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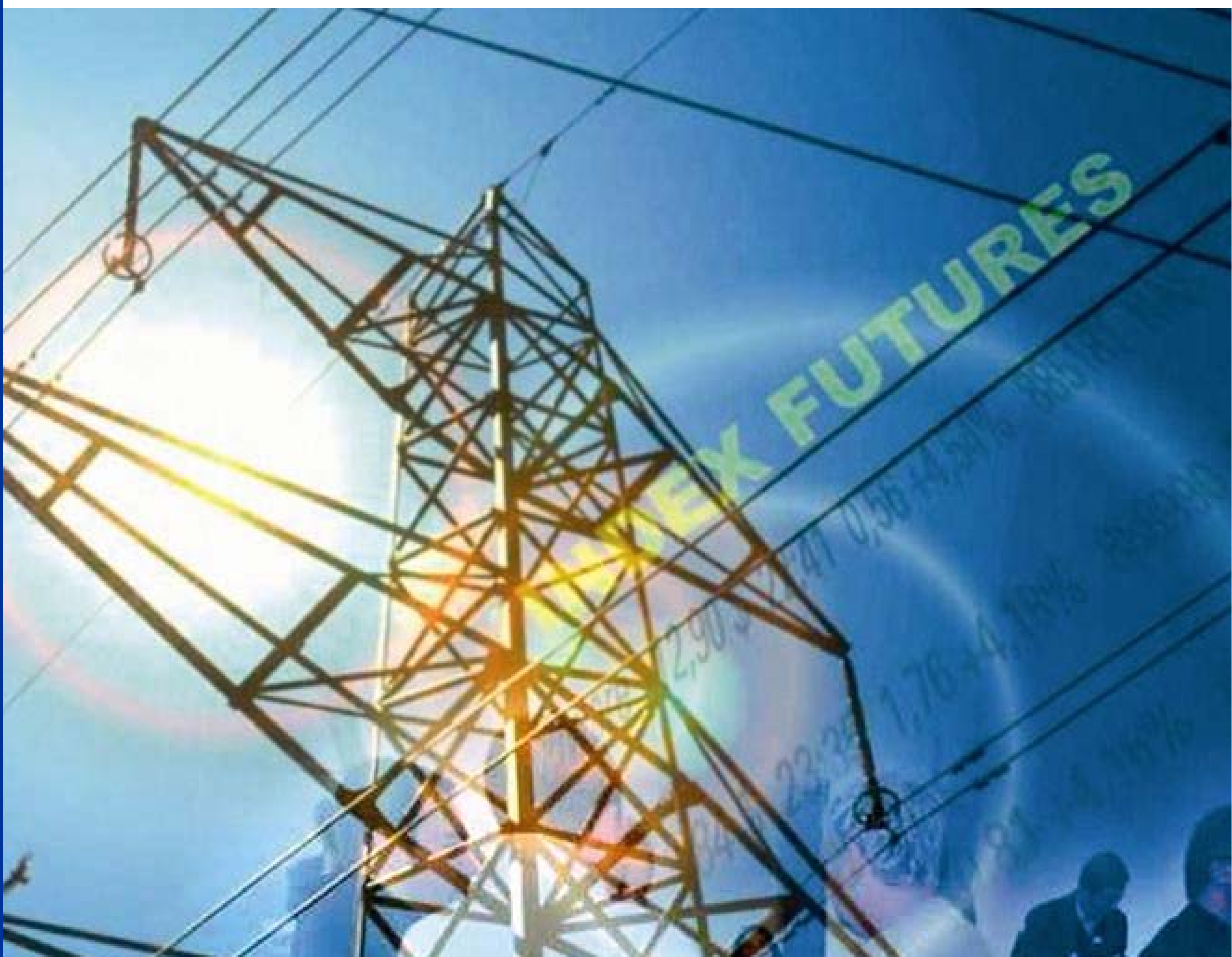
TIMELINE FOR WIND GENERATION TO 2020 AND A SET OF PROGRESS INDICATORS

A report to the Committee on Climate Change

July 2009

TIMELINE FOR WIND GENERATION TO 2020 AND A SET OF PROGRESS INDICATORS



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Pöyry Energy Consulting is Europe's leading energy consultancy providing strategic, commercial, regulatory and policy advice to Europe's energy markets. The team of 250 energy specialists, located across 15 European offices in 12 countries, offers unparalleled expertise in the rapidly changing energy sector.

Eversheds is a global law firm with one of the largest renewable and clean energy legal teams providing advice to developers of renewable energy proposals on corporate, M&A, construction, real estate, planning and consenting and shipping. A dedicated planning team specialising in renewable energy has amassed over 20 years experience in the sector and has advised developers on over 120 onshore wind farms proposals and the majority of the offshore wind farms proposals across the UK.

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EXECUTIVE SUMMARY

Introduction

The UK Government has identified onshore and offshore wind power generation as the key technologies for achieving its ambitious targets of increasing the share of renewable energy to 15% by 2020 and to reduce greenhouse gas emissions to 80% below 1990 levels by 2050.

The 2008 Renewable Energy Strategy Consultation suggested that installed wind capacity would need to increase from the current 3.6GW to around 28GW by 2020 to meet these ambitions. Though the UK has abundant wind resource, and the technology is relatively easier to deploy in the short-term compared to other low-carbon technologies, such as nuclear and CCS, this remains a very challenging growth target for industry participants and policy-makers.

Delivery of this significant increase in capacity requires a step change in investment levels and construction rates. Historic growth has been constrained by the lengthy planning process, long lead times for connection, lack of supply chain capacity and competition for finance. Given the importance of meeting the targets and the short timeframe in which to achieve them, it is essential that the commercial and regulatory environment develops to alleviate these constraints and facilitate faster deployment, Any remaining barriers must be identified, and responded to, as quickly and efficiently as possible.

The aims of this study are to:

- create a useful set of indicators that inform policymakers of the progress against targets;
- identify realistic trajectories of wind deployment given changes in market and regulatory structures;
- present the main stages of the project cycle from pre-development assessment through to operation;
- highlight the main constraints to faster deployment within the project cycle; and
- describe necessary steps to accelerate deployment if out-turns indicate non-delivery against trajectories.

This work is set to feed into a wider set of milestones and indicators which will be used by the Committee on Climate Change (CCC) to monitor whether the Government is on track to meet its carbon budgets and help identify challenges that need to be addressed. The main analysis was undertaken between April and June 2009 and therefore does not account for any new policy initiatives contained in The UK Low Carbon Transition Plan or UK Renewable Energy Strategy published in July 2009.

Project cycle and key constraints

Every new wind development must proceed through the key stages in the project cycle before it can generate electricity and contribute to meeting renewable energy and carbon targets. These stages, shown in the schematic representation provided in Figure 1, are:

- Pre-development – involving preliminary investigations into the commercial viability of the windfarm.

