: Northern Ireland Onshore Wind (>5MW) Annual Build Rate (MW/yr)

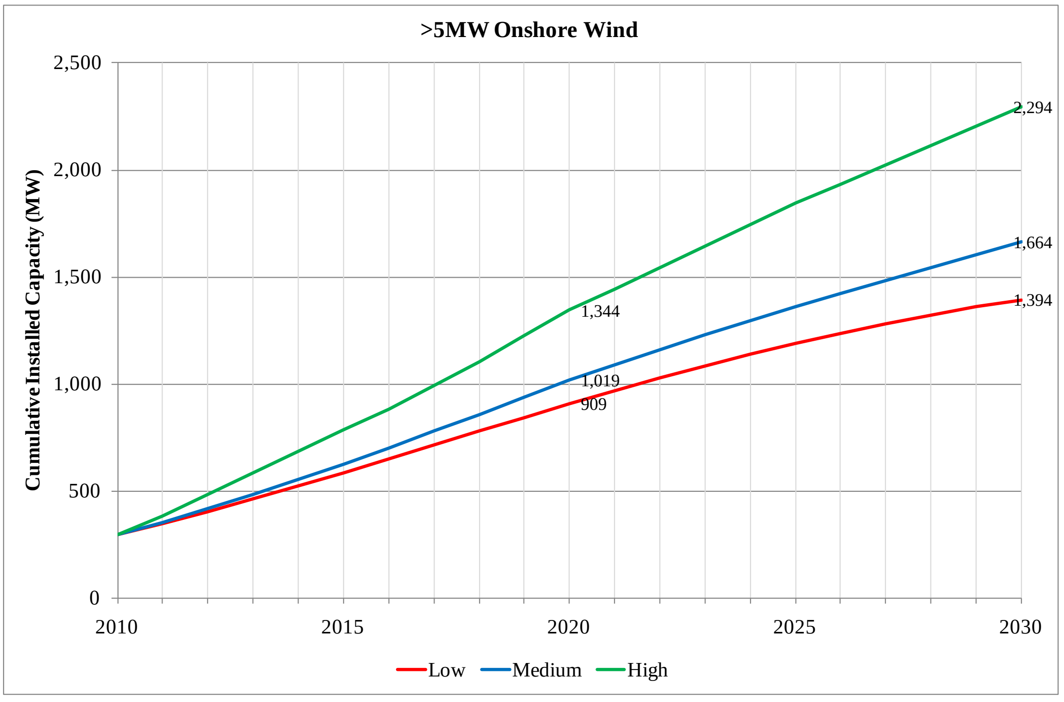


Figure 145: Northern Ireland Onshore Wind (>5MW) Cumulative Installed Capacity (MW)

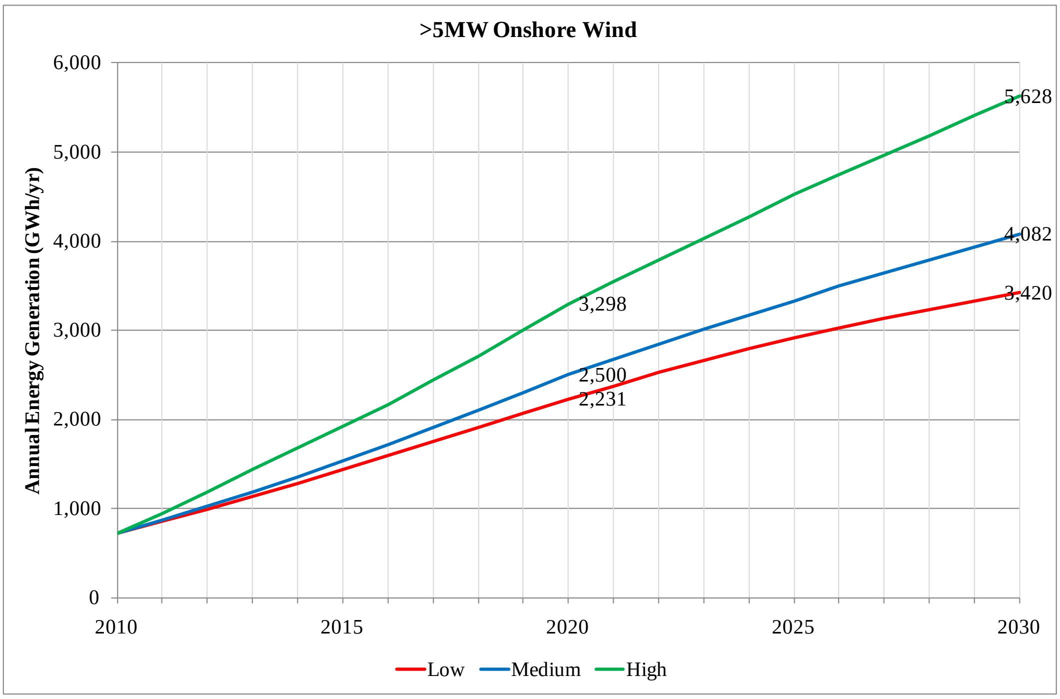


Figure 146: Northern Ireland Onshore Wind (>5MW) Annual Energy Generation (GWh/yr)

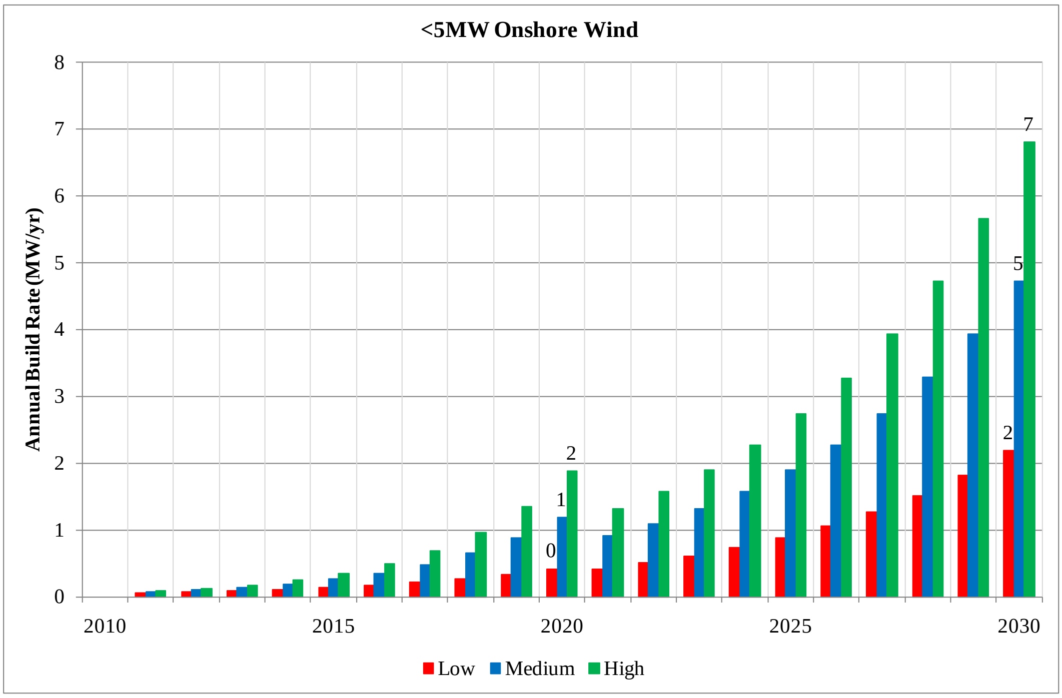


Figure 147: Northern Ireland Onshore Wind (<5MW) Annual Build Rate (MW/yr)

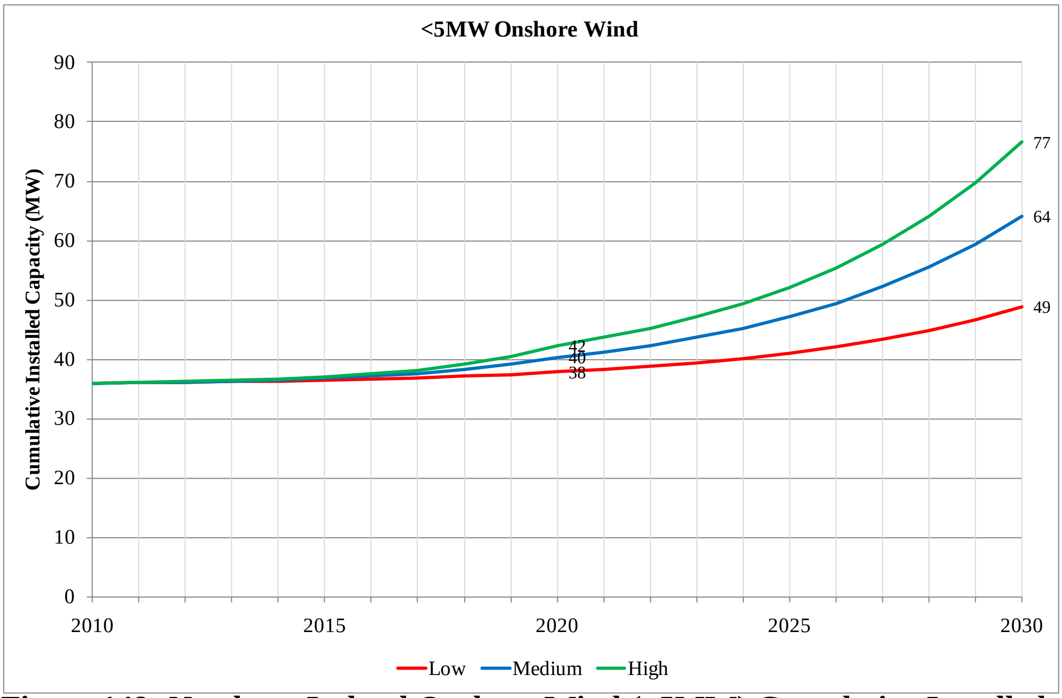


Figure 148: Northern Ireland Onshore Wind (<5MW) Cumulative Installed Capacity (MW)

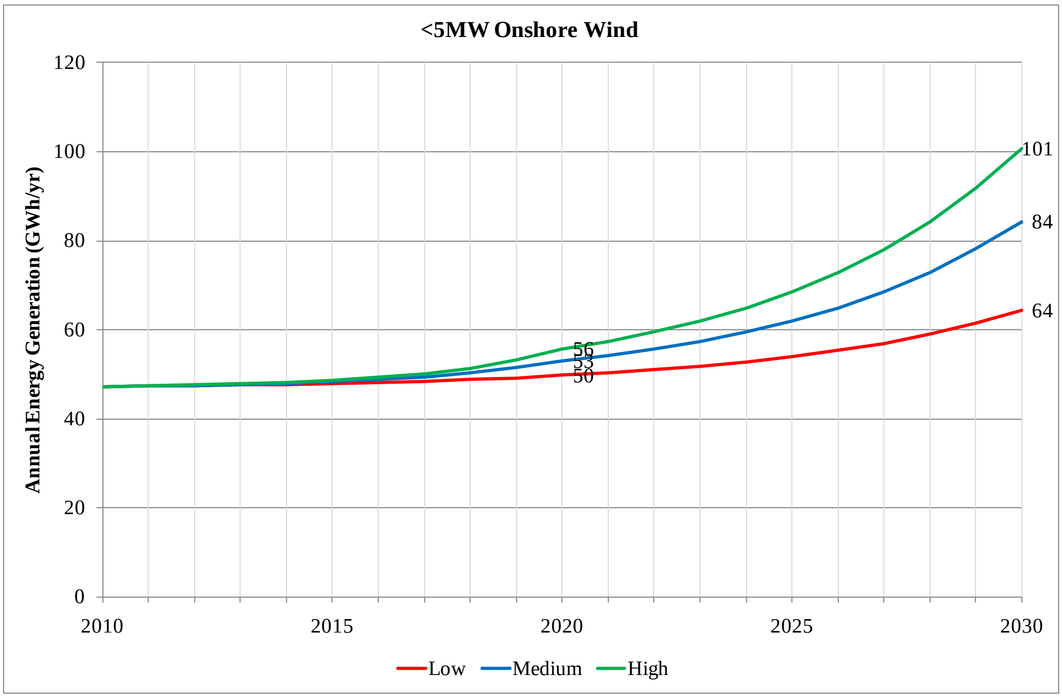


Figure 149: Northern Ireland Onshore Wind (<5MW) Annual Energy Generation (GWh/yr)

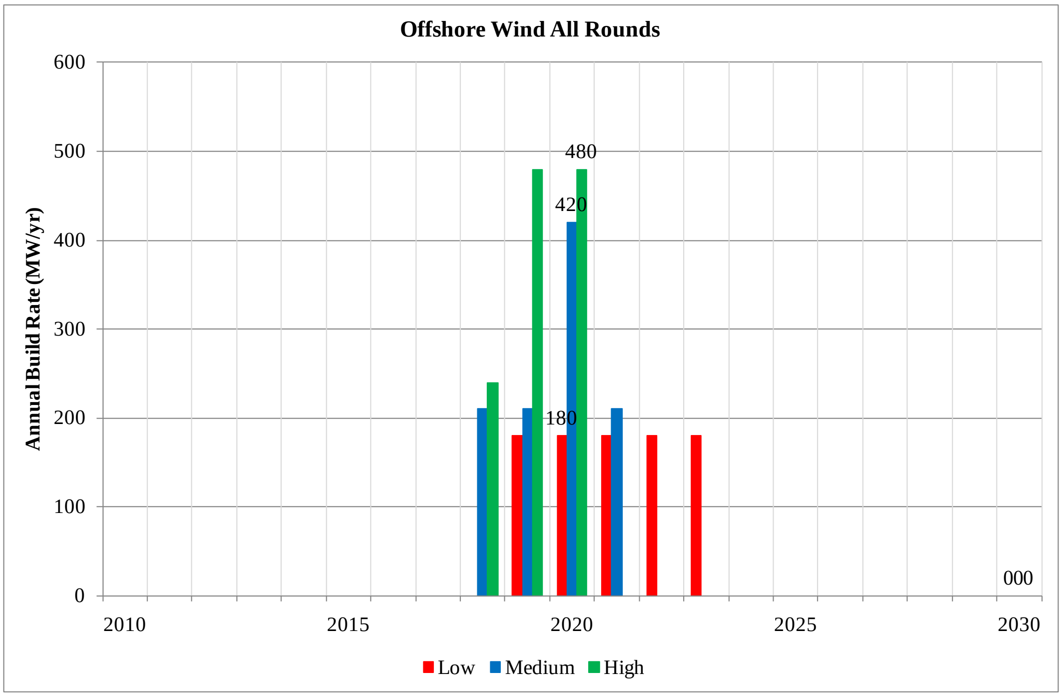


Figure 150: Northern Ireland Offshore Wind Annual Build Rate (MW/yr) (All Rounds)

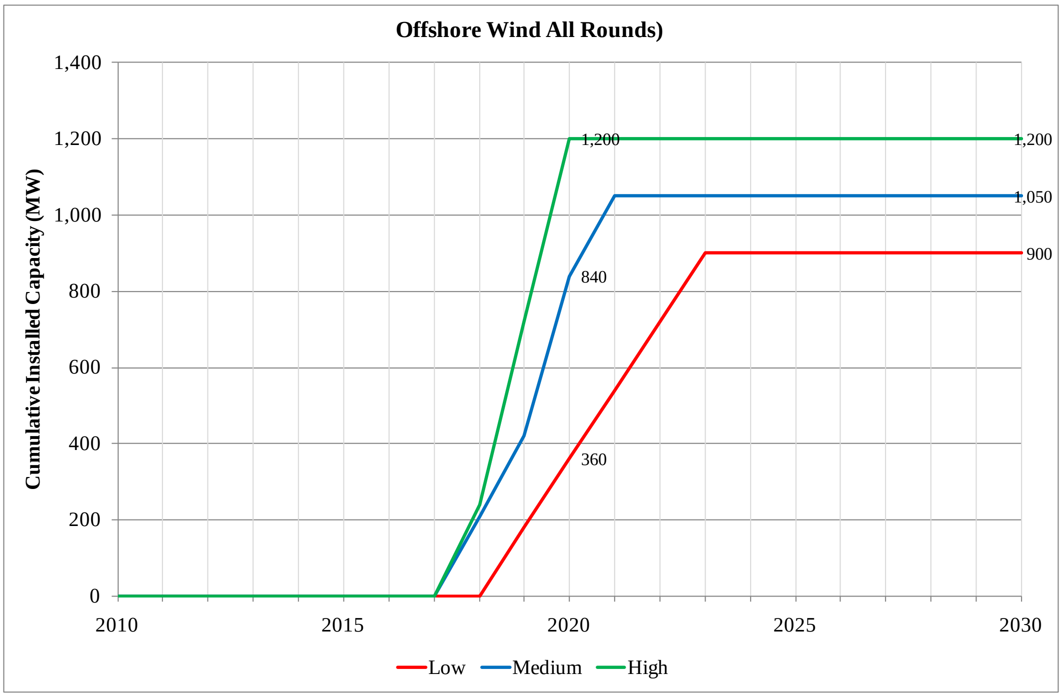


Figure 151: Northern Ireland Offshore Wind Cumulative Installed Capacity (MW) (All Rounds)

