The Offshore Valuation Group

The Offshore Valuation

A valuation of the UK's offshore renewable energy resource

Contents

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Designed by Lloyd Northover and Richard P Chapman Design Associates.

1 Foreword

Having been involved for nearly two decades in the creation and establishment of the UK's oil and gas industry, I find the first stirrings of Britain's nascent renewable offshore energy sector very exciting. I shall watch with fascination as today's generations embark on the difficult task of finding answers to the twin challenges posed by the need to meet the UK's long term energy requirements and doing so in a way consistent with our environmental concerns.

The publication of the Offshore Valuation is a major first attempt to put a real value on what the renewable energy resource around the coasts might bring in terms of jobs, investment, infrastructure creation, income and, of course, clean and affordable energy. It is required reading for all decision makers in the energy and environment sectors not least because it is so clear in the way that it lays out the challenges for Government, industry and for our wider society.

Thinking back to the late 1960's and early 1970's I am struck by how much we had to learn. In the North Sea the oil industry faced technical and environmental challenges which were new. Government knew nothing about managing the implications (and benefits) of a large indigenous oil and gas industry and had to learn on the job and the supply industry started at a massive disadvantage compared to its rivals.

I find echoes of this in the Offshore Valuation, although I believe that today we are much better placed than we were in 1970. There will be problems to overcome but the main components of success are there: technological innovation, daring, a skilled workforce and - crucially - cooperation between Government and industry. I have every confidence that the renewable energy industry and the companies that comprise it can emulate the successes of the UK's offshore oil and gas industry of the last century.

This report is, therefore, an invaluable contribution to the debate on how best to maximise our offshore resources and secure the nation's future energy supply while creating jobs and generating revenue at a time when it is crucial to reinforce our manufacturing base, I congratulate all those who have worked so hard to deliver it and I commend it to you as compelling reading.

John d'Ancona

Director General, Offshore Supplies Office [1981 - 1994]

The Offshore Valuation Group is an informal collaboration of government and industry organisations who have come together to address the question: what is the value of the UK's offshore renewable energy resource?

1. The Department of Energy & Climate Change
2. The Scottish Government
3. The Welsh Assembly Government
4. The Crown Estate
5. Energy Technologies Institute
6. Scottish & Southern Energy
7. RWE Innogy
8. E.ON
9. DONG Energy
10. Statoil
11. Mainstream Renewable Power
12. Renewable Energy Systems (RES)
13. Vestas
14. Public Interest Research Centre

Boston Consulting Group was commissioned to undertake a high level study of the UK's offshore renewable resource. The study was funded by and drew on the expertise of the Group. The study also benefited through funding and technical assistance from The Committee on Climate Change Secretariat.

The project was initiated and coordinated by Public Interest Research Centre, an independent think-tank and a registered charity.

This report was undertaken to better understand the potential value of the UK's offshore renewable energy resource. Its findings do not necessarily represent the policies or views of all members of the Offshore Valuation Group.

The Offshore Valuation Group would like to thank Joan Walley MP and Ed Miliband MP for their early enthusiasm that helped catalyse the broad support that has come to the project.

Thanks to the Institution of Mechanical Engineers for hosting the project.

Thanks to The Crown Estate and to the MArS team for the provision of relevant area data and for the creation of UK maps. It is acknowledged that The Crown Estate can accept no liability for the outputs.

The Offshore Valuation Group came together to answer a central question for the UK:

What is the value of our offshore renewable energy resource?

2 Executive Summary

The Offshore Valuation Group came together to answer a central question for the United Kingdom: What is the value of our offshore renewable energy resource?

What we found has exceeded our expectations. In harnessing 29% of the practical offshore renewable resource by 2050:

- **the electricity equivalent of 1 billion barrels of oil could be generated annually, matching North Sea oil and gas production and making Britain a net electricity exporter;**
- **carbon dioxide reductions of 1.1 billion tonnes would be achieved by the UK between 2010 and 2050 – a major contribution towards 2050 climate targets;**
- **145,000 new UK jobs could be created by industry.**

The next four decades of technological development could enable us to harness a practical resource ten times the size of today's planned deployments. Integration with neighbouring electricity networks though a 'super-grid' could provide access to a single European electricity market, enabling the UK to sell renewable electricity across the continent.

We assessed the extent of the practical resource through a detailed mapping process based on five electricity generating technologies: wind with fixed and floating foundations; wave; tidal range; and tidal stream. The full practical resource - 2,131 TWh/year - exceeds current UK electricity demand six times over.

Three deployment scenarios were examined to reveal a landscape of different options. Each scenario envisages a level of deployment greater than that currently planned but exploiting less than the full practical resource.

	Installed capacity	Resource utilisation	Capital expenditure	Annual Revenue in 2050	
Scenario 1	78 GW	13%	£170B	£28B	50% UK demand
Scenario 2	169 GW	29%	£443B	£62B	Net *electricity* exporter
Scenario 3	406 GW	76%	£993B	£164B	Net *energy* producer

The scenarios are neither predictive nor prescriptive. Their achievability will ultimately be determined by the level of the UK's ambition; by the level of demand for the UK's renewable electricity in the wider European market; and by evolving technology costs.

* New capacity editions plus offshore grid costs.

The infrastructure deployment required is similar in scale to that of oil and gas in recent decades. The major expansion of the supply chain this needs will not happen on its own, however, but will take strong and continuing support from government and industry in the coming years.

Scenarios forecast the deployment of estimated least-cost options for each decade, based on 78 geographically-specific site-types. Models of technological advances for each of the five technologies were constructed, using learning rates driven by deployment levels over time.

The net value derived in each of these scenarios is sensitive to a number of variables - foremost among them, future costs of electricity generation from the various offshore renewable technologies and development of the European electricity market.

Applying our cost estimates for Scenario 2, coupled with DECC's central wholesale price forecasts, implies a net present value from exports of £31 billion. Here the key sensitivity is the price at which Europe is willing to buy UK renewable electricity at scale: if higher DECC price scenarios are used this value rises and if alternative European price estimates are used in place of DECC's, the net value could be more neutral**.

Whilst the value identified by this study cannot be guaranteed as far ahead as 2050, some key enablers can ensure the UK does not prematurely give up the option of accessing this potentially significant export market. These are:

- **Make Offshore Wind Round 3 grid connections 'super-grid compliant' to avoid locking out potential future electricity sales to Europe (in scenarios 2 and above);**
- **Take a leadership role in the current EU super-grid negotiations, to ensure that the UK derives maximum value from its design and implementation;**
- **Continue to develop the UK supply chain as a key to deployment at scale and least cost;**
- **Evaluate and where appropriate, facilitate new financing structures that complement the fundamental features of renewable energy infrastructure and can support the scale and speed of industrial growth required.**

The UK is now most of the way through its first great offshore energy asset, our stock of hydrocarbon reserves. The central finding of this report is that our second offshore asset, of renewable energy, could be just as valuable. Britain's extensive offshore experience could now unlock an energy flow that will never run out.

** For example, the price forecasts from the European Climate Foundation 2050 EU Roadmap (2010).

We find ourselves in a comparable position to that of the nascent UK oil and gas companies in the 1970s

3 Preface

In 2007, the UK signed up to a European Union target to deliver 15% of energy supply from renewables by 2020. In 2008 the UK parliament signed the Climate Change Act, bringing into law an 80% reduction in greenhouse gas emissions by 2050. In 2009 the Climate Change (Scotland) Act set an interim target of a 42% emissions reduction by 2020. At the same time the UK's existing electricity generating plant is ageing: 80% will need to be replaced by 2030 including 8.5GW of coal power closing by 2017 due to the Revised Large Combustion Plant Directive, and 9GW of nuclear plants reaching the end of their lives[1].

Against this backdrop, the production of renewable electricity in the UK has been growing by 11% per year since 2000[2] and the offshore renewables industry has been gearing up for growth. In early 2010, The Crown Estate announced the successful bidders for each of the nine Round 3 offshore wind zones within UK waters which will occupy the industry for at least the next decade, and also announced the names of the successful bidders for the world's first commercial wave and tidal leasing round, for ten sites in Scotland's Pentland Firth and Orkney waters. Four manufacturers have signalled their intention to produce offshore wind turbines in the UK (Clipper, GE, Siemens and Mitsubishi). The UK is also home to an increasing concentration of wave and tidal power companies.

Yet despite all this activity, a full economic valuation of the UK's offshore renewable energy resource over the long term has not been conducted. Various reports have examined the potential for different offshore renewables, but these have typically either looked in detail only at individual technologies, or they have not attempted to value the national resource. Calculating the enduring value of this resource to the nation will support far-sighted policy formation for the offshore sector and provide security to investments that flow from this.

We find ourselves in a comparable position to that of the nascent UK oil and gas industry in the 1970s. Early work had begun and profits were emerging, but we had yet to gauge the full scale of the opportunity. In 1973, the International Mechanical Engineering Group, a US consultancy, produced a report that quantified the full potential of North Sea oil and gas, leading to the formation of the Offshore Services Office to help guide its development.

This study set out to answer the following questions:
- **What is the scale of the UK's offshore renewable resource?**
- **How much value could this bring to the UK?**
- **What steps are required to unlock this value?**

We studied five existing technologies; offshore wind with fixed foundations ('fixed offshore wind'), offshore wind with floating foundations ('floating offshore wind'), tidal stream, tidal range (including tidal barrages, lagoons and bars) and wave power. Each of these technologies is either in use or in development today.

1 PB Power, 'Powering the Future', December 2009
2 Ofgem, 2010

The scope required the collaboration of a broad set of stakeholders, including regional and national government, manufacturers and developers. Coordinated by the Public Interest Research Centre, a not-for-profit think tank, the group worked together with leading strategy consultants The Boston Consulting Group to deliver this report. New, in-depth analysis has been supported by interviews with leading industry and government stakeholders and access to detailed site-specific data. This has resulted in a set of findings that outline feasible pathways to extracting maximum value from our offshore renewable resource.

The most startling finding from this study is that UK's offshore renewable resource has the potential to transform the country from a net energy importer to a net energy producer over the next four decades. In the same way that investment in North Sea oil and gas infrastructure enabled the country to access a vast stock of hydrocarbon energy resources, large scale investment in offshore renewables could open up access to a permanent energy flow. This flow is of a comparable scale to current oil and gas production in the same area of sea.

This study is not designed as a predictor of the future. Our vision, while exciting, is not the only way forward. We recognise that our analysis is sensitive to many unknowns, including technological change across multiple industries, movements in energy and commodity prices, and the practical challenges of building a new industry. Therefore we have set out to describe the potential value of the UK's offshore renewable resource without trying to predict the future, nor to propose prescriptive recommendations.

Tim Helweg-Larsen

Chair, The Offshore Valuation Group
Director, Public Interest Research Centre

4 Report Summary

Introduction

This report assesses the value of the UK's offshore renewable resource that can be accessed via the generation of electricity from wind, wave and tidal power devices. This valuation is based on estimates of the future demand for clean energy, the size of the available resource, the practical constraints that could prevent this value from being realised, and the economic value of clean electricity. We have created three deployment scenarios to frame the valuation and illustrate a range of possible outcomes.

In viewing the offshore renewable resource, this study takes a new perspective, with significant implications. Rather than viewing the resource from the perspective of UK demand, this report explores the wider European demand for renewable power. This change in perspective has a profound effect on the scale of the UK's economically deployable resource.

Decarbonising the UK electricity supply

The UK's 2020 target to deliver 15% of energy from renewables will need to be met through expanding the use of renewable energy sources across a combination of transport, heating and existing electricity applications. While meeting the 2020 target will be challenging, it is only a step on the way to meeting the UK's 2050 target; the Committee on Climate Change estimates that electricity supply will need to decarbonise by more than 80% by 2030 in order for the UK to be on track to meet its 2050 target.

As the electricity supply decarbonises, electrification will become an increasingly attractive route for the decarbonisation of both transport and heat. This in turn will increase the total demand for electricity; assuming 75% electrification of vehicles and heat by 2050, combined with an underlying annual growth rate of 1%[3] and measures to promote energy efficiency, then electricity demand in 2050 could be 75% higher than in 2010 (from 350 TWh to 610 TWh).

Decarbonisation options

Looking ahead to 2050 there are only three groups of technologies that are likely to provide the majority of the UK's low or zero carbon electricity supply: nuclear, renewables (onshore and offshore) and fossil fuel generation with carbon capture and storage (CCS).

In this context, offshore renewables provide an opportunity for the UK to reduce risk. Security of supply will benefit from having a more diverse portfolio of generation technologies, and the UK will have an additional solution for meeting its climate change targets. In addition the UK is uniquely advantaged in terms of its offshore resource thanks to a combination of shallow waters, a long coastline, strong tides, high winds and exposure to Atlantic waves.

3 Historical growth in UK electricity consumption has been 1.3% per annum

With the necessary exception of offshore renewables, this study does not make any assessment of the relative contribution that each power generation technology might contribute over time, other than to note that a range of technologies are likely to be required.

Role for offshore renewables in meeting UK energy needs

Prior to 2010 the UK had already begun to develop its offshore renewable resource, with 15GW of fixed offshore wind sites allocated through Rounds 1, 2 and the Scottish Exclusivity Agreements. Then on January 8th 2010 32GW of new offshore wind farm licences were issued under Round 3, bringing the UK total to 47GW. Two months later, The Crown Estate announced the world's first commercial wave and tidal stream leasing round, for 1.2GW in Scotland's Pentland Firth and Orkney waters (600MW from each technology). If developed in its entirety, this capacity would generate 48% of current UK electricity demand, reducing to 30% in 2050 as total demand increases.

The five offshore renewable technologies considered in this study (fixed offshore wind, floating offshore wind, tidal stream, tidal barrages and wave power) are either in use or in development today, although we have assumed a level of technological progress over time that expands the size of the practical resource. This technological progress has parallels with developments in the oil and gas industry – such as horizontal drilling and floating platforms – that have expanded the total available resource.

Resource

For each of these technologies we conducted a highly detailed assessment of available site types in UK waters, taking into account resource quality, competing uses of the sea and accessibility constraints. We segmented UK waters into 78 different site types across the five technologies, and used this as a basis for estimating the maximum practical electricity generation from each technology, shown in the table below. Further detail on the methodology used to calculate these resource estimates can be found in the main body of the report.

Total practical resource for offshore renewables

Technology	Currently allocated capacity (GW)	Currently allocated capacity (TWh)	Additional practical resource (TWh)	Total practical resource (TWh)
Fixed wind	47	165	241	406
Floating wind	-	-	1,533	1,533
Tidal stream	0.6	2	114	116
Tidal range	-	-	36	36
Wave	0.6	1	39	40
Total	48.2	168	1,963	2,131

Our analysis shows that the UK's offshore resource, if developed to its maximum potential, could generate over 2,100 terawatt hours (TWh), equal to six times UK electricity consumption in 2009.

Floating wind: Practical resource

Wind Resource Contraint Areas
0-20% contrained
>60m depth
<100nm from shore

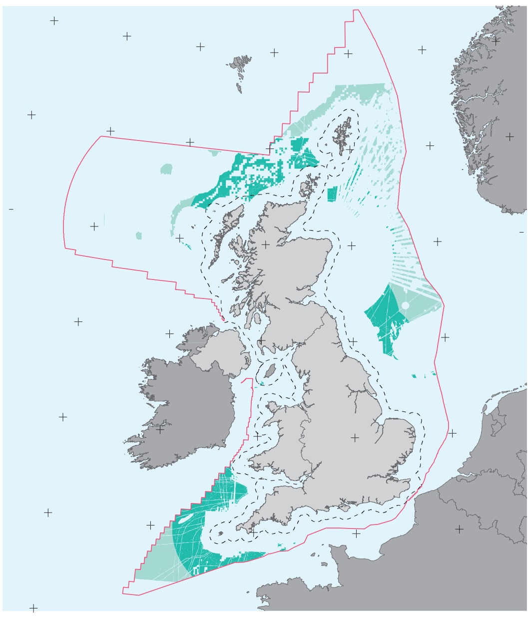
Wind Resource Contraint Areas
0-20% contrained
>60m depth
>100nm from shore

Exclusive Economic zone

Territorial Waters Limit

United Knigdom

Europe



Scenarios

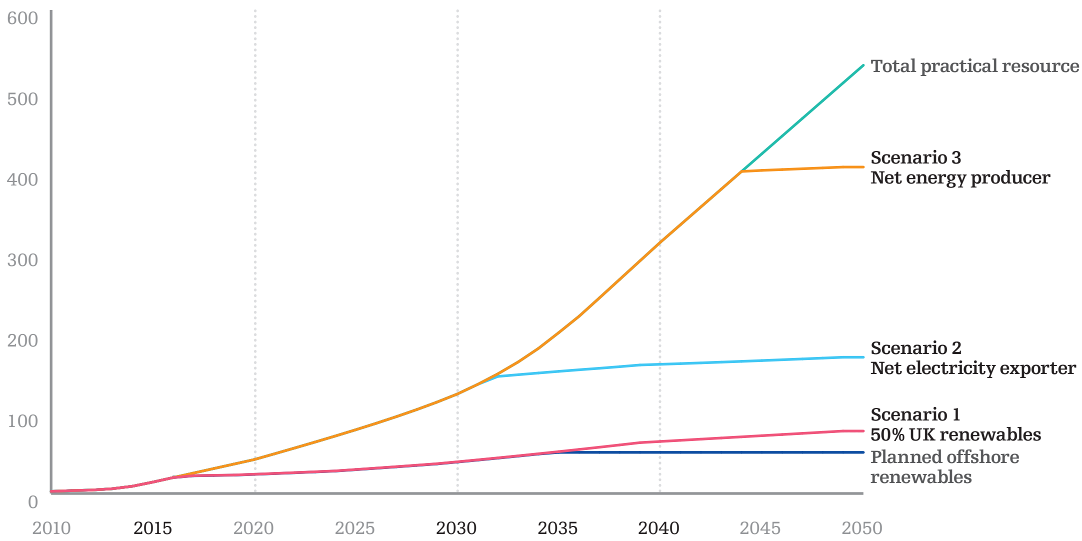
In order to illustrate the potential value from offshore renewables we examined three scenarios. These were selected as steps along the pathway that the UK would follow if it were to develop the full practical offshore renewable resource. Each scenario represents an inflection point in the way we think about our offshore resource.

- **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 net exports of electricity to other countries
  - The main limiting factor in this scenario will be the UK's ability to manage up to 50% variable electricity on the grid (see the variability chapter for more detail)

- **Scenario 2: The UK as a net exporter of electricity generated by offshore renewables**
  - The amount of electricity generated from offshore renewables is equal to total UK electricity demand in 2050
  - Any electricity generated in the UK from sources other than offshore renewables is offset by an equal level of electricity exports to Europe
  - The main limiting factors in this scenario will be the ability to build an offshore electricity grid with connections to several European countries, and the ability to scale up the supply chain

- **Scenario 3: The UK as a net exporter of energy generated by offshore renewables**
  - The amount of electricity generated from offshore renewables is equal to total UK energy demand in 2050 (i.e. electricity production is approximately 2.5 times the level produced in scenario 2)
  - Total UK energy demand is the sum of all energy delivered by electricity, gas, oil-based fuels and other sources
  - Achieving this scenario will require the peak installation rate of floating offshore wind to be four times that for fixed offshore wind, and a European market that will purchase more than 25% of its electricity from the UK (when the wind is blowing)

Deployment scenarios



One of the constraints present in all scenarios is cost. Unless all five technologies can become cost-competitive with alternative sources of electricity by 2050, development will only occur with government support. In order to assess changes in cost over time, we estimated the levelised cost of electricity each decade for each of the 78 different site types using learning curves while recognising that there will be significant uncertainty in any estimates made over such a long time period.

Learning curves are a simplified way of forecasting costs over an extended period of time, and as such were deemed suitable for this study. While many individual factors will drive changes in technology costs between now and 2050 (e.g. scaling up of processes, new materials, design innovation) we have not attempted to predict these in any detail. Instead we have assumed that costs will reduce as the installed capacity for each offshore renewable technology increases. Specifically, for every doubling in capacity, costs are forecast to decrease by an amount equal to the assumed learning rate.

The costs of fixed offshore were calibrated using today's costs, and learning rates of 5-15% were then applied to each of the major cost components to estimate changes in cost over time[4]. For the other four technologies, a wide range of sources were used to estimate levelised costs at the point at which the first four GW of capacity have been deployed – which we estimated to be 2020 – with learning rates of 10% applied in a similar manner as for fixed offshore wind.

The model used to calculate the cost of offshore wind is the same model that was used in the 2008 Carbon Trust report 'Big Challenge, Big Opportunity', updated to take into

4 A review of the relevant literature suggests that learning rates of 10-19% could be achieved by offshore wind; see the Cost chapter and Appendix for further details

account changes in cost over the last two years. While capital costs have increased by 26-33%[5] over this period, the majority of this rise can be accounted for by the fall in the value of the pound against the Euro (because turbines, cables and substations are not manufactured in the UK, turbines, cables and substations are generally priced in Euros). Once this effect has been removed, underlying capital costs have increased by 4-7% since 2008.

Given our assumptions on learning rates and global deployment levels for all five technologies, fixed wind will remain (on average) the cheapest of the five technologies considered to 2050. Floating wind and tidal stream are the next lowest cost technologies, followed by wave and tidal range. The most economic site types for floating wind and tidal stream are likely to be cost-competitive with typical fixed offshore wind sites in 2050.

In each scenario we have assumed that any additional backup capacity can and will be provided through interconnection, the cost of which is factored into our overall valuation. This backup capacity could also be provided by UK-based generation or storage – or may need to be if Europe cannot provide sufficient balancing services – but we have not attempted to model these costs for this study.

We have not created a new set of forecasts for future electricity prices as part of this study. Instead we have used wholesale price estimates from the Department of Energy and Climate Change, which comprise four scenarios: Low, Central, High and High High. Implicit in the use of these scenarios is the assumption that electricity generated by offshore renewables will receive an average market price. Although it is possible that the price realisation for variable renewables will be below 100% if there is insufficient balancing or storage capacity on the network, our calculations suggest that the value of offshore renewables is positive in all but the Low scenario.

5 Range of cost increases across the 48 modelled site types.

Scenario 1: Maximising the role of offshore renewables in meeting UK electricity demand

In order to value this resource to the UK, we first looked at what could be developed by 2050. The main barriers to deployment are the ability to manage the variability of the electricity generated, the ability to connect new capacity to the UK electricity grid and the ability of the supply chain to scale up. None of these constraints leads us to believe that there is a precise level beyond which no more offshore renewables could be deployed. However, increasing the level of variable renewable electricity on the grid is likely to present the greatest challenges. Our analysis suggests that the UK grid could accommodate approximately 50% variable renewables by 2050 – provided that 34GW of backup capacity, storage or interconnection[6] can be made available – and we have used this as the constraining factor. Grid connection and supply chain constraints are likely to limit deployment in the next one to two decades, but we see no fundamental reasons why these constraints could not be relaxed sufficiently in the very long term. Additional onshore grid upgrades would likely be required alongside new offshore grid connections, but these have not been quantified by this study. The table below shows a possible breakdown of technologies in 2050 under scenario 1[7].

Scenario 1 - Deployment by Technology

Technology	Capacity (GW)	Capacity (TWh)	Percentage of resource (%)
Fixed wind	70	245	60
Floating wind	2	8	1
Wave	2	4	11
Tidal stream	2	7	6
Tidal range	2	5	15
Total	78	270	13

In this scenario 13% of the UK's practical offshore resource would be utilised. To deploy this capacity by 2050 would require an average build rate of 2.8GW per year (four hundred 7.5MW turbines), once the effect of repowering capacity that has reached the end of its life is taken into account[8]. Under DECC's central price scenario the supply chain necessary to deliver this level of deployment would have annual revenues of £28 billion in 2050, profits of £8.5 billion, and could employ around 70,000 people in roles directly related to manufacturing, installation and operations & maintenance. Further revenue and jobs would also be created in the grid supply chain, as this scenario would require a North Sea supergrid with 21GW of capacity connecting the UK to mainland Europe. This grid would be used to export power in times of excess UK supply, and import power in times of excess UK demand.

6 The UK currently has 3.1GW of interconnection, and an additional 1.5GW is planned by 2020.
7 See the chapter on deployment for a more detailed explanation of how each scenario was developed.
8 Assumes an average lifetime for offshore generating plant of 20 years (tidal range 50 years).

The total net present value created through this scenario is shown in the table below, for each of the four electricity price scenarios[9]. These figures are arrived at by calculating the total revenue from electricity generation in each year, and then subtracting the levelised cost of generation for all installed capacity, the cost of UK grid connections and the cost of grid connections to Europe required to provide backup services.

As the table shows, for three of the four price scenarios developing 78GW of offshore renewables creates a large net present value for the UK[10]. Any highly negative values are unlikely to be realised in practice, as the build rate of offshore renewables will slow or cease in response to sustained low electricity prices.

Scenario 1 - Net Present Value

DECC electricity price scenario	Net present value (2010-2050; 2010 prices)
Low	- £79 billion
Central	£17 billion
High	£87 billion
High High	£126 billion

Scenario 2: The UK as a net exporter of electricity

The EU will face many similar high level issues to the UK in the medium to long term; greenhouse gas reduction targets, an increase in electricity demand, concerns about security of supply and reliance on many of the same technologies. It will also face similar practical issues, including the need to replace ageing energy infrastructure and practical constraints on the deployment of onshore renewables.

Against this backdrop the UK has potentially the largest offshore renewable resource in Europe, much of which is located close to the major markets of France and Germany. If offshore renewables were to prove economic for the UK, then it is possible that there would also be a market for the electricity in other European countries (once the costs of interconnection are factored in). Furthermore any grid connections built to address the variability issue of renewables could be used for net electricity exports (or indeed for net electricity imports in periods when European electricity prices are lower than in the UK).

The value of electricity exports

Building on the UK scenario outlined above, an additional 46GW of fixed offshore wind could be built to provide electricity exports to Europe. Additional capacity beyond this level will require significant contributions from the other offshore renewable technologies, with the largest (and potentially lowest cost) source of additional capacity being floating wind.

9 Cash flows are discounted using the Treasury Green Book recommended value of 3.5%.

10 This calculation assumes that the alternative to building offshore renewables will be other forms of generation with a levelised cost equal to the wholesale electricity price. Cash flows are calculated without any government support.

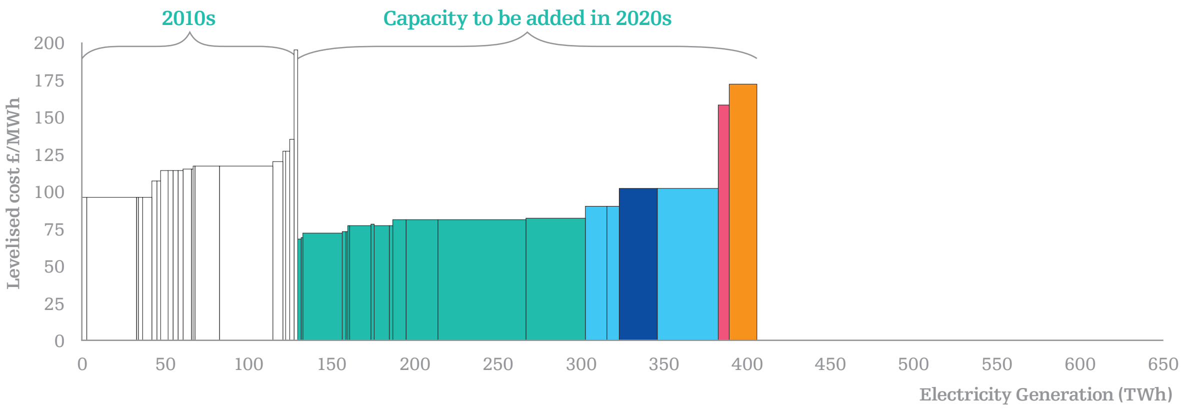
If the UK were to slightly more than double its production of electricity from offshore renewables (compared to scenario 1) it could become a net exporter of offshore electricity – i.e. produce as much electricity offshore as the UK consumes. At this scale UK offshore renewables would supply approximately 6% of Europe's electricity demand, in addition to 50% of UK demand. An illustrative breakdown of technologies for this scenario in 2050 is shown in the table below.