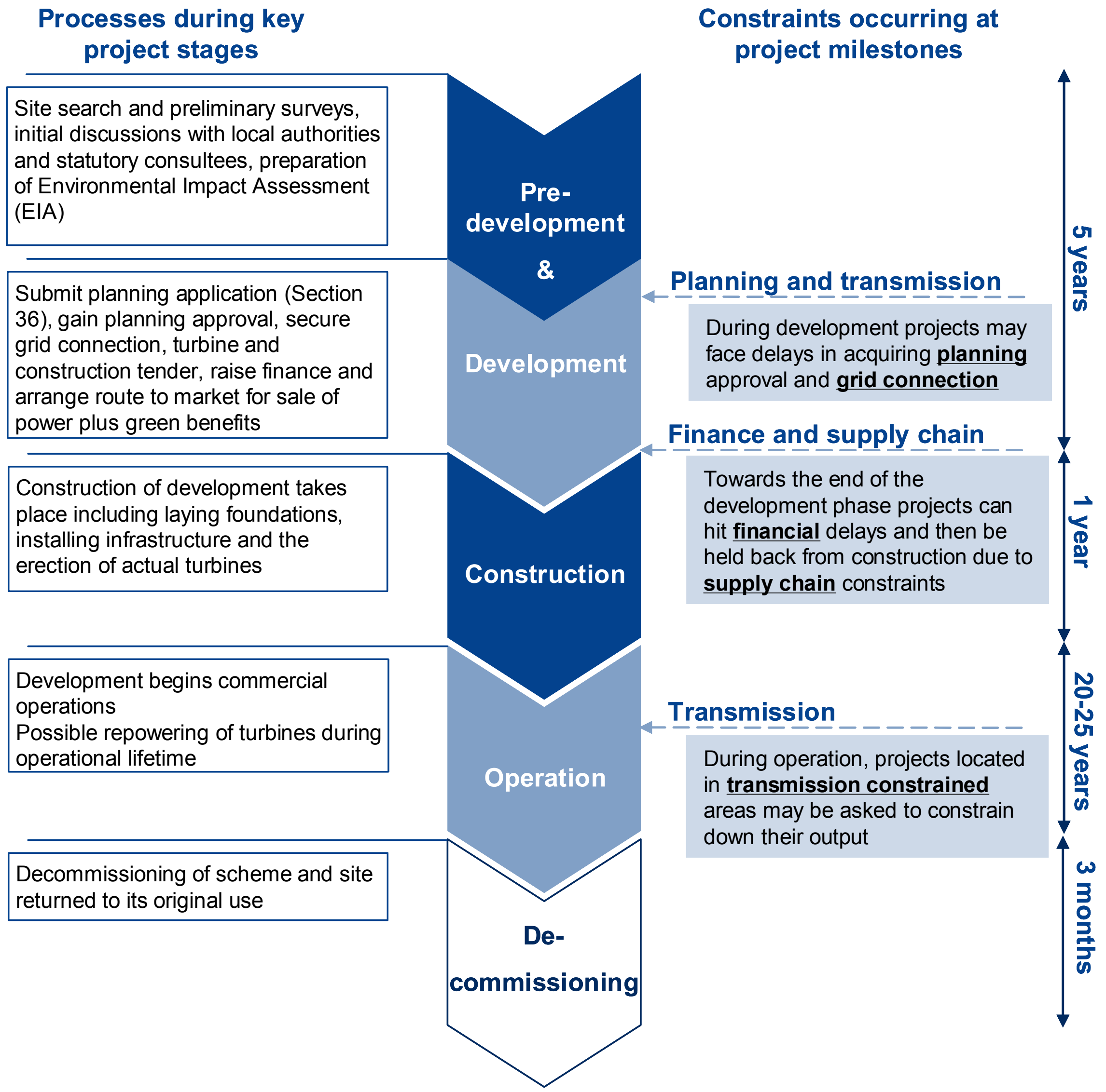
- Development – during which all the main consents (including planning and grid connection) are granted, infrastructure orders are placed, and the main bulk of financing is acquired.
- Construction.
- Operation.

Delays or barriers at any, or all, of these stages will affect the ability of the system to deliver the level of new capacity and associated generation that is required to meet policy targets. Our analysis has identified four main areas of constraint impacting on the level and/or timing of deployment.

- Insufficient **supply chain capability** to construct all projects that have completed development. Current activity suggests that the supply chain can deliver around 1.5GW per annum (0.85GW onshore and 0.65GW offshore), but the required build rate over the next decade is around 2.5GW per annum. For onshore, the shortfall is primarily related to the supply of wind turbines and skilled engineering resources, whereas for offshore, the major concern is the availability of specialist installation vessels, subsea cables and the supply of offshore turbines.
- Delays in **project development period**, often due to delays receiving planning approval. For example, at present, the average time an onshore windfarm project is in development is 52 months, compared to a potentially achievable minimum of 46 months.
- Insufficient or delayed **transmission reinforcement and investment**. For example, recent Electricity Networks Strategy Group (ENSG) and Crown Estates reports identify up to £14bn of transmission investment required before 2020 to enable 26 – 34GW of new wind capacity to be connected.
- **Lack of liquidity in the financial markets**, more recently, has affected the availability of both debt and equity and led to a lengthening in the time taken to obtain finance. For example, in the current environment, projects are taking up to three times longer to reach financial close and independent developers are struggling to access any finance.

These constraints have different effects depending on whether the development is onshore or offshore, which jurisdiction it is located in (England, Scotland, Wales or Northern Ireland), the size of the project and the type of developer (i.e. small or large independent market player or a utility).

Figure 1 – Example of an onshore wind project cycle and the stages of when the major constraints occur



NB: Timings are for an above 50MW windfarm located in England under existing planning statutory guideline timescales

Market and policy response

Aside from the impact of the current financial crisis, these constraints have already been recognised by Government and the industry. Where the constraints relate to the regulatory regime, these are being addressed via proposed changes to policy including:

- reform of the planning regime, including the introduction of the Infrastructure Planning Commission (IPC) under the 2008 Planning Act which aims to simplify the planning procedure for onshore wind projects greater than 50MW and offshore wind projects over 100MW;
- publication by the ENSG of a report identifying onshore transmission system reinforcements necessary to accommodate the growth in onshore and offshore wind to 2020 and a report by the Crown Estates identifying the offshore transmission

investment required to deliver up to 25GW of Round 3 offshore wind generation projects;

- creation of a new regulatory regime for offshore transmission introduced by Ofgem and DECC which provides for the allocation of Offshore Transmission Owner (OFTO) licences using a tender process; and
- revisions to the GB transmission access arrangements that replace the current model of 'invest and connect' to Ofgem's proposed 'connect and manage' whereby access rights can be allocated before the system has been appropriately reinforced to accommodate the new generation source.