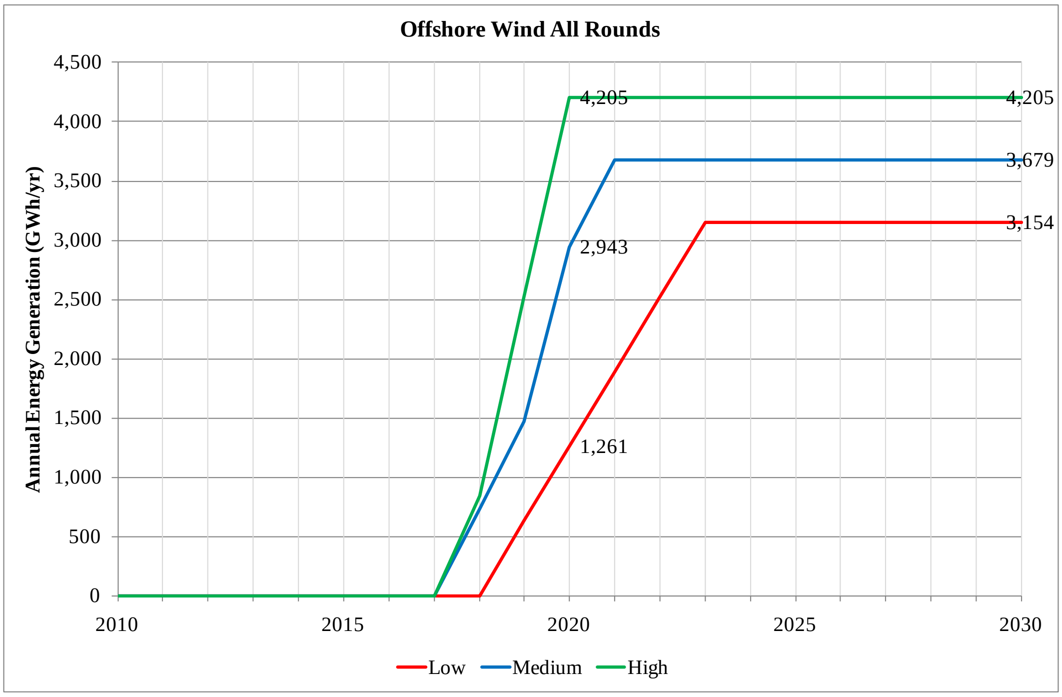


Figure 152: Northern Ireland Offshore Annual Energy Generation (GWh/yr) (All Rounds)

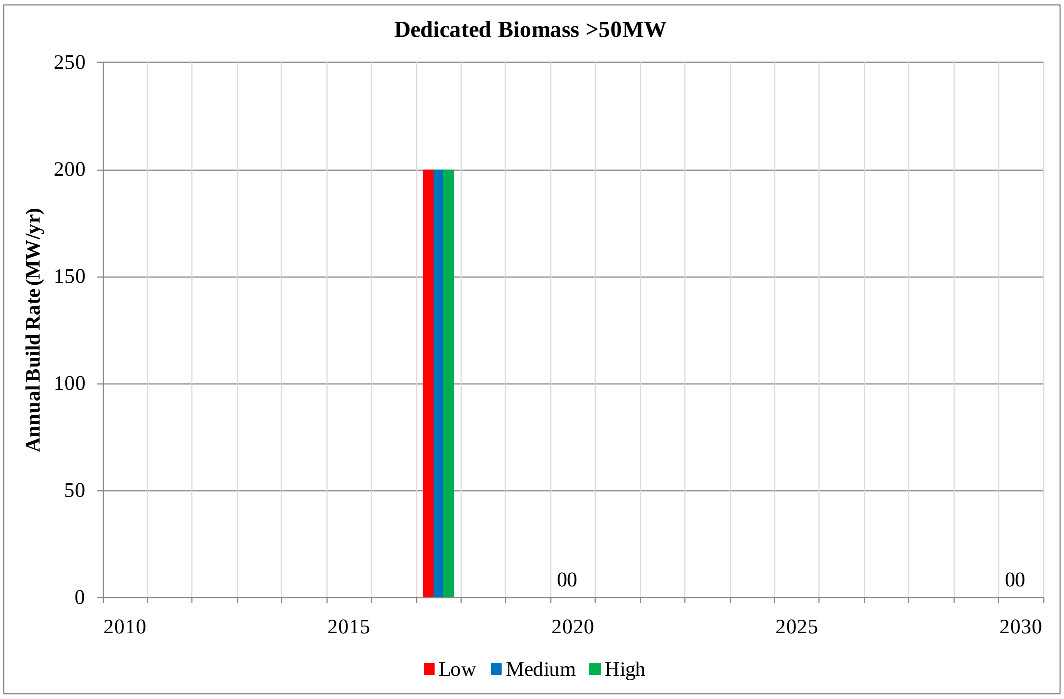


Figure 153: Northern Ireland Annual Build Rate Dedicated Biomass (Solid) >50MW (MW/yr)

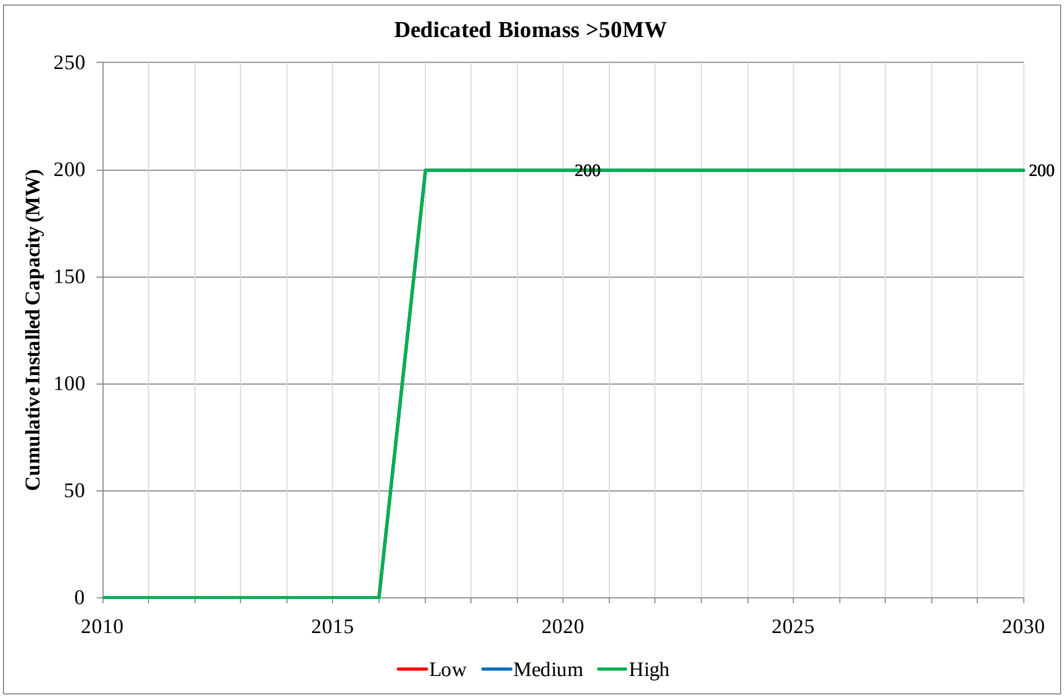


Figure 154: Northern Ireland Cumulative Installed Capacity Dedicated Biomass (Solid) >50MW (MW)

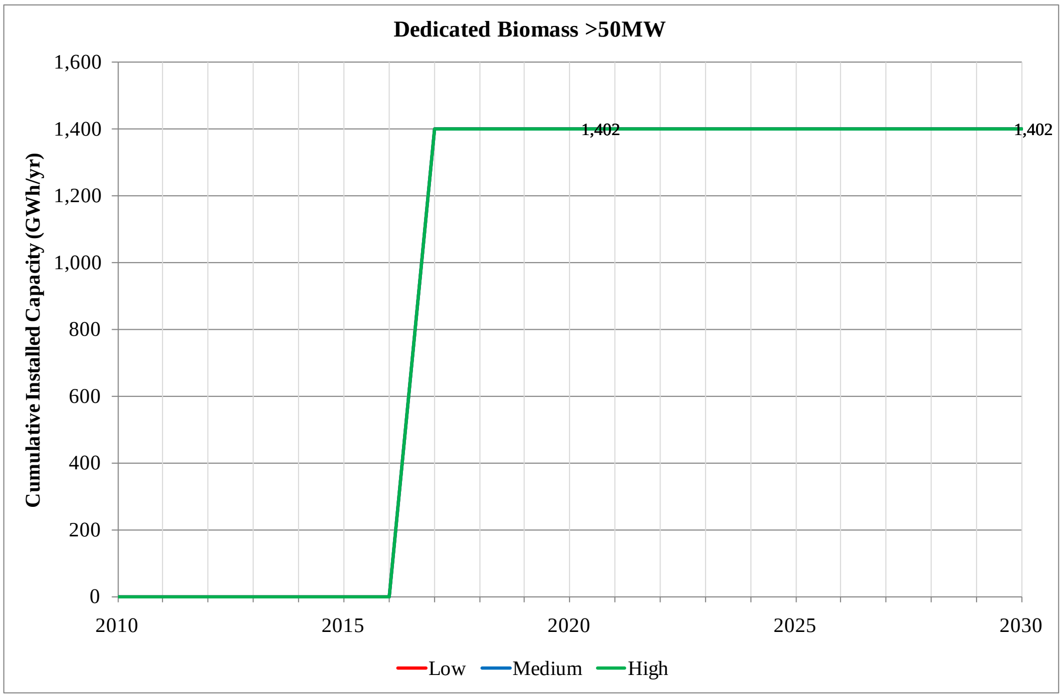


Figure 155: Northern Ireland Annual Energy Generation Dedicated Biomass (Solid) >50MW (GWh/yr)

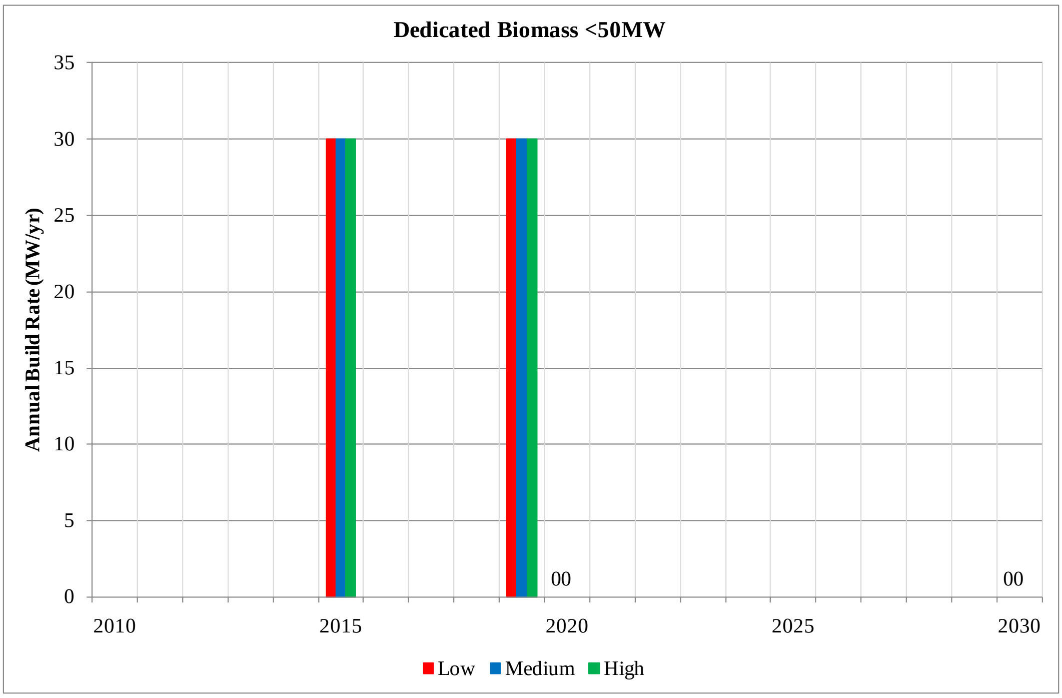


Figure 156: Northern Ireland Annual Build Rate Dedicated Biomass (Solid) <50MW (MW/yr)

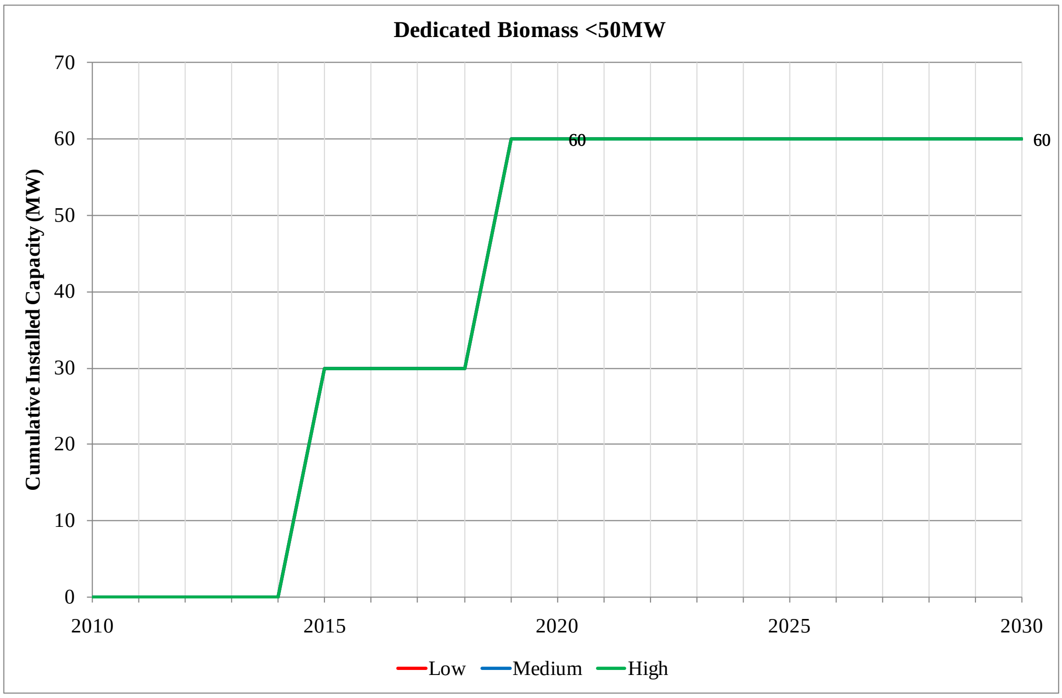


Figure 157: Northern Ireland Cumulative Installed Capacity Dedicated Biomass (Solid) <50MW (MW)

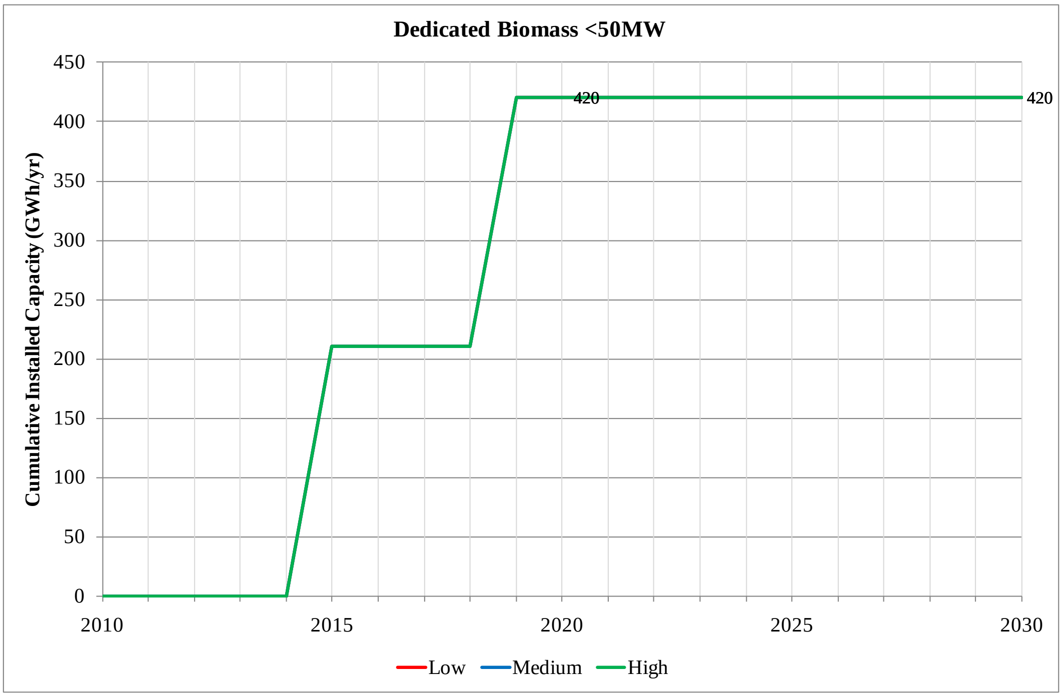


Figure 158: Northern Ireland Annual Energy Generation Dedicated Biomass (Solid) <50MW (GWh/yr)