Scenario 2 - Deployment by Technology

Technology	Capacity (GW)	Capacity (TWh)	Percentage of resource (%)
Fixed wind	116	406	100
Floating wind	33	145	9
Wave	5	10	25
Tidal stream	9	33	28
Tidal range	6	16	44
Total	169	610	29

Cost curves, like the one below, were built for each of the four decades across each of the three scenarios, as a tool to deploy technology at least-cost out to 2050. The complete set of these cost curves are reproduced in the body of the full report and its annexes.

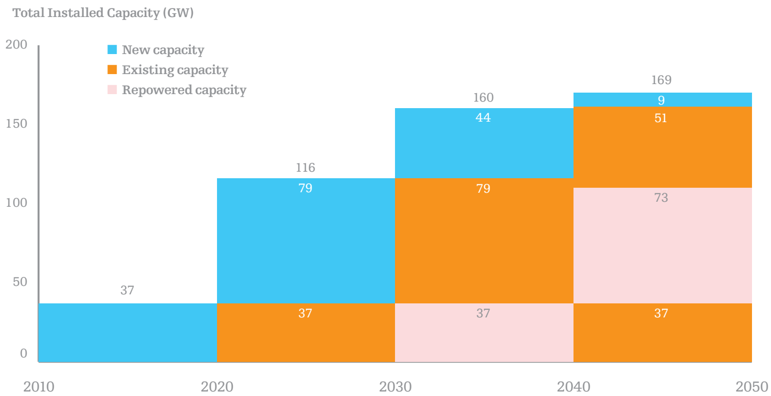
Scenario 2 - Technology Cost Curve



In this scenario 29% of the UK's practical offshore resource would be utilised. To deploy this capacity by 2050 would require an average build rate of 7.2GW per year (one thousand 7.5MW turbines per year), including repowering. Of this, 5.4GW would be fixed offshore wind, with the next largest share coming from floating wind. In

addition to the 34GW of capacity (backup plant, storage and interconnection) required to balance variable renewables on the UK grid in scenario 1, 85GW of interconnection would be required to allow electricity exports in scenario 2.
The cumulative deployment of new capacity and repowered capacity can be seen in the graphic below.

Scenario 2 - Deployment by technology each decade



Deployment at this level would result in an annual production of electricity in 2050 equivalent to 1 billion barrels of oil[11]. This is the average level of production experienced by the UK's North Sea oil and gas over the four decades leading up to 2008. The supply chain necessary to deliver this level of offshore renewables would have annual revenues of £62 billion in 2050, profits of £16 billion, and could employ around 145,000 people in direct roles[12].

The total net present value created through this scenario is shown in the table below, for each of the four electricity price scenarios.

Scenario 2 - Net Present Value

DECC electricity price scenario	Net present value (2010-2050; 2010 prices)
Low	- £209 billion
Central	£36 billion
High	£211 billion
High High	£303 billion

11 1TWh = 1.6 million barrels of oil equivalent.
12 Using DECC's central price scenario.

Scenario 3: The UK as a net exporter of energy

Given the scale of the UK's practical offshore renewable resource, it is possible that with sufficient international demand for low carbon electricity the UK could be not only a net electricity exporter, but also a net energy producer. By 2050, taking into account economic growth and the impact of electrification on demand for gas and oil-based fuels, we estimate that the UK will use 1,610 TWh of energy per year. This scenario sees the offshore renewable resource developed to a level that matches this total demand.

While ambitious, this scenario is not without precedent; between 1994 and 2004 the UK was a net producer of fossil fuel energy (coal, oil and gas[13]). At this level of deployment, annual offshore renewable electricity generation in 2050 would 2.6 billion barrels of oil or 150% of North Sea oil's peak year of production[14]. The crucial difference, of course, is that renewable energy by its nature will not deplete.

If this level of resource was developed, it would provide 50% of UK electricity demand and just over a quarter of EU electricity demand. The scale of interconnection required – 321 GW by 2050 for export alone – would likely require not only a North Sea supergrid but also connection from the south coast of the UK down to France and Spain.

As with each scenario, the development pathway is constructed by back-casting from the scenario objective (TWh output level in 2050). While large compared to current deployment levels, the report presents these scenarios for open consideration.

One possible way to achieve this level of generation is shown in the table below.

Scenario 3 Deployment by Technology

Technology	Capacity (GW)	Currently allocated capacity (TWh)	Percentage of resource (%)
Fixed wind	116	406	100
Floating wind	245	1,073	70
Wave	14	30	75
Tidal stream	21	75	65
Tidal range	10	26	72
Total	406	1,610	76

This level of deployment would require an average build rate of 13.1GW per year (eighteen hundred 7.5MW turbines per year), with a peak of 23GW per year in the 2030s. Although this build rate would ramp up over two decades and be spread across all five technologies, the practical challenges of such a high build rate – e.g. availability of skilled personnel and vessels – may constrain deployment.

13 BP Statistical Review of World Energy, 2008.
14 Peak production year was 1999. Source, Digest of UK Energy Statistics 2009.

The supply chain necessary to deliver this capacity would have annual revenues of £164 billion in 2050, profits of £24 billion, and could employ around 340,000 people in direct roles[15].

The total net present value created through this scenario is shown in the table below, for each of the four electricity price scenarios. As for both scenario 1 and our central scenario, this value is positive in all but the Low electricity price scenario.

Scenario 3 - Net present value

DECC electricity price scenario	Net present value (2010-2050; 2010 prices)
Low	- £343 billion
Central	£55 billion
High	£343 billion
High High	£489 billion

Scenarios 1-3 in context

To give a sense of scale for the above scenarios, we can compare the total energy produced by offshore renewables to UK offshore oil and gas production. In 2008 oil and gas production was equal to approximately one billion barrels of oil. By coincidence this is also the average level of production over the last four decades of UK oil and gas. By 2050 in scenario 1 we would be producing just under half of this amount of energy from offshore renewables, in scenario 2 we would be producing the same amount of energy as oil and gas in 2008, and in scenario 3 we would be producing more than two and a half times as much energy.

Scenario 1, 2 & 3 - Oil Equivalent

	TWh/year	Million barrels oil equivalent / year[16]
Senario 1	270	440
Senario 2	610	994
Senario 3	1,610	2,623

Using DECC's 2010 GHG appraisal guidance, offshore renewables will result in avoided carbon emissions of 1.1 billion tonnes over the next four decades under scenario 1[17]. Averaged over the 40 year period this represents 4% of the UK's 1990 GHG emissions.

In addition to the potential economic value and the climate value of each scenario, there are also major benefits to UK energy security. Simply moving from currently planned levels of offshore renewable deployment to scenario 1 could reduce fossil fuel imports by 20 million tonnes and reduce import costs by £7 billon in 2050. This would

15 Using DECC's central price scenario.
16 Comparison is made on the basis of delivered electrical energy.
17 See valuation section for further details of this calculation

in turn reduce the UK's dependence on fuel supplies from other countries and the price volatility that results from periods of political or economic instability – although the price of electricity from offshore renewables could be highly variable if demand and supply are not aligned. Offshore renewables also provide the UK with ownership of a large energy-producing resource that can be used to support economic development in a low carbon future.

The path forward

Each of the scenarios outlined above have the potential to create billions of pounds of value for the UK economy. Regardless of which scenario unfolds, it is certain that the UK has a very large practical resource that at the right price could be used to generate electricity both for domestic use and for export. The ability to create value from electricity exports will depend on European demand for renewable electricity, the availability of grid transport capacity and a sufficiently high market price. While none of these elements can be guaranteed looking so far into the future, the most important next step is to ensure that the UK is on a path forward that provides the option to realise any positive value in the future.

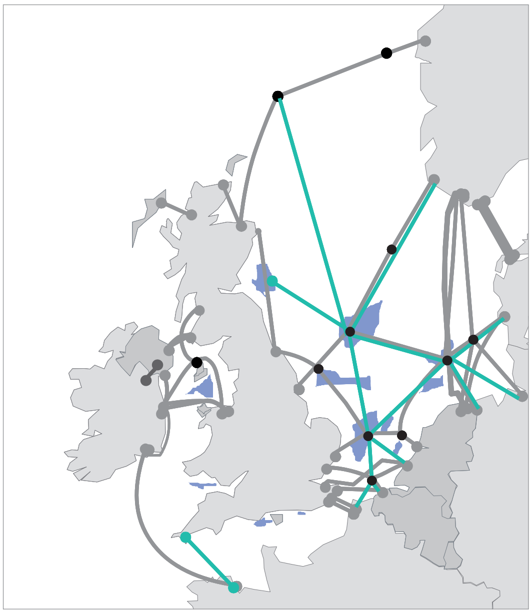
To put the UK on the pathway to maximising the value of its offshore renewable resource requires the actions listed below to begin in the next 12-24 months. Beyond this point the investment decisions for Round 3 will be underway and the industry will begin to settle on a way of working that may not be compatible with a long term view of value maximisation. These actions all have a relatively low cost compared to the potential value that could be realised, and they are essential to keep the UK's options open for possible value in the future.

a. Government to act now to ensure that the design, operation and regulation of grid connections being built in Round 3 is compatible with large scale interconnection between the UK and other European countries. Ideally a single entity would be responsible for coordinating the UK offshore grid, much in the same way that the onshore transmission system is managed today. This entity could then make strategic choices regarding the design of interconnection with other countries. Under all three scenarios, up to 10% of the capital investment in offshore renewables between now and 2020 will need to be channelled into building the first stage of a European supergrid. £6 billion could finance 16GW of interconnection by 2020, out of a total capital investment of £60 billion over the same period.

b. In support of the above point, government would benefit from taking a stronger leadership role in international discussions of the design of a North Sea supergrid, with the aim of securing an outcome that allows the UK to maximise the value of its offshore resource. This can be done through forums such as the North Sea grid initiative, ENTSO-E (which has recently published a draft 10-year grid development plan) and the European Commission (which is in the process of developing a North Sea Grid Blueprint).

Enhanced Supergrid

(teal line)	Additional capacity
(grey line)	North Sea Super Grid
●	Mid-sea supernode



c. Government and industry to continue to develop the UK supply chain. This could reduce the cost of deploying Round 3 by as much as £15 billion through limiting UK exposure to unfavourable changes in exchange rates, as well as providing employment for 145,000 people under scenario 2. Given the long lead times required to build a new industry, if the supply chain is to have an impact on Round 3 projects starting in the middle of this decade then immediate action is required.

d. Government and industry to work together to find ways to develop innovative financing mechanisms that can match the long term risk and reward profile of renewable energy investments. This could take the form of green energy bonds designed either for corporate investors such as pension funds or for individual investors, and should be designed to deliver finance at the required scale; under scenario 2 an average annual investment of £11 billion will be required between 2010 and 2050.

Total capital investment in offshore renewables and grid infrastructure

Capital investment (£ billion)	2010-2050
Senario 1	£170B
Senario 2	£443B
Senario 3	£993B

e. Government to set a national ambition to become an exporter of offshore renewable electricity. This will provide industry with the confidence it needs to invest for the longer term, it will demonstrate a strong commitment to existing renewable energy and climate targets, and it will help to guide long term policy development on related issues such as energy markets, grid and supply chain development.

In addition there are a number of current actions that should be enhanced to help reduce the costs of offshore renewables:

f. Government and industry to begin work on a comprehensive study to develop the business case for backup options, including the optimal balance between UK-based backup capacity, storage and interconnection. This could build on work such as DECC's Energy Market Assessment and Ofgem's Project Discovery. It is essential that this study considers scenarios where significantly more offshore renewables are deployed than the 48GW currently planned.

g. Government and industry to continue to work together to find ways to promote measures that can efficiently facilitate the integration of variable renewables into the grid, including smart grid technology and demand side management. It is unlikely that such measures alone will be sufficient to fully compensate for variable renewables, but may be cheaper than building new backup capacity.

h. Government and industry to continue to support a diverse range of offshore renewable technologies. Given the uncertainty around future costs for the five technologies included in this study, it is possible that the preferred order of technology deployment could change in the future.

5 Energy Demand in 2050

There are a number of drivers affecting the energy sector and therefore the potential for marine renewables. Climate change and carbon reduction targets, both nationally and for the EU and security of supply are all issues directly affecting the power sector.

However in the short term there is the pressing issue of a potential supply gap towards the end of this decade. Current plans for new nuclear and CCS are for new capacity to start coming online between 2017 and 2020, but this may not be sufficient to close the capacity gap. If onshore renewable generation cannot grow quickly enough to fill this gap – for example due to planning, grid, or financing constraints – then new combined cycle gas turbine (CCGT) plants are the most likely fallback option as they can be built both quickly and relatively cheaply.

In addition to the challenges of building sufficient capacity from onshore renewables, CCS and nuclear over the next decade, each of these technologies also faces challenges in the longer term. Nuclear is the most well-established technology, but expansion in the UK may be constrained by a lack of available sites and/or by global competition for critical components and expertise as other nations adopt ambitious deployment plans. CCS has not yet been proven on a full scale power plant – although many of the component technologies are in use today – and at some point in the distant future the UK's underground storage capacity will be exhausted[18]. There are long term challenges for all existing onshore renewables but these are typically technology-specific, e.g. spatial constraints for onshore wind, feedstock constraints for biomass, seasonal constraints for photo-voltaic.

Greenhouse Gas emissions

The 2007 IPCC report[19] proposed that global emissions should fall by at least half compared to 1990 levels to have a greater than 50% probability of limiting the average global temperature rise to 2°C. This temperature rise will "avoid the most dangerous impacts of climate change"[20] and would require a reduction in global greenhouse gas (GHG) emissions of 50-85% based on 1990 levels.

Given significantly higher per capita emissions in developed nations and the rapid industrialisation of developing nations (such as China), developed nations have discussed cutting emissions by more than the global average.

In line with these recommendations, the UK and EU both have in place carbon reduction targets, although in varying degrees of ambition. The UK has set a legally binding 80% reduction target for 2050 based on 1990 levels. In England and Wales an interim target of 34% reduction by 2020 has been set, while in Scotland the target for 2020 is 42%; overall the UK achieved a reduction of 20% as of 2008. Provisional figures for 2009 show a reduction of up to 26%, although the majority of this reduction is likely to be due to effect of recession and it is uncertain how much of this will rebound. The government has set itself carbon budgets every five years, which legally it

18 Based on current estimates of UK carbon storage capacity (e.g. EU GeoCapacity report 2009, DECC 2010), whether CCS uses gas or coal as a fuel, and the share of UK electricity generation that comes from CCS, the UK could run out of storage space from 2050 onwards.

19 IPCC "Climate Change 2007, Synthesis Report".

20 UK Low Carbon Transition Plan, 2009.

must meet under the Climate Change Act. Despite this, the rate of reduction required from 2020 to 2050 (CAGR -3.9%) is still extremely challenging, more than double the rate required from 2008 to 2020 (CAGR -1.6%).

The EU-27 has an aspiration for an 80% reduction by 2050 with current discussions supporting up to a 95% reduction[21]. The EU-27 has an interim target of 20% by 2020 and has already achieved reduction of ~10% as of 2008 based on 1990 levels. Provisional figures for 2009 show that carbon emissions are expected to be approximately 10% lower than the previous year, but as in the UK these are expected to rebound as the economy recovers. Similar to the UK, the rate of reduction required from 2020 to 2050 (CAGR -4.5%) is much greater than rate required from 2008 to 2020 (CAGR –0.9%) – and will need to increase further if EU raises its aspiration above 80%.

A number of factors will make these targets even more challenging than they already appear. Emissions from agriculture and some elements of industry will be particularly difficult to reduce by such a large degree, and the targets do not yet apply to aviation and shipping emissions[22]. If these were to be included, emissions from other sectors would likely need to be reduced even further; for example, if aviation and shipping emissions could be maintained at 2005 levels, all other sectors would need to achieve an 86% reduction rather than an 80% reduction.

Implications for the power sector

There are a number of studies and forecasts showing the emission trajectory required for the UK power sector. There is an emerging consensus that the UK power sector will need to reduce its carbon emissions by more than 70% from 1990 levels by 2030. This is driven by the relative ease and low cost with which electricity can be decarbonised relative to other sectors.

Energy efficiency is the most cost-effective and potentially easiest option. However, this can only close part of the gap. The technologies needed to decarbonise the power sector already exist and so wholly new technologies do not need to be developed from scratch. According to the IEA, the marginal abatement costs for decarbonising the global power sector is in the region of $0-50/tonne, considerably lower than CCS or other industrial measures, or switching transportation to alternative fuels.

Electrification of other sectors, such as transport and heating, is one of the main levers for decarbonisation, but this in turn requires a low carbon electricity supply. Biofuels are another option for decarbonisation, but the opportunity in specific sectors is limited and the government has estimated that an area of farmland equal to 25% of the UK would only provide enough bio-energy resources to meet 8-12% of the country's energy needs[23].

21 European Council proposal made in October 2009; dependent on a successful global agreement being reached
22 Except in Scotland
23 Land Use Futures: Making the most of land in the 21st century. Foresight, Government Office for Science, 2010

At the same time as the UK, the EU power sector will also need to be decarbonised. To achieve a level of emissions consistent with the IPCC recommendations, the IEA forecasts the EU power sector must reduce its emissions by approximately two-thirds by 2030 compared to 1990 levels[24]. A report by the European Climate Foundation in 2010 found that the EU power sector would need to decarbonise by at least 90% to enable an 80% reduction in greenhouse gas emissions[25].

UK electricity demand

A number of studies have attempted to estimate future UK electricity demand. Our approach has been based on building from four main constituents:

- **Underlying demand growth**
- **Energy efficiency**
- **Electrification of transport**
- **Electrification of heating**

To illustrate the uncertainties involved in forecasting so far into the future we have detailed two possible outcomes for electricity demand in 2050; a low and a high case. We have used the low case in all of our calculations, recognising that this is a conservative assumption and likely to be towards the lower end of possible electricity demand levels in 2050.

Low Case

For the low case we assume that underlying electricity demand grows at the same rate as forecast population growth, i.e. 0.7% per annum[26].

A 71% emission reduction is required in the transport sector overall to meet the UK's 2050 carbon reduction target, assuming a fully decarbonised power supply and a similar reduction in the heat sector. Given that certain elements of transport (e.g. aviation) will be harder to decarbonise, we have assume a 75% electrification of road transport, generating a demand increase of 80TWh.

The increase in electricity demand from heating is based on the UKERC "early action" scenario[27], at 100TWh in 2050. Energy efficiency is assumed to reduce net demand by 10%, resulting in a total electricity demand of approximately 610TWh, an increase of 74% from 2009.

High case

Between 1988 and 2008 electricity demand grew by 1.3% per year on average, and our high case assumes that this underlying trend will continue to 2050. In addition, we assume a 90% electrification of road transport by 2050, combined with an underlying annual growth rate of 0.4%. Electric vehicles are assumed to require one fifth as much energy as petrol, resulting in a demand increase of 113TWh by 2050.

24 IEA World Energy Outlook, 2009.
25 ECF: roadmap to 2050, Practical Guide to a prosperous low carbon Europe, May 2010.
26 ONS 2009 Population forecasts up to 2033.
27 UKERC: Pathway to a low carbon economy, Energy Systems Modelling, March 2009.

Similar assumptions are made for electrification of heating; 90% electrification and an underlying annual growth rate of 0.4%. Electric heating is assumed to require one third as much energy as gas – based on current heat pump efficiencies – generating a demand increase of 143TWh.

As in the low case, energy efficiency is assumed to reduce net demand by 10% (35TWh)[28], resulting in a total electricity demand of approximately 800TWh in 2050, an increase of 130% from 2009.

European electrity demand

Electricity demand among the EU-27 countries increased at an average rate of 1.9% per year between 1997 and 2007, more than half a percent above the UK rate over the same period. Looking forward to 2050, electrification of European transport should follow a similar path to the UK as the major carmakers switch their production from fossil-fuelled vehicles to electric, driving up electricity demand in all markets. The uptake of electric heating will be less consistent across markets as regional differences may provide more attractive alternatives. For example, in areas with large biomass resources – such as some of the Eastern member states – wood and other combustible plants may be more cost-effective. The opportunities for savings from energy efficiency across Europe cannot be compared with the UK. Some countries have had strict building regulations in place for many years and so future potential savings may be expected to be lower than in the UK, but there is no clear picture across countries.

For the purposes of this report we have made the following assumptions:

- **Without energy efficiency or electrification, underlying electricity demand will equal 4,800 TWh in 2050 (an increase of 1% per year)**
- **Energy efficiency will reduce demand by 1,400 TWh**
- **100% electrification of transport will increase demand by 800 TWh**
- **90% electrification of building energy demand will increase demand by 500 TWh**
- **90% electrification of industrial energy consumption will increase demand by 200 TWh**

The net effect of energy efficiency and electrification is just 100 TWh of additional demand on top of underlying demand, resulting in a total European electricity demand of 4,900 TWh in 2050. This is in line with other recent studies such as the European Climate Foundation[29] and the US Energy Information Administration[30]. 4,900 TWh in 2050 represents a 40% increase from 2008 levels.

28 DECC Heat and Energy Saving Strategy Consultation, February 2009.
29 ECF, Roadmap 2050, 2010; electricity demand is forecast at 4,800-4,900TWh in 2050 for the EU-27 plus Norway and Switzerland.
30 EIA, International Energy Outlook, 2009; electricity demand is forecast at 4,600TWh in 2030 for OECD Europe.

6 Sizing the Offshore Renewable Resource

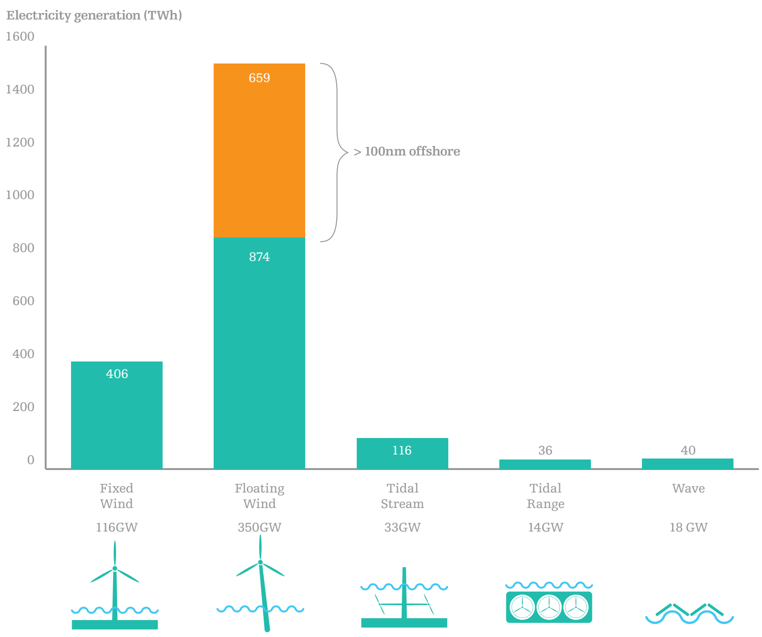
Summary of Findings

The UK's total practical offshore renewable resource is 531GW or 2,131TWh, equal to more than six times current electricity demand. The split by technology is shown in the table below.

Practical resource by technology

TWh by technology[31]	Low estimate	High estimate	Estimate used in report
Fixed offshore wind	376	436	406
Tidal range	16	44	36
Tidal stream	33	200	116
Wave	30	100	40
Floating offshore wind	860	1,533[32]	1,533
Total	-	-	2,131

Practical resource by technology (GW & TWh/yr)



Regional breakdown

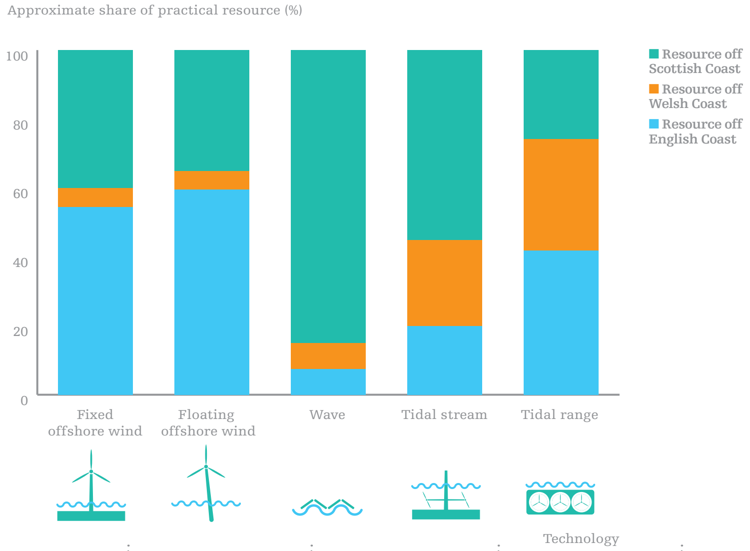
The practical resource is distributed around the UK in the approximate proportions outlined below[33]. Devolved government have certain devolved responsibilities within

31 Load factors of 40%, 50%, 40%, 30%, 25% used for fixed-wind, floating-wind, tidal-stream, tidal range and wave respectively.
32 Includes sites more than 100nm offshore.
33 We have not estimated the resource in the waters around Northern Ireland as part of this study. However a Strategic Environmental Assessment for the region has identified approximately 1.5GW of suitable offshore wind sites and 0.1GW for tidal power

12nm of their coastline; beyond the 12nm limit there are mixed responsibilities largely managed by the UK government.

- The waters around the Scottish coastline include the site of The Crown Estate's first leasing rounds for wave and tidal, as well as approximately 11GW of fixed offshore wind sites. These waters contain approximately 40% of the fixed offshore wind practical resource, 35% of the floating resource, three quarters of the wave resource and over a third of the combined tidal stream and tidal range resource.
- Around the Welsh coastline there is 5% of the offshore wind practical resource, along with a large number of suitable tidal range and tidal stream sites. This area of sea is also the location of around 10% of the total wave resource. The total resource off the coast of Wales (39.5 GW) exceeds the total of all nine zones awarded across the UK in Round 3.
- The sea around the English coastline contains half of the fixed and floating wind practical resource, around 10% of the wave resource off the coast of Cornwall, a fifth of the tidal stream resource and two fifths of the tidal range resource.

Practical Resource by Technology and Region



	Fixed wind		Floating wind		Wave		Tidal stream		Tidal range		TOTAL		%
	GW	TWh	GW	TWh	GW	TWh	GW	TWh	GW	TWh	GW	TWh	
Resource off Scottish coast	46	162	123	537	15	34	18	64	4	9	206	806	39%
Resource off Welsh coast	6	22	19	83	1.5	3	8	29	5	12	39.5	148	7%
Resource off English coast	63	222	209	914	1.5	3	7	23	6	15	286.5	1177	54%
TOTAL	**116**	**406**	**350**	**1533**	**18**	**40**	**33**	**116**	**14**	**36**	**531**	**2131**	

Approach

This chapter summarises the methodology used to quantify the UK's total practical offshore renewable resource in 2050. The practical resource available for each of the five offshore technologies – fixed wind, tidal range, tidal stream, wave and floating wind – has been analysed separately, but using a similar approach to ensure the final numbers are as comparable as possible.