Furthermore, it is anticipated that the market will respond to signals to alleviate the current supply chain constraints through further investment. There have been several recent studies[1] focusing on supply chain issues, highlighting the necessary market developments to ensure the successful deployment of wind to meet the 2020 targets. These include an additional ten offshore installation vessels operating by 2020 and the construction of two new turbine manufacturing facilities in the UK. Though there is no firm evidence that this expansion in construction capability is underway, anecdotal evidence from developers suggests that the market is gearing up to meet this anticipated increase in demand with some utilities acknowledging the need to commission an installation vessel if they are to build their Round 3 offshore wind projects.

An achievable deployment trajectory

To investigate the impact of these announced and anticipated developments in the environment for wind deployment, we have developed a simulation model of national deployment potential that produces trajectories of annual capacity growth by technology type (onshore/offshore) and location (England, Wales, Scotland, Northern Ireland) under different commercial and regulatory scenarios.

If all the proposed improvements to the planning process and transmission access regime are effective and timely, and occur alongside a rapid growth in the UK's supply chain capability as projected in reports by SKM and BVG Associates then, by 2020, the UK has the potential to deliver 27GW of onshore and offshore wind, as shown in Figure 2. This is in line with existing projections underpinning the EU renewable energy target.

However, there is a material risk that not all the market and regulatory changes will occur to time, or deliver the expected acceleration in the speed of wind deployment. Our scenario analysis suggests that failure to realise improvements across all of the current constraints affecting wind deployment may mean wind capacity falling short of the feasible potential by around 5GW or 20%. Furthermore, it suggests that policies must address simultaneously constraints across the project cycle, else they risk altering where constraints arise rather than improving rates of growth in capacity.

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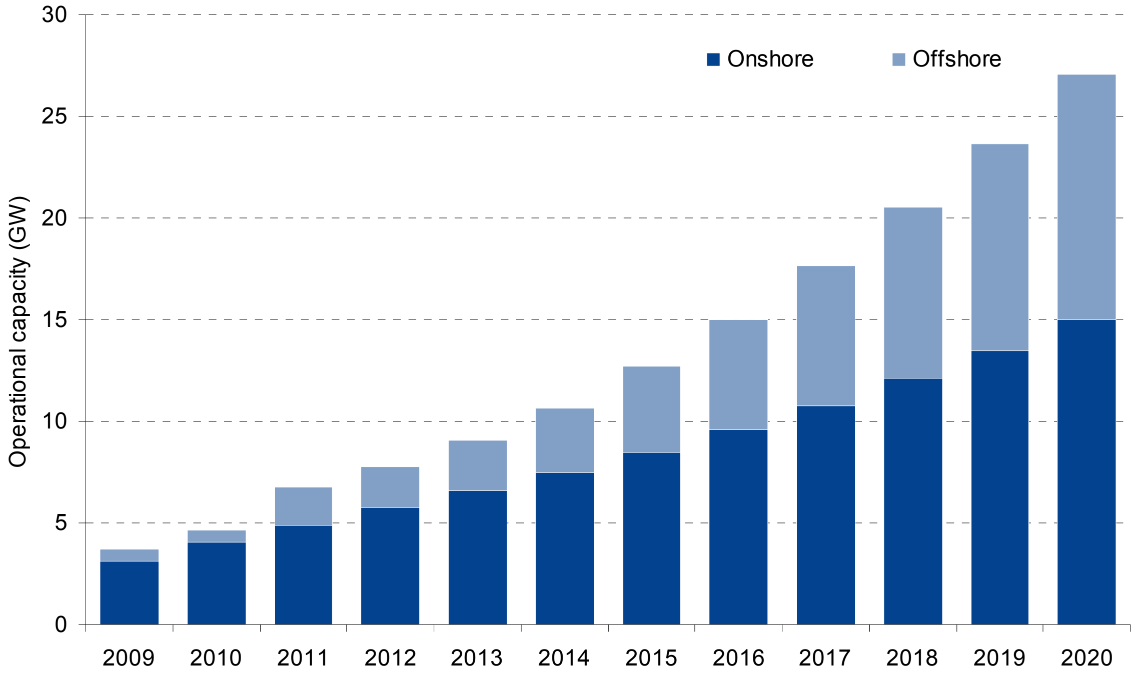
1 These include the 2008 SKM report 'Quantification of Constraints on the Growth of UK Renewable Generating Capacity' and the more recent study by BVG Associates on how to improve delivery of UK offshore wind.

Figure 2 – Growth in onshore and offshore capacity to 2020 under a High Feasible scenario



Monitoring progress and indicators

Consequently, it is important that barriers or risks are identified as early as possible and acted upon quickly and efficiently. We have therefore developed a set of indicators to assist the CCC in performing this essential task.

In selecting appropriate indicators to track progress against a targeted level of wind capacity (and output) by 2020, it was essential they encompassed observed levels of deployment and achievement of specific policy or market milestones. Consequently, the indicators derived for the CCC were split into two groups – core and underpinning.

Core indicators were chosen on the basis that the CCC would be able to compare actual wind deployment and the implied trajectory to 2020, with that envisaged by a pre-determined trajectory[2] for the corresponding year (such as that shown in Figure 2). Separately, underpinning indicators were selected to help the CCC identify the cause(s) of any differences between the current position and the feasible target trajectory. Based on the results of looking at the various constraints that impede and reduce the growth in wind generation, a set of underpinning indicators were selected to cover three main areas:

- policy milestones/deliverables;
- development and planning; and

[2] For testing purposes, we used the High Feasible scenario shown in Figure 2, although this does not preclude the CCC from revising their required trajectory in future years should they choose to do so.

- supply chain.

Table 1 and Table 2 present the final set of core and underpinning indicators, respectively, chosen for the CCC to measure progress in wind capacity and wind generation. In each table, the sub-bullets indicate the degree of disaggregation in the specific indicator.

Table 1 – Summary table of core indicators

Core Indicators	Unit
Total installed wind capacity in current year: – Onshore and offshore – England, Scotland, Wales and Northern Ireland	GW
Total generation in current year: – % of overall UK energy demand – % of UK electricity generation	TWh
Load factor in current year: – Onshore and offshore – England, Scotland, Wales and Northern Ireland	%
Projected installed capacity in 2020	GW
Projected generation in 2020	TWh

Table 2 – Summary table of underpinning indicators

Underpinning Indicators	Unit
Policy milestones:	Year
– Implementation of transmission access rules	
– ENSG transmission reinforcement dates	
Average period for a project in planning:	Months
– Onshore and offshore	
– England, Scotland, Wales and Northern Ireland	
– 1-5MW, 5-50MW, Over 50MW – onshore	
– ±100MW – offshore	
Average period for a project in development	Months
– Type of developer – independent, utility	
– Onshore and offshore	
– England, Scotland, Wales and Northern Ireland	
– 1-5MW, 5-50MW, Over 50MW – onshore	
– ±100MW – offshore	
Supply chain indicators	
– Current capacity under construction	GW
– Proportion of successfully approved projects	%
– Annual required capacity of planning applications	GW
– Cumulative capacity of planning applications since 2009	GW
– Number of vessels for UK market (offshore)	No. of vessels
– Number of turbine factories (onshore)	No. of factories

To complement the reported indicators, a traffic light monitoring system has also been developed. This will enable the CCC to assess whether a particular indicator is falling outside a pre-determined tolerance band and hence may cause future problems if not addressed.