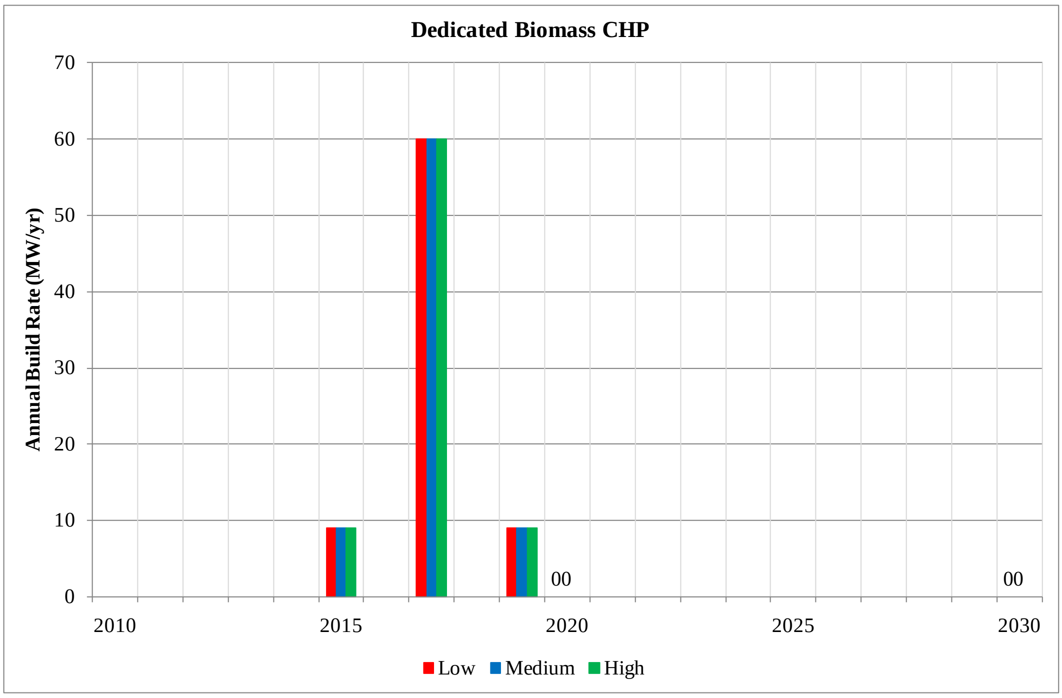


Figure 159: Northern Ireland Annual Build Rate Dedicated Biomass CHP

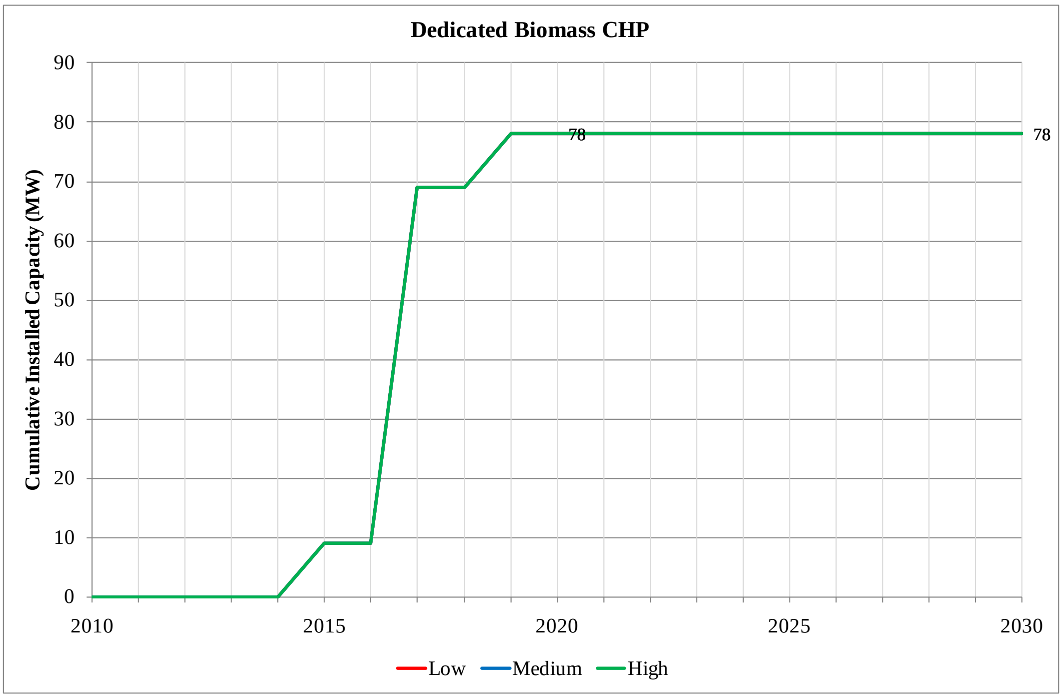


Figure 160: Northern Ireland Cumulative Installed Capacity Dedicated Biomass CHP

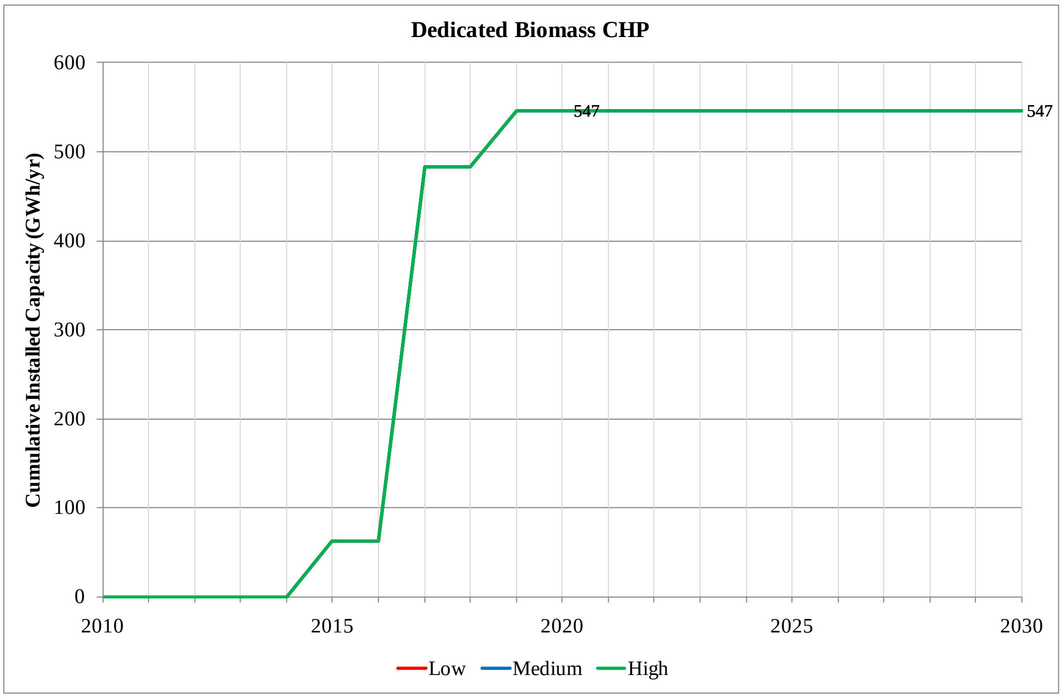


Figure 161: Northern Ireland Annual Energy Generation Dedicated Biomass CHP

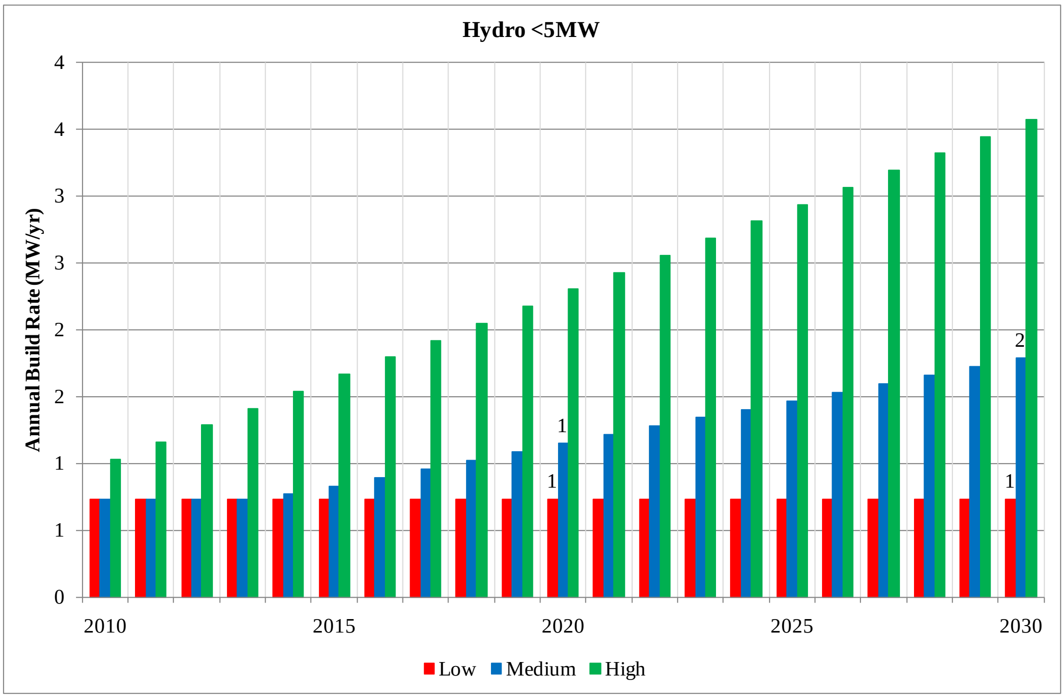


Figure 162: Northern Ireland Hydro < 5MW Cumulative Installed Capacity (MW/yr)

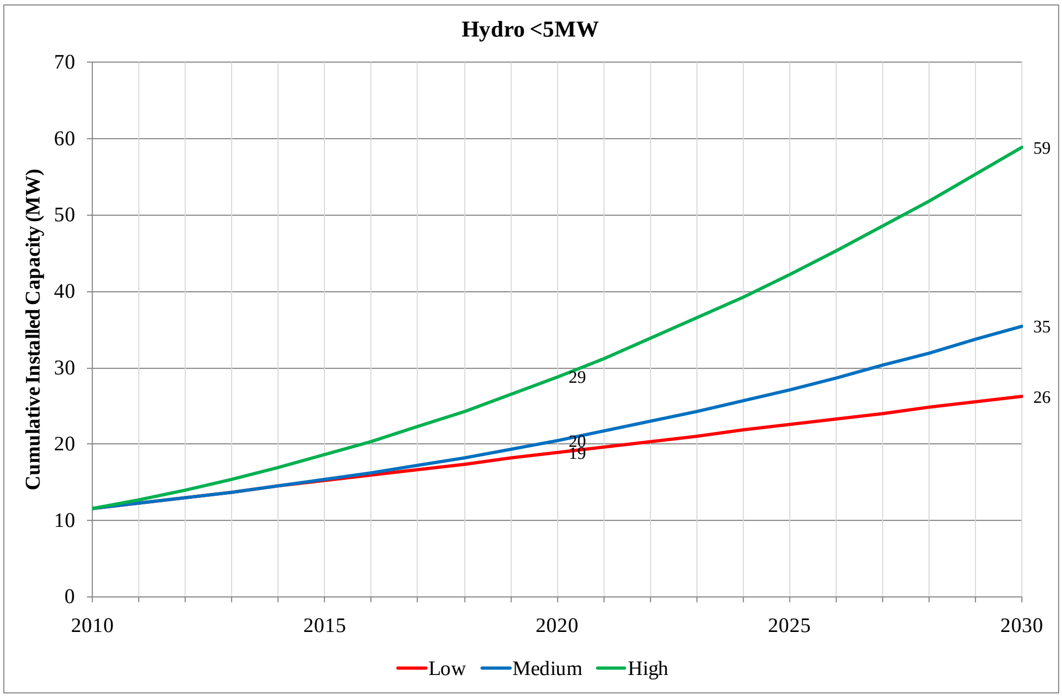


Figure 163: Northern Ireland Hydro < 5MW Cumulative Installed Capacity (MW)

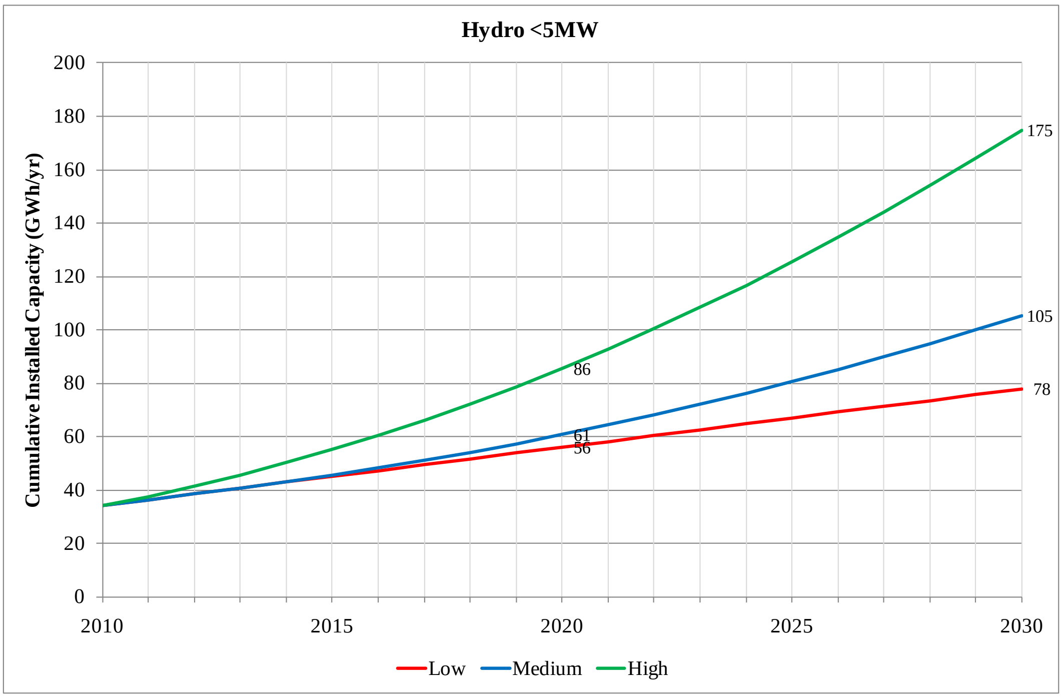


Figure 164: Northern Ireland Hydro < 5MW Annual Energy Generation (GWh/yr)

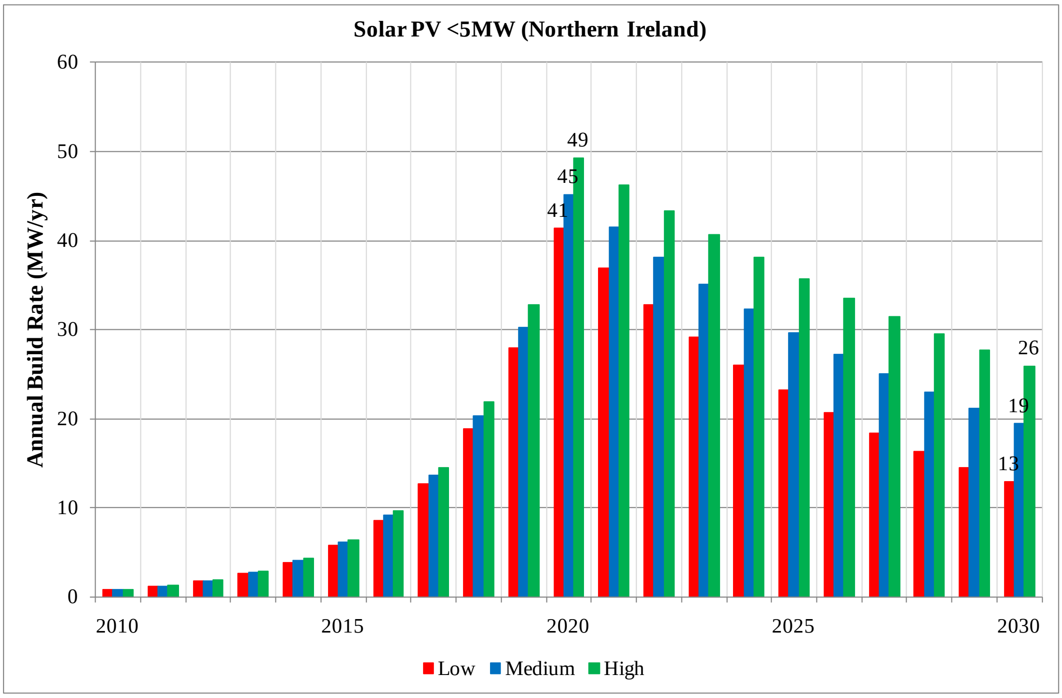


Figure 165: Northern Ireland PV Annual Build Rate <5MW (MW/yr)

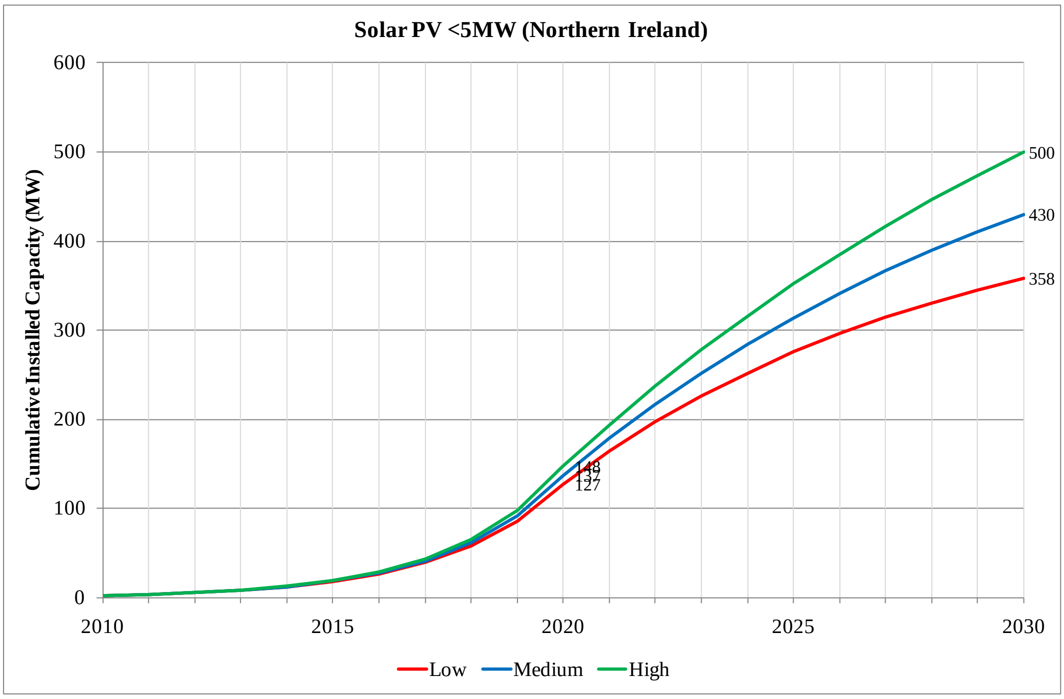


Figure 166: Northern Ireland PV Cumulative Installed Capacity <5MW (MW)