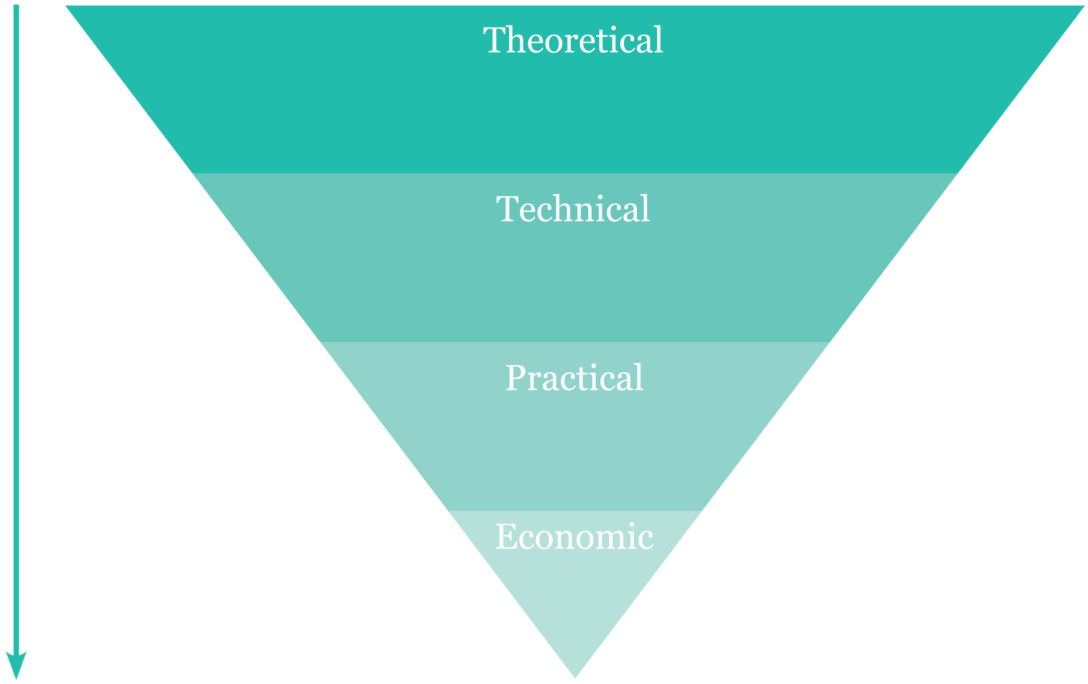
The existing body of literature quantifying the UK's renewable resource contains some very detailed and comprehensive analysis of individual technologies and specific geographic regions. By necessity this report does not go down to a similar level of detail. Our overall approach had two components: (i) a comprehensive literature survey, combined with responses from expert interviews and (ii) where relevant, a direct calculation of the practical resource via either top-down or bottom-up modelling. Our detailed assumptions are summarised in the appendix, and where uncertainty remained a range is presented and the average used in subsequent analysis.

Direct modelling of the practical resource was required for three reasons. Firstly, there is no publicly available research relating to floating wind due to the novelty of the technology. Secondly, the precise definition of 'practical resource' differs between existing reports, thus inter-technology comparisons such as those required for this report are difficult to make. For example, predictions of the UK's offshore fixed-wind resource are often considered within the context of current and planned deployment, and are constrained by cost estimates. In comparison, estimates of the size of the tidal range resource typically focus on the maximum potential resource, excluding any cost constraints. Thirdly, several areas of uncertainty and disagreement have been identified, for example in the estimation of the practical resource for tidal stream power.

Definition of practical resource

Resource size can be most easily defined by use of a resource pyramid, shown in the figure below. The highest tier consists of the theoretical resource, which covers the total energy available in the entire resource, for example the energy contained in the wind over UK waters. The technical resource constrains the theoretical resource based on the limitations of each technology. This includes restricting device deployment to areas of suitable depth and where appropriate, by conversion efficiency, load factor and power density. The practical resource is what is available after consideration of external physical constraints, therefore excluding areas due to conflicting uses, for example world heritage sites or shipping lanes. The economic resource considers the available energy which can be exploited at a cost considered to be economic. The definition of what is economic is subject to change, for example as electricity, commodity and carbon prices evolve out to 2050, thus resource estimates are presented in terms of practical resource, with subsequent chapters discussing both cost and deployment in more detail.

Resource Pyramid



Fixed offshore wind

Several reports[34] estimate a value for the technical or practical offshore wind resource in UK waters, which is widely reported to be the best in Europe. The range in reported figures can be attributed to differences in underlying assumptions regarding load factors, conversion efficiencies and deployment depths. There remains a need to quantify practical resource in a transparent manner accounting for real uses which currently restrict deployment of offshore wind. The same method can be applied to floating wind to allow a like-for-like comparison.

In order to determine the practical wind resource in 2050, and accounting for the actual practical constraints in UK waters, GIS spatial mapping was used to identify areas within the UK's EEZ[35] in which fixed wind could be deployed. In its most simple form, this bottom-up model multiplies the practically available area by a power density and load factor to determine the total practical resource. The bottom-up method implicitly assumes the theoretical resource is not limiting; a reasonable assumption when considering the nature and scale of wind energy.

Within the EEZ, the UK's sea floor was segmented into 48 site types, based on wind speed (<700W/m2,700-800W/m2/800-900W/m2,>900W/m2), distance from the UK mainland[36] (0-12nm,12-30nm, 30-60nm, 60+nm) and depth (0-20m, 20-40m, 40-

34 See, for example: BERR, 2009; REAG, 1992; PIU, 2002; Greenpeace, 1999.
35 EEZ refers to the Exclusive Economic Zone, which coincides with the Renewable Economic Zone (REZ) in which offshore renewable technologies can be deployed.
36 Measured in nautical miles (nm), and represents distance from onshore grid.

60m). These are the same segments that were used in the 2008 Carbon Trust report[37], and the depth limit of 60m is in line with the deep water sites allocated by The Crown Estate in round 3.

All areas containing hard constraints were then removed. Hard constraints are existing uses of the sea that exclude all possibility of the deployment of wind energy. These include offshore mines, pipelines and existing renewable energy leases; a full list of constraints can be found in the appendix.

The remaining sites were then subdivided according to the level of practical constraint within each segment. This was done using data from The Crown Estate to identify over 50 soft constraints[38], including various densities of shipping lanes and nature reserves, and then applying a weighting to each constraint based on the degree to which they conflict with the deployment of wind energy. The soft constraint weightings within each unit area were summed and used to determine the level of constraint in each area. Sites were then grouped according to the constraint level, such that a constraint level of x% would include all sites with a weighted constraint value less than or equal to x%[39].

To estimate the area that could be used for fixed offshore wind a constraint level of 35% was chosen, which would allow development of approximately 16,000km_2. 35% was selected based on analysis of the constraint levels in areas which have already received wind energy licences. Any areas smaller than 10km_2 – the size of a typical round 1 site – were excluded from the analysis on the grounds that these would be too small to warrant development.

To calculate the practical resource, this practical area was multiplied by a power density and combined with a site specific load factor to reflect the wind speed in each site type. Load factors of 35%, 39%, 41%, and 44% were used which corresponded to wind powers of <700W/m_2, 700-800W/m_2, 800-900W/m_2, >900W/m_2 respectively[40]. Average power density in 2050 was estimated to be 3-4MW/km_2, based on trends in increasing turbine size, analysis of power densities achieved and planned in Rounds 1, 2 and 3, and acknowledging the impact of wake losses. The power density for Rounds 1, 2 and 3 is shown in the appendix.

Based on the above calculations, the additional practical resource available in addition to current site allocations is 180TWh/yr – 240TWh/yr, or approximately 61GW of fixed wind. Existing Crown Estate leasing round have consented 47GW of wind and it is assumed that 8GW of extensions within these areas will be possible, under the assumption that the average power density could be increased to 2MW/km_2 over the next four decades. This gives a total practical resource for fixed offshore wind of 116GW.

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37 'Big Challenge, Big Opportunity', Carbon Trust, 2008.

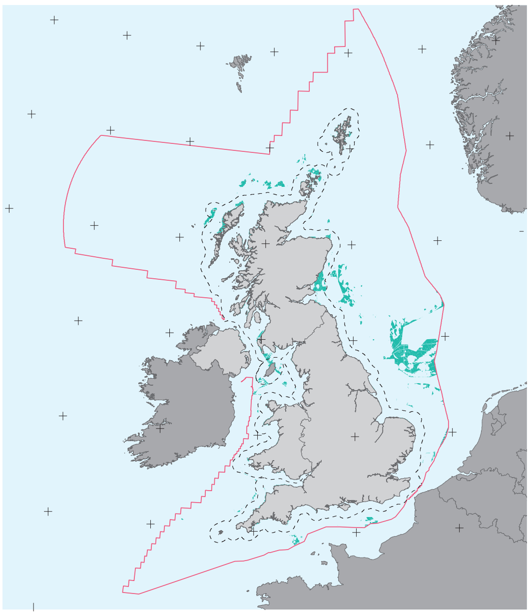
38 Soft constraints are defined as existing uses of the seabed, water column or airspace which may restrict the deployment of offshore wind. Areas without full soft constraint data have been excluded, which explains the blank areas at the very edges of the EEZ.

39 GIS spatial mapping & supporting programme was used for this analysis, which was carried out by The Crown Estate's MaRS team.

40 Load factors were calculated based on statistical distribution of annual wind speed and corroborated via reported data and expert interviews

Map of fixed wind practical resource

	Wind Resource Contraint Areas 0-20% contrained >60m depth <100nm from shore
	Wind Resource Contraint Areas 0-20% contrained >60m depth >100nm from shore
	Exclusive Economic zone
------	Territorial Waters Limit
	United Knigdom
	Europe



The map above shows the practical offshore wind resource beyond Round 3. This resource is located off both the East and West Coasts of England, as well as around the coast of Scotland. Looking at the resource by region, approximately 5% is located around the Welsh coast, 40% off the coast of Scotland, and the remaining 55% around the English coast, with a single large area adjacent to the existing Dogger Bank Round 3 site and smaller area off the south east of Scotland.

Tidal range

Tidal range devices extract the energy associated with the difference in height between high and low tides. Tidal range practical resource is well understood, and there is broad agreement regarding the energy available in the various sites due to the well established theory surrounding energy extraction.

The tidal range practical resource is highly site specific, with the largest potential coming from the Severn Estuary which has the second largest tidal range in the world. Additional suitable sites get increasingly smaller, and only the largest eight sites were considered within our estimate of the practical resource[42]. Complete utilisation of the Severn has the potential to generate approximately 16TWh, while the next seven largest sites could generate ca. 20TWh/yr[43], giving a practical resource of 36TWh/yr, or 18GW[44].

42 Burrows (2009) estimates that an additional eight sites could contribute another 8TWh/yr
43 Burrows, 2009
44 Based on a load factor of 30%; exploitation of both ebb and flow tides may increase this value.

Tidal stream

The UK's tidal stream resource has been the subject of extensive research[45] and until recently the UK's practical resource had been estimated to lie within the range 4-30TWh/yr. However, academic research has since highlighted uncertainty in both the underlying methodology and the assumptions used to estimate this resource, which has had the impact of increasing this range to 4-110TWh/yr.

The uncertainties surrounding the calculation of practical resource and the disparities between the published literature has been briefly summarised below, however the reader is encouraged to refer to the specific texts where further detail is required. This report does not intend to determine which method is the most appropriate or lead academic debate, merely to lay out the current uncertainties and encourage further research.

The primary area of uncertainty surrounds the method for estimating theoretical resource. Three different methods have thus far been used to determine the theoretical resource; (i) Kinetic Energy Flux (ii) Bottom Friction and (iii) Shallow Wave Model.

The kinetic energy flux method, as used by the widely-quoted Black and Veatch Study[46] calculates the kinetic energy in water moving through a perpendicular plane within a channel. Salter uses a bottom friction method to calculate the water's impedance and the power dissipated by friction to the sea-bed. The shallow wave method calculates the power in a wave of tidal wave dimensions, as illustrated by Mackay. The latter two methods broadly agree, but differ from the first by a factor of 10-20. The Kinetic energy flux method has historically been the preferred method, although recent papers have questioned its applicability in all but very specific situations[47].

A second area of disparity concerns the impact of energy extraction on the remaining resource; given limited practical experience there is considerable uncertainty regarding the degree to which deployment of a row of tidal devices alters the available resource for subsequent rows. The impact of farms is likely to be highly site specific and further research is required in order to determine the appropriate level of constraint. There has also been disagreement in the published literature as to whether application of the Betz limit is appropriate for tidal stream, and there is notable variation in the specific technical restrictions used; for example, the cut-in speed, maximum device size and maximum operating depth.

In order to navigate these uncertainties and determine a range which reflects the UK's potential practical resource (assuming the theoretical resource is not limiting) a bottom-up calculation has been employed.

45 For example: Black & Veatch for the Carbon Trust, 2005, ABPmer for the CWW, 2004; ABPmer/NPower Juice, 2007; Salter, 2007; Mackay, 2009; SKM, 2008; ETSU, 1993; Sustainable Development Commission (SDC), 2007; Project Management Support Services/Welsh government, 2006; Environmental change Institute, 2005; Carbon Trust, 2006;

46 ibid

47 See Salter's response to DTI Energy Review, 'Possible under-estimation of UK tidal resource'; Mackay, 2007, 'Underestimation of UK's Tidal Resource'.

Within the EEZ, the UK's sea floor was segmented into 45 site types, based on Mean Spring Peak Current (<1m/s, 1-1.5m/s, >1/5m/s); depth (0-20m, 20-40, 40-60m) and distance from shore (0-12nm, 12-30nm, 30-60nm, 60-100nm, >100nm). Based on a review of current and planned devices, it has been assumed that tidal stream devices will operate at depths of between 20 and 60m, and only in areas with a MSPC of >1.5m/s.

This technical resource was then reduced by 60% to provide an estimate of the practical resource. This number was chosen based on the impact of usage constraints in reducing the area of sea available for fixed offshore wind, as no such site-specific data is available for tidal stream sites. This figure is in broad agreement with published 'technical: practical' resource ratios.

The resource size was calculated for each site type, by multiplying the practical area available by a range in power density 5-30MW/km$_2$. This range is broad to reflect the uncertainty in both the available theoretical resource and the impact of energy extraction from neighbouring devices. The upper limit was based on an analysis of The Crown Estate's recent Pentland Firth site allocations for tidal stream, in which the average power density was 27MW/km$_2$ (this was rounded up to30MW/km$_2$). The lower bound is approximate only, but is in line with achieved power densities for offshore wind. This range is consistent with that found in published literature.

Using the methodology outlined above, the practical resource for tidal stream is estimated at 33-200TWh/yr based on analysis of the suitable area available. This corresponds to a power density of 5MW/km$_2$ and 30MW/km$_2$ respectively. The average of this range – 116TWh/yr – has been used in the rest of this report; this corresponds with the maximum published estimate of 110TWh/yr[48].

It should be noted that there may be some overlap between tidal stream and tidal range resources; a degree of mutual exclusivity exists. However an assessment of this overlap was not possible given the data available at the time this report was written.
From a regional viewpoint, there are hotspots of tidal stream resource off the north coast of Scotland (for example in and around the Pentland Firth), between south west Scotland and Ireland, between south west 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.

Wave

The most commonly quoted practical resource value for wave is 50TWh/yr, which can be linked back to the work carried out by ETSU between 1993 and 2001. Despite advances in technology since this time, recent reports have questioned whether this scale of resource is practically available.

48 Mackay, 2008.

There is a general consensus in published reports that the average wave power entering the UK waters is 40W/m, coming primarily from a North-Westerly direction. This is based on theoretical calculations as well as primary field data[49]. However, research by Mollison[50] has indicated that frequency and alignment losses[51] are often not considered when converting to technical and practical resource; Mollison has estimated these losses may cause a reduction in practical resource of between 30%-50%. This would reduce the practical wave resource to between 25-35TWh/yr.

Unlike wind energy, wave energy cannot be calculated based on the suitable area available for deployment, as the maximum extractable power is per unit length of wave crest, not per area. For example, if a row of devices were to extract 100% of the incoming energy, there would be no wave energy available for subsequent rows. Conversion factors of 100% are unlikely to be achievable, and the currently deployed Pelamis devices have load factors of around 25%. In order to test the impact of the losses noted above, as well as the possibility of multiple rows of devices, a simplified model was developed to estimate the number of rows of devices required to reach 50TWh/yr. This is described in the appendix.

This illustrative calculation suggests that under some optimistic assumptions the first row could produce 37TWh/yr, the second row, 14TWh/yr and the near shore row 3TWh/yr, making a total of 53TWh/yr. Each row of devices would need to be approximately 1,000km long. Deployment of the second and third rows is unlikely to be attractive to developers, thus 37TWh/yr, rounded up to 40TWh/yr[52] has been used for the practical wave resource in this report. This translates into an installed capacity of approximately 18GW.

As the strongest wave resource will be located on the west coast of the UK, a large share of the total generation can be expected to be located in three regions: off the coasts of western Scotland, south-west Wales and Cornwall.

49 Crabb, 1984; Mollison, 1986; Mackay, 2008;
50 Mollison (1986) Wave climate and wave power resource.
51 Frequency losses: Most devices are unable to capture energy from the full frequency range; devices tend to be optimised to operate within a particular frequency range. Capturing the lowest frequencies is not yet technically feasible. Alignment losses: Devices may not always be at the optimum angle to ensure maximum extraction of incoming wave power.
52 This is in agreement with the currently considered practical wave resource of 50TWh/yr, and if frequency and alignment effects are considered, this would be reduced to 33TWh/yr.

Floating wind

There are several designs and prototypes for floating wind, with one full scale device currently deployed in the North Sea off the coast of Norway[53]. The relative novelty of floating-wind explains the lack of publically available resource estimates. Thus the floating-wind resource was calculated using the same method as that for fixed-wind with appropriate adjustments to technical and practical constraints.

The technical limitations of current designs restrict floating wind to water depths of between 60m and 700m[54]. There has also been some concern that it will not be possible to install floating wind beyond 100nm from the coast due to the time taken to get to and from the site. Thus the floating wind resource which lies beyond 100nm has been calculated separately to acknowledge that at this distance from shore access for installation and maintenance may be limited. It has been assumed that floating wind will only be deployed in areas of less than 20% practical constraint level. This is deliberately more conservative than for fixed offshore wind: Firstly, the area available for floating wind is considerably larger than for fixed offshore wind, reducing the pressure to modify existing uses of the sea. Secondly, the economics of fixed wind are more favourable[55], which further decreases the probability that a very large resource could be utilised. A power density of 3-4MW/km_2 has been used to convert from km_2 to MW.

Using the assumptions above, spatial mapping identifies that within 100nm from the UK coast approximately 870TWh/yr of practical floating wind resource is available, with a further 660TWh/yr available beyond 100nm. This corresponds to a total installed capacity of 350GW[56].

Of this 350GW of floating wind, 45% lies greater than 100nm from the UK mainland, leaving just over 190GW within the 100nm boundary. The practical resource is broadly divided into three discrete areas; off the south-west coast of England and Wales, off the north and north-east of Scotland and off the east coast of northern England. Approximately 5% of the total resource is located off the Welsh coast and 35% in waters around Scotland, with the largest single resource area around Cornwall and south west of the Severn estuary. Consideration of the locations of the floating-resource when planning the future offshore grid as well as interconnections with Europe would maintain the option to fully exploit the UK's practical resource. Grid and interconnection are considered further in later chapters.

Comparison to Oil and Gas

The territorial waters of Britain hold two valuable energy resources. The first is an energy stock of hydrocarbon deposits. The second is a renewable energy flow in the form of wind, waves and tides.

53 Statoil Hydro deployed a 2.3MW floating device in 2009.
54 Water depths of less than 60m have not been considered so as to avoid any double-counting of the practical resource already allocated to fixed offshore wind; depths greater than 700m have been excluded due to the technical challenges associated with anchoring devices in very deep water.
55 The economics are discussed in detail in chapters 6 and 7.
56 Calculated using a load factor of 50%.

Tapping the first of these energy resources has advantaged the UK in energy, in jobs and ultimately in its balance of payments. Our approach to the extraction of this finite resource has been one of maximising short term gain and this is reflected in the UK's North Sea reserves that have been declining at between 5% and 10% per year since 2003[57]. Norway, by comparison, recognised at an early stage the finite nature of its oil and gas resource and invested the returns into what is now Europe's largest sovereign wealth fund[58]. This fund – originally names the Government Petroleum Fund but now titled the Government Pension Fund – is today worth $97,000 per citizen.

The annual flows of energy that would be unlocked under each of our three deployment scenarios can be compared directly with the annual energy flows from oil and gas over the last four decades, as shown in the table below.

Electricity equivalent of oil & gas

	TWh/year	Million tonnes oil equivalent / year (in 2050)[59]	Million barrels oil equivalent / year (in 2050)	RE energy in 2050 as a % of O&G in 2008	RE in 2050 as a % of O&G in 1999
Currently allocated capacity	168	37	274	27%	15%
Scenario 1	270	60	440	44%	25%
Scenario 2	610	136	994	99%	56%
Scenario 3	1,610	358	2,653	262%	147%
Total practical resource	2,131	474	3,471	347%	194%
Combined oil and gas production in 1999 (peak production year)[60]	1,096	244	1,758		
Combined oil & gas production in 2008[61]	614	136	1,000		

Annual extraction of North Sea oil and gas has fallen by nearly 40% since its peak in 1999[62]. By contrast the flow of renewable energy, once developed, can be accessed indefinitely through repowering of existing equipment. Indeed technology advances are likely to lead to a practical resource that increases in size over time rather than shrinking. There are similar implications for employment; in comparison to the 450,000 people employed in upstream oil and gas in the UK, up to 345,000 people could be employed in direct jobs in the offshore renewable supply chain by 2050 – and this could rise in future decades.

57 BP Statistical review of world energy 2008.
58 $457Billion as of 31st December 2009.
59 Conversion Factors from www.bp.com/conversionfactors.jsp
60 DECC, consistent with DUKES 2009.
61 Oil and Gas UK, consistent with DUKES 2009.
62 Digest of UK Energy Statistics, 2008.

7 Deployment Scenarios

Three deployment scenarios have been used to put the scale of the potential resource for offshore electricity generation into context and to illustrate some of the available options for offshore development. These are listed below.

- **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**

- **Scenario 2: The UK as a net exporter of electricity generated by offshore renewables**
  - **The amount of energy generated from offshore renewables is equal to total UK electricity demand in 2050 (175% of current electricity demand)**
  - **As the power generated by offshore renewables will be variable, an amount of electricity will need to be generated from sources other than offshore renewables; this will be equal to the level of offshore renewable electricity exports**

- **Scenario 3: The UK as a net producer of energy through offshore renewables**
  - **The amount of energy generated from offshore renewables is equal to total UK energy demand in 2050**

Achieving either of scenarios 2 or 3 would be a significant achievement for the UK energy sector and could generate considerable value for the UK in terms of export revenues, security of supply, reduction of emissions and growth in UK-based industry. Scenario 3 would return the UK to a level of energy exports 1.5 times larger than the peak year of North Sea oil and gas production. Under all scenarios the need for repowering wind, wave and tidal stream installations every 20 years will create a self-sustaining industry beyond 2050.

A further two outcomes could be considered as upper and lower bounds: The lower bound would see limited or no deployment of offshore renewables beyond the 48GW of sites already allocated. An upper bound would see the full practical resource developed (531GW). These are summarised in the table below.

Scenarios by technology

	Base Case (planned offshore renewables)	Scenario 1	Scenario 2	Scenario 3	Maximum resource
Total TWh/year	177	270	610	1610	2131
Total GW	51	78	169	406	531
Average Load factor	40%	40%	41%	45%	46%
Breakdown by technology (GW):					
Fixed wind	47	70	116	116	116
Wave	1	2	5	14	18
Tidal steam	1	2	9	21	33
Tidal range	1	2	6	10	14
Floating wind	1	2	33	245	350
Percentage of UK supply from variable renewables (of which offshore)[63]	36% (30%)	50% (44%)	50% (44%)	50% (44%)	50% (44%)
TWh exported /year	0	0	340	1,340	1,861

As can be seen in the figure below, the base case and scenarios 1, 2 and 3 are on the path to fully utilising the practical offshore renewable resource. Therefore the UK needs to maintain a trajectory of rapid development if it is to be able to access the option for maximising the value from this resource. The first crucial decision point is in 2016, when the pathway for scenario 1 diverges from that for scenarios 2 and 3. While it may be possible to accelerate deployment at a later stage and move away from the pathway for scenario 1 and onto the pathway for scenario 2, this will become increasingly difficult over time. A significant deviation from the pathway for scenario 3 in 2030 could mean that scenario 3 becomes unreachable.

63 15GW of onshore renewables have been included as a conservative estimate, equating to 6% of the UK electricity demand in 2050.

Scenario 1: Maximising the role of offshore renewables in meeting UK electricity demand

Reaching the maximum capacity of the UK grid would be equivalent to generating 305TWh of variable renewable electricity in 2050, or 50% of UK electricity demand. The 50% limit on the electricity supplied by variable sources through the UK grid is due to the challenges of managing periods of low supply (calm weather and seas), peak demand (cold winters) and short term fluctuations. For further detail see the chapter on variability.

Subtracting 35 TWh for onshore wind[64] leaves 270 TWh of offshore renewables – equivalent to 160 million barrels of oil every day. As this is less than the total practical resource for fixed offshore wind, and given the relative cost advantage of the technology, it is reasonable to expect that the majority of this capacity will come from fixed offshore wind. In the scenario outlined in the summary above this would require a 50% increase in the site allocations for fixed offshore wind, from 47GW today to 70GW. Wave and tidal stream site allocations would need to be increased by 233%, along with 2GW of new site allocations for floating wind and tidal range.

This scenario has the lowest average levelised cost of any of the three scenarios. This is due to two factors; firstly, the majority of the resource comes from the lowest cost technology (fixed offshore wind), and secondly the most attractive site types for each technology are developed first. While learning rates have been used to reduce the capital and operating costs as the deployment level of each technology increases, this effect is small compared to the cost increase resulting from the combined impact of technology and site-specific factors.

At this level of variable renewable generation, the UK would have maximised the benefit of offshore renewables to the UK electricity sector, but would only be using 12.5% of the practical resource.

Scenario 1 - Costs & revenue by decade

	2020	2030	2040	2050
Installed capacity	23 GW	37 GW	63 GW	78 GW
Revenue	£6.7B	£14.0B	£23.0B	£27.6B
Cost of generation	£9.2B	£12.2B	£17.0B	£19.1B
Average levelised cost per MWh	£107	£89	£76	£71
% of offshore renewable electricity on the UK grid	23%	33%	43%	44%

64 Note: All scenarios assume 15GW / 35TWh of onshore wind in the UK by 2050.

Scenario 2: The UK as a net exporter of electricity generated by offshore renewables

As outlined above, Europe faces similar challenges relating to decarbonisation as the UK. By increasing the deployment of offshore renewables to a level equal to total UK electricity demand the UK offshore renewable sector could become a net electricity exporter. Although the UK has, and will continue to need, a mix of different technologies and – in our analysis – is assumed to only absorb a maximum of 50% of electricity from variable sources, there would be additional value in exporting electricity provided that it could be sold at a high enough price (see the Valuation chapter for more detail). At this point the volume of electricity generated by offshore renewables would exceed the total electrical energy generated in the UK using imported fossil fuels, uranium and biomass. The UK's electricity-related trade balance would be positive.

Becoming a net electricity exporter would utilise 29% of the practical resource, generating 610TWh of electricity. This is likely to require utilisation of most or all of the available fixed wind resource, along with large scale deployment across wave, tidal stream, tidal range and floating wind technologies. The sites types developed at this stage will reflect current planning and government support as well as the drive to minimise levelised costs.