No-one underestimates the scale of the challenge ahead. Progress must be seen in removing constraints on the development of wind capacity and targeted, transparent indicators of performance that can be benchmarked and monitored are a means of supporting the changes that the industry needs.

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1. INTRODUCTION

1.1 Background

The Committee on Climate Change (CCC) was set up as part of the Climate Change Act and is tasked with providing advice to the UK Government on climate change issues and particularly the setting of carbon budgets for the UK. In December 2008, the CCC published its first report[3], concluding that:

- climate change poses a huge threat to human welfare, and the UK must act now to significantly reduce emissions by 34%-42% by 2020 and 80% by 2050;
- a 34%-42% reduction in emissions by 2020 is achievable through a combination of measures to reduce the carbon intensity of electricity and heat generation, encourage energy efficiency and move towards the electrification of transport; and
- meeting the 2050 target is likely to require the almost complete decarbonisation of the power sector and the extension of electricity to a wider range of energy end uses (primarily heat and transport).

As acknowledged by the CCC, these are challenging medium- and long-term targets for carbon reduction and renewable energy within the UK and will require a step change in the development and deployment of low-carbon technologies. They will also require a concerted effort from industry and government to deliver them.

Although the CCC did not recommend a specific technology mix to decarbonise the power sector, given the UK's commitment to meeting its share of the EU renewable energy target and the pace at which other technologies such as nuclear and CCS could be deployed, renewables, especially wind, are expected to play a significant role in the period to 2020.

However, delivering required growth in wind generation over the next twelve years will be challenging, as illustrated by Figure 3, and therefore it will be essential for any barriers to be identified and responded to as quickly and efficiently as possible.

Against this background, Pöyry Energy Consulting, together with Eversheds and Energyline, was commissioned by the CCC to develop a set of indicators that inform policymakers of:

- the progress against targets;
- what can realistically be expected from industry under certain circumstances;
- where the main constraints to faster deployment are; and
- what must be done if growth does not follow the required trajectory.

This work is set to feed into a wider set of milestones and indicators which will be used by the CCC to monitor whether the Government is on track to meet its carbon budgets and help identify challenges that need to be addressed.

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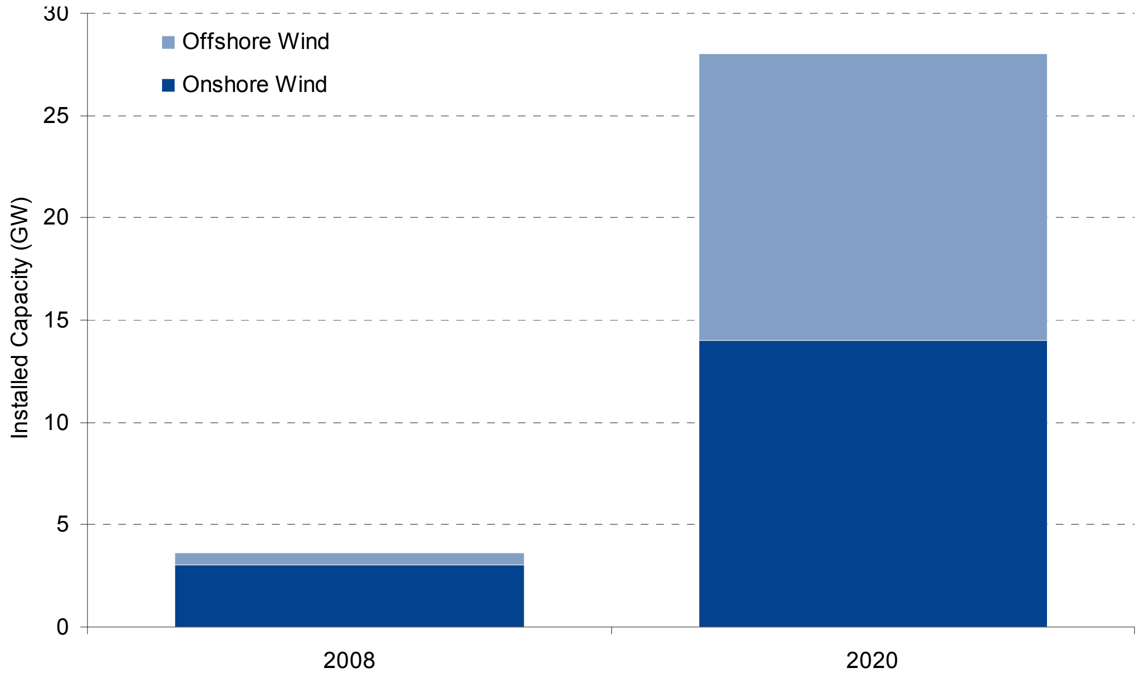
[3] Building a low-carbon economy – the UK's contribution to tackling climate change. Committee on Climate Change, December 2008.

Figure 3 – 2008 and indicative 2020 levels of wind deployment

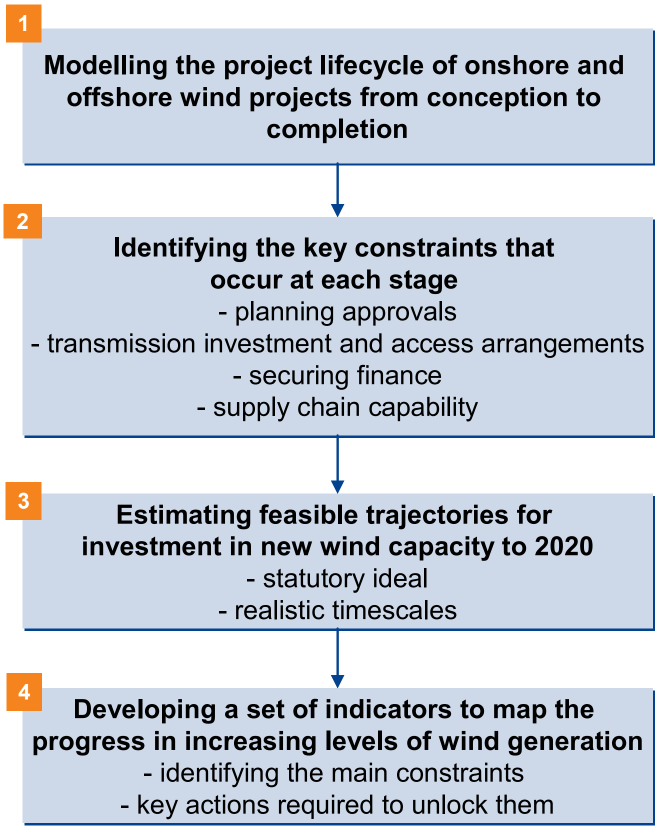


Source: BWEA, Committee on Climate Change.