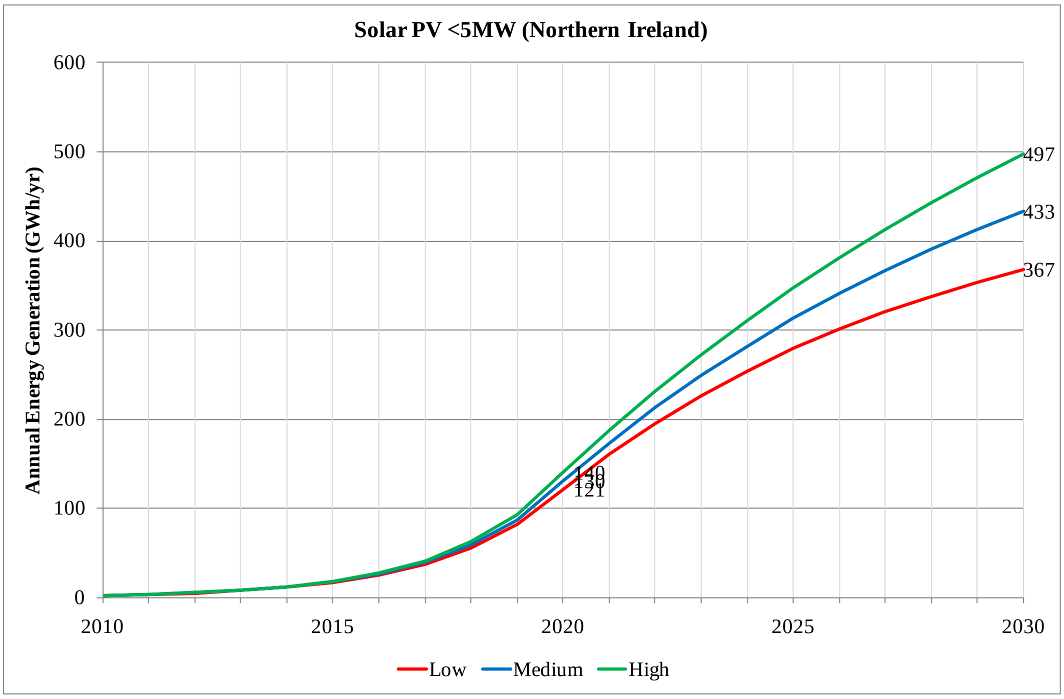


Figure 167: Northern Ireland PV Annual Energy Generation <5MW (GWh/yr)

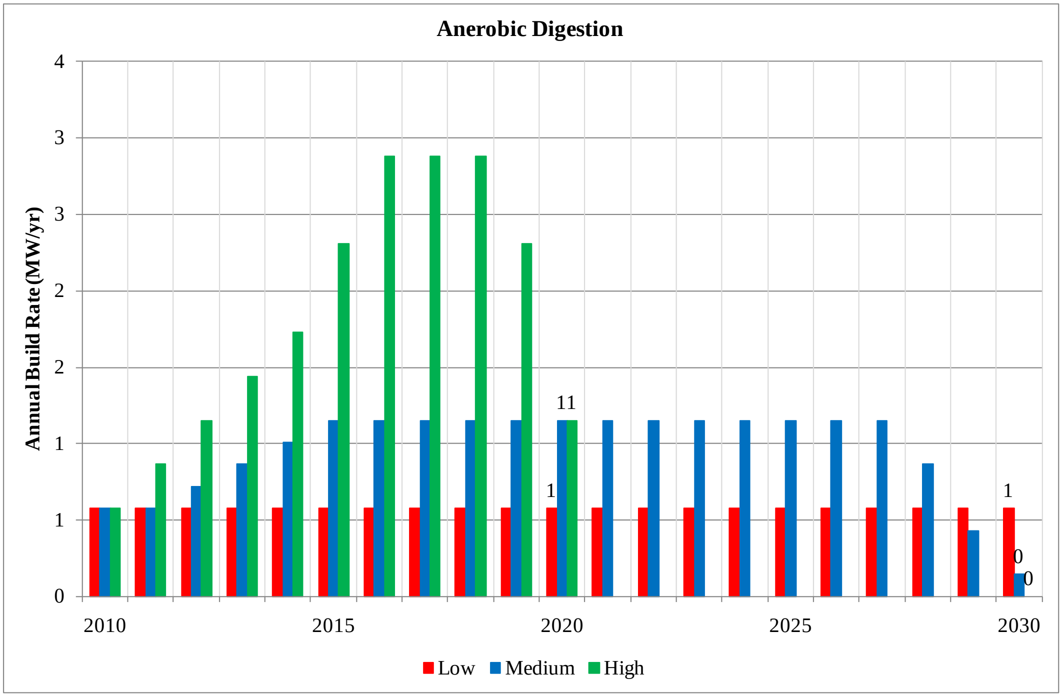


Figure 168: Northern Ireland Anaerobic Digestion Annual Build Rate (MW/yr)

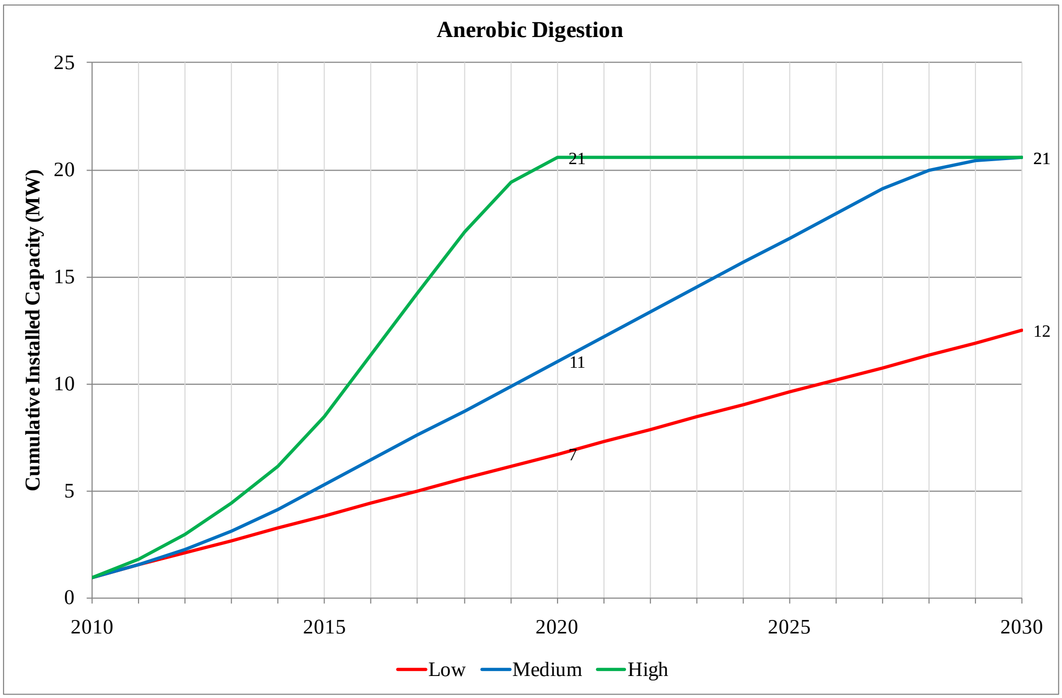


Figure 169: Northern Ireland Anaerobic Digestion Cumulative Installed Capacity (MW/yr)

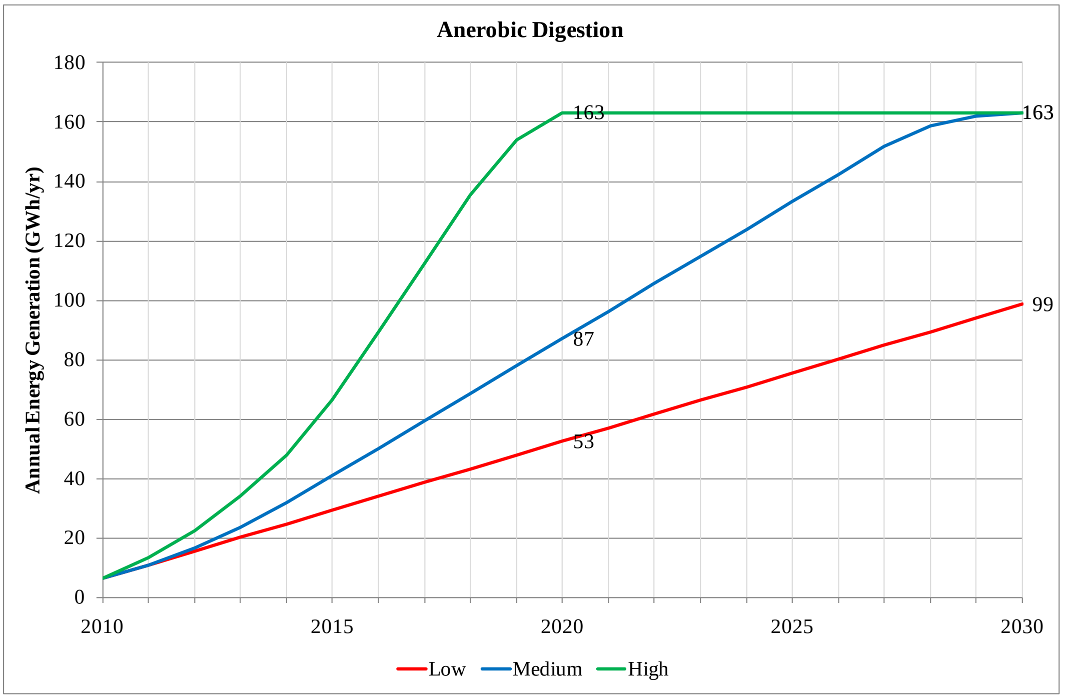


Figure 170: Northern Ireland Anaerobic Digestion Annual Energy Generation (GWh/yr)

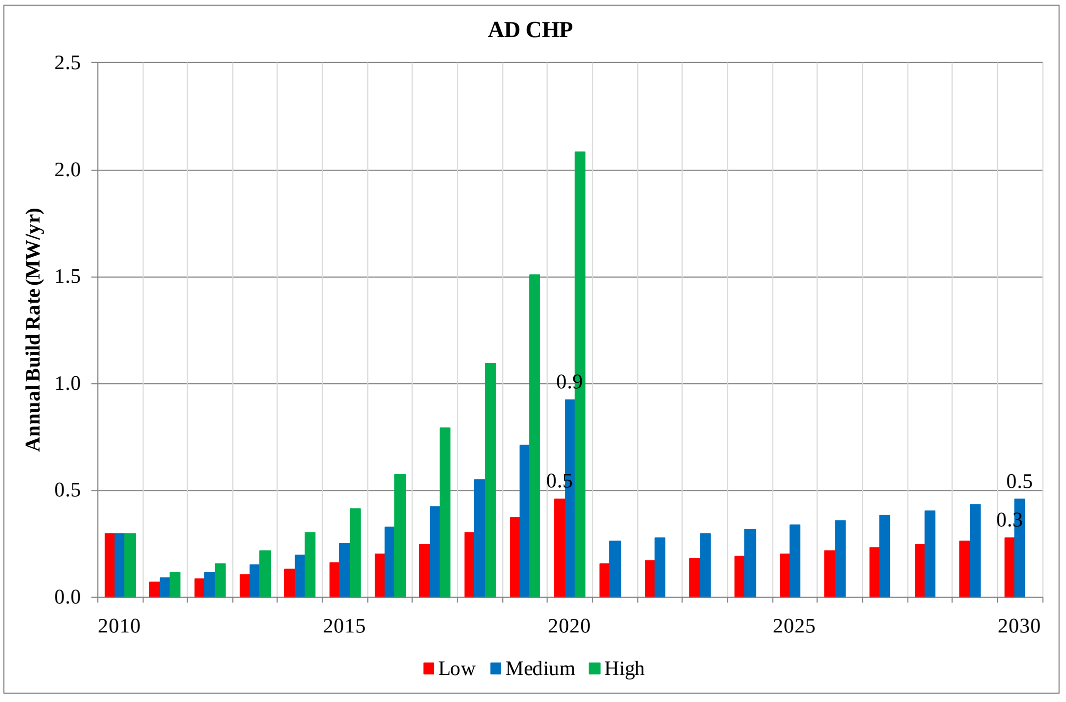


Figure 171: Northern Ireland AD CHP Annual Build Rate (MW/yr)

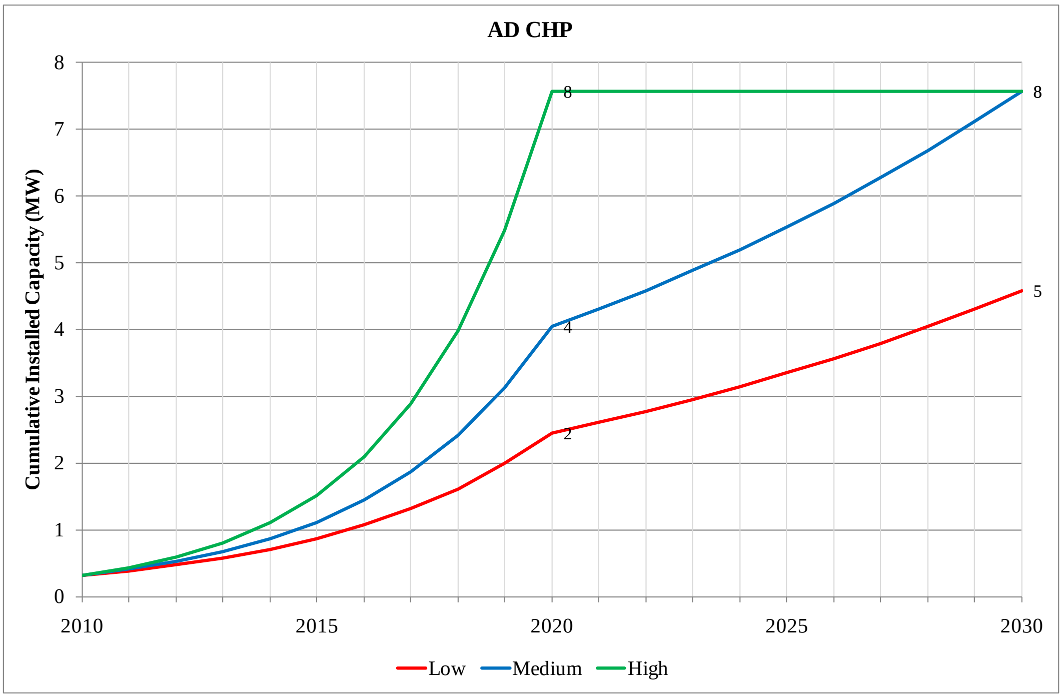


Figure 172: Northern Ireland AD CHP Cumulative Installed Capacity (MW)

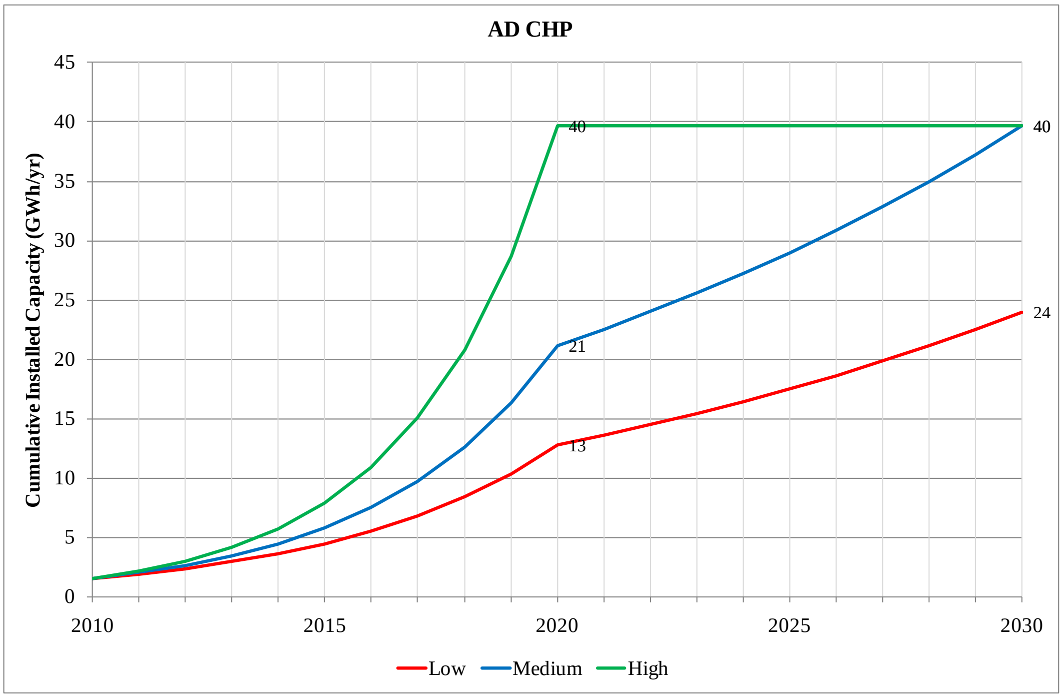


Figure 173: Northern Ireland AD CHP Annual Energy Generation (GWh/yr)