Scenario 3 - Costs & revenue by decade

	2020	2030	2040	2050
Installed capacity	37 GW	116 GW	160 GW	169 GW
Revenue	£11.5B	£44.0B	£59.2B	£62.4B
Cost of generation	£15.9B	£41.5B	£48.8B	£46.8B
Average levelised cost per MWh	£108	£97	£84	£77
% of offshore renewable electricity on the UK grid[65]	25%	35%	44%	44%

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

The UK has been a net energy producer in the past. At the peak of the North Sea oil and gas production in 1999, the UK was a net exporter[66]. Although our stock of hydrocarbons continues to decline, offshore renewables offer a new and sustainable alternative which would allow us to regain and retain our role as a net energy producer. Indeed, at this level of deployment our offshore renewable energy generation would be 1.5 times larger than the 1999 peak in oil and gas extraction.

To be a net energy producer indicates, in this instance, that the export of electricity generated from offshore wind, wave and tidal resources is greater than the imports

65 Total amount of variable renewables (onshore wind & offshore renewables) on the UK grid is limited by available backup / interconnection, with an upper limit of 50%. All excess power is exported.
66 BP Statistical Review of World Energy, 2008.

needed to meet the rest of our energy demands. Although the UK may remain reliant on other nations for imports (e.g. of uranium and fossil fuels), balancing imports and exports of energy would improve the UK's security of supply and energy independence.

Using current projections of energy demand in 2050, the UK will become a net energy producer when over 1,600TWh of electricity is generated from offshore wind, wave and tidal resources, requiring a total installed capacity of over 400GW. To reach this point will require an extensive deployment of floating wind in addition to most or all of the fixed offshore wind resource and contributions from wave, tidal stream and tidal range. Without large scale floating wind technology it will not be possible for the UK to become a net energy producer using offshore renewables. In total, this would utilise nearly 75% of the total practical resource.

Scenario 2 - Costs & revenue by decade

	2020	2030	2040	2050
Installed capacity	37 GW	116 GW	310 GW	406 GW
Revenue	£11.5B	£44.0B	£122.2B	£164.3B
Cost of generation	£15.9B	£42.3B	£108.6B	£140.0B
Average levelised cost per MWh	£108	£98	£91	£87
% of offshore renewable electricity on the UK grid	25%	35%	44%	44%

8 Supply Chain

The ability of the supply chain to increase capacity in the UK could not only limit the ability of the UK to benefit from the development of offshore renewables, but it could also constrain the ultimate level of resource development. While supply chain constraints are possible across all five technologies they are likely to be most acute for fixed and floating offshore wind, given the relative scale of potential development and the supply chain elements shared between the two technologies.

The development of the fixed offshore wind supply chain has been slow, both in the UK and across Europe. There are only two manufacturers making offshore wind turbines at scale (Siemens and Vestas), and there is a shortage of suitable vessels to install these turbines. However there are signs that both these constraints may ease in the coming years. For example, RePower, Multibrid and BARD have started producing offshore wind turbines, and three additional manufacturers are expected to bring products to market in the coming years (Clipper, GE, Mitsubishi). China has also instructed its domestic manufacturers to start developing offshore wind turbines as part of a plan to install 30GW of capacity by 2020. Orders have also been placed for between 5 and 10 installation vessels, which will be purpose-built for offshore wind work.

In an assessment of the potential deployment of Round 3 The Crown Estate has estimated a maximum annual deployment of approximately 7.5GW of offshore wind in 2018, with an average rate above 4GW per year between 2015 and 2020[67]. This would result in the vast majority of Round 3 sites being built by 2022. The European Wind Energy Association forecasts that offshore wind will follow a similar growth trajectory to onshore wind[68], with annual installations rising to 7GW per year by 2020, although this covers Germany, the Netherlands and other European markets as well as the UK. For simplicity's sake we have used a maximum annual build rate of 5GW pear year for fixed offshore wind, equivalent to just under two 7.5MW turbines per day or three 5MW turbines[69]. This could be achieved by ten turbine installation vessels each installing one turbine per day for 100 days a year, and ten foundation installation vessels operating at a similar rate (year-round installation is generally not possible due to weather conditions). At this rate, the full UK practical resource for fixed offshore wind could be developed by 2037.

If the UK's offshore renewable resource were to be developed to its maximum practical capacity, floating offshore wind turbines would need to be deployed at a much greater scale than any of the other four technologies. Assuming that the first GW of floating wind is deployed by 2020 and following an aggressive growth trajectory similar to that experienced by the onshore wind industry – a 30% annual growth rate – the deployment rate would reach 20GW in 2037. Installations would then need to be maintained at this level to deliver the full practical resource for floating offshore wind (350GW) by 2050.

This level of deployment is double the current installation rate for onshore wind across the whole of the EU, and may not be achievable in practice. Although vessels may not

67 Crown Estate, Supply Chain roadshow event, March 2010.
68 The EU onshore wind industry grew by an average of 30% per year between 1995 and 2005.
9 The largest offshore wind turbine currently available is a 5MW RePower machine, although manufacturers such as Clipper are working on larger designs.

be a constraint as floating wind turbines are unlikely to require specialist vessels when they are towed out to sea, other constraints could include insufficient deep water ports and material shortages. As the development of floating wind technology progresses it will become easier to estimate the likely constraints and to develop ways in which these could be addressed.

To get an idea of the scale involved in installing 20GW per year we can draw some useful comparisons with other UK industry sectors. Assuming each MW of floating wind requires 600 tonnes of steel, 12 million tonnes of steel would be required each year[70]. This is equal to 80% of UK steel demand in 2007, or nearly twice the level consumed by the engineering and construction industries. The number of people who would be employed in installing 20GW per year – approximately 200,000 – is half of the size of the UK upstream oil and gas industry[71] and similar to the total automotive workforce[72].

A summary of the direct jobs for each technology is shown below, under scenarios 1, 2 and 3. This includes people working in installation, operation and maintenance but excludes jobs elsewhere in the supply chain.

Scenario 1, 2 & 3 - Direct Jobs by technology

	Scenario 1	Scenario 2	Scenario 3
Fixed wind	65,000	102,000	102,000
Tidal stream	~2,000	8,000	19,000
Wave	~2,000	4,000	4,000
Tidal barrage	~1,000	2,000	3,000
Floating wind	~2,000	29,000	214,000
Total	71,000	145,000	342,000

As noted in the following chapter on costs, if a UK-based supply chain can be put in place for Round 3 it could save the UK as much as £15 billion in upfront investment by reversing the recent negative impact of exchange rate changes on the cost of offshore turbines and grid equipment. In order for this supply chain to be ready in time, government action is required now to promote investment in ports, factories and other supporting infrastructure. The UK will also be competing with other countries to create a domestic offshore renewable supply chain, such as Germany, Denmark, the Netherlands and China.

70 Average volume of steel per MW across four floating technologies: Hywind, Sway, Blue H, Wind Float.
71 According to Oil and Gas UK, industry employment is approximately 450,000 people.
72 The Department of Business, Innovation and Skills estimates that the UK automotive industry employs 180,000 people.

9 Cost

Methodology

A similar approach for forecasting levelised costs has been used for all technologies. Assumptions have been made on global deployment for all technologies, which are used as the basis for applying learning rates. Learning rates – defined as cost reductions that occur every time cumulative installed capacity doubles – have been applied from 1/1/2010 for fixed offshore wind, from 1/1/2020 for floating offshore wind, tidal stream and wave, and from 1/1/2030 for tidal range (the date at which 1GW of capacity for each technology is assumed to be installed). For wind these learning rates have been applied to individual cost components; for tidal stream, tidal range and wave power these have been applied to the overall levelised cost. Repowering of the relevant technologies has been included based on a 20 year lifetime for all technologies with the exception of tidal range, which has a lifetime of 50 years. A single discount rate of 10% has been used across all technologies.

Overall learning rates by technology

Technology	Load Factor	Date at 1GW capacity	Learning rate	Lifetime	Sources for initial estimate
Fixed offshore wind	35-44%	-	<10%	20 years	Carbon Trust
Floating wind	35-40%	2020	<10%	20 years	Carbon Trust
Tidal stream	40%	2020	10%	20 years	BERR DECC
Wave	25%	2020	10%	20 years	BERR DECC
Tidal Barrage	30%	2020	10%	20 years	BERR DECC

Fixed offshore wind costs have been forecasted based on a detailed site segmentation using the 48 site types described above (Three depth categories [0-20m, 20-40m and 40-60m], four distance from shore categories [0-12nm, 12-30nm, 30-60nm and 60nm+], four wind speed categories [<700W/m2, 700-800 W/m2, 800-900 W/m2, >900 W/m2]). The analysis used an updated version of the cost model used for the 2008 Carbon Trust report "Offshore Wind: big challenge, big opportunity". The site-specific costs calculated for 2010 were calibrated using publicly available cost data and interviews with industry experts.

Capital costs for fixed offshore wind increased by 26-33%[73] between 2008 and 2010. The majority of this rise can be accounted for by the fall in the value of the pound against the Euro, as turbines, cables and substations are not manufactured in the UK and are generally priced in Euros. Once this effect has been removed, underlying capital costs have increased by only 4-7% since 2008. This could be due to a shortage of manufacturing capacity and vessels over the period, rising energy and commodity costs, or increases in the underlying cost profile of offshore wind.

Going forward we have assumed no major changes in commodity costs or the underlying cost profile of offshore wind. Changes in energy prices are reflected in our

73 Range of cost increases across the 48 modelled site types.

electricity price scenarios, but the impact of high fossil fuel prices on the capital costs of alternative technologies and thus on the competitiveness of offshore renewables has not been taken into account. Crucially we have assumed that the negative effect of the falling pound over the last two years can be offset in the next decade through an expansion of the UK supply chain (helped by the decisions of GE, Siemens and Mitsubishi to build offshore turbine factories in the UK). If the pound regains some or all of the value it has lost against the Euro this will also help to reduce the cost of offshore wind.

Although the overall learning rate for fixed and floating offshore wind is less than 10% (when calculated based on the deployed capacity for each of the two technologies) several of the individual learning rates applied to the cost components are over 10%. This effect comes about because the learning rate for offshore wind turbines – the largest cost component – is based on the global volume of offshore and onshore turbines. Therefore the cost of an offshore turbine is assumed to decrease by 15% every time the global installed base of onshore and offshore turbines doubles. Because the onshore wind market is expected to grow at a slower rate than offshore wind in the future, this results in an effective learning rate for offshore wind of less than 10%.

An analysis of the relevant literature suggests a learning rate of 10-19% for onshore wind turbines[74], although in recent years rising commodity prices have made it difficult to estimate the underlying cost reductions that have been achieved through mass production, design improvements and new materials. The learning rates used for the cost components of fixed and floating offshore wind are shown below.

Learning rates for fixed & floating wind

Cost component	Experience curve	Driver
Turbine	15%	Onshore and offshore installations
Foundations	10%	Offshore installations
Grid connection:	5%	Offshore installations
Cables: HVAC	10%	Offshore installations
Cables: HVDC	15%	Offshore installations
Substations: HVDC	10%	Offshore installations
Substations: Offshore AC	10%	Offshore installations
Substations: Onshore AC	10%	Onshore and offshore installations
Installation	15%	Offshore installations
Opex	15%	Offshore installations

74 Neuhoff and Coulomb (2006), Junginger and Faaij (2004), Lako (2002).

Tidal stream has been modelled based on three achievable power densities (5MW/km$_2$, 5-18MW/km$_2$ and 18-30MW/km$_2$). Site-specific calculations were not possible given the lack of publicly available data on both the resource characteristics and the costs of different devices. Therefore high, middle and low cost estimates were mapped to each of the three power density categories as an approximation in place of a site-specific segmentation. Only the two most attractive of these site types were assumed to be practical by 2050, equating to a total resource of 116TWh, of which 33TWh is in the lowest cost category.

Wave has been modelled as a single site type. This is for two reasons: Firstly, the technology is at a similar stage of development as tidal stream and therefore detailed and reliable cost data is not available. Secondly, there is no standardisation among the wave devices in development (unlike offshore wind and, to some extent, tidal stream). Rather than pick a certain technology over other options we have treated all wave devices equally and assumed that the winning design or designs will be able to extract the full practical resource.

Tidal range has been estimated on a site specific basis, as the top 5 site types constitute 26TWh out of the entire practical resource of 36TWh. These top 5 sites are the Severn, Solway Firth, Morecambe Bay, Wash and Humber. The remaining resource is assumed to be equal in cost to the most expensive of these five, given that there are likely to be diseconomies of scale for smaller schemes. The Severn is assumed to be the site most likely to be developed given the planning already done. However, it is assumed that it will not be in operation until 2030 due to planning constraints and the time taken for construction.

Floating offshore wind has been modelled using 20 site types varying with distance from shore and wind speed. The cost model is similar to the fixed offshore wind model, except that a provision has also been made for sites that are more than 100nm offshore[75]. Foundation costs have been estimated using a bottom-up calculation based on the expected size and weight of the structure, and corroborated with expert interviews.

Initial cost estimates

Initial cost estimates for different technologies were taken from published literature and expert interviews; further information can be found in the appendix. Table 2 below shows the initial cost estimate used in the study.

75 A similar adjustment for fixed offshore wind was not necessary as the resource does not extend as far offshore.

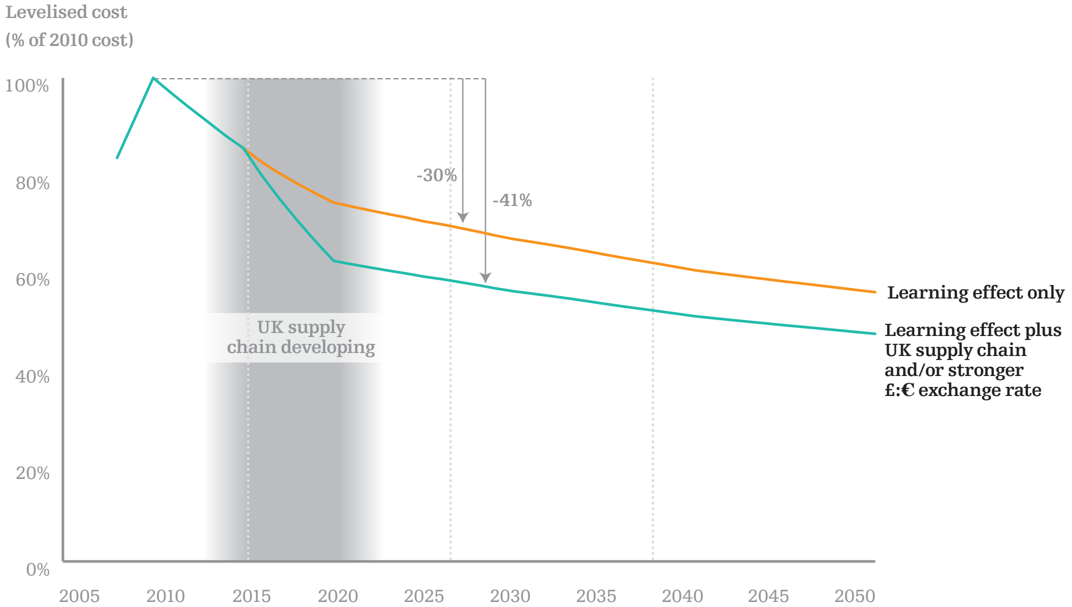
Initial cost estimates for Wave, Tidal Stream and Tidal range

Levelised cost (£/MWh)	Low	Central	High	Year
Wave	150	195	247	2020
Tidal Stream	135	179	241	2020
Tidal Range:				
- Severn	127	172	214	2030
- Shoots	150	204	253	2030
- Welsh Tidal	187	254	316	2030
- Beachley	107	146	182	2030
- Bridgewater	178	242	301	2030
- Other sites	187	254	316	2030

Exchange rate fluctuations between the euro and sterling also have an important impact on levelised costs for fixed and floating wind. The majority of the observed cost increase between 2008 and 2010 can be explained by the falling value of the pound against the Euro; stripping out this effect shows that underlying capital costs have increased by only 4-7%.

Going forward two factors could reverse the impact of the weakened pound. The first is for the exchange rate to return to 2008 levels, while the second is for a UK supply chain presence to develop which could in turn offset a share of the observed cost increase. Our cost models for fixed and floating wind assume that this effect will have dissipated by 2020, reducing levelised costs by approximately £16/MWh and reducing capex by £0.4-0.5m/MW. If a UK supply chain alone could deliver this saving, it would create £15bn of value over the course of Round 3 deployment.

Impact on 2008-2010 exchange rate on cost reduction of typical fixed wind site



Summary

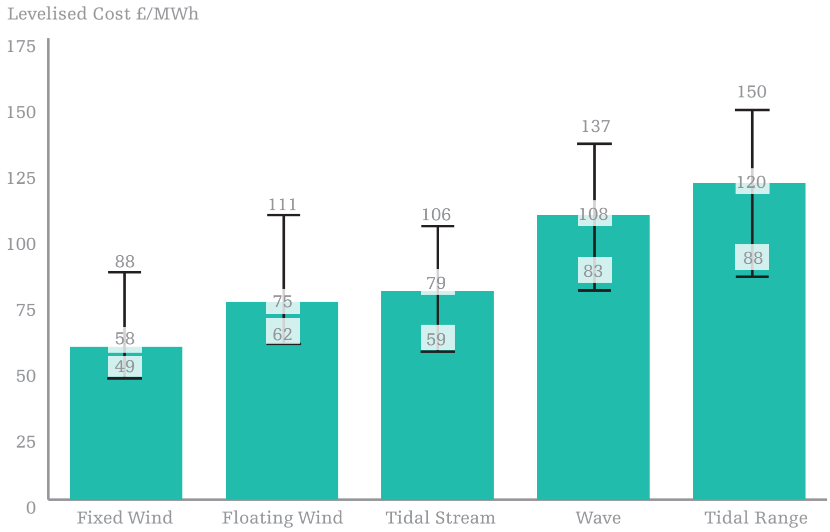
Fixed wind has a cost advantage due to being commercialised earlier than the other technologies, and the sharing of some components and expertise with onshore wind. Floating wind is expected to benefit in a similar manner, both as a result of existing onshore and fixed offshore wind supply chains.

Tidal stream appears to be the next most competitive technology, with the best sites becoming comparable with wind around 2030. Current tidal stream devices share design principles with wind, if not actual components, and therefore may benefit indirectly from a growing wind supply chain.

In our central scenario wave is not expected to be cost competitive with wind by 2050. The size of the resource limits the ability for cost reduction through learning, although given that a preferred technology has not yet been settled upon it is entirely possible that innovation could reduce costs to a level where wind and wave are similarly economic.

Tidal range schemes by their very nature offer limited opportunities for cost reduction through learning, as each one is essentially a large one-off project. As a result schemes are likely to be developed using criteria other than a cost comparison with other offshore renewables.

Summary of 2050 cost estimates for marine technologies



The chart above shows 2050 costs for each technology in the central scenario, along with the likely cost range given the economics of different site types and the uncertainty inherent in such long term forecasting.
The lowest cost sites for wind (both fixed and floating) are generally 12-30nm from shore; closer to shore sites suffer from a lower wind speed, while further offshore sites are impacted by the increased costs of grid connection and operation & maintenance.

Given the site specific nature of the costs and the overlap, the next step is to find the pathway to the deployment targets based on minimising cost.

Least cost deployment optimisation: A walk through the decades

We have combined our cost estimates for each technology and site type to identify the least cost pathway to achieve each of the three scenarios outlined above. For simplicity costs are reported at the midpoint of each decade. For each decade we show the cost of any offshore renewables already installed at the start of the decade, as well as the additional offshore capacity that would need to be deployed in that decade to achieve the scenario. For each technology the lowest cost sites are developed first.

The deployment picture for 2010-2020 is similar for all three scenarios but then diverges over time and become increasingly different under each scenario.

Scenario 1

78 GW; 13% of practical resource, 50% UK electricity Demand in 2050

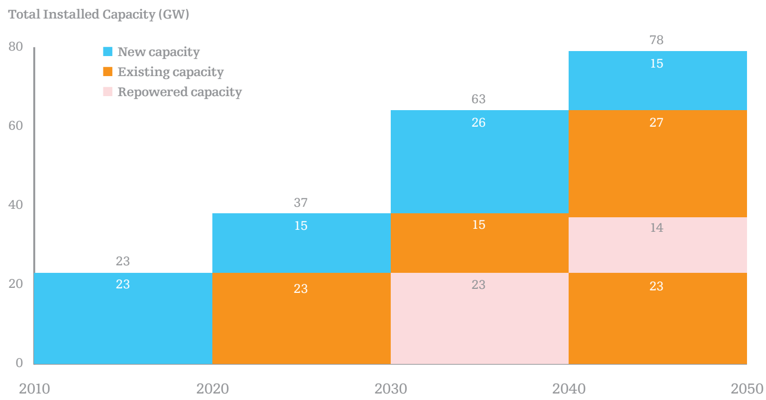
Maximising the role of offshore renewables in meeting UK electricity demand

Between 2010 and 2020, development will focus on Rounds 1, 2 and 3. Rounds 3 sites are typically more expensive sites due to the greater distance from shore and depth. With the level of deployment illustrated in the charts below, variable electricity from onshore and offshore renewables will exceed 25% of UK electricity demand by 2020, so steps to ensure variability can be managed are important even in the short term.

Between 2020 and 2030 fixed wind will continue to be the lowest cost technology, with a levelised cost range of £70-80/MWh. Floating wind, tidal stream and wave technologies are also deployed in this decade in order of increasing cost. By 2030 variable renewables will account for 40% of UK electricity generation.

From 2030-2040, the deployment of fixed wind continues although costs are similar to those in the previous decade, as the effect of learning is offset by the increased costs of more expensive sites. By the end of the decade, deployment has meant the UK has reached its 50% constraint of variability. Repowering will be starting to take place as the capacity built between 2010 and 2020 reaches the end of its 20 year lifetime.

From 2040 onwards, the final fixed wind sites are deployed and repowering has taken place for the first sites to be developed, reducing costs significantly.



Average build rate (GW/year)	2010s	2020s	2030s	2040s
Fixed wind	1.8	1.1	4.3 (1.8)	2.5 (1.1)
Floating wind	0.1	0.1	0.1 (0.1)	0.1 (0.1)
Tidal stream	0.1	0.1	0.1 (0.1)	0.1 (0.1)
Tidal range	0.1	0.1	0.1 (0.1)	0.1 (0.1)
Wave	0.1	0.1	0.1 (0.1)	0.1 (0.1)
Total	2.2	1.5	4.7 (2.2)	2.9 (1.5)

Least cost deployment to 2050

Scenario 2

169 GW; 29% practical resource; net electricity exporter in 2050

The UK as a net exporter of electricity generated by offshore renewables

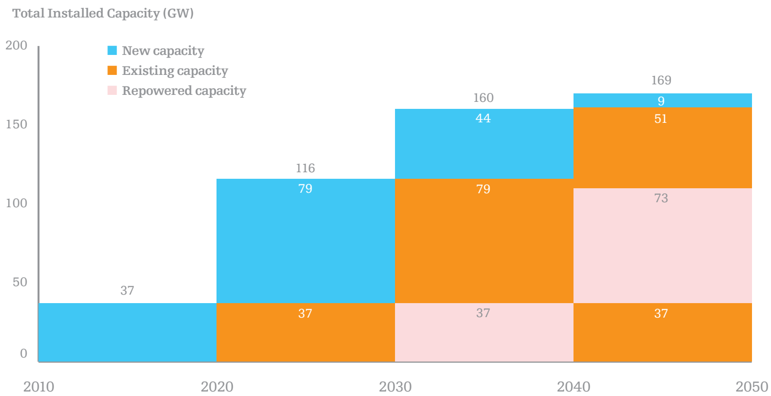
To become a net exporter of electricity, the deployment pathway is considerably more aggressive than in scenario 1. The deployment assumptions for each decade are based on the constraints of interconnection, variability and demand as detailed elsewhere in the report.

Between 2010 and 2020, a greater amount of fixed wind sites must be deployed from licensed sites than under scenario 1.

Between 2020 and 2030, fixed wind continues to be developed rapidly, alongside the best floating wind and attractive tidal stream sites. In this decade the UK begins to export electricity to Europe, as the installed base of variable renewable electricity moves above the 40% limit in 2030.

Between 2030 and 2040, additional fixed and floating wind sites are developed with costs in a similar range to the previous decade (£70-90/MWh). Tidal stream is now cost competitive with fixed and floating wind for the most attractive sites.

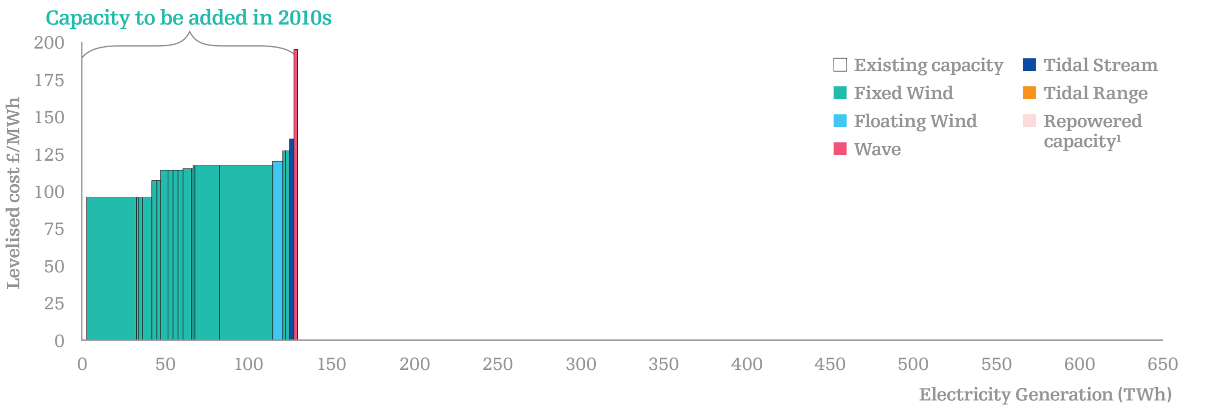
After 2040, there is a small amount of floating wind deployment remaining. Repowering has taken place and reduced the cost of fixed offshore wind capacity to as low as £60MWh.