Our approach to this study is detailed in Figure 4 and consists of four main stages:

- modelling the project lifecycle of onshore and offshore wind projects from conception to operation;
- identifying the key constraints that occur at each stage;
- estimating a feasible trajectory for investment in new wind capacity to 2020; and
- developing a set of indicators to map the progress of increasing levels of wind generation against the feasible trajectory.

Figure 4 – Study approach



1.2 Structure of report

The first half of this report focuses on the various constraints that may slow, or halt, deployment:

- Section 2 introduces the various stages involved in the project cycle and the key constraints that occur at each of these stages.
- Section 3 provides a discussion on the financial bottlenecks that are currently affecting wind investments.
- Section 4 presents an overview of the planning regime in the UK for wind energy proposals; discusses the timescales and approval rates of onshore and offshore wind in the UK that occur in practice and identifies the constraints encountered in the planning process and reasons for delays.
- Section 5 discusses the key issues that affect the supply chain for building onshore and offshore wind projects and presents some measures necessary to alleviate such constraints.
- Section 6 assesses required transmission investments and access arrangements needed to facilitate increasing levels of wind generation, taking specific account of the recent ENSG report and the multiple CUSC amendments proposed under TAR.

The second half of the report sets out the results of the various trajectories for investment in new wind capacity to 2020 and presents the proposed indicators to measure progress:

- Section 7 sets out the approach to, and the results of, our trajectories for investment in new wind capacity to 2020. This includes a High Feasible scenario where any proposed developments are implemented and operated according to defined timescales and an Alternative scenario where some proposed improvements to the regulatory and commercial environment are not realised.
- Section 8 presents the core indicators that would be used to assess the position in any one year relative to the trajectory assumed under the High Feasible and our suggested approach to help the CCC in assessing the magnitude and implication of any one indicator.

Annexes to this report provide further detail on the planning cycle (Annex A), the offshore transmission regime (Annex B), the various transmission access related CUSC modifications (Annex C), alternative scenario results (Annex D) and typical transmission investment project timelines (Annex E).

2. THE PROJECT CYCLE

To monitor the deployment of onshore and offshore wind generation effectively, progress and performance at each stage of the project cycle must be reviewed since constraints may occur at any of the key stages in developing a wind project.

This Section describes the key stages from project conception to completion for an onshore and offshore wind project and introduces the key constraints at each stage. Subsequent Sections then discuss these constraints in further detail – finance (Section 3), planning (Section 4), supply chain (Section 5) and transmission investment (Section 6)

2.1 Project cycle

The principal stages of a project cycle are pre-development, development, construction and operation. Within each stage there are a number of processes or actions that have to be completed, some of which may be sequential, while others may happen concurrently.

Table 3 presents an overview of the project cycle for an onshore wind project whilst Table 4 presents the same for an offshore wind project. Though the stages are similar, the requirements, the relevant authorities and the timescales involved may differ. This brief overview is not comprehensive but is designed to give a general idea of the processes involved. Further detail is provided on the precise arrangements in the relevant Sections. In particular, the planning process outlined below will differ between England and Wales and Scotland and by size of project (with the implementation of the Planning Act 2008).

Table 3 – Overview of the project cycle for an onshore wind project

Stage	Processes
Pre-development	*Funding to launch prospecting and site acquisition phase* *Site selection and acquisition:* Site search, preliminary surveys to identify any constraints, initial discussions with local authorities and statutory consultees to identify key concerns in relation to the development of the site, initial identification of turbine layout and type of turbine that can be deployed. *Environmental Impact Assessment (EIA):* Scoping opinion sought from the relevant statutory authority for remit of EIA, consultation with statutory consultees to identify areas of concern, finalise layout following any iterations to avoid any sensitive areas, preparation of Environmental Statement and other documentation ready for planning submission:
Development	
Planning	*Submission, consideration and determination of planning application:* Submission of application to Local Planning Authority (LPA) for <50MW or to relevant Secretary of State if >50MW; consultation process with statutory consultees and public. *Decision of planning application:*

Stage	Processes
	Decision for under 50MW made to either approve or refuse the application although some applications can remain undetermined. For over 50MW proposals if the LPA object to the proposal a public inquiry is almost always called. *Post decision stage:* If the application is approved, the developer must comply with conditions attached to the permission to proceed with development. *Appeal stage:* For onshore proposals under 50 MW only, applicant has option of submitting an appeal to the relevant body if the application is refused by the LPA or not determined within the relevant time period. Relevant appeal body determines how the appeal is dealt with after consideration from appellant and LPA. Three modes for hearing an appeal: written representations; informal hearing; or public inquiry, with majority of onshore wind farm appeals are heard by the latter (around 90%). *Judicial review/legal challenge (if applicable):* An increasing number of decisions are challenged either by way of legal challenge for under 50MW proposals in England, Wales and Northern Ireland or judicial review for under 50MW proposals in Scotland and all over 50MW proposals.
Electricity Connection Agreements	Developer makes an application for a connection to the electricity infrastructure to the GB Transmission System Operator (TSO) or the local Distribution System Operator (DSO) and the SO has to respond with a connection offer within a certain timescale. In addition the TSO or DSO must apply for the necessary consents in relation to the grid connection route and if the grid connection is to be by overhead line they must make an application under Section 37 of the Electricity Act 1989.
Offtake arrangements	Arrange route to market for sale of power plus any green benefits e.g. Renewable Obligation Certificates (ROCs).
Finance	Main part of financing, often referred to as financial close. Where projects are to be funded by project finance, developers need to be in a late stage of development before they can approach finance partners and financial close will not take place until project has full planning consents and a connection agreement.
Supply	Placing of supply orders, e.g. turbines, and construction contracts.
Construction	Construction and installation of civil engineering infrastructure (including site access); installation of substation; laying of turbine foundations; erection of turbines; commissioning and testing of turbines. We assume this stage takes around one year when creating our trajectories

Stage	Processes
Operation	Development begins commercial operation. After a certain period of operation, developer may consider repowering the site which requires new planning application and need to go through the planning cycle again to obtain planning permission.