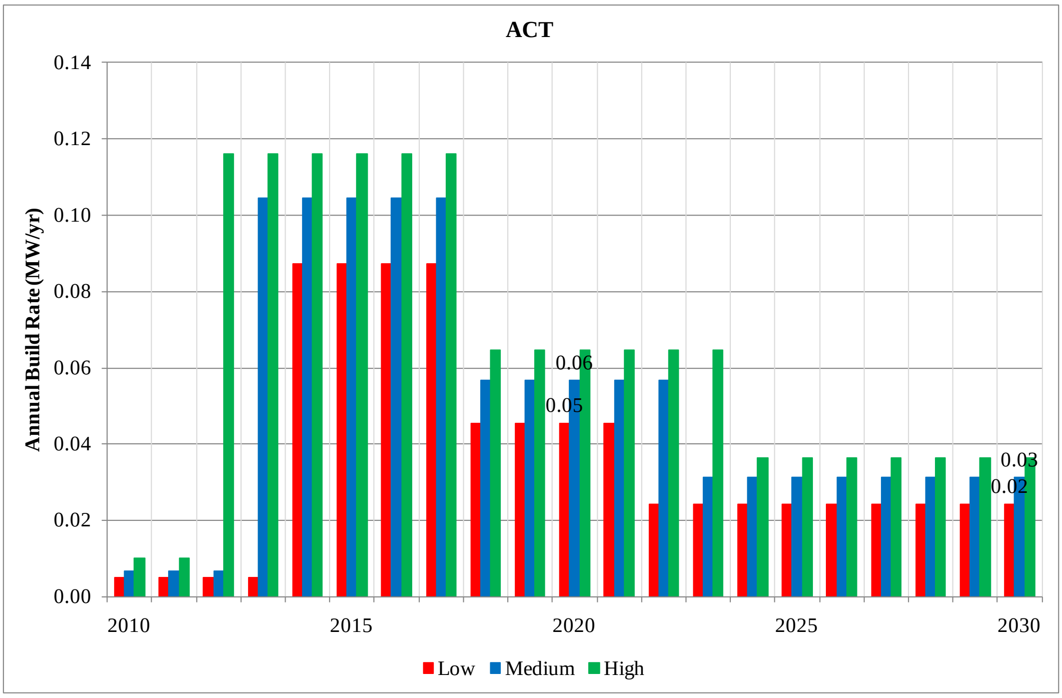


Figure 174: Northern Ireland Advanced Conversion Technology Annual Installed Capacity (MW/yr)

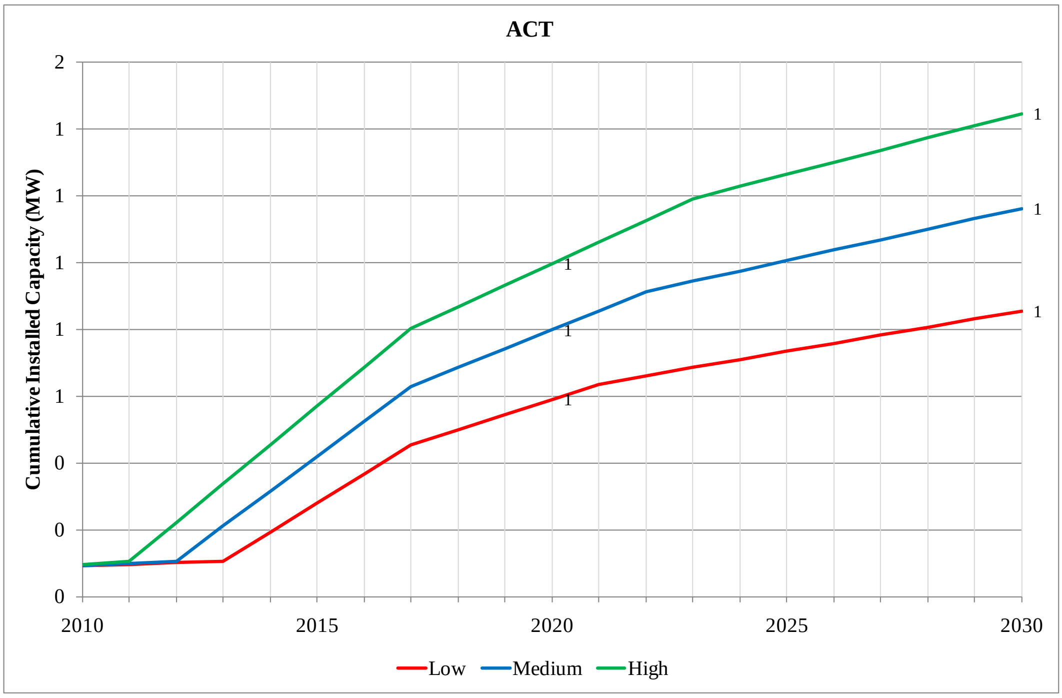


Figure 175: Northern Ireland Advanced Conversion Technology Cumulative Installed Capacity (MW)

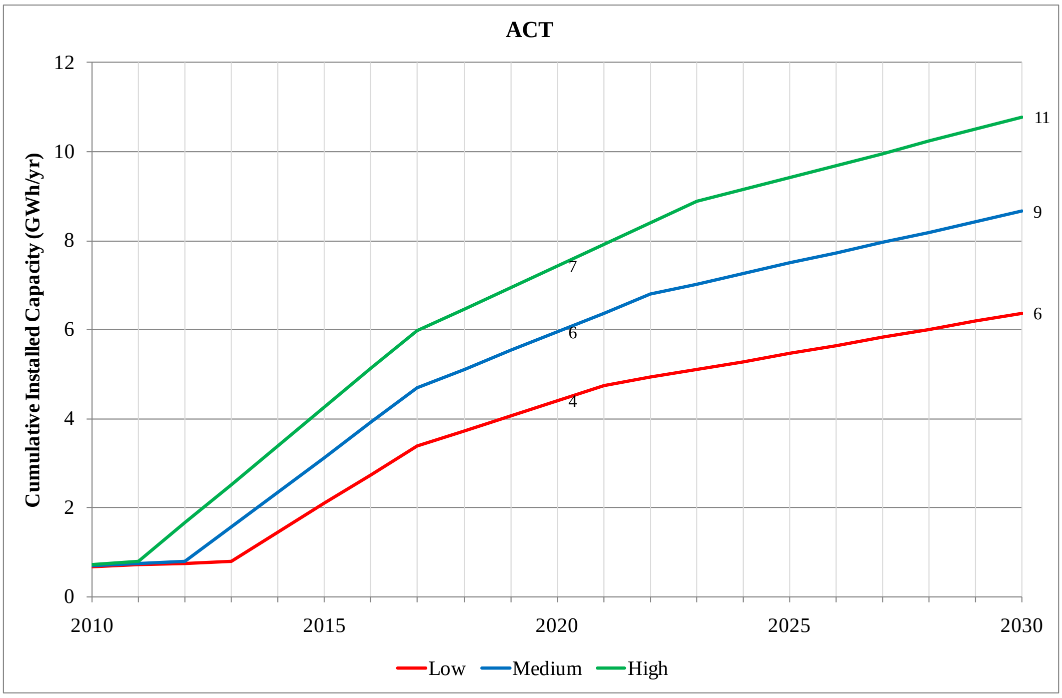


Figure 176: Northern Ireland Advanced Conversion Technology Annual Electricity Generation (GWh/yr)

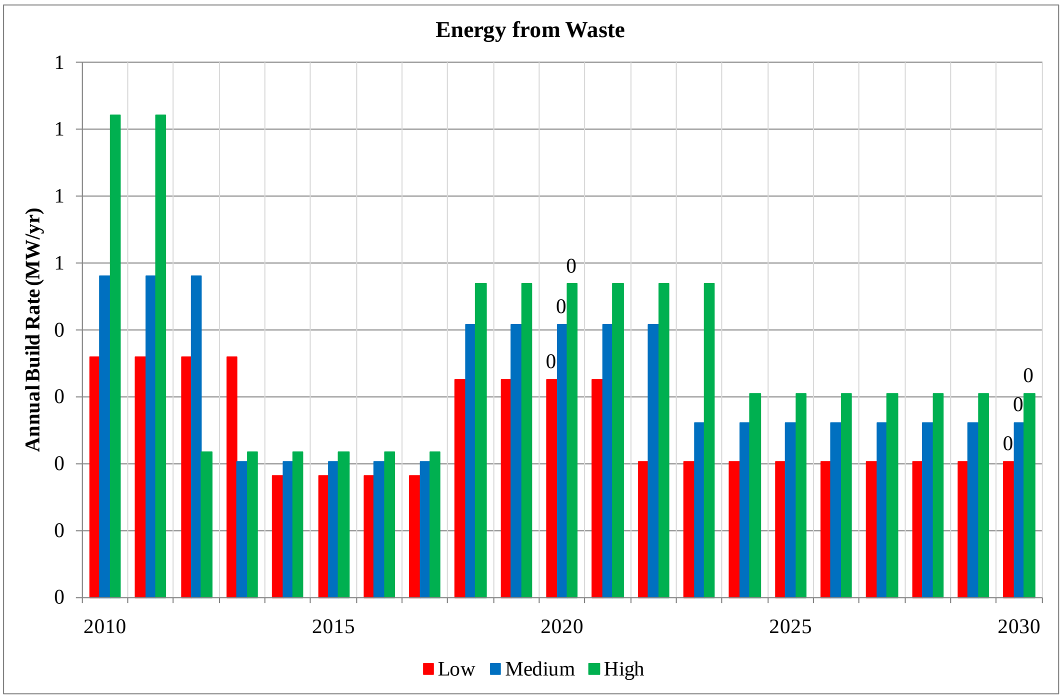


Figure 177: Northern Ireland Energy from Waste Annual Build Rate (MW/yr)

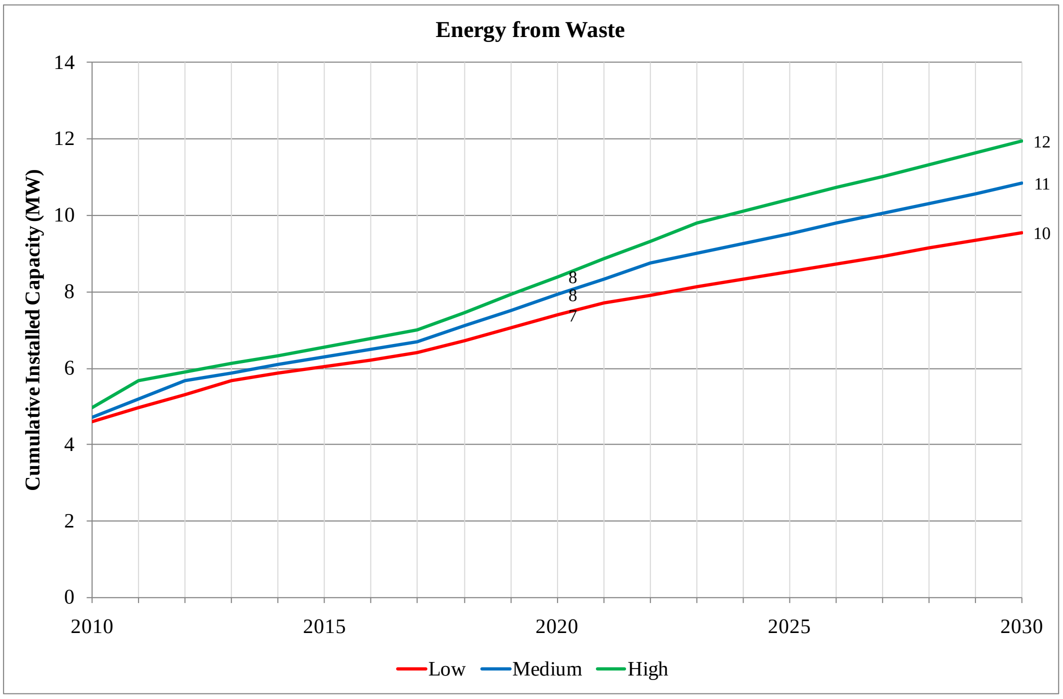


Figure 178: Northern Ireland Energy from Waste Cumulative Installed Capacity (MW)

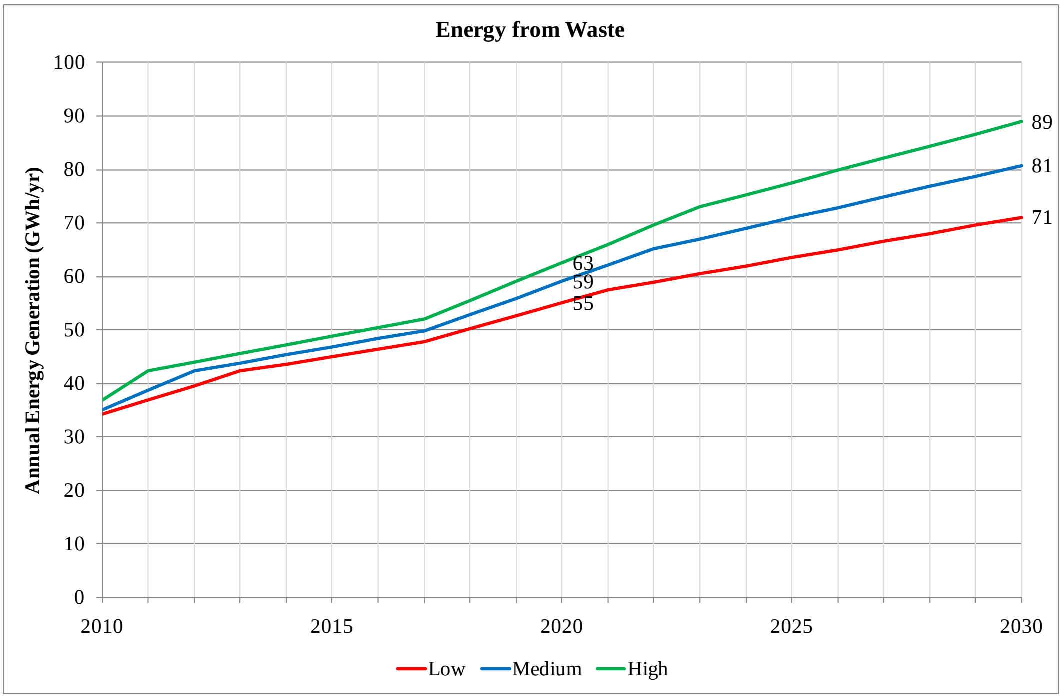


Figure 179: Northern Ireland Energy from Waste Annual Energy Generation (GWh/yr)

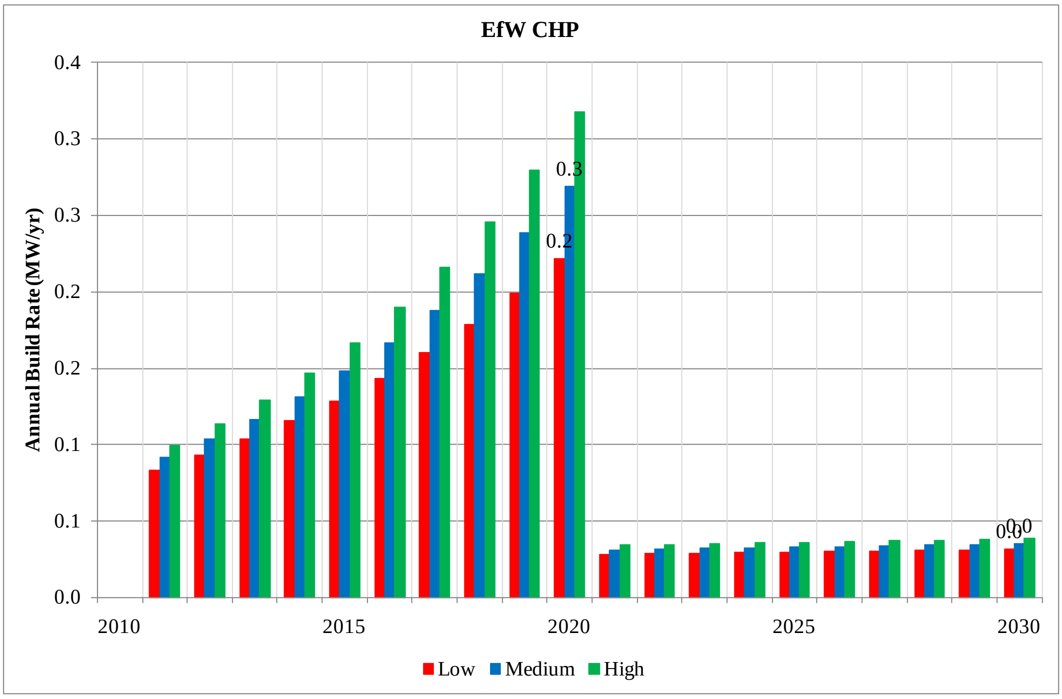


Figure 180: Northern Ireland Energy from Waste CHP Annual Build Rate (MW/yr)