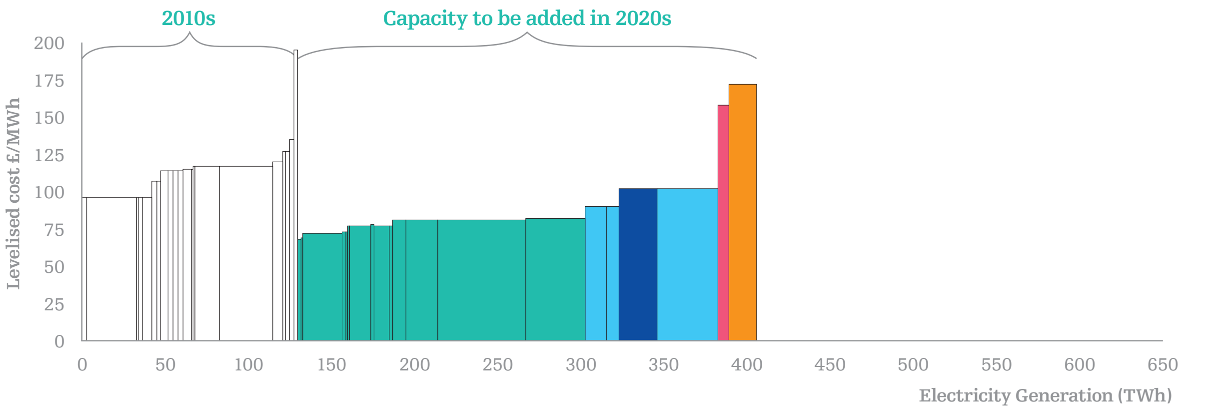
Average build rate (GW/year)	2010s	2020s	2030s	2040s
Fixed wind	3.2	5.0	6.5 (3.2)	5.0 (5.0)
Floating wind	0.1	1.3	1.0 (0.1)	2.2 (1.3)
Tidal stream	0.1	0.7	0.3 (0.1)	0.7 (0.7)
Tidal range	0.0	0.6	0.0	0.0
Wave	0.1	0.6	0.1 (0.1)	0.3 (0.3)
Total	3.5	8.2	7.9 (3.5)	8.2 (7.3)

Least cost deployment to 2050

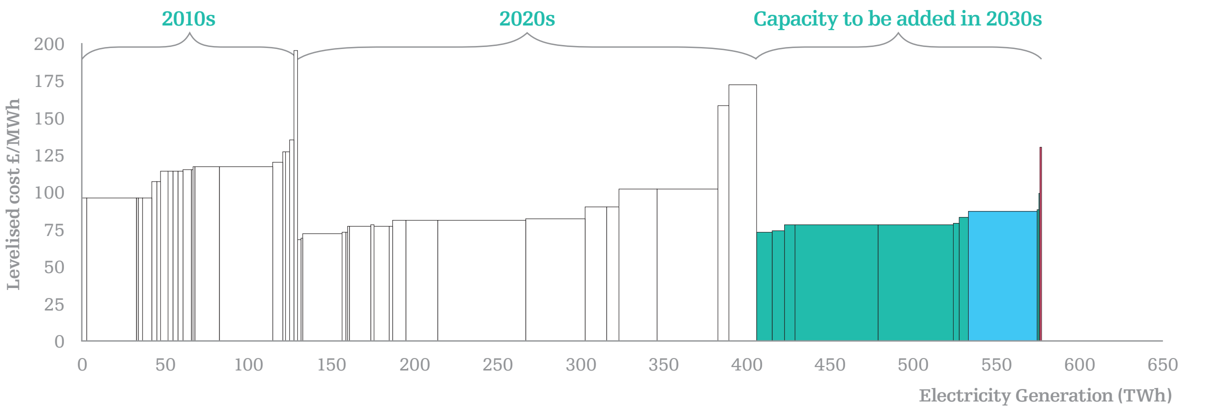
2010



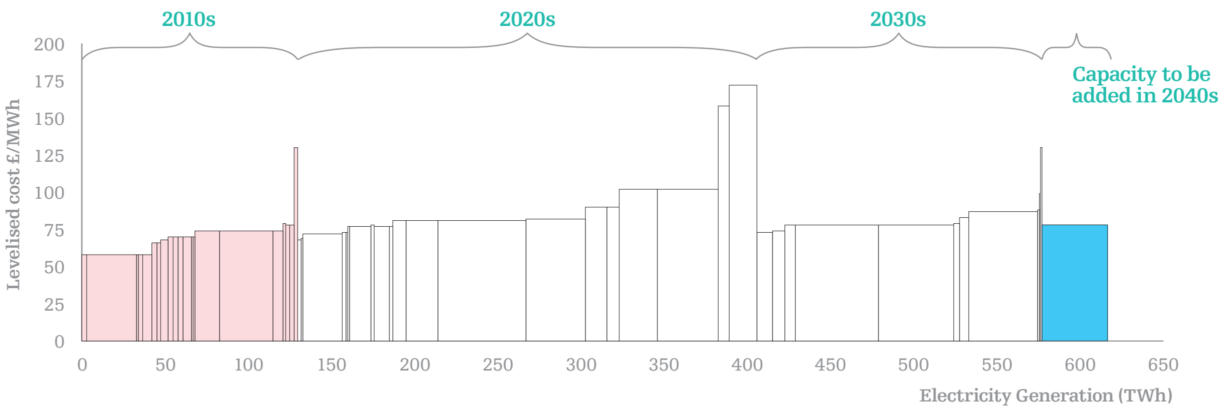
2020



2030



2040



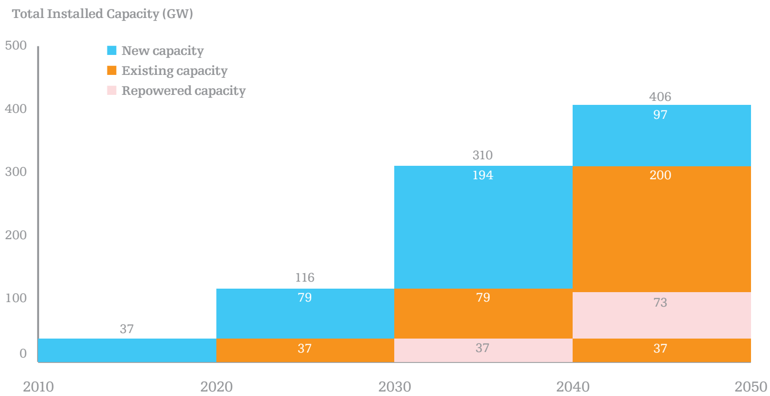
2050

Scenario 3

406 GW; 76% of practical resource; net energy producer in 2050

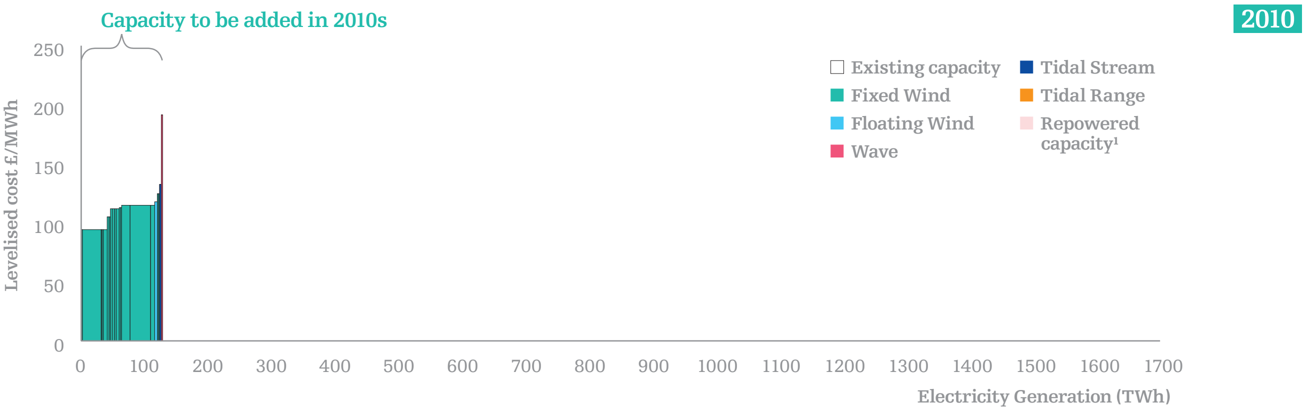
The UK as a net energy producer through offshore renewables

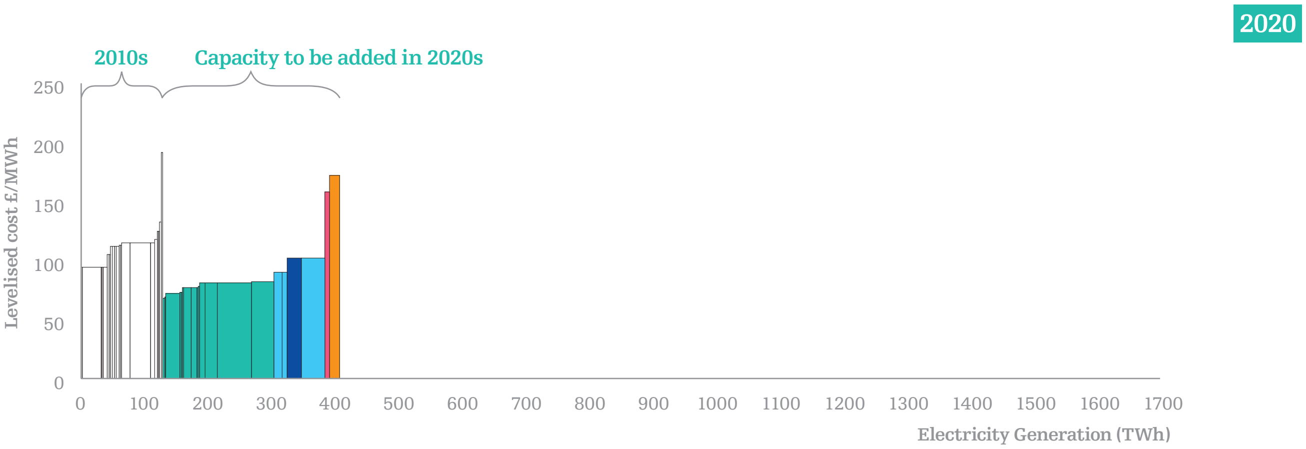
To become a net energy producer, the same path is followed as under scenario 2, up until 2032. At this point in scenario 2 the deployment rate for new capacity slows markedly, and any new deployment is primarily a result of growing electricity demand. In scenario 3 the deployment rate accelerates in the 2030s, increase from 10GW per year in 2030 to more than 20GW per year by 2040. This is achieved through an aggressive expansion of floating offshore wind, tidal stream, tidal range and wave power. Floating offshore wind costs from £84/MWh to £90/MWh.

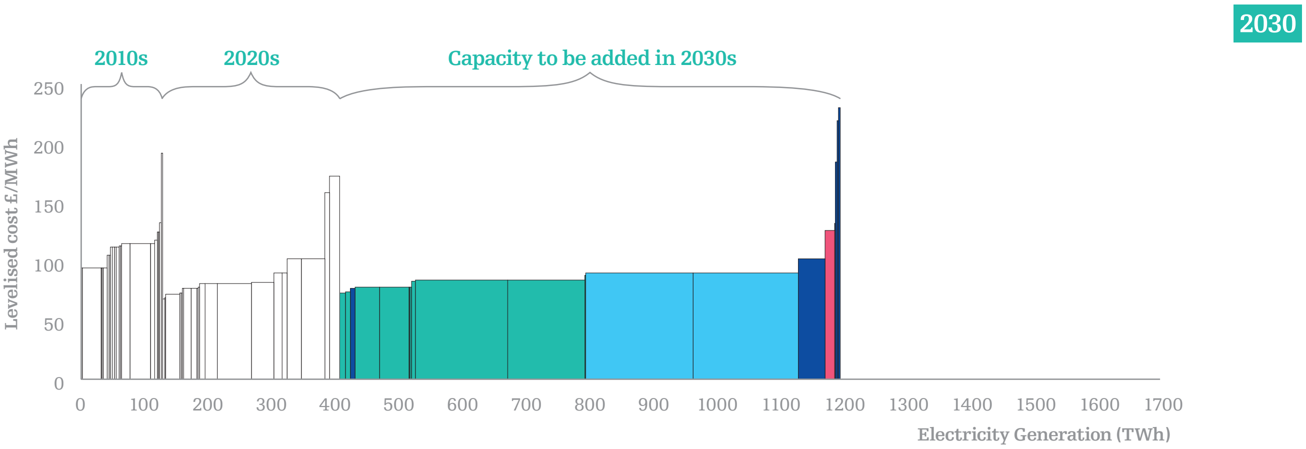


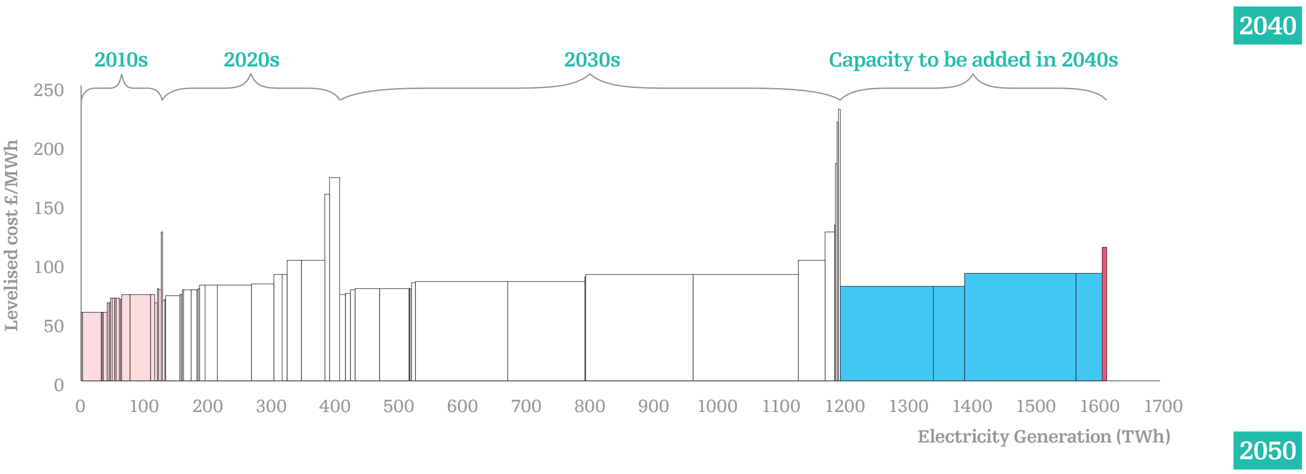
Average build rate (GW/year)	2010s	2020s	2030s	2040s
Fixed wind	3.2	5.0	6.5 (3.2)	5.0 (5.0)
Floating wind	0.1	1.3	13.8 (0.1)	10.7 (1.3)
Tidal stream	0.1	0.7	1.5 (0.1)	0.7 (0.7)
Tidal range	0.0	0.6	0.4 (0.0)	0.0 (0.0)
Wave	0.1	0.3	0.8 (0.1)	0.6 (0.3)
Total	3.5	7.9	23 (3.5)	17 (7.3)

Least cost deployment to 2050









Summary

The key finding from these optimisation pathways is that the costs for offshore wind will stabilise in a region of £70-90/MWh from the mid-2020s, due to the opposing effects of learning and moving to more expensive technologies and sites. Fixed wind will generally be deployed before other technologies due to its initial and sustained cost advantage. Floating wind will become increasingly important in later decades as the UK moves towards becoming a net electricity and even a net energy producer. Tidal stream will become comparable with wind for the most attractive sites from 2025 onwards.

Repowering has an impact after 2030, and repowered existing sites will typically have a lower levelised cost than new sites. After 2050, when no further new capacity is being deployed, repowering will result in a self-sustaining industry.

The period from 2020-2030 onwards is a critical decade. The scale of the deployment will determine the path forward and the ability of the UK to maximise the value of the offshore resource. The rapid deployment in this period required to allow the UK to become a net electricity exporter will not result in any significant cost penalty compared to scenario 1. Issues of grid and variability will therefore be greater constraints than cost, highlighting the importance of planning for interconnection to allow the UK to begin exporting electricity.

Costs in context - energy return on energy invested

Long range cost forecasting is sensitive to many variables and assumptions. A useful additional metric to the cost estimates above is that of energy return on energy invested (EROEI). EROEI is a measure of the ratio of energy output to energy input and is an indicator of the relative value of investing in energy producing technologies. For example, if extracting ten barrels of oil requires the amount of energy contained in one barrel of oil, then the oil has an EROEI of 10. If the EROEI drops below one then the energy production process becomes unsustainable.

A review of published EROEIs – summarised below – shows that offshore renewables typically have a high EROEI, while fossil fuels have much lower values[76]. Energy spent on developing renewables is therefore a way of generating higher returns from our finite pool of energy resources than through investing in fossil fuels. This implies that, over the long term, electricity generated from renewables could be more cost-effective than conventional (fuelled) sources of energy.

76 oCo Carbon, 2010

Energy return on energy invested

Technology	Average EROEI	Number of studies reviewed
Tidal range	116	1
Wind	25	108
Tidal stream	17	1
Wave	12	2
Nuclear	11	50
Concentrated Solar Power	10	7
Photovoltaics	8	45
Coal power[77]	5	10
Gas power[78]	3	6

77 Average estimated EROEI for coal with CCS = 2
78 Average estimated EROEI for gas with CCS = 1.5

10 Financing

Financing the development of the UK's offshore renewable resource will require investment in multiples of ten billion pounds, even if no more sites are awarded on top of the 48GW allocated so far. The table below shows the total capital investment by decade for each of the three deployment scenarios (excluding repowering).

Scenario 1, 2 & 3 - Capital investment by decade

Capital investment (£ billion)	2010-2020	2020-2030	2030-2040	2040-2050
Scenario 1	£59B	£30B	£53B	£28B
Scenario 2	£102B	£198B	£119B	£24B
Scenario 3	£102B	£198B	£458B	£235B

If funding is not available at these levels it will constrain the growth of the UK offshore renewable industry.

In the short term, the hangover from the credit crunch will continue to limit the availability of capital for projects such as offshore renewables. However the completion and production risk components will lessen over time as more projects are built, and the financial markets are able to see positive track records for both installation and energy production. In all our levelised cost calculations we have assumed a constant discount rate of 10% for all technologies – and therefore implicitly assumed a constant risk profile over time – but it is possible that the discount rate required by developers will reduce over time as the technologies mature.

This technology maturity should be accompanied by a maturity in the financing mechanisms for offshore renewables. Development and construction costs will be financed by a combination of developer balance sheets, third party equity, and potentially public private programme structures (PPP's) but once sites have been in operation for a period of time it should be possible to refinance with a much greater share of lower cost debt (for example from pension funds or long term infrastructure investors). This will then release equity for developers to invest in subsequent projects.

Not all of the risks associated with offshore renewables will decrease over time. Firstly, the expected scale of offshore projects means that a single underperforming project could seriously undermine the financial health of even a large company. Secondly, renewables rely directly and implicitly on government actions, such as adherence to long term carbon reduction targets and carbon trading schemes. This introduces a level of government risk that the financial markets will price into the cost of financing. Thirdly, projects are exposed to market prices for electricity that over the longer term may be significantly affected by the amount of renewables on the system. Electricity prices in countries with high wind penetration such as Denmark and Spain have already fallen to zero on occasions when demand has been exceptionally low and the wind is blowing strongly[79]

79 Note: In the long term this effect may result in a higher average price being achieved for a unit of power generated from tidal or wave power than for a unit of wind power.

Long term finance

Institutional UK pension fund assets were worth approximately £1,200 billion at the end of 2009[80]. If an amount equal to one percent of this was allocated to offshore renewables each year, it could finance over 200GW of capacity by 2050. The return on this investment – assuming a perpetual bond with a rate of return of 5% – would provide an income to UK pension funds of more than £500 billion over four decades. The lifetime of a typical offshore renewable project is also a particularly good match for the time horizon of a pension fund investment.

The Housing Finance Corporation (HFC) provides a working model for very low risk infrastructure finance in the UK that avoids increasing the size of the Treasury balance sheet. The bonds issued by the HFC are highly rated for two key reasons: the principle is underpinned by real assets in the forms of bricks and mortar, and bond servicing costs guarantee regular rental payments, largely paid directly as housing benefits by the government. There is a parallel with the renewable energy sector in that 'energy bonds' would be backed by real assets, in this case steel, copper and concrete, and the returns would be underpinned by electricity sales – currently augmented by the government-backed Renewables Obligation.

New sources of finance

Given the importance of offshore renewables to the government's long term climate and energy security goals, and the desire to minimise the cost to the consumer, there also may be a more direct role for government in reducing the financing risk in both the short and long term. Further work is required to assess the optimal solution or solutions, but one option is for the government to take an active role in the financing of offshore renewables. This could be similar to the co-investments in Round 3 proposed by The Crown Estate, or – as has already been suggested – it could be a central role for a UK Green Investment Bank.

Taking the concept of the Green Investment Bank (GIB) one step further, it could be used to open the door for ordinary people to invest in offshore renewables. Energy Bonds or Green Energy ISAs could be offered to the public through the GIB, with the proceeds invested not only in offshore wind farms but also in the offshore supply chain or in other renewable technologies. The population of the UK would then have the ability to invest directly in securing the country's low carbon future.

80 Towers Watson, Global Pension Assets Study 2010

11 Variability

Variability as a constraint

There is an extensive body of work in the field of variability, covering the potential impacts, costs and possible solutions. The majority of this work focuses on the near term, looking at levels of between 10-30% variable renewables on the UK system by 2020. There are limited quantitative studies looking out to 2050, and no detailed analysis of the UK's ability to absorb variable renewables over the long term. Therefore in order to determine an appropriate value for the maximum penetration of variable renewables in 2050, existing literature was used to understand the role of variability as a constraint. This was then combined with information on the actual experiences of countries with high penetrations of variable renewable energy.

This chapter is split into four sections; part (i) summarises the major impacts of variability, looking at the characteristics of each offshore technology and their impact on the grid. Part (ii) identifies a portfolio of solutions which have the potential to mitigate the impacts of variability and estimates when these options will be available. Part (iii) aims to identify the maximum penetration of variable renewables which can be absorbed by the UK grid in 2050. Part (iv) uses this proportion to estimate the levels of interconnection which are likely to be required.

i. Impacts of variability

There are numerous reported impacts of variability, which range from the technicalities of connection at grid periphery to the high level impacts on electricity prices. The starting points for this report are the primary impacts of variability, i.e. those which occur as a direct result of a fundamental difference between variable renewables and conventional thermal generation. A secondary impact occurs only as a result of a primary impact. For example, the primary impact of increased penetrations of variable supply is the increased uncertainty on the system, which requires additional balancing actions. There are numerous secondary impacts, for example the reduction in load factor of thermal plant; which may have to operate more as peaking plant to follow load, this has tertiary impacts on the electricity price, as thermal generation attempts to recover fixed costs in shorter time periods.

Fundamental differences between variable renewables and conventional thermal plant have resulted in three primary issues, shown below. These are likely to restrict deployment of variable renewables without significant modification of the existing system.

The variability characteristics of wind, wave and tidal are summarised in the figure below. Note that tidal stream and tidal range technologies do not increase the need for short term balancing actions, as the resource is predictable. In addition, a portfolio of tidal sites spread around the UK would benefit from a spread of high tide times across locations, resulting in a power output with lower variability than that from a single location. A similar effect would result from a broad geographic spread of offshore wind sites, wave power locations, and from a portfolio of different offshore renewable technologies.

Three most important impacts of variable renewables

A Increased supply uncertainty	• Mid & short-term fluctuations in wind output lead to increased difficulty in real-time matching of load and supply (balancing). • Requires additional balancing services to cope with the increased level of uncertainty • Need to analyse increased impacts associated with short-term uncertainty in supply as part of the entire system
B Decreased reliability (peak)	• An increase in varRE increases the size of the system margin required to maintain the LOLP , as the output from RE is less likely to correspond with peak demand Quantified in terms of capacity credit ; which decreases as penetrations of varRE increases the amount required can be reduced if the capacity credit is increased. • Typically referred to as 'backup' or 'reserve margin'
C Increased Congestion	• Congestion occurs when the transmission or distribution capacity restricts the ability to transfer power into or out of a region • One major consequence of congestion is curtailment • Congestion already a problem between North & South; Wind connection in Scotland is restricted due to insufficient transmission capacity across the Scottish border; in 2007, 16GW of wind awaited connection

ii. Managing the primary impacts of variable renewables

A. Increased Supply uncertainty

Currently, system uncertainty is dominated by uncertainty in demand and even with relatively high levels of variable renewables any additional uncertainty is likely to be manageable in the short term. The UK has robust methods in place to manage system uncertainty, including sophisticated forecasting techniques, balancing services; which include contracts with appropriate generators for response, reserve, black start and reactive power[81].

It should be noted that the UK's Transmission system operator, National Grid Company (NGC) do 'not think it likely that there will be a technical limit on the amount of wind that may be accommodated as a result of the short term balancing issues, but economic and market factors will become increasingly important'[82]. The cost of these additional contracted balancing services, for penetrations of up to 20%, is reported to be in the range £2-4/MWh of installed variable output[83].

81 For a full description of the balancing services refer to National Grid's most recent Severn Year Statement.
82 National Grid - SYS 2009.
83 Gross et al, (2006) The costs and impacts of intermittency – looked at over 200 studies and consolidated the currently available work. This has been cross checked with more recent reports including Milborrow's 2009 report 'managing variability' and IEA's wind report in 2009.

B. Decreased reliability

Uncertainty is indirectly managed by the presence of a capacity margin, which is historically maintained at around 20%. In addition the market should signal if there is necessity for increased margin or peaking plant through indicators such as imbalance price spreads and the value of balancing and other long term contracts.
To ensure the system remains reliable, peak demand should not exceed the production capacity of installed generation. Reliability can be characterised statistically by indicators such as the commonly used Loss of Load Probability (LOLP). The LOLP is a measure of the likelihood that the peak load will not be met, and in the UK is ~9%. An increase in variable generation increases the size of the system margin needed to maintain the LOLP; as the output from RE is less likely to correspond with peak demand[84]. This additional capacity margin has associated costs; reported to be between £3-5/MWh for penetrations of less than 20%[85].

C. Increased Congestion

National Grid has acknowledged that the current network is inhibiting new generation from being built in Scotland and have reported that 'it is unlikely that they will be able to connect any new applicants in the next seven years'[86]. Wales also has limited grid capacity running between its western coast and the major demand centres in England. Reinforcing the network and alleviating congestion is generally more cost effective than curtailing local generation. The Electricity Network Strategy Group (ENSG) have found that if the local network can accommodate 90% of the total variable renewables output, the cost of the 10% of output that is curtailed would be around £5-7M per year per GW of installed wind. However there is increasing concern regarding the costs of constraint and congestion (Cook, 2009) and recent estimates have suggested transmission upgrades alone will be around £4.7 Billion by 2020[87].

An offsetting effect will come from the development of wave and tidal technologies in tandem with wind. Although wave and tidal are likely to comprise a smaller share of generation than onshore and offshore wind, the power that they generate will be largely uncorrelated with wind[88]. This will result in an output of electricity from offshore renewables that is less variable than under a pure wind generation scenario[89]. In addition a geographic spread of sites for any given technology will act to smooth variations in electricity production from any one site.