Source: SKM, Eversheds and Pöyry

Table 4 – Overview of the project cycle for an offshore wind project

Stage	Processes
Pre-development	*Funding to launch prospecting and title acquisition* *Site selection and acquisition* Site search and selection based on offshore wind resource potential, preliminary surveys to identify any constraints, acquire title to develop site from the Crown Estate, initial identification of turbine layout and type of turbine that can be deployed, seabed surveys to facilitate foundation piling and cable laying for the transmission of electricity to the grid. *Environmental Impact Assessment (EIA):* Scoping opinion sought from the relevant statutory authority for remit of EIA, consultation with statutory consultees to identify areas of concern, preparation of Environmental Statement and other documentation ready for planning submission:
Development	
Planning	*Submission, consideration and determination of application for consent:* Two methods of obtaining consent - a) application for operation and consent of a generating station under Section 36 submitted to DECC, plus consent to cover onshore electrical sub-station and an application for a licence under FEPA submitted to the Marine and Fisheries Agency; or b) application for an Order under the Transport and Works Act 1992. *Decision:* The Secretary of State makes the decision as to whether to give consent or not. There is no time limit for the application, in the absence of a public inquiry the Secretary of State determines the application *Post decision stage:* Applicant complies with conditions attached to the permission to proceed with development. *Judicial review (if applicable):* No appeal mechanism under the Electricity Act. The decision of the Secretary of State is final unless challenged in the High Court within 3

Stage	Processes
	months of the decision date. In Scotland a similar process is in place using the Scottish government instead of DECC.
Electricity Connection Agreements	Developer makes an application for a connection to the electricity infrastructure to the GB Transmission System Operator (TSO) or the local Distribution System Operator (DSO) and the SO has to respond with a connection offer within a certain timescale.
Offtake arrangements	Arrange route to market for sale of power plus any green benefits e.g. Renewable Obligation Certificates (ROCs).
Finance	Main part of financing, often referred to as financial close. Developers need to be in a late stage of development before they can approach finance partners, or gain Board approval for on balance sheet finance, and financial close will not take place until project has full planning consents and a connection agreement.
Supply	Placing of supply orders and construction contracts e.g. turbines, sub-sea cables and specialist installation vessels.
Construction	Installation of the offshore substation and laying of subsea export cable, installation of monopiles (cylindrical steel foundations which provide a base for the turbine towers), securing of transition piece (to enable future access to windfarm), cable laying within the windfarm, turbine installation (including towers, nacelle, hub and blades), onshore work to enable export of power onto transmission system. We assume this takes two years when creating our trajectories, although for the larger Round 3 projects which are further out to sea, this could take longer.
Operation	Development begins commercial operation.

Source: SKM, Eversheds and Pöyry

2.2 Key constraints

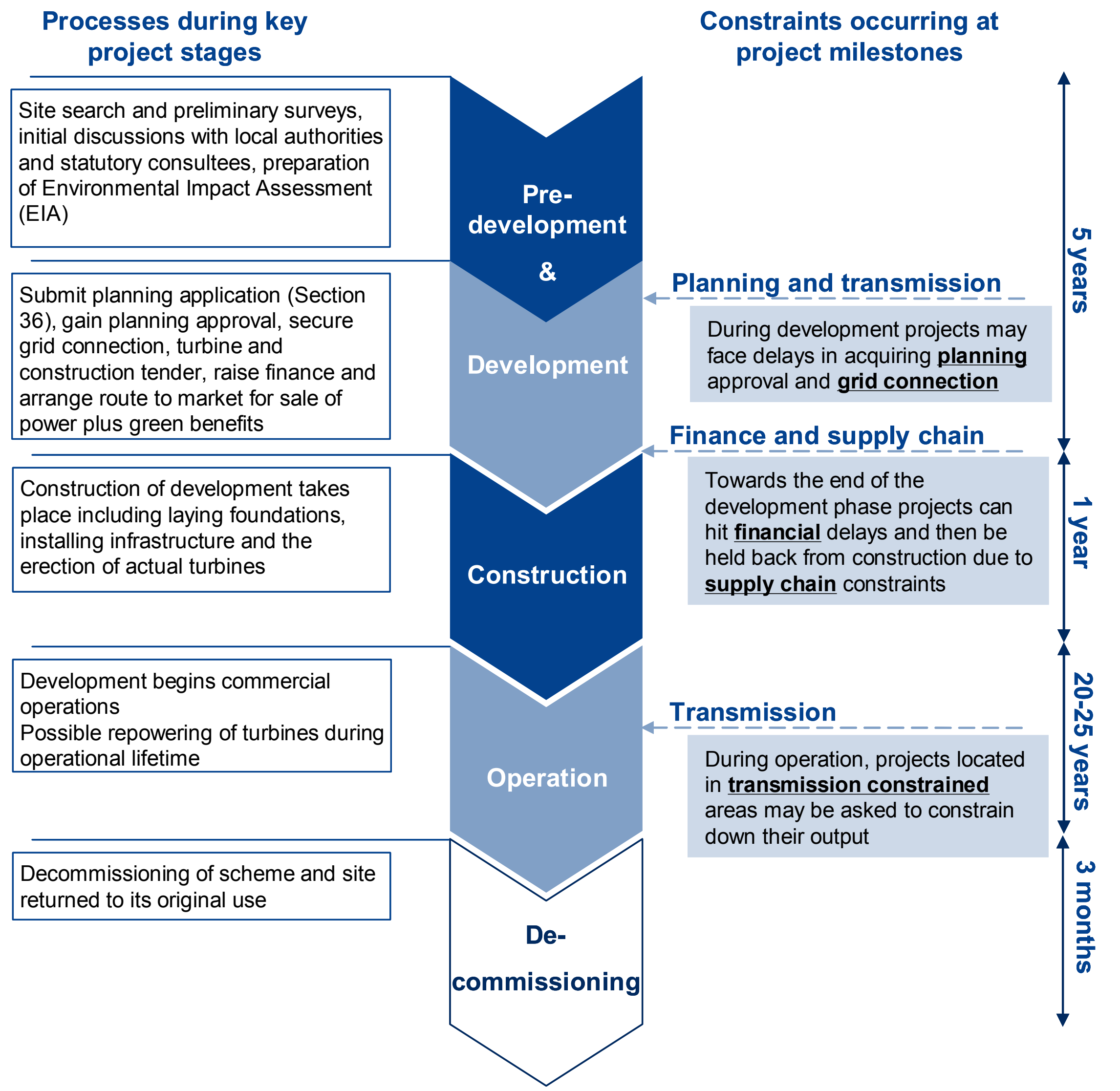
Figure 5 provides a schematic representation of where the main constraints occur during the development of a wind project, using the example of a 50MW onshore wind project cycle and timeline, but can be categorised into the four main areas:

- lack of liquidity in the financial market which has affected the availability of both debt and equity and led to a lengthening in the time taken to obtain finance;
- delays in projects receiving planning approvals;
- insufficient supply chain capability; and
- delays to necessary transmission reinforcements and new investments leading to constraints.