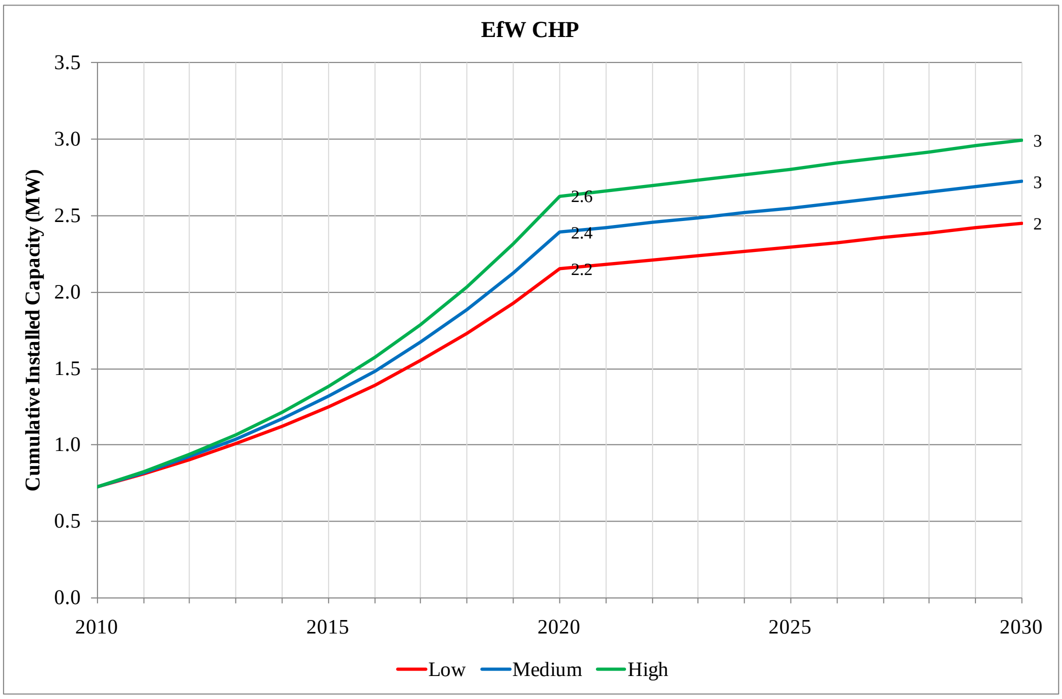


Figure 181: Northern Ireland Energy from Waste CHP Cumulative Installed Capacity (MW)

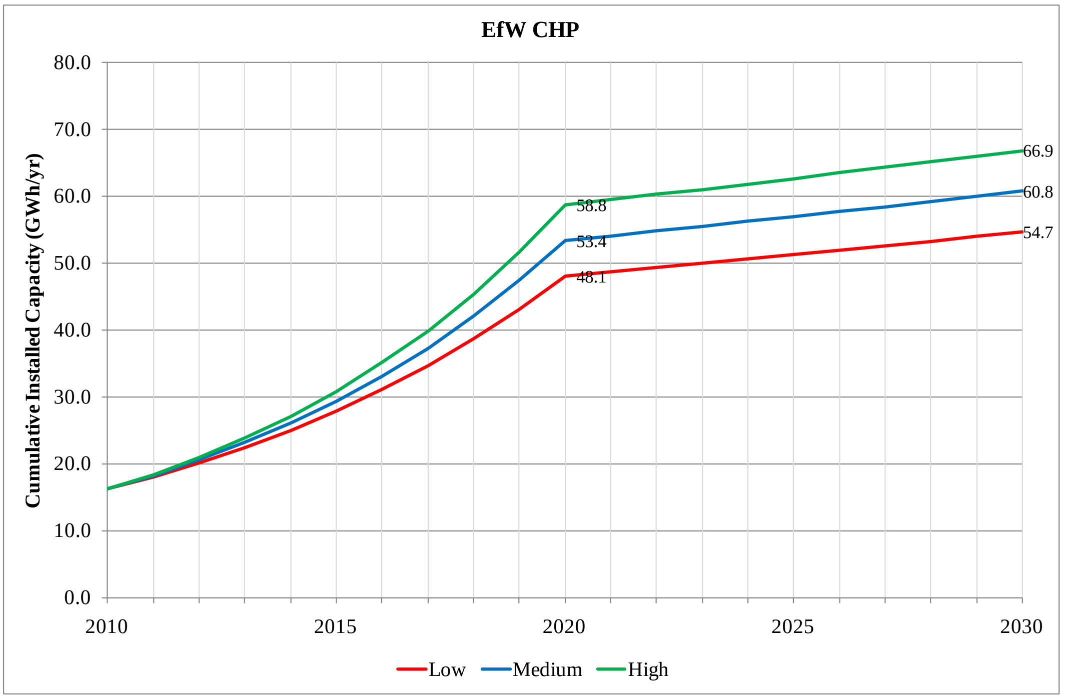


Figure 182: Northern Ireland Energy from Waste CHP Annual Energy Generation (GWh/yr)

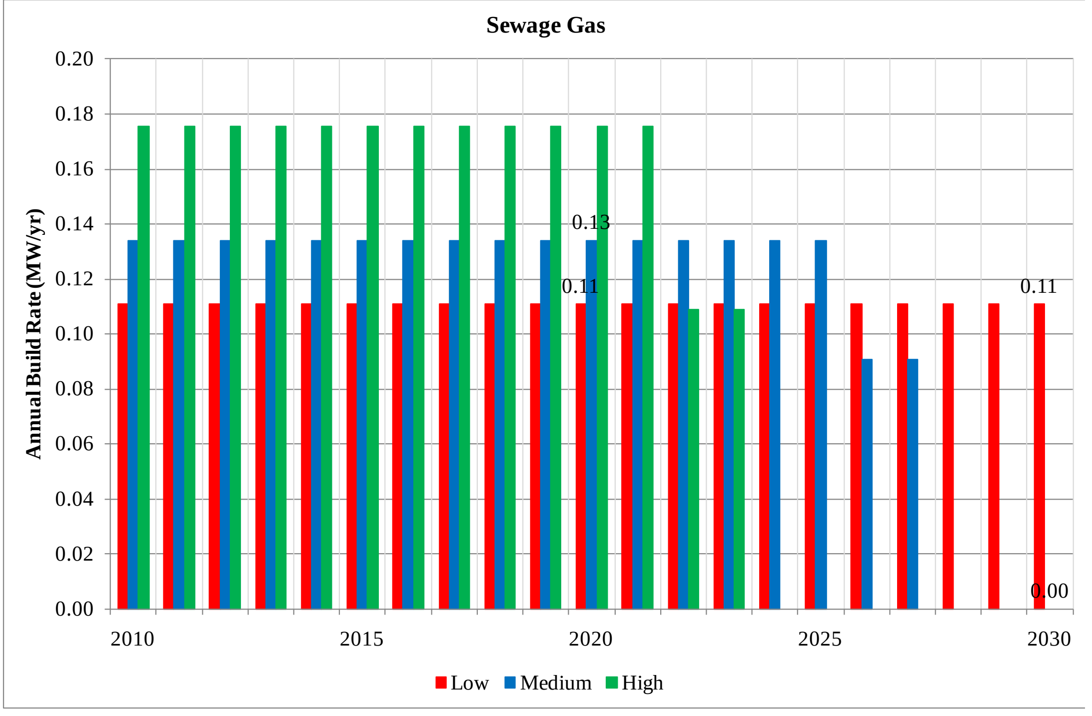


Figure 183: Northern Ireland Sewage Gas Annual Installed Capacity (MW/yr)

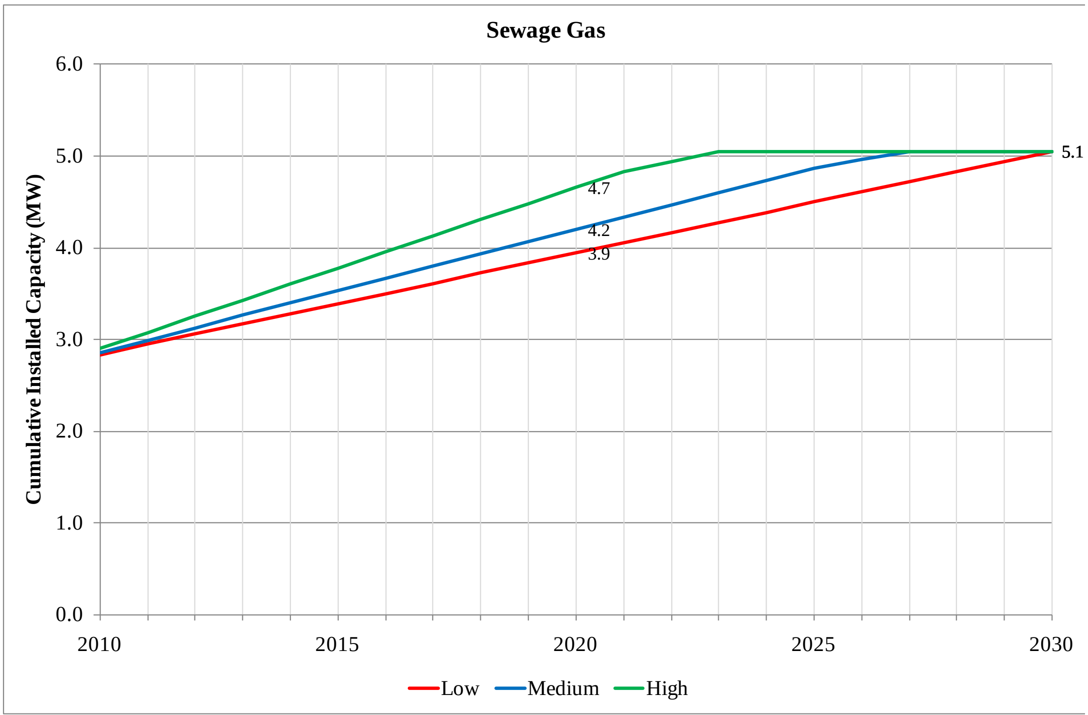


Figure 184: Northern Ireland Sewage Gas Cumulative Installed Capacity (MW)

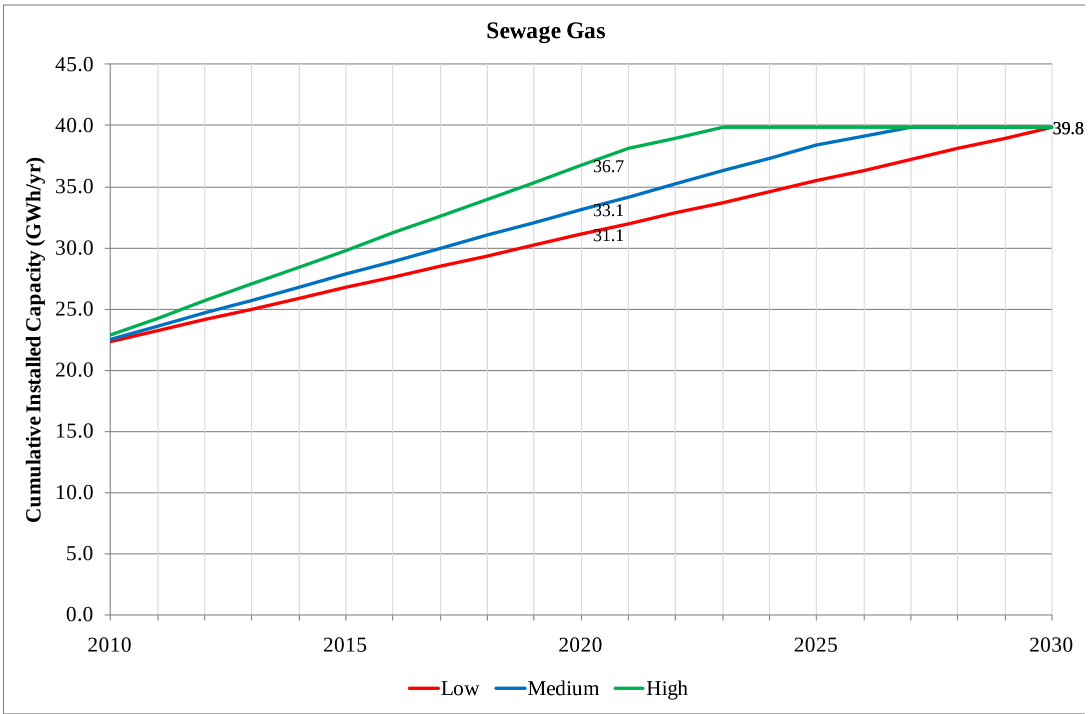


Figure 185: Northern Ireland Sewage Gas Annual Energy Generation (GWh/yr)

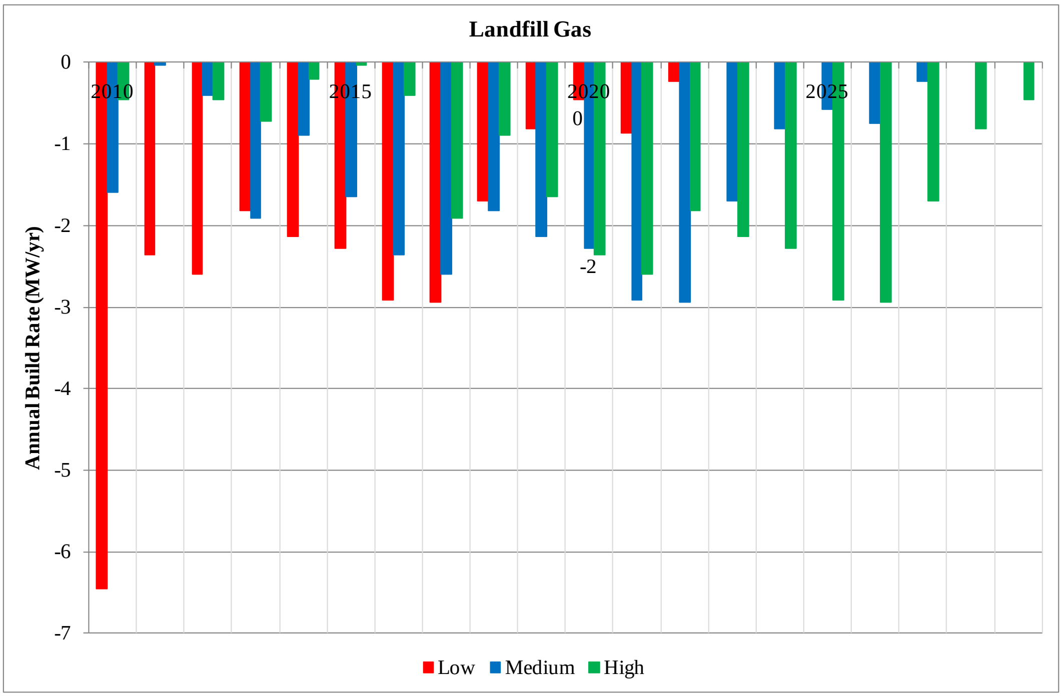


Figure 186: Northern Ireland Landfill Gas Annual Installed Capacity (MW/yr)

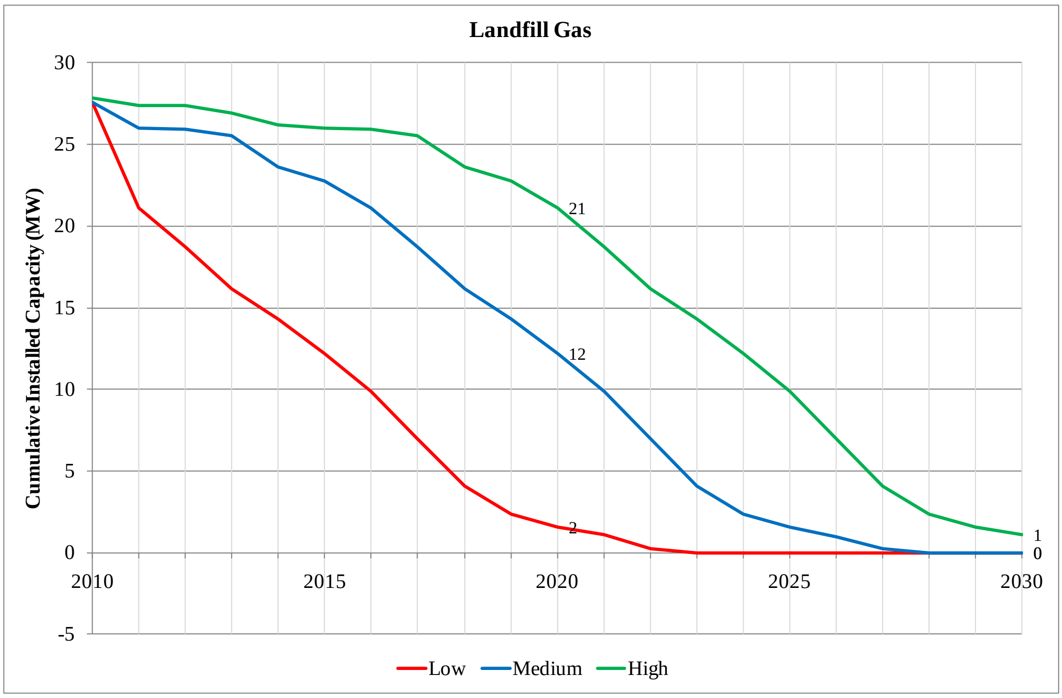


Figure 187: Northern Ireland Landfill Gas Cumulative Installed Capacity (MW)