Managing impacts of variable renewables in 2050

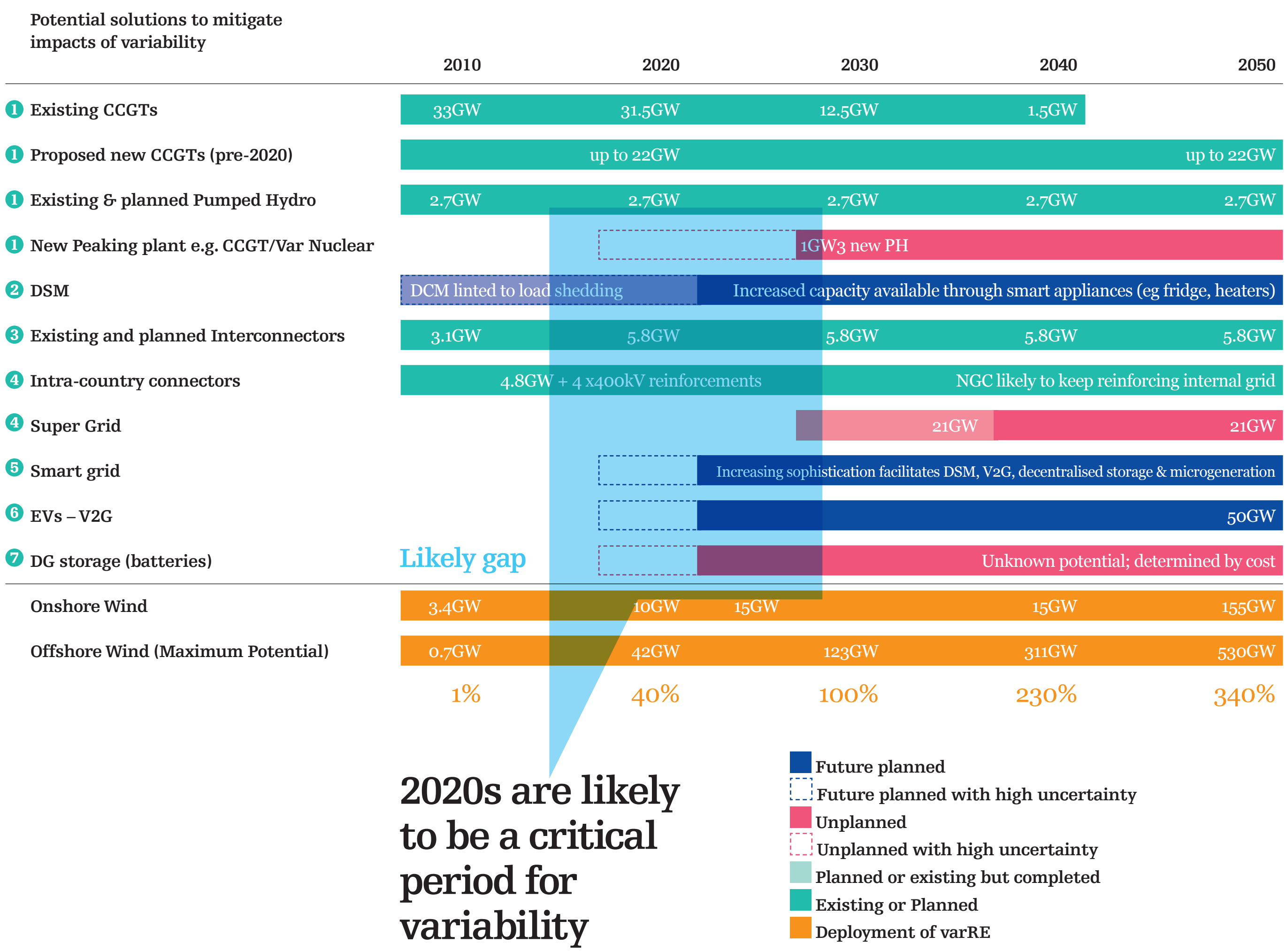
Many potential solutions to the impacts of variability have been identified including but not limited to flexible plant (new and existing), Demand Side Management (DSM), intra-country connectors, inter-country connectors, smart grids, electric vehicles (using either variable charging or vehicle to grid technology) and decentralised storage. There is at present no agreement on the specific role of each of these options,

84 Strbac, 2002, Quantifying the additional system costs of additional renewables in 2020 and Poyry, 2009, The Implications of Renewables and Intermittent Generation: Summary Report.
85 Gross et al (UKERC), 2006, The costs and impacts of intermittency.
86 National Grid – SYS 2009
87 ENSG, 2009 Our electricity transmission network: A vision for 2020
88 F. Fusco, G. Nolan and J. V. Ringwood, 2009: Variability reduction through optimal combination of wind/wave resources – An Irish case study

but it is probable that a combination of some or all of these will help to address the primary impacts of variable renewables outlined above. All of these options will have an incremental cost, in addition to constraints on timing as summarised in the figure below.

A high level analysis of these options has identified a potential gap in the 2020s during which options for mitigating the impacts of intermittency are limited. This has the potential to restrict deployment unless action is taken to scale up these solutions in parallel to the proportion of variable renewables or to find alternative options.

Deployment time frame for variability mitigation options



Determining the maximum penetration level for variable renewables in 2050

There has been no research defining the maximum or 'optimum' quantity of variable renewables that can be absorbed on the UK grid. This is due to a number of factors. Firstly there is limited historic data as few countries have a penetration level of more than 5% and no country has reached their upper limit. Secondly, the ability to absorb variable renewables is highly region specific and any maximum limit can only be applied to the unique set of market, generation and interconnection conditions. Thirdly, the ability to absorb variable renewables is only constrained by cost; there are no technical reasons for limiting deployment. Thus, in order to determine an appropriate maximum penetration for the offshore deployment scenarios we have extrapolated based on a combination of existing research and the experiences of EU countries with high penetrations of variable renewables.

2050: 50% variable renewables on the UK grid

If the UK follows the Spanish trajectory, 10-15% variable renewables can be absorbed on the UK grid with minimal modification to the incumbent system or infrastructure[90].

Various reports directly examine variability as a potential constraint, modelling up to ~45% variable renewables[91]. The general conclusion is that variability will not be a technical constraint to the level of variable renewables, but that costs will rise in proportion to the penetration level. In order for the UK to meet the 15% renewable energy target in 2020, it has been estimated that the power sector needs to incorporate between 30-40% renewables.

Within Europe, Western Denmark has already achieved over 40% variable renewables and has ambitions to achieve 50% by 2025. To achieve this, Denmark is highly interconnected and trades extensively with neighbouring countries, accessing Scandinavian hydro power at times of low wind output.

Several reports look at the potential for the UK and EU electricity systems to move to an even greater share of variable renewables. For example, the ECF's 2050 roadmap looks at scenarios for the EU ranging from 40-80% renewables and identifies the necessary capacity margin in order to achieve this[92]. Significant uncertainty remains as to the feasibility of achieving of moving beyond this to achieve 80-100% variable renewables. Recently published reports including those from EREC and PWC and CAT have all looked at the possibility of a 100% renewables scenario, although not as an optimum pathway but as one possible vision of the UK's future. Within these reports variability was identified as a potential constraint, and further research would be required to model the impact on cost and security of supply.

There is some political support for such a scenario and the central role of offshore

90 An analysis of similarities in the levels of interconnection, market size, share of hydro power and wind generation potential identifies Spain as the most suitable comparator for the UK.

91 Poyry, 30% by 2030 (43GW); SKM, up to 43% in2020 (33-48); Milborrow, 2009; UKERC 2006.

92 ECF, 2010.

renewables; the 2010 Liberal Democrat manifesto contained the following pledge: "[To] set a target for 40 per cent of UK electricity to come from clean, non-carbon-emitting sources by 2020, rising to 100 per cent by 2050, underpinned by guaranteed price support; and **ensure that at least three-quarters of this new renewable energy comes from marine and offshore sources**"

If the UK can implement a full range of solutions to mitigate the impacts of variability, including increasing the levels of interconnection with Europe, increased demand side management, as well as investing in new peaking plant and various forms of wide area storage such as electric vehicles, it is reasonable to assume that in the very long term the UK has the potential to emulate the Danish plan for 50% variable renewables.

How much interconnection is needed for each scenario?

A simplifying calculation was used to estimate the required quantity of interconnection under each of our three scenarios. Under the assumption that the requirement for interconnection is dominated by the need for back-up capacity, the quantity of thermal generation required to maintain system reliability (i.e. the loss of load probability) was calculated based on an estimate of the ratio of capacity factors for wind and thermal plant, less the capacity credit for wind[93].

Interconnection assumptions

Data assumptions	
Capacity factor of offshore wind	40%
Capacity factor of thermal equivalent e.g. CCGT	85%
Capacity credit of wind at 30% varRE	20%
Capacity credit of wind at 50% varRE	10%

Definitions
Capacity factor Maximumratioofgeneratedpowertorated power, which corresponds to the max number of load hours, net of outages i.e. independent of actual utilisation
Load factor Ratioofaverageloadtoratedpower
Capacity credit Firmcapacityasafractionoftotalinstalled. Note at low penetrations CC = CF

93 The LOLP provides a simplified comparison of the reliability of the systems; it does not provide any indication of how regular or severe the potential shortages might be, but is the best available approximation.

The quantity of 'back-up' required under each of the scenarios is presented on the left hand side in figure below. With a simplifying assumption that all options to maintain reliability have a capacity factor[94] of 85% (a reasonable assumption for CCGTs, nuclear, interconnection and the various storage options), we can directly substitute one back-up option with another. For example, in a scenario with 30% variable renewables, 18GW of back-up is required which could come from peaking plant, storage or via interconnection (assuming that Europe is able to provide power when required). Currently ~5GW of interconnection is proposed and thus it is assumed that this will be used to provide 5GW of 'backup' in the base case scenario. An additional 13GW of conventional generation or storage would then be required to maintain system reliability. For all other scenarios in which 50% variable renewables is the maximum limit it is assumed that no new conventional generation or storage are added for back-up. This has the effect of increasing the level of interconnection to 21GW; a level similar to that contained in EWEA's plans for a North Sea super grid (the proposal includes 26GW of UK interconnection). To be clear, under any scenario, interconnection does not in itself provide balancing or backup services but simply the means to connect to them. Under situations of low or no wind Europe-wide, such as the well characterised 'Atlantic blocking' events, sufficient backup (most likely dispatchable thermal plant) will be required.

Backup, storage & interconnection requirements

		% varRE in UK	Backup Required	Export Required	Conventional generation / storage	Interconnection
1	Base Case	30% 66GW varRE	18 GW	0 GW	13 GW	5 GW •4.6GWcurrently proposed Total = 5 GW
2	UK Forced	50% 93GW varRE	34 GW	0 GW	13 GW •13-29 GW	21 GW •5–21 GW Total = 21 GW
3	Net electricity exporter	50% 183GW varRE	34 GW	90 GW	13 GW •13-29 GW	21 GW •5–21 GW 90 GW Total = 111 GW
4	Net energy exported	50% 420GW varRE	34 GW	326 GW	13 GW •13-29 GW	21 GW •5–21 GW 327 GW Total = 348 GW

94 Using UKERC's definition of capacity factor as the maximum ratio of generated power to rated power, representing the maximum number of load hours per year independent of actual utilisation. Thus capacity factor is an indirect indicator of the reliability if supply.

12 Grid Connection

Developing offshore wind, wave and tidal resources beyond the currently planned 48GW will require large sub-sea electrical cables connecting regions of high resource concentration[95], and between the UK and Europe. The UK-Europe cables will initially be used for balancing the grid during periods of low supply. As the development of offshore renewables increases, additional interconnection will be required to export large volumes of electricity to European power markets. In scenario 2 where the UK becomes a net electricity exporter, 20 times more interconnection would be required than is currently installed.

Scenario 1: Interconnection needed to help balance supply and demand in the UK

The UK already has 3.1GW of international electricity cables which is used for balancing the UK electricity grid. There are plans for another 1.5GW of export cable capacity connecting Wales with Ireland and England with the Netherlands. In addition studies such as the Irish Scottish Links in Energy Study and work by the Energy Networks Strategy Group are examining options including the feasibility of an offshore grid in the Irish Sea and sub sea links to the Scottish Islands.

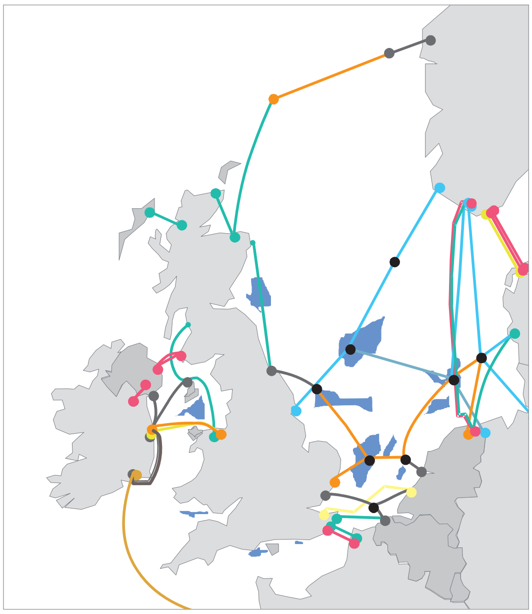
In scenario 1 additional interconnection would be required to manage the balance between supply and demand. An offshore grid capable of balancing electricity directly between countries bordering the North Sea and redirecting electrical flows to maximise that value of the electricity would be more effective than direct point-to-point connectors at this scale of interconnection capacity. An offshore Supergrid would also ease congestion in the onshore grid. Technology already exists for transferring large amounts of electricity over long distances using High Voltage Direct Current (HVDC) cables, but further development will be required to provide the necessary switching technology to enable an HVDC grid to be built.

A North Sea and European Supergrid has been proposed in several recent reports. One such proposal is the EWEA[965] Supergrid which would have a total of 26GW of international interconnection for the UK. It would use Supergrid 'nodes' in the North Sea to allow optimised electricity flows between countries rather than through direct country-to-country connections. The ~21GW of interconnection required for balancing the UK grid in scenario 1 would fit within this model, as illustrated in the figure below. The capital cost of the initial Supergrid borne by the UK would be approximately £6B and would increase the unit cost of electricity generated by approximately £5/MWh over the 50 year lifetime of the HVDC system.

95 E.g. for balancing and power distribution.
96 EWEA, Oceans of Opportunity, September 2009.

Initial Supergrid layout[97]

- Currently operating
- Under construction
- Under study
- Under study and EWEA recommended
- EWEA recommended for 2020s
- EWEA recommended for 2030s
- Mid-sea supernode



Connecting the UK to the rest of Europe will be critical to enable export of clean electricity

Moving beyond scenario 1 will require greater levels of international interconnection for exporting electricity to European countries. A carefully designed enhanced offshore grid would be needed to transmit exports directly to Europe without routing the electricity generated at sea through the UK's onshore grid.

Designing a grid for exports: modelling methodology and assumptions

To model the offshore electricity grid, a number of assumptions have been made:

- **Following the analysis in the previous section, the UK grid is assumed to absorb a maximum of 50% of electricity from variable sources such as offshore wind, wave and tidal, and onshore wind.**
- **Onshore wind capacity is assumed to be installed according to plans for 15GW at a constant rate of installation up to 2025. This reduces the available grid capacity for offshore renewables due to the variability constraint above**

97 EWEA, Oceans of Opportunity, September 2009.

- Conversions between the electricity generated by each technology in a year and the installed generation capacity are based on load factors for each technology, provided in the appendix
- The rate of installation of offshore devices for each scenario is assumed to follow the maximum rate until the capacity limit due to variability constraints, interconnection capacity and the UK electricity demand is reached. The installation rate then drops to remain within these constraints.
- 2010 cost £150M for HVDC substations and £1.3M per nautical mile for a 500MW HVDC cable (the same assumptions are used in the offshore wind cost models)
- Estimated learning curves were used to forecast the reduction in the cost of HVDC cables and substations as global deployment increases. For HVDC cables the learning rate is 10%, and for onshore and offshore HVDC substations the rate is 15% (the same assumptions are used in the offshore wind cost models)
- Costs of the HVDC grid were calculated using the estimated distance of 500MW HVDC cables needed in each scenario, the cost of cabling per nautical mile and substation at the midpoint of the decade in which they would need to be constructed.
- National HVDC connections (e.g. between Scotland, England and Wales) are assumed to be funded solely by the UK. Where a cable crosses international boundaries and is for the benefit of both countries the costs are split equally; interconnectors for the principle use of exporting UK generated electricity to Europe are assumed to be funded by the UK.

The maximum allowable GW capacity of total offshore wind, wave and tidal for each year was calculated based on the grid and interconnectivity constraints for each scenario. Maximum installation rates required to achieve full resource utilisation by 2050 and the maximum allowable GW capacity for each year were used to estimate the installed capacity for each scenario for each year. For each of the modelled scenarios, the capacity of international interconnection used for export, the quantity of exported electricity and the cost of the grid structure were then calculated.

Scenario 2: Enabling exports to Europe

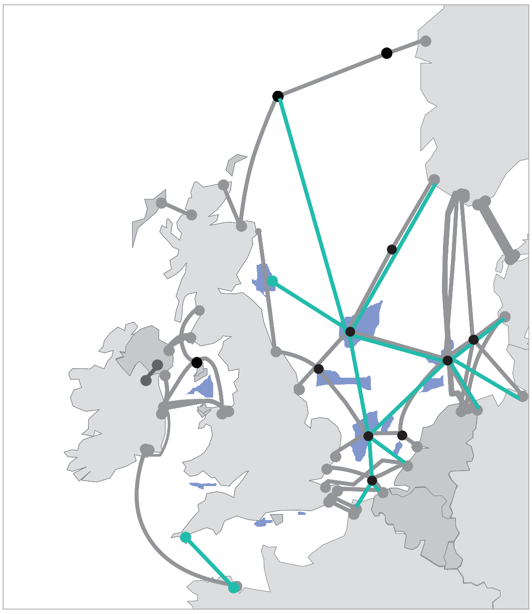
In scenario 2, with 15GW of onshore variable renewables and with the constraint of only 50% variable electricity on the grid, more than half of the electricity generated offshore is exported. This will require an additional 75GW of export capacity through subsea electrical cables. Developing a North Sea Supergrid would be a necessity in order to handle the volume of exported electricity in this scenario.

This level of interconnection goes significantly beyond any of the Supergrids currently proposed. Enhancements to the initial Supergrid proposed in scenario 1 would be necessary to adapt and extend it to handle the huge volume of exported electricity. An enhanced grid would need to be specifically designed to support offshore wind, wave and tidal sources using HVDC technology and a common EU standard for electricity transmission. Utilising and expanding the mid-sea electrical 'nodes' that formed the basis of the initial Supergrid, an enhanced Supergrid could be built in a modular way to allow flexible development as offshore electricity generation increases and the European onshore Supergrid is expanded. The balancing function of the Supergrid would remain; in addition to exporting, during periods of calm weather it would be used to import electricity to meet demand.

For the purposes of cost modelling, this enhanced Supergrid design has been based on the mid-sea nodes that form the structure of the EWEA's proposed Supergrid. The figure below shows the EWEA's Supergrid in grey, and the cables for the enhance grid shown in green.

Enhanced Supergrid layout used for cost modelling

Additional capacity
North Sea Super Grid
Mid-sea supernode



Using this enhanced Supergrid layout, the lengths of 500MW cables have been estimated and the capacities for each connection optimised based on the overall export capacity required. In total, the capital expenditure on the enhanced Supergrid for this scenario would be approximately £38B. This corresponds to an additional transmission cost of approximately £10/MWh[98] for exported electricity when taken over the lifetime of the HVDC cable[99].

98 Operational expenditure estimated at 5% of capital expenditure each year.
99 Assumed to be 50 years: TenneT, HVDC Transmission and Lifetime Expectancy, 2004.

Scenario 3: Another step change in interconnection

Further development of offshore wind, wave and tidal resources beyond scenario 2 will require a one-for-one addition of international interconnection for each GW of new generation capacity. Expanding the capacity of the enhanced North Sea Supergrid and additional connections from western Scottish waters and off the south west coast of England and Wales will be critical to enable more electricity exports and thereby justify greater utilisation of our offshore renewable resource. Building the offshore grid in a modular, flexible way would be critical to enable deployment of offshore technologies that will progress the UK towards becoming a net energy producer. Scaling up the enhanced Supergrid developed to reach the net electricity exporter milestone, the additional capital expenditure is estimated to be £78B. This corresponds to an approximate cost of £7/MWh for each unit of exported electricity, when averaged over the life of the HVDC system. The resulting grid would be capable of exporting more than double the UK's forecasted electricity needs in 2050.

The co-dependent nature of developing our offshore resource and international interconnection

The international grid will have to be developed in parallel with greater offshore resource deployment. It may well be the case that the capacity of exports and the ability to get a reasonable price on the European electricity markets will limit the overall utilization of our offshore resource.

The above calculations assume that the rest of Europe will be willing and able to connect to a grid and buy electricity generated in the UK at a price that is comparable with UK electricity prices. If the rest of Europe develops a grid and generation capacity that is not optimised for UK exports, the deployment of offshore wind, wave and tidal could be significantly constrained.

As noted in an earlier chapter, there is an implicit assumption that the electricity generated from offshore renewables will receive the average market price. However in scenarios 2 and 3, where Europe is purchasing large volumes of electricity from the UK, it is possible that this price realisation will drop significantly below 100% – either due to the weak negotiating position of the UK, or because of a general surplus of electricity in the market due to windy conditions elsewhere in Europe.

A secondary constraint may be the ability to build such a large a complex offshore grid system. Not only will this require the management of complex interactions between different country's electricity networks, national regulators and power companies, but the upfront capital cost and length of cable required will be enormous – particularly in scenario 3 as shown in the table below.

Interconnection requirements by scenario

	Base case	Scenario 1	Scenario 2	Scenario 3	Maximum resource
GW of International interconnection	4.6 GW	21 GW	106 GW	342 GW	464 GW
TWh of exports /year	0	0	370	1,340	1,860
Estimated nm of 500MW cable	500	11,200	48,400	155,500	221,200
Estimated Capital expenditure £ billion	£0.4	£6	£38	£115	£130
Cost per MWh (max cost averaged over exported electricity)	£1.10	£5.25	£5.80 (£10.30)	£6 (£7.25)	£6 (£6.90)
Percentage of resource utilized	8%	12.5%	29%	75%	100%

13 Valuing the Offshore Resource

In valuing the offshore renewable resource we have taken a two phase approach. Firstly, we have estimated the direct financial value that would result from developing the resource, given our cost estimates and assumptions for future energy prices. Secondly, we have conducted a more qualitative valuation encompassing both tangible benefits where the value is difficult to estimate (e.g. job creation) and more intangible benefits (e.g. a reduction in energy price volatility).

Direct financial value

The direct financial value of offshore renewable energy can be measured by the differential between the cost of electricity delivered to the market, and the electricity price in that market. For the purposes of this report we have defined market as the wholesale market, i.e. the costs of generation and grid connection are included, but the costs of electricity distribution and supply are not.

A key assumption of this valuation – apart from the four UK wholesale price scenarios – is the level of European electricity prices. We have not created separate scenarios for EU prices, but have assumed that they move in tandem with UK prices. It is feasible that by 2050 a single market may exist for electricity in Europe, but if this is not the case then it is possible that the European wholesale electricity prices could be significantly higher or lower than UK prices. This will impact the balance of value between electricity sales to the UK and to the EU, as well as the total value of the offshore resource; further consideration of these points is made in the European value section below.

The table below shows the net value created in each of our three deployment scenarios, under each of the four DECC prices scenarios. The value of exported electricity is highly positive in all but the Low price scenario, when it is highly negative (i.e. electricity sales to Europe would result in a loss). The value of electricity consumed in the UK is highly negative in the Low price scenario, close to zero when exporting under the Central price scenario, and otherwise highly positive. Any highly negative values are unlikely to be realised in practice, as the build rate of offshore renewables will slow or cease in response to sustained low electricity prices.

Net exports are zero under scenario 1, as although the UK would be connected to Europe by 34GW of interconnectors, any electricity exports across these cables would be offset by an equal volume of electricity imports.

Scenario 1, 2 & 3 - Net present value

	Scenario 1	Scenario 2	Scenario 3
Net value of UK electricity sales under DECC price scenarios (£B):			
Low	-79	-93	-102
Central	17	5	-5
High	87	74	63
High-High	126	112	102
Electricity sales to UK, 2010-2050 (TWh)	5,995	5,995	5,995
Net value of EU electricity sales under DECC price scenarios (£B):			
Low	0	-116	-241
Central	0	31	61
High	0	137	280
High-High	0	191	387
Electricity sales to EU, 2010-2050 (TWh)	0	9,023	20,867

	Scenario 1	Scenario 2	Scenario 3
Net value of UK & EU electricity sales (£B, central price scenario)	17	36	55

It should be noted that as we move from scenario 1 to scenarios 2 and 3, and the total installed capacity increases, the value to the UK goes down despite the TWh of electricity consumed by the UK remaining constant. This is because adding more generation capacity requires the development of more costly site types and technologies, and as a result the average levelised cost is higher than under a lower deployment scenario. In addition the split of value between sales to the UK and to the EU is not proportional to the split of TWh, because the relative size of UK versus EU sales changes over time.

In addition to the uncertainty in future electricity prices, the underlying levelised costs of each technology are also uncertain. The appendix details the impact on net value that results from an increase or decrease in the average levelised costs across all five technologies.

Regional value

In scenario 2 the total practical resource is equal to 610TWh, with 64% coming from fixed offshore wind, 26% from floating wind, 5% from tidal stream, 3% from tidal range and 2% from wave power. The location of the UK's practical offshore resource varies considerably for each technology, as noted in the resource chapter, and can be approximately allocated by region.

Under the simplifying assumption that each TWh of resource is of approximately equal value, this resource breakdown can be used to allocate the £36 billion of net value under scenario 2, central electricity prices. This suggest that the resource around the Scottish coast is worth approximately £14 billion, with more than 90% of this value coming from fixed and floating offshore wind. The resource off the coast of Wales is worth around £3 billion but the distribution of this value is more even across fixed and floating wind, tidal stream and tidal barrage (with a small contribution from wave power). The remaining resource is worth £19 billion[100], predominantly as a result of fixed and floating offshore wind.

European value

Central to the value calculation for EU electricity sales are three assumptions: there will be sufficient demand across Europe for low carbon electricity exports, these exports can be transported to the relevant demand centres, and a sufficient electricity price (net of interconnection costs) can be realised to cover the costs of offshore renewables.

As noted, the value calculations for EU electricity sales are made using DECC's wholesale electricity price forecasts and thereby assume that UK and EU electricity prices converge over time.

Although creating demand and price scenarios for renewable power across Europe did not form part of this study, the European Climate Foundation's 2010 report on the market for low carbon electricity suggests that this demand could be between 1,960 and 3,920 TWh in 2050[101]. This compares to potential UK exports of offshore renewable electricity of 340 TWh in scenario 2 and 1,340 TWh in scenario 3, i.e. 7% and 27% of European demand respectively. The report also considered the need for new onshore and offshore grid connections to enable balancing of variable renewable power across Europe.

Based on ECF's forecasts for European electricity prices – an average of €78-97/MWh between 2010 and 2050[102] – fixed offshore wind will become cost competitive in the 2030s and floating wind in the 2040s. This forecast sits between DECC's Low and

100 Note: In this calculation value is allocated equally across all technologies.
101 European Climate Foundation, EU Roadmap, 2010.
102 Price range for 60% and 80% renewables scenarios; the price range is lower for in the 40% renewables scenario.

Central price scenarios, suggesting that if these prices materialise then the net present value from electricity exports would be close to zero when summed over the period 2010-2050.

Given the sensitivity of the value calculation to the three assumptions listed above, further work is required to develop a clearer picture of the European demand for UK offshore renewable power.

Additional sources of value

In addition to the value of electricity generation, the UK will generate value through energy security, achieving its climate change objectives and creating a UK-based offshore renewable industry. These will take the form of supply chain activities (jobs and taxes), avoided CO_2 emissions, avoided fossil fuel imports (and the volatility associated with them), financial returns on investments and improvements in the balance of trade. While the impact of each of these can be readily identified, it is difficult to assign a precise monetary value that is separate from other measures of value creation. Therefore a high level assessment of value has been made in the table below, noting that this is very sensitive to specific assumptions.

Energy security

Value driver	High level assessment	Assumptions
Avoided fossil fuel imports	The incremental avoided fossil fuel imports of 20 million tonnes of oil equivalent in moving from currently planned deployment to 50% renewables on the UK grid could be worth another £7 billion by 2050	This assumes that offshore renewables displace CCS gas generation, at a gas price of 3p/kWh in 2050; displaced generation could also be a combination of nuclear, CCS coal, biomass and other renewables, each of which would impact the value calculation
Avoided fossil fuel volatility	Reduced risk of volatile energy prices due to e.g. geopolitical instability	Any reduction in fuel imports will increase the UK's energy independence, although variable renewables may introduce a different form of price volatility into the market
Improved balance of trade	Reduced imports (of energy and energy fuels), plus increased exports under scenarios 2 and 3	
Energy independence	National ownership of electricity-producing infrastructure leading to (net) self-sufficiency in scenarios 2 and 3	

Climate change targets

Value driver	High level assessment	Assumptions
Avoided CO2 emissions	Carbon emissions of 1.1 billion tonnes would be avoided between 2010 and 2050 under scenario 1	This assumes avoided CO2e emissions of 430g/kWh from 2010 to 2030, falling to 20g/KWh by 2050, using DECC's 2010 GHG appraisal guidance.