Each constraint can have having differing magnitudes of impact depending on whether the development is onshore or offshore, which country it is located in (England, Scotland, Wales or Northern Ireland), its size and the type of developer (e.g. small or large independent market player or a utility).

We now discuss each of these constraints in turn and set out how we have reflected them in our modelling.

Figure 5 – Example of an onshore wind project cycle and the stages of when the major constraints occur



NB: Timings are for an 50MW+ windfarm located in England under existing planning statutory guideline timescales

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3. FINANCE

3.1 Introduction

The current credit crisis has dampened the progress of wind capacity development in the UK. Obtaining finance is one of the main hurdles faced by developers, and more recently a lack of project finance has caused a significant slow down in development activity. This slowdown is seen as a temporary disruption to the growth in wind capacity but should not permanently hamper progress towards targets, provided credit conditions improve.

Although onshore wind is considered a mature technology and is one of the cheapest forms of renewable energy, it has still been affected due to a general lack of project finance. Offshore projects face additional challenges because they introduce greater technology risk to investors. Furthermore, offshore projects are more capital intensive than onshore projects and with current wholesale electricity prices (at the time of writing) significantly lower than 2008, additional support in the form of a ROC uplift has been required to improve the economics of offshore wind projects.

Developers have different funding options depending on the type of developer and the type of project. For example, smaller, independent, developers rely more on external project finance, with larger developers such as the main incumbent energy providers having grater recourse to internal, on balance sheet financing options. Normally this is a combination of debt and equity. Equity providers include venture capital funds, private equity funds, utilities, energy companies, investment banks and infrastructure funds. Equity holders own a stake in the physical assets and normally a claim to a proportion of the output generated in the form of power and ROCs. Debt for wind development is provided by project finance, commercial banks or development banks. This is normally secured against the physical asset and is usually only available for less risky projects, and therefore predominantly onshore projects.

Wind projects will have multiple financing rounds. At each stage, ownership of the asset may change and the ownership structure will evolve over time. The purpose of a financing event is either to raise money required to progress the project or to provide an exit for current owners to realise a return on their original investment (or both).

The crisis has impacted each financing stage, and has affected the availability of both debt and equity. The main result is a lengthening of the time taken to obtain finance. In some cases, the impact of the crisis has been that, for certain projects, developers are unable to obtain finance at all.

Given these current constraints, we have considered how the financial crisis has impacted the various types of wind project, split into type of developer, technology – onshore versus offshore – and project size. This section, therefore, covers:

- a description of the key investment points for wind projects;
- a discussion of the financial bottlenecks that are affecting wind investment; and
- the financial assumptions used for the development of the trajectories for wind investment to 2020 as presented in Section 7.

3.2 Key investment points

The key investment points for wind projects depend on two factors, the type of developer and the type of technology, onshore or offshore. The amount of money raised at each stage is different and reflects the upcoming expenditure requirements at the stage of development the project is in. Multiple investors may participate in the same funding round and the capital raised may come from either external or internal sources.

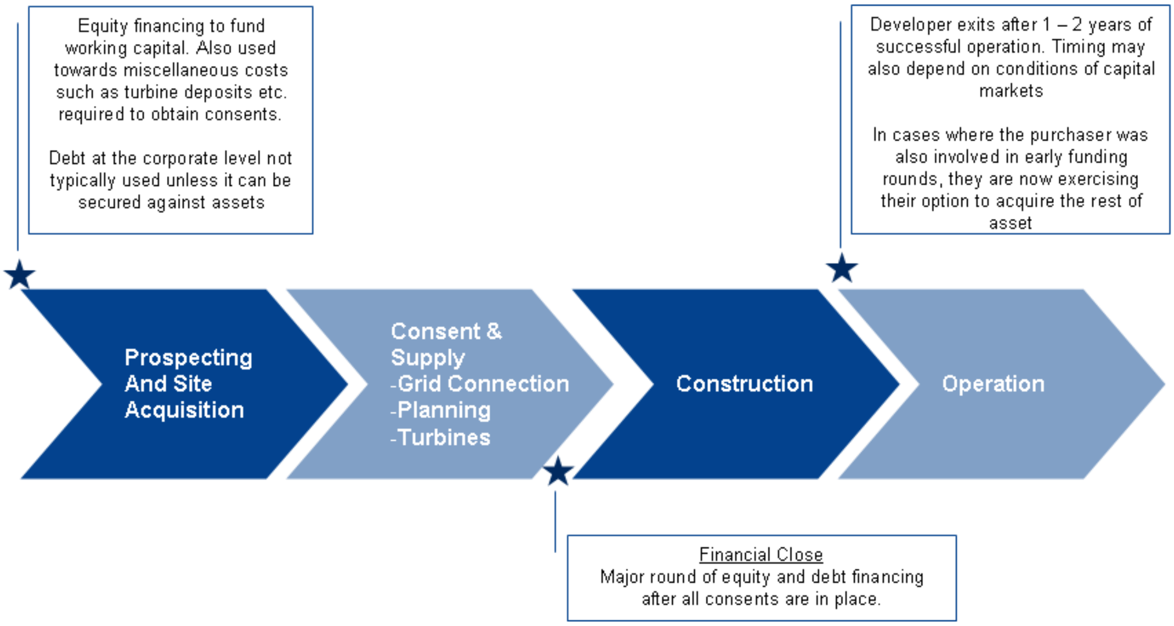
3.2.1 Small independent onshore wind developer

A small independent developer is characterised by a small portfolio of projects (or in some cases a single project) with individual project capacity usually less than 100MW. Small developers rely heavily on external sources of finance because they do not have the size of funds required to finance all of the development internally. They are less attractive to lenders, even more so in current conditions, unless they have existing relationships or a pipeline of future investable projects to offer. Projects undertaken by small developers usually involve multiple external financing rounds. Small onshore wind developers under this definition include companies such as Cornwall Light and Power, Wind Prospect and Your Energy.

Figure 6 illustrates the key investment points for small developers. The first financing event in the investment lifecycle is funding to launch the prospecting and site acquisition phase. The funds are used for working capital, planning applications and later on, for turbine deposits. This is normally external financing from a private equity, venture capital or incubation fund. However, these funds can also come from the founders themselves. Bank loans and debt are not typically raised at this stage because the level of risk is too high for lenders, unless the developer holds corporate assets against which the loans can be secured.