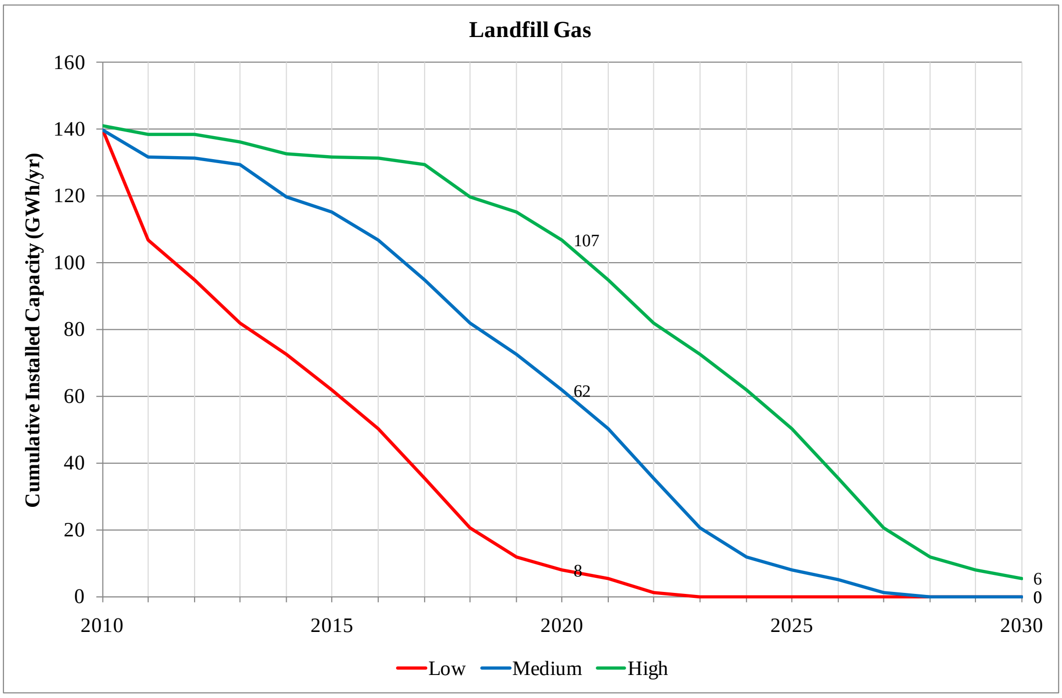


Figure 188: Northern Ireland Landfill Gas Annual Energy Generation (GWh/yr)

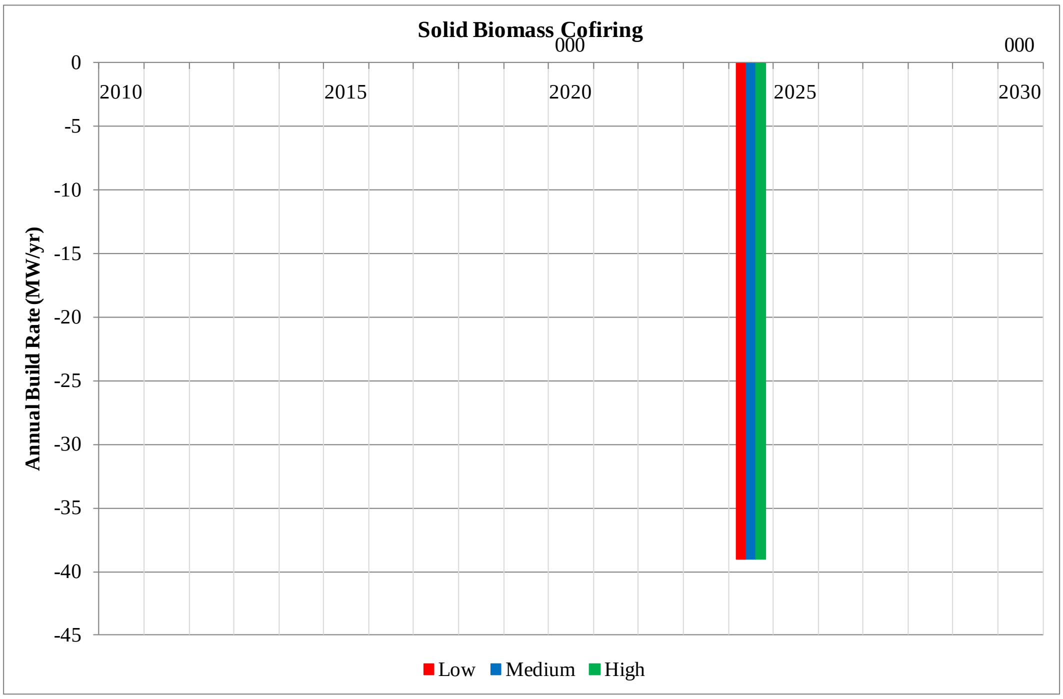


Figure 189: Northern Ireland Biomass Cofire Annual Installed Capacity (MW/yr)

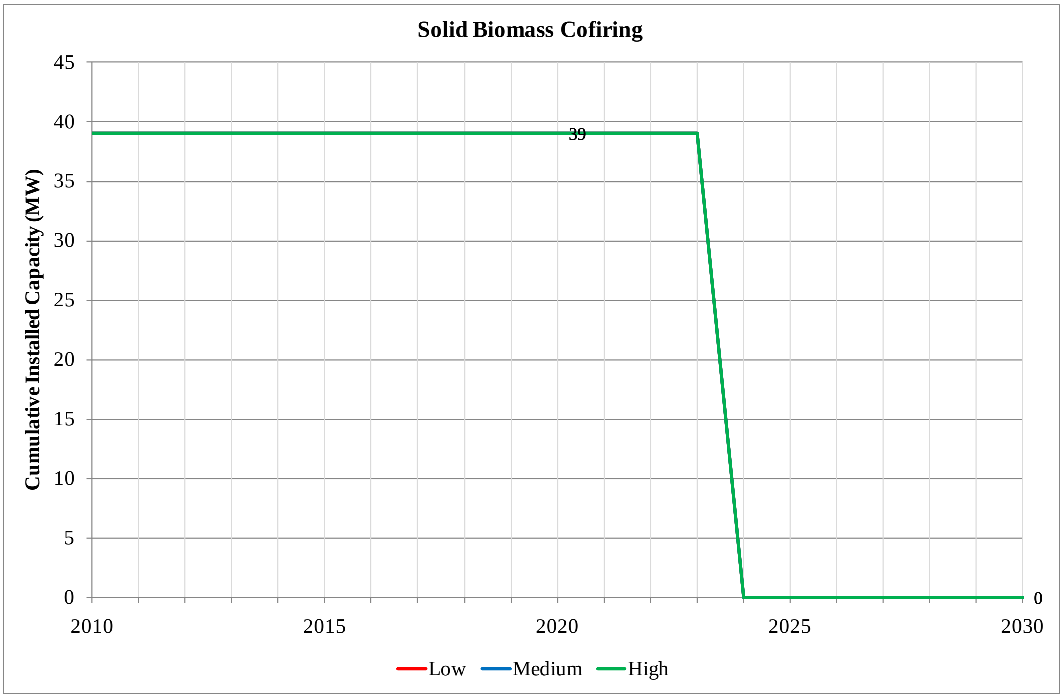


Figure 190: Northern Ireland Biomass Cofire Cumulative Installed Capacity (MW)

Figure 191: Northern Ireland Biomass Cofire Annual Energy Generation (GWh/yr)

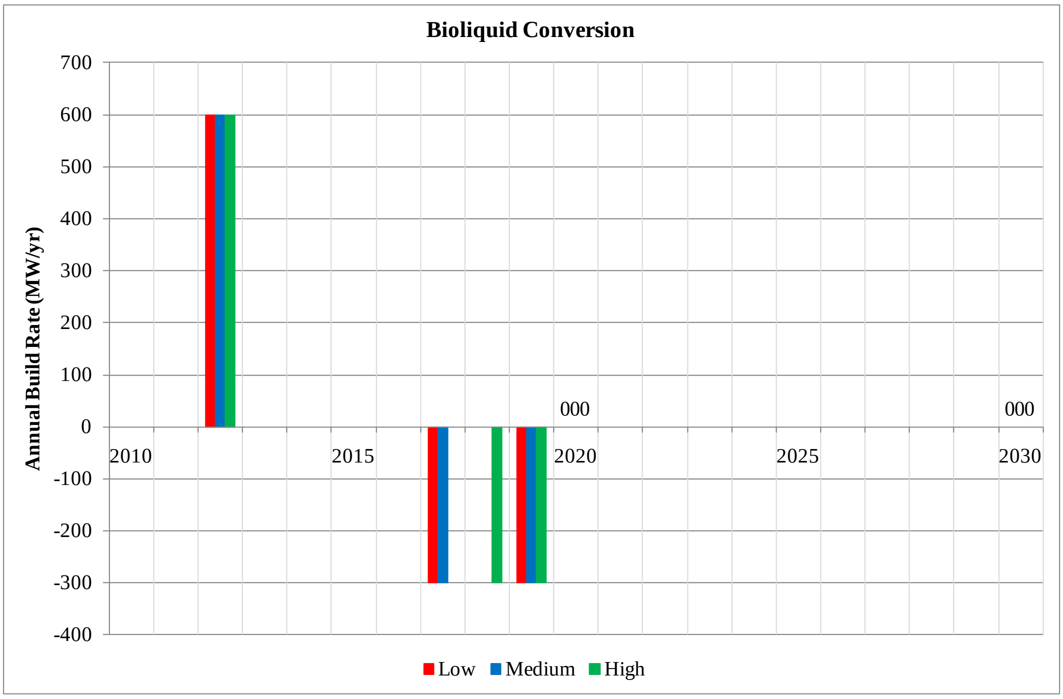


Figure 192: Northern Ireland Bioliquid Conversion Annual Installed Capacity (MW/yr)

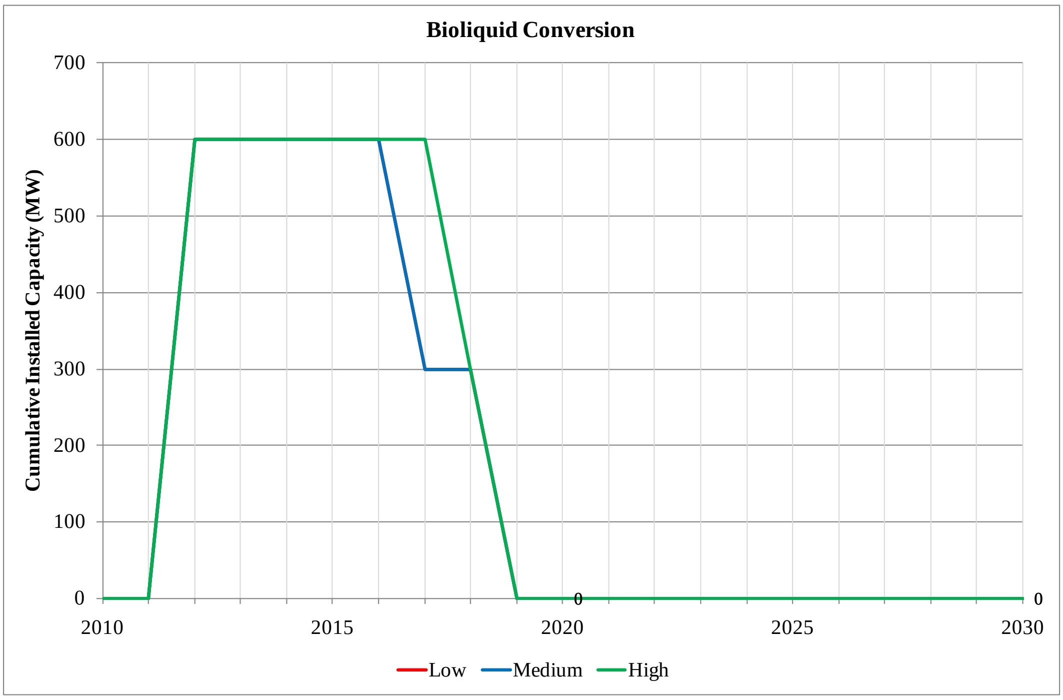


Figure 193: Northern Ireland Bioliquid Conversion Cumulative Installed Capacity (MW)

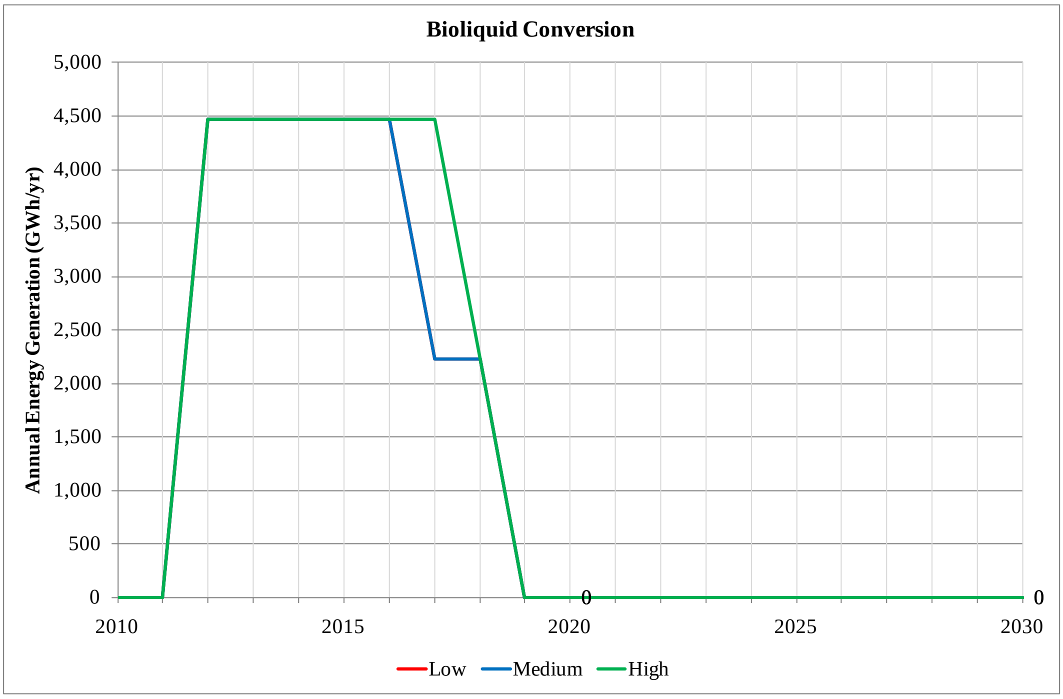


Figure 194: Northern Ireland Bioliquid Conversion Annual Energy Generation (GWh/yr)

Appendix D– Levelised costs

The following tables show the levelised costs of technologies in two cases:

Case 1: projects being started in 2011
Case 2: projects being started in 2017

These costs are based on central estimates of all levelised cost data and are all discounted at 10%. The levelised costs presented in each section in the main report are discounted at technology specific hurdle rates. Prices and gate fees for fuel have been provided by DECC (as explained in the main report).

Case 1: 10% discount rate, 2011 project start at projected EPC prices, FOAK/NOAK mix							
		Dedicated Biomass >50MW	Dedicated biomass 5-50MW	Offshore R2	Offshore R3	Onshore 5 MW >	Onshore <5MW
LEVELISED COSTS							
Capital costs	£/MWh	40.6	55.1	83.0	102.5	70.9	85.4
Fixed operating costs	£/MWh	15.1	17.6	37.0	45.0	16.6	15.8
Variable operating costs	£/MWh	4.5	5.2	1.6	-	2.7	3.6
Carbon costs	£/MWh	-	-	-	-	-	-
Fuel costs	£/MWh	84.3	49.7	-	-	-	-
Decomm and waste fund	£/MWh		-	-	-	-	-
CO2 transport and storage	£/MWh	-	-	-	-	-	-
Total	£/MWh	£144.6	£127.6	£121.6	£147.5	£90.2	£104.9

Case 1: 10% discount rate, 2011 project start at projected EPC prices, FOAK/NOAK mix							
		Solar >50kW	Bioliquids Diesel	Bioliquids CHP Diesel	Cofiring Conventional	Cofiring Enhanced	Cofiring Conversion
LEVELISED COSTS							
Capital costs	£/MWh	292.0	25.3	27.2	5.3	11.6	12.2
Fixed operating costs	£/MWh	22.3	20.0	(18.4)	4.4	5.2	7.2
Variable operating costs	£/MWh	-	5.4	5.4	1.2	1.4	2.2
Carbon costs	£/MWh	-	-	-	-	-	-
Fuel costs	£/MWh	-	255.5	255.5	85.8	89.1	92.6
Decomm and waste fund	£/MWh	-	-	-	-	-	-
CO2 transport and storage	£/MWh	-	-	-	-	-	-
Total	£/MWh	£314.3	£306.2	£269.8	£96.7	£107.4	£114.2

Case 1: 10% discount rate, 2011 project start at projected EPC prices, FOAK/NOAK mix							
		EfW	EfW CHP	Geothermal	Geothermal CHP	Hydropower 0-5MW	Hydropower 5-16MW
LEVELISED COSTS							
Capital costs	£/MWh	58.6	74.3	70.6	76.5	115.7	60.1
Fixed operating costs	£/MWh	46.0	10.2	13.2	(58.7)	8.2	7.0
Variable operating costs	£/MWh	14.9	36.4	10.5	10.1	6.7	5.5
Carbon costs	£/MWh	-	-	-	-	-	-
Fuel costs	£/MWh	(150.3)	(150.3)	-	-	-	-
Decomm and waste fund	£/MWh	-	-	-	-	-	-
CO2 transport and storage	£/MWh	-	-	-	-	-	-
			-				
Total	£/MWh	-£30.8	-£29.5	£94.3	£27.9	£130.6	£72.6

Case 1: 10% discount rate, 2011 project start at projected EPC prices, FOAK/NOAK mix								
		ACT	ACT CHP	AD 0-5MW	AD CHP	Sewage gas	Landfill	Biomass CHP
LEVELISED COSTS								
Capital costs	£/MWh	91.1	95.6	65.1	65.6	65.6	28.3	75.2
Fixed operating costs	£/MWh	39.8	11.7	47.1	21.6	16.6	8.7	(51.1)
Variable operating costs	£/MWh	14.5	14.5	20.3	21.2	-	7.1	8.5
Carbon costs	£/MWh	-	-	-	-	-	-	-
Fuel costs	£/MWh	(140.0)	(140.0)	(27.2)	(27.2)	-	-	102.2
Decomm and waste fund	£/MWh	-	-	-	-	-	-	-
CO2 transport and storage	£/MWh	-	-	-	-	-	-	-
Total	£/MWh	£5.5	-£18.2	£105.2	£82.6	£82.2	£44.2	£134.8

Case 2: 10% discount rate, 2017 project start at projected EPC prices, all NOAK							
		Dedicated Biomass >50MW	Dedicated biomass 5-50MW	Offshore R2	Offshore R3	Onshore >5MW	Solar >50kW
LEVELISED COSTS							
Capital costs	£/MWh	39.6	53.9	72.6	85.4	68.2	218.5
Fixed operating costs	£/MWh	14.7	17.3	32.0	37.1	16.6	22.3
Variable operating costs	£/MWh	4.4	5.1	1.2	-	2.7	-
Carbon costs	£/MWh	-	-	-	-	-	-
Fuel costs	£/MWh	84.3	49.7	-	-	-	-
Decomm and waste fund	£/MWh	-	-	-	-	-	-
CO2 transport and storage	£/MWh	-	-	-	-	-	-
Total	£/MWh	£143.0	£126.0	£105.7	£122.4	£87.5	£240.8

Appendix E –Efficiency assumptions

The following table shows the net Higher Heating Value efficiencies that have been used in calculating levelised cost estimates. These are based on the gross Lower Heating Value efficiencies collected by Arup.