UK-based offshore renewables industry

Value driver	High level assessment	Assumptions
Supply chain jobs	Approximately 340,000 direct jobs in scenario 3, 145,000 in scenario 2 and 70,000 in scenario 1	Direct jobs include only those in roles directly related to the construction, operation and maintenance of offshore renewables. Inclusion of the broader supply chain could increase these numbers significantly, as would any export of UK technology or skills overseas
Supply chain taxes	Approximately £10 billion in annual corporation tax from 2050 in scenario 3, £6 billion in scenario 2 and £3 billion in scenario 1	Profits are calculated using the steady state revenue and cost of electricity generation from 2050. Assumes a corporate tax rate of 40%
Financial returns on investment	Annual interested payments of £18.5 billion on invested capital from 2050	Assumes £370 billion invested by UK investors over the period 2010-2050, at a rate of 5%; this will displace other investment options and is not a benefit to society in the same way as other benefits listed here
Improved balance of trade	Reduced imports (of energy and energy fuels), plus increased exports under scenarios 2 and 3	

14 Appendix

Initial cost estimates

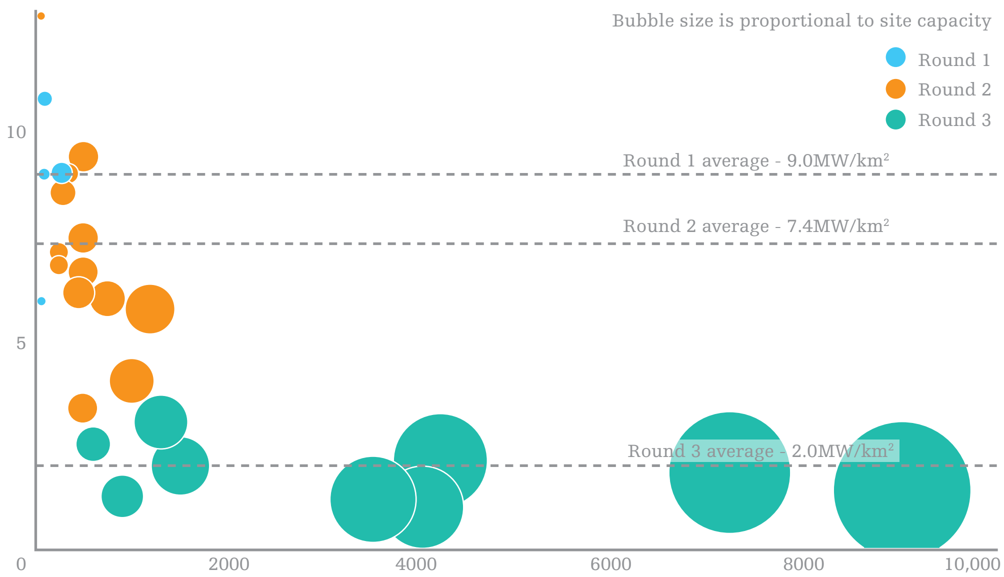
For fixed offshore wind, the model used in the 2008 Carbon Trust report 'Big Challenge, Big Opportunity' was updated to reflect changes in exchange rates and calibrated using published capital costs of recent projects and expert interviews.

Floating offshore wind costs were estimated using a modified version of the fixed wind model, with foundation costs being the most significant change. These were estimated based on publicly available data on the weight and composition of the floating structure for the various technologies currently at the prototype stage, including Blue H and Hywind. These estimates were then tested through expert interviews.

Our starting estimates for wave power and tidal stream levelised costs were based on an assessment of the relevant literature, including the recent estimates produced for DECC and BERR[103]. This provided a broad range of estimates, from which the average was used as the starting point for our cost curves in 2020. For tidal stream the range of cost estimates was used to produce an estimate for each of our three site types, with the lowest cost assigned to the first site type, the average cost assigned to the second site type, and the highest cost assigned to the third site type.

For tidal range, initial levelised costs were taken from the SDC "Turning the Tide" report (2007) and then adjusted based on updated construction costs estimates from DECC (2009) and a discount factor of 10%. Many publicly available cost estimates for tidal range use a lower discount rate than 10% and therefore show lower levelised costs. In order to keep our analysis comparable we have used a 10% discount rate across all five technologies and for all years.

Power density for offshore wind Rounds 1, 2 and 3



103 Reports included: "Compliance Costs for Meeting the 20% Renewable Energy Target in 2020", March 2008, Poyry report for BERR; DECC Marine Action Plan 2010; "Impact of banding the Renewables Obligation, Costs of electricity production", Ernst & Young, April 2007.

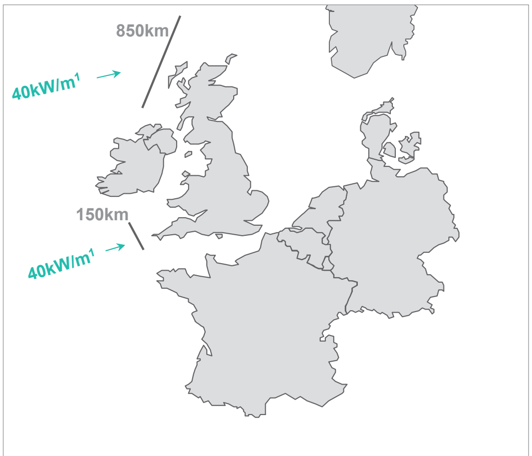
Wave: Illustrative calculation of the number of rows of wave devices required to capture a resource of 50TWh/yr

The maximum length of coastline within the UK's EEZ that is exposed to incoming waves is approximately 1000km (see figure below). Three rows of wave devices were considered, one 30-60nm from shore, a second row 12-30nm from shore and a near shore row. With each subsequent row the available energy will diminish, and in addition a proportion of the total energy is lost due to friction as the depth of water decreases close to the coast. Friction was assumed to decrease the available power by 25% between each row of devices, i.e. 100% of incoming power was available far from shore, decreasing to 75% and 50% as for the rows closer to shore. Conversion efficiency was estimated at 30%.

Given that a continuous row of devices offshore would cause significant disruption to existing uses of the sea, it was assumed that up to 50% of the 1000km strip could be filled with devices. Thus at distance far from shore, 50% of the incoming power was available. For the inner two rows of devices, an additional constraint was applied to account for greater use of the sea; this was based on the proportion of sea available under a 50% consenting scenario for offshore wind. Thus at 0-12nm, 13% of the incoming power was available, and at 12-30nm offshore 37% of the incoming power was available. A 30% reduction for losses due to frequency and alignment effects was assumed, based on Mollison's lower estimate.

Wave power resource

Incoming Wave Resource



Technical Resource: Illustrative calculation

~ 1000km length exposed to incoming waves within the UK's EEZ – measured along interface between wave heights of >2m (SW) & >3m (NW)

If we assume
- 20-30% conversion factor
- 40 kW/m incoming wave power

Technical resource estimated to be 70-105 TWh/yr
- This excludes frequency effects & other losses; which Mollison (1986), estimates reduces extractable resource by 25-50%

Including such effects reduces technical resource to 35-78 TWh/yr

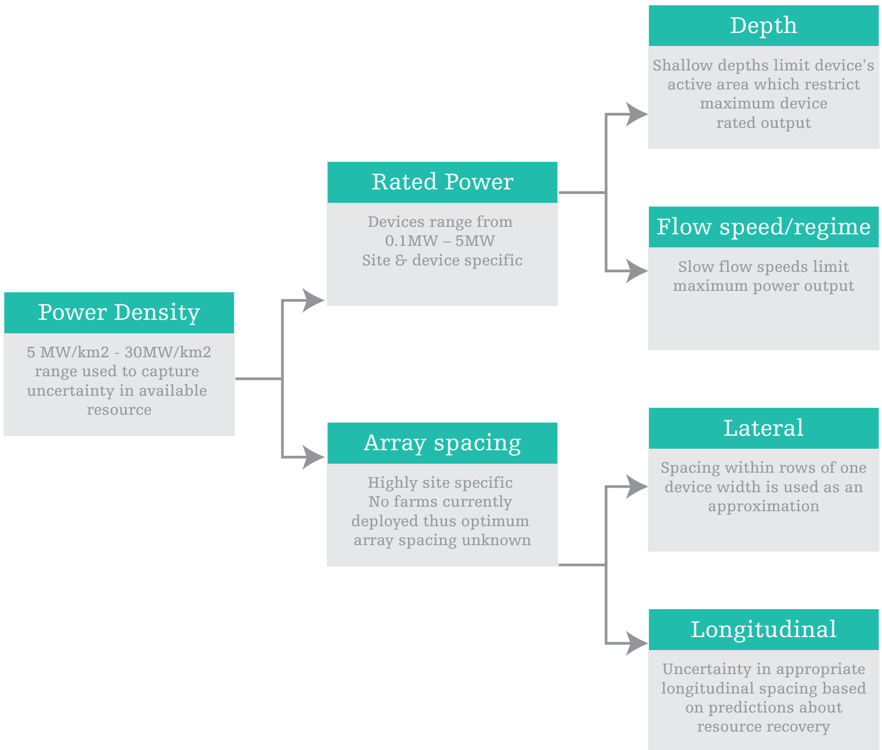
Practical constraints expected to reduce this by at least 30%, to 25-55 TWh/yr due to considerations of existing uses; notably shipping lanes

This simplified calculation suggests that the first row of devices could produce 37TWh/yr, the second row 14TWh/yr and the near shore row 3TWh/yr, making a total of 53TWh/yr. The first row is likely to have significantly better economics than the second and third rows, therefore we have taken 37TWh/yr, rounded to 40TWh/yr[104], as our upper limit for the practical wave resource. This corresponds to 18GW[105] of wave devices, which would require a 1MW device to be positioned every 55m for 1000km.

It is possible that the practical resource from wave power could be higher than the level indicated above, if elements such as wave reformation in deep water and the wave resource on the east coast of the UK are taken into account. This may explain the discrepancy between the estimated practical resource of 40TWh used in this report and the figure of 50TWh quoted by sources such as ETSU (1985) and Carbon Trust (2006).

Tidal stream

The figure below indicates the factors which influence tidal stream power density; the greatest uncertainty lies within the estimates of the longitudinal spacing, which reflects the limited research into the field of tidal stream resource recovery. In practice the power density that can be achieved will be highly site specific.



104 This is in line with the frequently quoted practical wave resource of 50TWh/yr, which reduces to 33TWh/yr if frequency and alignment effects are taken into account.
105 Assuming a load factor of 25% (Renewables UK).

Variability: Assumptions

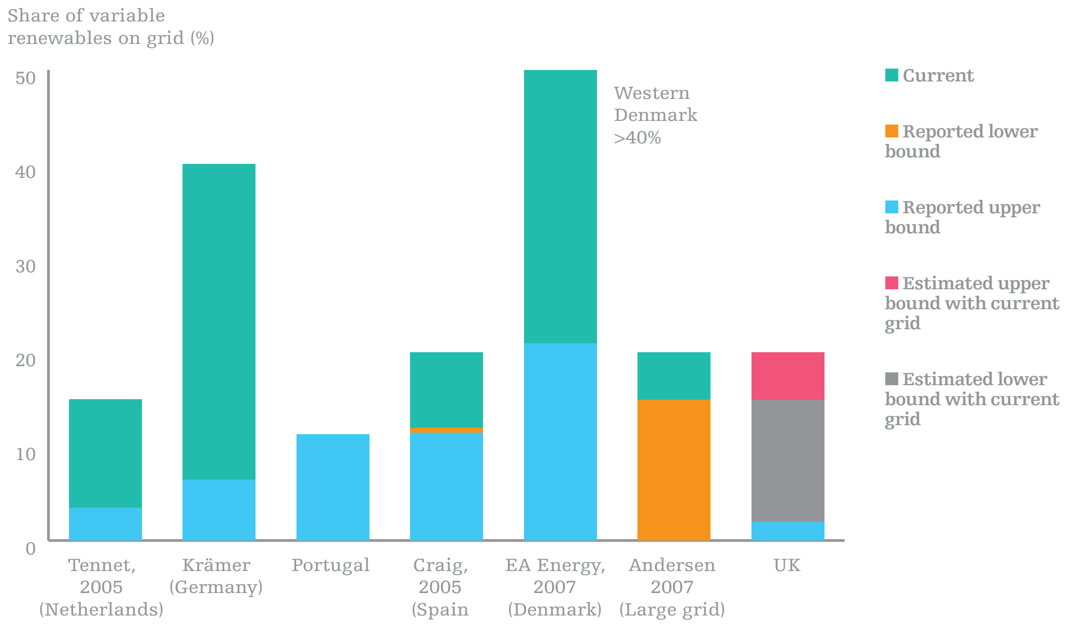
Assumptions & sources for the options for mitigating impacts of intermittency

A range in power density is required to reflect uncertainty in extractable resource: 5-30MW/km²

	Potential Solutions to mitigate impacts of intermittency	Sources & Assumptions
1	Existing CCGTs	Modelled using BP Powering the future, 2009 report
1	Proposed new CCGTs/PH	NGC's Transmission Entry Capacity (TEC) list, 2009; all CCGT proposed to be built post 2010 have been included. Note that not all plants will be built & new capacity beyond 2020 is likely, but is not included in SYS09[1]
1	New Peaking plant	This could include variable nuclear; CCS; CCGTs and Pumped hydro
2	DSM	DSM, facilitated by smart grids, based on kWh from available heating, cooling and key appliances to estimate maximum available capacity in 2050.
3	Existing & planned Interconnectors	Current interconnectors sourced from DECC; proposed interconnectors sourced form National Grid's TEC connection queue, accessed April, 2010.
4	Intra-country connectors	Smart meter mandate by 2020; but meter's and suppliers not expected to be sophisticated enough for mitigating impacts of variable supply and managing power flows for 10 years
4	Supergrid Grid	Using EWEA's proposed supergrid, 21GW interconnection would be built within the 2030s timeframe
5	Smart grid	Assumes smart grid facilitates DSM and EVs; through bi-directional flows and actively managed distribution networks – employs high-tech devices including meters to load shed and transform homes into power & storage hubs
6	EVs – V2G	Used average kWh of currently available vehicles, & average charger value of available chargers to estimate total power and energy assuming 75% of car fleet electrified by 2050 (In accordance with low bio-fuel scenario)
7	DG storage (batteries)	Unknown potential form decentralised storage; dependant on cost competitiveness of future technologies as well as evolution of regulatory framework e.g. Currently TSO or DNO cannot own or operate storage as it is registered as a generation asset
	Onshore Renewables Offshore Renewables	Onshore: 15GW onshore assumed to be linearly connected between 2010-2025 Offshore: Assumes maximum roll-out such that all practical resource is developed by 2050, as a percentage of BCG estimated electricity consumption at the end of each decade. Current data supplied by Renewables UK - UK Wind energy Database.

1. National Grid Seven Year Statement 2009
Source: BCG Analysis

Estimates of maximum penetration of variable renewables by market



Constraints used to determine practical resource[106]

Soft constraints	Hard constraints
Fish Spawning Nursery	Subsurface Infrastructure
Helicopter Platform	Surface Infrastructure
Sites of Special Scientific Interest	Oil and Gas Safety Zones
Special Protected Areas SAC in Scotland	Protected Wrecks (Polygon)
Protected Wetlands (RAMSAR)	Protected Wrecks
Candidate Special Areas of Conservation	Active Wells
Draft Special Areas of Conservation	Round 1 Wind Farm Lease
Potential Special Areas of Conservation	Round 2 Wind Farm Lease
World Heritage Sites	Round 3 Wind Farm Lease
Heritage Coastline	Wind Farm Exclusion Zone
Bird Reserves	Scottish Wind Farm Exclusivity Awards
Important Bird Areas	Interconnectors
MOD PEXA 6, 10	Pending Aquaculture Leases
TCE Wind Knowledge	Current Aquaculture Leases
Coastal Seascape	Anemometers
MOD Munitions Dumps	Active Pipelines
Proposed Cables & Pipelines	Active Cables
Offshore Obstructions	Round 2 SEA Zones
Wave Lease	Wave Lease
Channel Tunnel	Tidal Lease
Anchorage Areas	Dredging Prospecting
Medium Interference	Dredging Options
Areas of Natural Beauty	Dredging Licences
National Nature Reserves	Dredging Applications
Main Helicopter Routes	Dredging Future Interest Areas
Local Nature Reserves	Offshore Mines
LAR Aviation Routes	IMO Routes
Civil Airfields (24 km Buffer)	
Scheduled Ancient Monuments	
Shipping Density	
Tidal Lease	
Open Dumps	
CO2 and Gas Fields	
Not in Use Pipelines & Cables	
Inshore & Offshore Ship Zones	
Disused Dumps	
Oil Fields	
Suspended Wells	
Navigation Points	
Yacht Sailing & Racing Areas	
Yacht Cruising Areas	

106 Crown Estate, 2010.

MOD Airfields (24 km Buffer)
NATS Radar Interference: High Interference
Total Annual Fishing Value

Load factors

	Minimum (site-specific)	Maximum (site-specific)	Average
Fixed offshore wind	35%	45%	40%
Floating offshore wind	35%	55%	50% [107]
Tidal range	n/a	n/a	30%
Tidal stream	n/a	n/a	40%
Wave power	n/a	n/a	25%

Load factors (sometimes referred to as capacity factors) are the average power output for each device type as a proportion of the device's rated capacity. Therefore a 1MW tidal stream device will produce, on average, 0.4MW of power throughout the year.

Capital costs of the offshore supergrid

(£ billion)	2010-2020	2020-2030	2030-2040	2040-2050	Total
Scenario 1	6	-	-	-	6
Scenario 2	6	26	5	-	37
Scenario 3	6	26	53	30	115

These costs are in addition to the grid connections linking offshore renewables to the UK onshore grid, which are included in the levelised cost estimates for each of the five technologies.

Scenarios 1,2,3 - Revenue & profit by price scenario

			Scenario 1	Scenario 2	Scenario 3
		UK (TWh/year)	270	270	270
		Export (TWh/year)	0	340	1,337
		Total	270	610	1,607
DECC Price Scenario	Low	Revenue (£B)	16	37	97
		Profit (£B)	-3	-10	-43
	Central	Revenue (£B)	28	62	164
		Profit (£B)	9	16	24
	High	Revenue (£B)	36	81	213
		Profit (£B)	17	34	73
	High High	Revenue (£B)	40	90	236
		Profit (£B)	21	43	96

107 Note: The majority of floating offshore wind sites are far from shore in high wind speed areas.

Valuation: Levelised cost sensitivity analysis

Net value of UK + EU electricity sales (£B, Central price scenario)	Scenario 1	Scenario 2	Scenario 3
Estimated levelised costs -15%	47	110	177
Estimated levelised costs used in the report	17	36	55
Estimated levelised +15%	-17	-51	-85

Carbon reduction

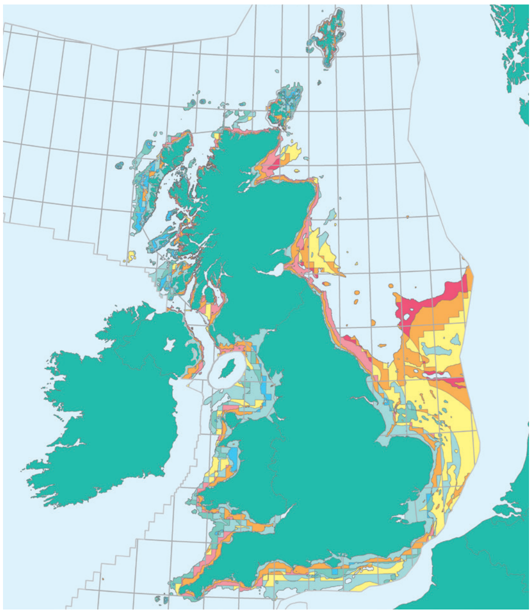
(million tonnes of CO_2)	2010-2020	2020-2030	2030-2040	2040-2050	Total	Average
Scenario 1	225	469	366	72	**1,133**	**28**
Scenario 2	288	1,255	1,131	173	**2,847**	**71v**
Scenario 3	288	1,255	1,433	440	**3,417**	**85**

This is the total carbon reduction from offshore renewables, assuming avoided CO_2 emissions of 430g/kWh from 2010 to 2030, falling to 20g/kWh by 2050. This is based on DECC's 2010 GHG appraisal guidance, and uses CCGT power generation as the reference generation alternative between 2010 and 2030.

Fixed offshore wind: Site specific costs

Levelised costs of offshore wind development at available sites, £/MWh (2008)[1]

Blue	80
Light green	80-87
Dark green	87-94
Pale blue	94-100
Yellow	100-104
Orange	104-111
Pink	111-118
Red	>118
White	UK continental shelf boundary



This map shows the area of UK waters at a depth of less than 60m, colour coded for the levelised cost of fixed offshore wind. Red areas have the highest levelised cost; the next cheapest sites in order are pink, orange, yellow, light green, dark green, with the lowest cost sites shaded in blue[108].

108 Note: This map is identical to the one produced for the Carbon Trust report 'Big Challenge, Big Opportunity' in 2008, as the costs modelling was based on the same underlying methodology.

DECC electricity price forecasts

The following paragraphs are taken from the DECC publication 'Valuation of Energy Use and Green House Gases (GHG) Emissions for Appraisal and Evaluation', January 2010. These explain the methodology used to calculate the Low, Central, High and High-High wholesale price scenarios used in this report.

"To produce estimates of the future long term marginal generation costs, we have produced a number of scenarios. These have been determined by looking at the estimated costs of different low carbon technologies. Estimates suggest the costs of low carbon technologies in the 2030s will range from around £60/MWh to £150/MWh with a central range of around £100/MWh (all 2009 prices . Using this range and the range of costs for CCGT generation we have developed four scenarios for the future cost of marginal electricity generation:

- *Low*
  CCGT costs rise in line with low fossil fuel prices and low EUAs series and CCGT remains the marginal plant until around 2030 after which a mix of low carbon and CCGT generation costing around £60/MWh (incl. carbon) becomes the marginal plant.

- *Medium*
  CCGT costs rise in line with central estimates for fossil fuel prices and central EUAs series and CCGT remains the marginal plant until 2030, after which a mix of low carbon and CCGT generation costing around £100/MWh (incl. carbon) becomes the marginal plant.

- *High*
  CCGT costs rise in line with the high fossil fuel prices and high EUAs series and CCGT remains the marginal plant until 2030, after which a mix of low carbon and CCGT generation costing around £130/MWh (incl. carbon) becomes the marginal plant.

- *High high*
  CCGT costs rise in line with the high high fossil fuel prices and high EUAs series and CCGT remains the marginal plant until 2030, after which a mix of low carbon and CCGT generation costing around £150/MWh (incl. carbon) becomes the marginal plant.

Note that these scenarios have only been produced for the purpose of policy appraisal and should not be read as a government forecast of future power generation costs and prices. Focus on the long run scenarios should be around the cost of generation rather than any implication as to which technology is considered the marginal plant."

DECC price forecasts are set in line with fossil fuel forecasts. The following paragraphs are taken from the DECC publication 'Communication on DECC Fossil Fuel Price Assumptions'
http://www.berr.gov.uk/files/file51365.pdf
These explain the methodology used to calculate the Low, Central, High and High-High fossil fuel price scenarios.

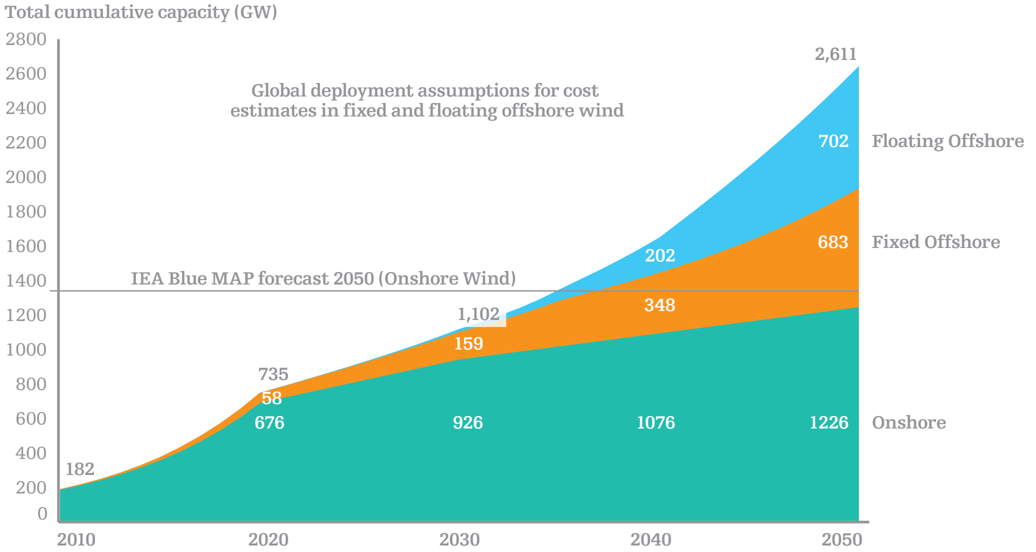
"We have revised the assumptions in line with the best information available on market fundamentals and the feedback received on previous assumptions. The last year has seen extremely volatile markets and there is a great deal of uncertainty over future trends in fossil fuel prices. We capture this through four illustrative scenarios which reflect different patterns of demand and investment in supply. The four scenarios are as follows:

Scenario 1 - Low global energy demand
Scenario 2 - Timely investment and moderate demand
Scenario 3 - High demand and producers' market power
Scenario 4 - High demand, significant supply constraints

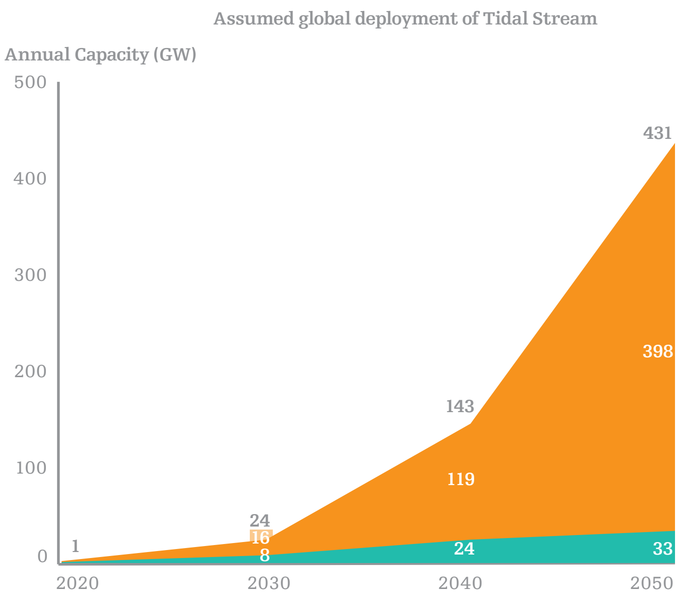
These illustrative scenarios are meant to capture the uncertainty around the outturn of future fossil fuel prices. We recommend that policy makers use all four scenarios for sensitivity analysis."