	HHV efficiency
5-50MW dedicated biomass	27.6%
>50MW dedicated biomass	33.0%
Bioliquids	37.5%
Bioliquids CHP	37.5%
Conventional co-firing	32.5%
Enhanced co-firing	30.9%
Conversion	30.1%
EfW CHP	19.2%
EfW	19.2%
ACT	20.6%
ACT CHP	20.6%
Biomass CHP	18.5%
AD	36.5%
AD CHP	36.5%

Appendix F – Load Factor assumptions

The following table shows the load factors (net of availability) that have been used in calculating levelised cost estimates. These are based on information collected by Arup (2011) and Ernst & Young (2010) for marine technologies.

Technology	**Load factor (net of availability)**
Onshore Wind >5MW	28.6%
Onshore Wind <5MW	25.0%
Offshore Wind	37.7%
Hydro	45.8%
Tidal Stream Deep	41,3%, by 2022 dropping to 32.8%
Tidal Stream Shallow	27.4%
Wave	30.0%
Geothermal	91.2%
PV	10.8%
Dedicated biomass	90.0%
Co-Firing Standard	51.0%
Enhanced Co-Firing	63.8%
Biomass Conversion	63,3%
Bioliquids	72.7%
Energy from waste CHP	82.7%
AD	83.7%
Advanced conversion technologies	83.6%
Landfill Gas	81.0%
Sewage Gas	68.0%
Bioliquids CHP	72.7%
Advanced conversion technologies CHP	83.6%
Biomass CHP	76.9%
Geothermal CHP	91.2%

Appendix G –Technology Bibliography

Onshore Wind >5MW

Onshore wind is covered extensively in all the key reference documents included in the introduction of this report. In addition, the following documents were reviewed specifically for this technology:

- Poyry (2009) - Timeline for Wind Generation to 2020 and a set of progress indicators
- RenewableUK (2010) - State of the Industry Report – On and offshore wind progress update
- RenewableUK (2010) - Small wind systems – UK Market update
- Element Energy (2009) - Design of Feed-in Tariffs for sub-5MW electricity in the UK
- SQW/LUC (2010) - North West Renewable and Low Carbon Energy capacity and deployment (as a general example of UK regional deployment forecasts for onshore wind)
- DUKES generation database: http://www.decc.gov.uk/en/content/cms/statistics/publications/dukes/dukes.aspx

Onshore Wind <5MW

SKM, Quantification of Constraints on the Growth of UK Renewable Energy (2008)

Element Energy, Growth Potential for On-Site Renewable Electricity Generation (2008);

Renewable UK, Small Wind Systems – UK Market Report and Deployment Scenarios to 2020 & 2030 (2010)

DECC, National Renewable Energy Action Plan for the UK (2009)

HM Government, 2050 Pathways Analysis (2010)

Poyry, Timeline for Wind Generation to 2020 (2010)

Offshore Wind

In addition to the reports in Section 2.2, the following documents were reviewed specifically for this technology:

- Renewables UK (2010) - State of the Industry Report – On and Offshore Wind Update
- Poyry (2009) - Timeline for wind generation to 2020 and a set of progress indicators
- BVG Associates (2010) - Towards Round 3: Building the Offshore Wind Supply Chain
- Douglas Westwood (2010) - UK Offshore Wind: Building an Industry –

Analysis and scenarios for industrial development

- National Grid (2010) - Offshore Development Information Statement.

Hydro

- Nick Forrest Associates Ltd, The Scottish Institute of Sustainable Technology and Black & Veatch Ltd (August 2008) - Scottish Hydropower Resource Study, Scottish Government
- Nick Forrest Associates Ltd and Highland Eco-Design Ltd (September 2009) - The Employment Potential of Scotland's Hydro Resource, Scottish Government
- Entec UK (February 2010); Mapping Hydropower Opportunities in England and Wales, Environment Agency
- British Hydropower Association and IT Power (October 2010) - England and Wales Hydropower Resource Assessment, DECC and Welsh Assembly Government
- British Hydropower Association (October 2010), Driving the Low Carbon Economy Paper 2: Hydropower, Scottish Renewables

Marine Technologies

- Ernst & Young (October 2010) - Cost of and financial support for wave, tidal stream and tidal range generation in the UK ('the E&Y report')
- Public Interest Research Centre & The Boston Consulting Group (May 2010) - The Offshore Valuation ('The Offshore Valuation')
- RenewableUK (October 2010) - Channelling the Energy – A way forward for the UK wave and tidal industry towards 2020 ('the RUK report')
- SKM (June 2008) - Quantification of Constraints on the Growth of UK Renewable Generating Capacity ('the SKM report')

Geothermal

- MacDonald, P., Stedman, A. and Symons, G. (1992) - The UK Geothermal Hot Dry Rock R&D Programme, Proceedings, Seventeenth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, January 29-31, 1992
- Allen, D.J., Gale, I.N. and Price, M. (1985) - Evaluation of the Permo-Triassic Sandstones of the UK as Geothermal Aquifers, *Hydrogeology in the Service of Man*, Mémoires of the 18th Congress of the International Association of Hydrogeologists, Cambridge, 1985
- Barker, J.A., Downing, R.A., Gray, D.A., Findlay, J, Kellaway, G.A., Parker, R.H. and Rollin, K.E. (2000) - Hydrogeothermal Studies in the United Kingdom. *Quarterly Journal of Engineering Geology and Hydrogeology*, 33, 41-58
- Downing, R.A. and Gray, D.A. editors (1986) - Geothermal Energy: the potential in the United Kingdom. HMSO. 187pp

- Rollin, K.E. Low enthalpy geothermal options for the UK (Abstract) - The Geological Society of London. Available at: http://www.geolsoc.org.uk/template.cfm?name=geoevents_abstracts&eventId=PG20&abstractId=cwcc_ab24&abstractType=ext
- McLoughlin, N., (2006) - Geothermal Heat in Scotland. SPICe briefing 06/54. The Scottish Parliament.
- Stephens, E (November 2009) - Geothermal Energy Potential of Scotland's Geology. University of St Andrews
- Busby, J (April 2010) - Geothermal Prospects in the United Kingdom. Proceedings World Geothermal Congress 2010 Bali, Indonesia, 25-29
- Batchelor, A. and Ledingham, P. (2005) - Country Update for the United Kingdom. Proceedings World Geothermal Congress 2005, Antalya, Turkey, 24-29 April 2005
- Deep Geothermal Group, (December 2010) -Renewable Energy Association Parliamentary Briefing - Deep Geothermal: Heat and Power. *Developing an Enabling Framework in the UK*
- Younger, P.L. and Manning, D.A.C. (2010) - Hyper-permeable granite: lessons from test-pumping in the Eastgate Geothermal Borehole, Weardale, UK. *Quarterly Journal of Engineering Geology and Hydrogeology*, 43, 5–10
- The Future of Geothermal Energy: Impact of Enhanced Geothermal Systems (EGS) on the United States in the 21st Century (Massachusetts Institute of Technology, 2006) http://www1.eere.energy.gov/geothermal/future_geothermal.html.

Photovoltaic

German Federal Ministry of the Environment (2010) historic data on annual PV deployment

DECC (1996 to 2009), UK annual deployment data for MW capacity and generation.

Dedicated Biomass, Biomass Co-Firing, Biomass Conversion and Bioliquids

E4Tech (2009) - Biomass Supply Curves for the UK

AEA (December 2010) UK Global Bioenergy Resource – Final Report

AEA (December 2010) UK and Global Bioenergy resource – Annex 1 Report: Details of Analysis (Issue 2). (see www.decc.gov.uk/.../1465-aea-2010-uk-and-global-bioenergy-annex.pdf)

NNFCC (February 2011, updated April 2011) Evaluation of Bioliquid Feedstocks and heat, Electricity and CHP Technologies

Energy from Waste

- AEA (December 2010) UK Global Bioenergy Resource – Final Report.
- AEA (December 2010) UK and Global Bioenergy resource – Annex 1 Report: Details of Analysis (Issue 2). (see www.decc.gov.uk/.../1465-aea-2010-uk-and-global-bioenergy-annex.pdf)

- Chartered Institution of Waste Management (June 2010), UK Waste to Energy Plants, Incineration Transformation, pages 47 to 48
- Community and Local Government (December 2010), General Development Control (County Matters) CPS1/2 Returns, 2009 and 2010 planning decision statistics for waste planning applications in England
- Department for Environment, Food and Rural Affairs (December 2010). Spending Review 2010 – Changes to Waste PFI Programme. Supporting Analysis http://archive.defra.gov.uk/environment/waste/localauth/funding/pfi/documents/pfi-supporting-analysis-waste101206.pdf
- Environment Agency (2010) Incineration facilities that accepted waste in England and Wales during 2009: Permitted capacity and tonnage incinerated
- Environment Agency WRATE model for technical data
- National Audit Office (January 2009) Department for Environment, Food and Rural Affairs – Managing the Waste PFI Programme (see http://www.nao.org.uk/publications/0809/managing_the_waste_pfi_program.aspx)
- Pöyry (October 2010) A Comparison of EfW Technologies with selected Waste Feedstocks to determine their potential CO_2 Emissions and CO_2 Savings (Revision 2) (Not yet published)
- Renewable Energy Association (April 2010) REPAP 2020 - Renewable Energy Industry Road Map UK
- Sustainable Development Commission Scotland (January 2010) – Energy from Waste Potential in Scotland
- Waste Management World (December 2010). On the Road to Recovery: Achieving R1 Status, Confederation of European Waste to Energy Plants article. (see http://www.waste-management-world.com/wmw/en-us/index/display/article-display.articles.waste-managementworld.volume-11.issue-6.features.on-the-road-to-recovery-achieving-r1-status.html)
- Umweltbundesamt (November 2009), The Role of Waste Incineration in Germany
- UmweltMagazin Springer VDI Verlag (January/February 2011) Abfallverwertung auf japanisch (Waste Treatment in Japan) www.umweltmagazin.de

Anaerobic Digestion

- Sustainable Development Commission Scotland (January 2010) - Energy from Waste Potential in Scotland
- AEA Technology (2010) UK and Global Bioenergy Resources and Prices. Produced for DECC
- Defra: Demonstration project, Biocycle South Shropshire Ltd, Biowaste digester
- NNFCC (July 2009) Evaluation of Opportunities for converting Indigenous UK Wastes to Fuels and Energy, Report to the Non-Food Crops Centre, funded by DECC; ED45551

- AEAT (2005) Assessment of Methane Management and Recovery Options for Livestock Manures and Slurries. AEAT/ENV/R/2104. Report for: Sustainable Agriculture Strategy Division, Department for Environment Food and Rural Affairs, London SW1P 3JR
- The Scottish Government (2010) A Zero Waste Plan for Scotland.

ACT

- AEA (December 2010). UK Global Bioenergy Resource – Final Report
- AEA (December 2010). UK and Global Bioenergy resource – Annex 1 Report: Details of Analysis (Issue 2) (see www.decc.gov.uk/.../1465-aea-2010-uk-and-global-bioenergy-annex.pdf)
- Chartered Institution of Waste Management (June 2010) UK Waste to Energy Plants, Incineration Transformation (see pages 47 to 48)
- Community and Local Government (December 2010), General Development Control (County Matters) CPS1/2 Returns, 2009 and 2010 planning decision statistics for waste planning applications in England
- Department for Environment, Food and Rural Affairs (December 2010) Spending Review 2010 – Changes to Waste PFI Programme. Supporting Analysis http://archive.defra.gov.uk/environment/waste/localauth/funding/pfi/documents/pfi-supporting-analysis-waste101206.pdf
- Environment Agency (2010) Incineration facilities that accepted waste in England and Wales during 2009: Permitted capacity and tonnage incinerated
- Environment Agency WRATE model for technical data
- National Audit Office (January 2009). DEFRA – Managing the Waste PFI Programme. (see http://www.nao.org.uk/publications/0809/managing_the_waste_pfi_program.aspx))
- NNFCC (January 2011) Advanced Conversion Technologies for Wastes in the UK – Assessment of Deployment Potential (Not yet published)
- Pöyry (October 2010) A Comparison of EfW Technologies with selected Waste Feedstocks to determine their potential CO_2 Emissions and CO_2 Savings (Revision 2) (Not yet published)
- Renewable Energy Association (April 2010) REPAP 2020 – Renewable Energy Industry Road Map UK
- Scottish Environment Protection Agency (November 2010) Scotgen (Dumfries) Ltd, Dargavel Energy from Waste Facility, Site Status Report
- Sustainable Development Commission Scotland (January 2010) – Energy from Waste Potential in Scotland
- The Renewables Obligation Order 2009 (England and Wales). (http://www.legislation.gov.uk/uksi/2009/785/made?view=plain)
- University of Southampton (June 2010). The New Technologies Demonstrator Programme: Summary and Key Findings
- Waste Management World (December 2010). On the Road to Recovery:

Achieving R1 Status, Confederation of European Waste to Energy Plants article. (see http://www.waste-management-world.com/wmw/en-us/index/display/article-display.articles.waste-managementworld.volume-11.issue-6.features.on-the-road-to-recovery-achieving-r1-status.html)

Landfill Gas

- AEA (December 2010) UK Global Bioenergy Resource – Final Report
- AEA (December 2010) UK and Global Bioenergy resource – Annex 1 Report: Details of Analysis (Issue 2)
- Ofgem (2010). Landfill Gas – UK List of Accredited Stations
- Ofgem Renewables Obligation: Annual Report 2008-2009, ref: 32/10 8th March 2010, Section 3 and 4
- Ofgem Renewables Obligation: Annual Report 2009-2010, ref: 21/11 1st March 2011, Section 3 and 4
- Renewable Energy Association (April 2010). REPAP 2020 - Renewable Energy Industry Road Map UK
- AEA Future Energy Solutions (no date). Renewable Heat and Heat from Combined Heat and Power Plants - Study and Analysis Report (Version 1), pages 62 to 64. http://www.berr.gov.uk/files/file21141.pdf
- Sustainable Development Commission Scotland (January 2010) – Energy from Waste Potential in Scotland
- DECC website accessed for calorific value of landfill gas. http://chp.decc.gov.uk/cms/fuel-calorific-value/

Sewage Gas

- Sustainable Development Commission Scotland - Energy from Waste Potential in Scotland
- AEA Technology (2010) UK and Global Bioenergy Resources and Prices. Produced for DECC
- NNFCC (July 2009) Evaluation of Opportunities for converting Indigenous UK Wastes to Fuels and Energy, Report to the Non-Food Crops Centre, funded by DECC; ED45551, July 2009
- Water Strategy (2007) Annex C6 on Sewage sludge, as a part of Waste Strategy for England 2007
- Water UK (2008) Sewage sludge production and disposal routes

Renewable CHP

- Integrated Energy: The Role of CHP and District Heating in Our Energy Future, CHPA, November 2010
- Building a Roadmap for Heat: 2050 Scenarios and Heat Delivery in the UK, University of Surrey & Imperial College London, February 2010
- Low Carbon Transition Plan Emissions Projections (2010 – 2020), DECC,

2009

- Digest of UK Energy Statistics 2010, DECC 2010
- Interaction Between Different Incentives to Support Renewable Energy and Their Effect on CHP: Renewable Obligation and Renewable Heat Incentive, AEA, January 2010