Deployment assumptions

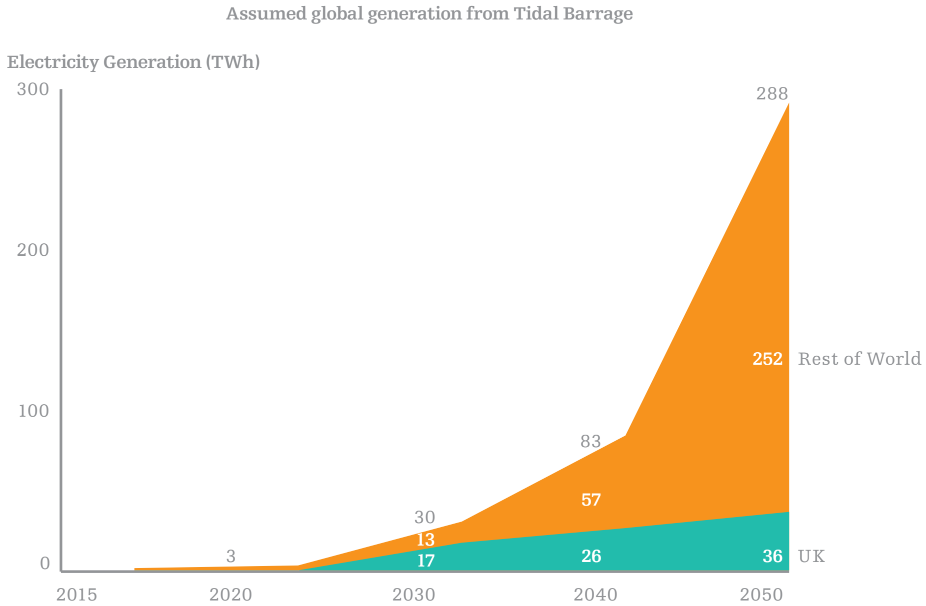
Fixed & floating wind global deployment assumptions under maximum scenario



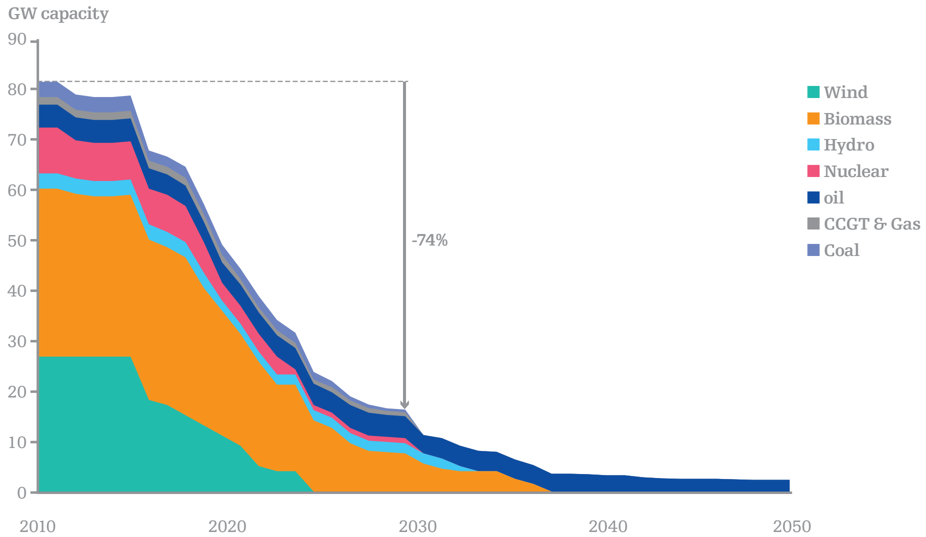
Tidal stream global deployment assumptions for maximum scenario



Tidal range global deployment assumptions under maximum scenario



Decline in existing UK generation



Levelised costs by site type

Site segmentation under Scenario 1: Maximising the role of offshore renewables in meeting UK electricity demand

Fixed and floating wind

Site type	Technology	Segment				Sea floor km²		Capacity	Levelised Cost (£/MWh)			
		Depth (m)	Distance from shore (mm)	Wind speed (W/m²)	No constraints	Hard plus low level soft constrained sites (20% least constrained sites)	Base Case (35% least constrained sites)	MW Available (excl R1, R2, R3 and all extensions)	2015	2025	2035	2045
1	Fixed wind	0-20	0-12	<700	17,688	28	208	728	115	79	71	65
2	Fixed Wind	0-20	0-12	700-800	2,910	2	13	45	103	70	64	58
3	Fixed Wind	0-20	0-12	800-900	1,729	0	-	0	97	67	60	55
4	Fixed Wind	0-20	0-12	900+	475	0	-	0	91	62	56	52
5	Fixed Wind	0-20	12-30	<700	965	-	64	223	121	83	75	69
6	Fixed Wind	0-20	12-30	700-800	364	0	-	0	108	74	67	62
7	Fixed Wind	0-20	12-30	800-900	1,593	-	-	0	102	70	64	59
8	Fixed Wind	0-20	12-30	900+	1,528	0	51	177	95	66	59	55
9	Fixed Wind	0-20	30-60	<700	569	1	37	130	136	94	86	80
10	Fixed Wind	0-20	30-60	700-800	83	0	30	106	121	84	77	71
11	Fixed Wind	0-20	30-60	800-900	21	0	-	0	114	80	72	67
12	Fixed Wind	0-20	30-60	900+	1,655	0	45	157	107	74	68	63
13	Fixed Wind	0-20	60+	<700	196	-	-	0	153	103	92	84
14	Fixed Wind	0-20	60+	700-800	18	-	-	0	137	92	82	75
15	Fixed Wind	0-20	60+	800-900	28	0	-	0	129	87	77	71
16	Fixed Wind	0-20	60+	900+	1,667	0	681	2382	121	82	72	66
17	Fixed Wind	20-40	0-12	<700	12,378	81	670	2346	121	84	76	70
18	Fixed Wind	20-40	0-12	700-800	4,061	1	97	339	108	75	68	62
19	Fixed Wind	20-40	0-12	800-900	3,620	0	78	272	102	71	64	59
20	Fixed Wind	20-40	0-12	900+	3,982	0	15	53	96	67	60	55
21	Fixed Wind	20-40	12-30	<700	1,482	-	137	479	127	89	80	74
22	Fixed Wind	20-40	12-30	700-800	391	0	-	0	114	79	72	66
23	Fixed Wind	20-40	12-30	800-900	4,392	-	39	136	107	75	68	62
24	Fixed Wind	20-40	12-30	900+	11,916	1	156	546	100	70	63	58
25	Fixed Wind	20-40	30-60	<700	444	8	103	361	142	100	91	84
26	Fixed Wind	20-40	30-60	700-800	54	10	27	96	127	90	81	75
27	Fixed Wind	20-40	30-60	800-900	88	1	36	126	120	85	77	71
28	Fixed Wind	20-40	30-60	900+	15,828	70	945	3308	112	79	72	66

Site type	Technology	Segment				Sea floor km²		Capacity	Levelised Cost (£/MWh)			
		Depth (m)	Distance from shore (mm)	Wind speed (W/m²)	No constraints	Hard plus low level soft constrained sites (20% least constrained sites)	Base Case (35% least constrained sites)	MW Available (excl R1, R2, R3 and all extensions)	2015	2025	2035	2045
29	Fixed Wind	20-40	60+	<700	247	0	-	0	160	110	97	89
30	Fixed Wind	20-40	60+	700-800	22	0	-	0	143	98	87	80
31	Fixed Wind	20-40	60+	800-900	20	0	-	0	135	93	82	75
32	Fixed Wind	20-40	60+	900+	14,417	428	3,320	11620	126	87	77	70
33	Fixed Wind	40-60	0-12	<700	7,730	11	223	780	127	90	81	74
34	Fixed Wind	40-60	0-12	700-800	3,202	0	155	543	114	80	72	66
35	Fixed Wind	40-60	0-12	800-900	3,081	-	184	643	107	76	68	62
36	Fixed Wind	40-60	0-12	900+	6,537	-	12	43	100	71	63	58
37	Fixed Wind	40-60	12-30	<700	566	-	-	0	133	94	85	78
38	Fixed Wind	40-60	12-30	700-800	635	1	-	0	119	84	76	70
39	Fixed Wind	40-60	12-30	800-900	2,043	-	88	309	112	79	72	66
40	Fixed Wind	40-60	12-30	900+	23,490	281	1,755	6143	105	74	67	62
41	Fixed Wind	40-60	30-60	<700	110	0	-	0	149	106	96	89
42	Fixed Wind	40-60	30-60	700-800	53	4	13	46	133	95	86	79
43	Fixed Wind	40-60	30-60	800-900	132	-	36	126	125	89	81	75
44	Fixed Wind	40-60	30-60	900+	13,460	940	3,927	13744	117	84	76	70
45	Fixed Wind	40-60	60+	<700	255	0	11	40	168	116	103	95
46	Fixed Wind	40-60	60+	700-800	36	1	-	0	126	104	92	84
47	Fixed Wind	40-60	60+	800-900	12	0	-	0	119	98	87	80
48	Fixed Wind	40-60	60+	900+	7,196	1,552	2,934	10267	111	92	81	74

Site type	Technology	Segment				Sea floor km²		Capacity	Levelised Cost (£/MWh)			
		Depth (m)	Distance from shore (mm)	Wind speed (W/m²)	No constraints	Hard plus low level soft constrained sites (20% least constrained sites)	Base Case (35% least constrained sites)	MW Available (excl R1, R2, R3 and all extensions)	2015	2025	2035	2045
1	Floating Wind	-	0-12	<700	4,877	1	-	4	152	112	97	84
2	Floating Wind	-	0-12	700-800	2,295	-	-	-	136	100	86	75
3	Floating Wind	-	0-12	800-900	3,270	-	-	-	129	95	82	71
4	Floating Wind	-	0-12	>900	9,946	-	-	-	120	89	76	66
5	Floating Wind	-	12-30	<700	461	-	-	-	159	117	101	88
6	Floating Wind	-	12-30	700-800	600	2	-	6	142	105	91	79
7	Floating Wind	-	12-30	800-900	1,864	-	-	-	134	99	86	74
8	Floating Wind	-	12-30	>900	45,335	1,622	-	5,676	125	93	80	69
9	Floating Wind	-	30-60	<700	82	-	-	-	178	132	115	101
10	Floating Wind	-	30-60	700-800	133	2	-	8	159	118	103	90
11	Floating Wind	-	30-60	800-900	287	-	-	-	150	112	97	85
12	Floating Wind	-	30-60	>900	80,739	19,739	-	69,086	141	104	91	80
13	Floating Wind	-	60-100	<700	0	-	-	-	201	144	124	109
14	Floating Wind	-	60-100	700-800	-	-	-	-	180	128	110	97
15	Floating Wind	-	60-100	800-900	-	-	-	-	170	121	104	92
16	Floating Wind	-	60-100	>900	102,123	34,518	-	120,814	159	113	98	86
17	Floating Wind	-	100-200	<700	296	0	-	0	226	140	117	105
18	Floating Wind	-	100-200	700-800	292	0	-	0	202	125	105	94
19	Floating Wind	-	100-200	800-900	11	0	-	0	191	118	99	89
20	Floating Wind	-	100-200	>900	138,840	44,148	-	154,519	179	111	92	83

Wave & Tidal Site segmentation

Site	Technology	Description	Available MW	Levelised Cost (£/MWh) 2020	Levelised Cost (£/MWh) 2025	Levelised Cost (£/MWh) 2035	Levelised Cost (£/MWh) 2045
1	Wave	Single site	4,566	195	161	132	119
1	Tidal Stream	High attractive	9,418	135	106	79	64
3	Tidal Stream	Medium Attractive	23,687	179	140	104	85
4	Tidal Stream	Least Attractive	23,687	241	188	141	114
1	Tidal Range	Site type 1	1,027		146	138	112
2	Tidal Range	Site type 2	609		204	192	156
3	Tidal Range	Site type 3	875		242	228	185
4	Tidal Range	Site type 4	989		254	240	194
5	Tidal Range	Site type 5	6,393		172	162	132
6	Tidal Range	Site type 6	3,805		254	240	194

Site segmentation under Scenario 2: The UK as a net exporter of electricity

Fixed and floating wind segmentation

Site type	Technology	Segment				Sea floor km²		Capacity	Levelised Cost (£/MWh)			
		Depth (m)	Distance from shore (mm)	Wind speed (W/m²)	No constraints	Hard plus low level soft constrained sites (20% least constrained sites)	Base Case (35% least constrained sites)	MW Available (excl R1, R2, R3 and all extensions)	2015	2025	2035	2045
1	Fixed Wind	0-20	0-12	<700	17,688	28	208	728	115	77	70	64
2	Fixed Wind	0-20	0-12	700-800	2,910	2	13	45	103	69	62	57
3	Fixed Wind	0-20	0-12	800-900	1,729	0	-	0	97	65	59	54
4	Fixed Wind	0-20	0-12	900+	475	0	-	0	91	61	55	50
5	Fixed Wind	0-20	12-30	<700	965	-	64	223	121	81	74	68
6	Fixed Wind	0-20	12-30	700-800	364	0	-	0	108	72	66	61
7	Fixed Wind	0-20	12-30	800-900	1,593	-	-	0	102	68	62	57
8	Fixed Wind	0-20	12-30	900+	1,528	0	51	177	95	64	58	54
9	Fixed Wind	0-20	30-60	<700	569	1	37	130	136	92	84	77
10	Fixed Wind	0-20	30-60	700-800	83	0	30	106	121	82	75	69
11	Fixed Wind	0-20	30-60	800-900	21	0	-	0	114	77	70	65
12	Fixed Wind	0-20	30-60	900+	1,655	0	45	157	107	72	66	61
13	Fixed Wind	0-20	60+	<700	196	-	-	0	153	98	88	81
14	Fixed Wind	0-20	60+	700-800	18	-	-	0	137	87	78	72
15	Fixed Wind	0-20	60+	800-900	28	0	-	0	129	82	74	68
16	Fixed Wind	0-20	60+	900+	1,667	0	681	2382	121	77	69	64
17	Fixed Wind	20-40	0-12	<700	12,378	81	670	2346	122	82	74	68
18	Fixed Wind	20-40	0-12	700-800	4,061	1	97	339	108	73	66	61
19	Fixed Wind	20-40	0-12	800-900	3,620	0	78	272	102	69	63	57
20	Fixed Wind	20-40	0-12	900+	3,982	0	15	53	96	65	58	54
21	Fixed Wind	20-40	12-30	<700	1,482	-	137	479	127	86	78	72
22	Fixed Wind	20-40	12-30	700-800	391	0	-	0	114	77	70	64
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24	Fixed Wind	20-40	12-30	900+	11,916	1	156	546	100	68	62	57
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26	Fixed Wind	20-40	30-60	700-800	54	10	27	96	127	87	79	73
27	Fixed Wind	20-40	30-60	800-900	88	1	36	126	120	82	75	69
28	Fixed Wind	20-40	30-60	900+	15,828	70	945	3308	112	77	70	65
29	Fixed Wind	20-40	60+	<700	247	0	-	0	160	104	93	86
30	Fixed Wind	20-40	60+	700-800	22	0	-	0	143	93	83	76
31	Fixed Wind	20-40	60+	800-900	20	0	-	0	135	87	78	72

Site type	Technology	Segment				Sea floor km^2		Capacity	Levelised Cost (£/MWh)			
		Depth (m)	Distance from shore (mm)	Wind speed (W/m^2)	No constraints	Hard plus low level soft constrained sites (20% least constrained sites)	Base Case (35% least constrained sites)	MW Available (excl R1, R2, R3 and all extensions)	2015	2025	2035	2045
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35	Fixed Wind	40-60	0-12	800-900	3,081	-	184	643	107	73	66	61
36	Fixed Wind	40-60	0-12	900+	6,537	-	12	43	100	68	62	57
37	Fixed Wind	40-60	12-30	<700	566	-	-	0	133	91	83	76
38	Fixed Wind	40-60	12-30	700-800	635	1	-	0	119	82	74	68
39	Fixed Wind	40-60	12-30	800-900	2,043	-	88	309	112	77	70	64
40	Fixed Wind	40-60	12-30	900+	23,490	281	1,755	6143	105	72	65	60
41	Fixed Wind	40-60	30-60	<700	110	0	-	0	149	103	93	87
42	Fixed Wind	40-60	30-60	700-800	53	4	13	46	133	92	83	77
43	Fixed Wind	40-60	30-60	800-900	132	-	36	126	126	86	79	73
44	Fixed Wind	40-60	30-60	900+	13,460	940	3,927	13744	117	81	74	68
45	Fixed Wind	40-60	60+	<700	255	0	11	40	168	110	99	91
46	Fixed Wind	40-60	60+	700-800	36	1	-	0	150	98	88	81
47	Fixed Wind	40-60	60+	800-900	12	0	-	0	141	93	83	77
48	Fixed Wind	40-60	60+	900+	7,196	1,552	2,934	10267	132	87	78	72

Site type	Technology		Segment			Sea floor km²		Capacity	Levelised Cost (£/MWh)			
		Depth (m)	Distance from shore (mm)	Wind speed (W/m²)	No constraints	Hard plus low level soft constrained sites (20% least constrained sites)	Base Case (35% least constrained sites)	MW Available (excl R1, R2, R3 and all extensions)	2015	2025	2035	2045
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2	Floating Wind	-	0-12	700-800	2,295	-	-	-	136	98	83	73
3	Floating Wind	-	0-12	800-900	3,270	-	-	-	129	92	79	69
4	Floating Wind	-	0-12	>900	9,946	-	-	-	120	86	73	65
5	Floating Wind	-	12-30	<700	461	-	-	-	159	114	98	86
6	Floating Wind	-	12-30	700-800	600	2	-	6	142	102	87	77
7	Floating Wind	-	12-30	800-900	1,864	-	-	-	134	96	82	73
8	Floating Wind	-	12-30	>900	45,335	1,622	-	5,676	125	90	77	68
9	Floating Wind	-	30-60	<700	82	-	-	-	178	129	111	99
10	Floating Wind	-	30-60	700-800	133	2	-	8	159	115	99	88
11	Floating Wind	-	30-60	800-900	287	-	-	-	150	109	93	84
12	Floating Wind	-	30-60	>900	80,739	19,739	-	69,086	141	102	87	78
13	Floating Wind	-	60-100	<700	0	-	-	-	201	140	118	106
14	Floating Wind	-	60-100	700-800	-	-	-	-	180	125	105	94
15	Floating Wind	-	60-100	800-900	-	-	-	-	170	118	100	89
16	Floating Wind	-	60-100	>900	102,123	34,518	-	120,814	159	111	93	83
17	Floating Wind	-	100-200	<700	296	0	-	0	226	153	128	115
18	Floating Wind	-	100-200	700-800	292	0	-	0	202	136	114	103
19	Floating Wind	-	100-200	800-900	11	0	-	0	191	129	108	97
20	Floating Wind	-	100-200	>900	138,840	44,148	-	154,519	179	121	101	91

Wave & Tidal Site segmentation

Site	Technology	Description	Available MW	Levelised Cost (£/MWh) 2020	Levelised Cost (£/MWh) 2025	Levelised Cost (£/MWh) 2035	Levelised Cost (£/MWh) 2045
1	Wave	Single site	4,566	195	158	130	117
1	Tidal Stream	High attractive	9,418	135	102	78	64
3	Tidal Stream	Medium Attractive	23,687	179	135	103	84
4	Tidal Stream	Least Attractive	23,687	241	182	139	114
1	Tidal Range	Site type 1	1,027		146	134	110
2	Tidal Range	Site type 2	609		204	187	153
3	Tidal Range	Site type 3	875		242	222	182
4	Tidal Range	Site type 4	989		254	234	191
5	Tidal Range	Site type 5	6,393		172	158	130
6	Tidal Range	Site type 6	3,805		254	234	191

Site segmentation under Scenario 3: The UK as a Net Energy Producer

Fixed and floating wind segmentation

Site type	Technology	Segment				Sea floor km²		Capacity	Levelised Cost (£/MWh)			
		Depth (m)	Distance from shore (mm)	Wind speed (W/m²)	No constraints	Hard plus low level soft constrained sites (20% least constrained sites)	Base Case (35% least constrained sites)	MW Available (excl R1, R2, R3 and all extensions)	2015	2025	2035	2045
1	Fixed Wind	0-20	0-12	<700	17,688	28	208	728	115	77	69	63
2	Fixed Wind	0-20	0-12	700-800	2,910	2	13	45	103	69	62	57
3	Fixed Wind	0-20	0-12	800-900	1,729	0	-	0	97	65	59	53
4	Fixed Wind	0-20	0-12	900+	475	0	-	0	91	61	55	50
5	Fixed Wind	0-20	12-30	<700	965	-	64	223	121	81	73	67
6	Fixed Wind	0-20	12-30	700-800	364	0	-	0	108	72	66	60
7	Fixed Wind	0-20	12-30	800-900	1,593	-	-	0	102	68	62	57
8	Fixed Wind	0-20	12-30	900+	1,528	0	51	177	95	64	58	53
9	Fixed Wind	0-20	30-60	<700	569	1	37	130	136	92	83	77
10	Fixed Wind	0-20	30-60	700-800	83	0	30	106	121	82	74	69
11	Fixed Wind	0-20	30-60	800-900	21	0	-	0	114	77	70	65
12	Fixed Wind	0-20	30-60	900+	1,655	0	45	157	107	72	66	61
13	Fixed Wind	0-20	60+	<700	196	-	-	0	153	98	87	80
14	Fixed Wind	0-20	60+	700-800	18	-	-	0	137	87	78	71
15	Fixed Wind	0-20	60+	800-900	28	0	-	0	129	82	74	67
16	Fixed Wind	0-20	60+	900+	1,667	0	681	2382	121	77	69	63
17	Fixed Wind	20-40	0-12	<700	12,378	81	670	2346	122	82	74	68
18	Fixed Wind	20-40	0-12	700-800	4,061	1	97	339	108	73	66	60
19	Fixed Wind	20-40	0-12	800-900	3,620	0	78	272	102	69	62	57
20	Fixed Wind	20-40	0-12	900+	3,982	0	15	53	96	65	58	53
21	Fixed Wind	20-40	12-30	<700	1,482	-	137	479	127	86	78	72
22	Fixed Wind	20-40	12-30	700-800	391	0	-	0	114	77	70	64
23	Fixed Wind	20-40	12-30	800-900	4,392	-	39	136	107	73	66	60
24	Fixed Wind	20-40	12-30	900+	11,916	1	156	546	100	68	62	56
25	Fixed Wind	20-40	30-60	<700	444	8	103	361	142	97	88	81
26	Fixed Wind	20-40	30-60	700-800	54	10	27	96	127	87	79	73
27	Fixed Wind	20-40	30-60	800-900	88	1	36	126	120	82	74	69
28	Fixed Wind	20-40	30-60	900+	15,828	70	945	3308	112	77	70	64
29	Fixed Wind	20-40	60+	<700	247	0	-	0	160	104	93	85
30	Fixed Wind	20-40	60+	700-800	22	0	-	0	143	93	83	76
31	Fixed Wind	20-40	60+	800-900	20	0	-	0	135	87	78	71

Site type	Technology	Segment				Sea floor km²		Capacity	Levelised Cost (£/MWh)			
		Depth (m)	Distance from shore (mm)	Wind speed (W/m²)	No constraints	Hard plus low level soft constrained sites (20% least constrained sites)	Base Case (35% least constrained sites)	MW Available (excl R1, R2, R3 and all extensions)	2015	2025	2035	2045
32	Fixed Wind	20-40	60+	900+	14,417	428	3,320	11620	126	82	73	67
33	Fixed Wind	40-60	0-12	<700	7,730	11	223	780	127	87	78	72
34	Fixed Wind	40-60	0-12	700-800	3,202	0	155	543	114	78	70	64
35	Fixed Wind	40-60	0-12	800-900	3,081	-	184	643	107	73	66	60
36	Fixed Wind	40-60	0-12	900+	6,537	-	12	43	100	68	62	56
37	Fixed Wind	40-60	12-30	<700	566	-	-	0	133	91	83	76
38	Fixed Wind	40-60	12-30	700-800	635	1	-	0	119	82	74	68
39	Fixed Wind	40-60	12-30	800-900	2,043	-	88	309	113	77	70	64
40	Fixed Wind	40-60	12-30	900+	23,490	281	1,755	6143	105	72	65	60
41	Fixed Wind	40-60	30-60	<700	110	0	-	0	149	103	93	86
42	Fixed Wind	40-60	30-60	700-800	53	4	13	46	133	92	83	77
43	Fixed Wind	40-60	30-60	800-900	132	-	36	126	126	86	79	72
44	Fixed Wind	40-60	30-60	900+	13,460	940	3,927	13744	117	81	73	68
45	Fixed Wind	40-60	60+	<700	255	0	11	40	168	110	98	90
46	Fixed Wind	40-60	60+	700-800	36	1	-	0	150	98	88	80
47	Fixed Wind	40-60	60+	800-900	12	0	-	0	141	93	83	76
48	Fixed Wind	40-60	60+	900+	7,196	1,552	2,934	10267	132	87	78	71

Site type	Technology	Segment				Sea floor km²		Capacity	Levelised Cost (£/MWh)			
		Depth (m)	Distance from shore (mm)	Wind speed (W/m²)	No constraints	Hard plus low level soft constrained sites (20% least constrained sites)	Base Case (35% least constrained sites)	MW Available (excl R1, R2, R3 and all extensions)	2015	2025	2035	2045
1	Floating Wind	-	0-12	<700	4,877	1	-	4	152	108	90	79
2	Floating Wind	-	0-12	700-800	2,295	-	-	-	136	97	80	71
3	Floating Wind	-	0-12	800-900	3,270	-	-	-	129	91	76	67
4	Floating Wind	-	0-12	>900	9,946	-	-	-	120	86	71	63
5	Floating Wind	-	12-30	<700	461	-	-	-	159	113	94	83
6	Floating Wind	-	12-30	700-800	600	2	-	6	142	101	84	75
7	Floating Wind	-	12-30	800-900	1,864	-	-	-	134	95	80	70
8	Floating Wind	-	12-30	>900	45,335	1,622	-	5,676	125	89	74	66
9	Floating Wind	-	30-60	<700	82	-	-	-	178	128	107	96
10	Floating Wind	-	30-60	700-800	133	2	-	8	159	114	95	85
11	Floating Wind	-	30-60	800-900	287	-	-	-	150	108	90	81
12	Floating Wind	-	30-60	>900	80,739	19,739	-	69,086	141	101	84	75
13	Floating Wind	-	60-100	<700	0	-	-	-	201	138	114	101
14	Floating Wind	-	60-100	700-800	-	-	-	-	179	123	102	91
15	Floating Wind	-	60-100	800-900	-	-	-	-	170	117	96	86
16	Floating Wind	-	60-100	>900	102,123	34,518	-	120,814	159	109	90	80
17	Floating Wind	-	100-200	<700	296	0	-	0	198	158	129	116
18	Floating Wind	-	100-200	700-800	292	0	-	0	177	141	115	103
19	Floating Wind	-	100-200	800-900	11	0	-	0	167	133	109	98
20	Floating Wind	-	100-200	>900	138,840	44,148	-	154,519	156	124	102	91

Wave & Tidal Site segmentation

Site	Technology	Description	Available MW	Levelised Cost (£/MWh) 2020	Levelised Cost (£/MWh) 2025	Levelised Cost (£/MWh) 2035	Levelised Cost (£/MWh) 2045
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1	Tidal Range	Site type 1	1,027		146	132	109
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4	Tidal Range	Site type 4	989		254	230	190
5	Tidal Range	Site type 5	6,393		172	156	129
6	Tidal Range	Site type 6	3,805		254	230	190

The Offshore Valuation Group

The Offshore Valuation Group is an informal collaboration of government and industry organisations who have come together to address the question: **what is the value of the UK's offshore renewable energy resource?**

1. The Department of Energy & Climate Change
2. The Scottish Government
3. The Welsh Assembly Government
4. The Crown Estate
5. Energy Technologies Institute
6. Scottish & Southern Energy
7. RWE Innogy
8. E.ON
9. DONG Energy
10. Statoil
11. Mainstream Renewable Power
12. Renewable Energy Systems (RES)
13. Vestas
14. Public Interest Research Centre

Boston Consulting Group was commissioned to undertake the study. The study was funded by and drew on the expertise of the Group. The study also benefited through funding and technical assistance from The Committee on Climate Change Secretariat. The project was initiated and coordinated by Public Interest Research Centre.
This report was undertaken to better understand the potential value of the UK's offshore renewable energy resource. Its findings do not necessarily represent the policies or views of all members of the Offshore Valuation Group.

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