The second and most significant round of financing is often referred to as financial close. At this point, a combination of equity and bank debt/project finance is raised to fund the construction of the wind farm. The equity investor(s) at this point will require a rate of return on investment commensurate with the level of project risk still remaining. The majority of capital expenditure (greater than 90% of overall) required for project development is also raised during the second financing round. Achieving financial close marks an important milestone, because investors will be reluctant to commit funds unless a number of other development milestones have been achieved, namely turbine supply contracts, planning permissions and grid connection (see Table 3 in Section 2). Clarity is needed on these issues to minimize the amount of development risk assumed by investors. This aversion to risk has been even more emphasised in current conditions.

Figure 6 – Key investment points for small independent onshore wind developers



The third financial transaction in this model occurs after the wind farm is successfully operational and exporting power. Some or all of the equity in the wind farm is sold to an operational asset investor. This transaction allows previous equity investors to realise a return on their investment.

3.2.2 Utility

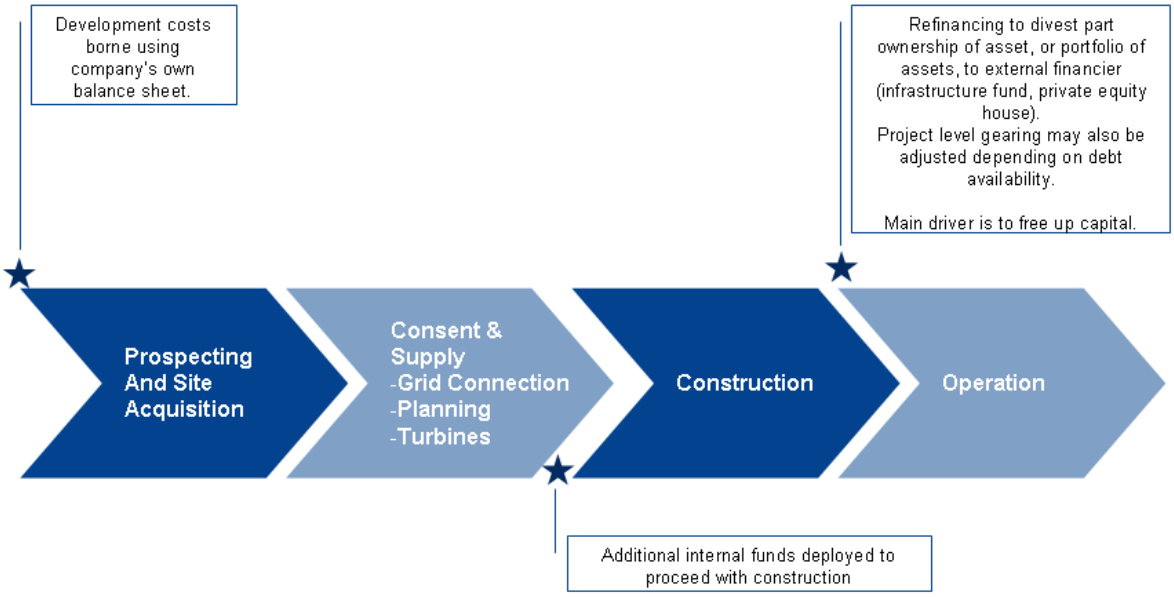
This class of developer is a company that has a diversified portfolio of generating assets (both renewable and conventional) and is often vertically integrated into energy supply. Vertically integrated utilities have the advantage of more options for the off-take of the windfarm's output. This means they are better positioned to obtain debt finance, being able to structure project cash flows in a way that satisfies strict lending criteria. Utilities are also characterised by having interests in operating assets, whereas developers will attempt to exit the project once it is operational.

Utilities and other energy companies that sponsor wind farm development will normally fund early development internally, on the balance sheet (see Figure 7). They are able to spread the high risk involved in project development by maintaining a diverse portfolio of development projects.

Before commencing with construction, an internal board decision is made to commit additional funds. At this point internal stakeholders will only grant approval to commence, if the economics of the project are sound.

The final transaction in this model is a refinancing step, and this can be done only once the project risk has been removed. The purpose of refinancing is to free capital for other projects. The refinancing counterparty is typically a bank, providing debt against the operating asset. Often a substantial minority of the equity will be divested to an infrastructure investor.

Figure 7 – Key investment points for utilities



3.2.3 Large independent onshore wind developer

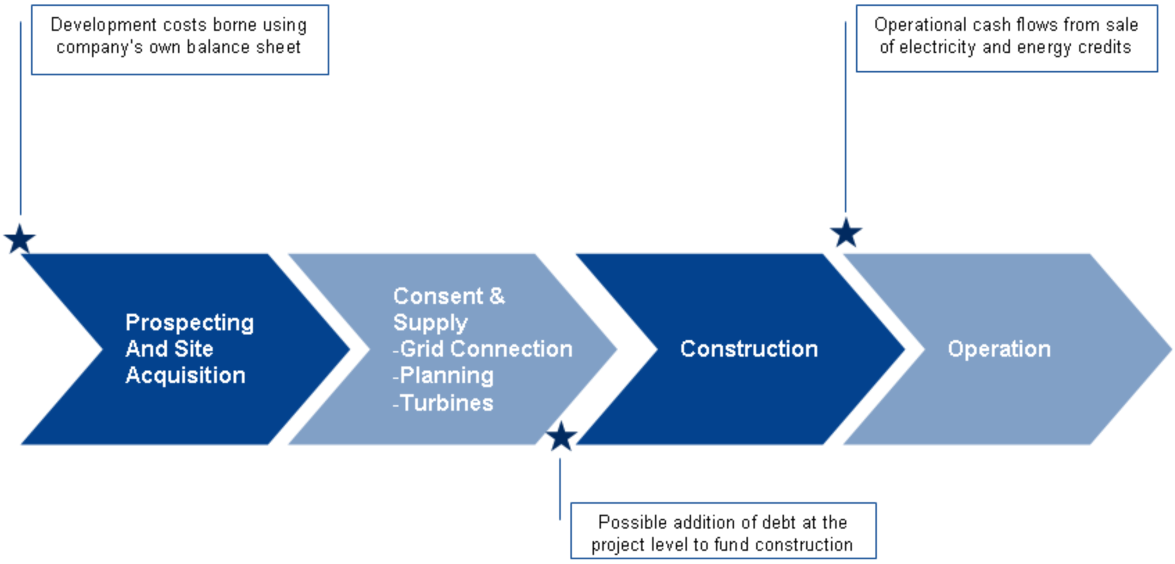
Like utilities, large independent developers also have an extensive portfolio of projects at various stages of development, but are different in the sense that they will have a greater emphasis on owning development assets, rather than operational assets. This is because operating assets do not yield the kind of returns required to offset their higher cost of capital. Large onshore wind developers under this definition include companies such as Renewable Energy Systems (RES) and Fred Olsen Renewables.

Initial development is funded in the same way as the utility model, using internal funds (see Figure 8). Large developers are able to do this as they have more capital than small independent developers.

Prior to commencing construction, large project developers will often raise debt to help fund capital expenditure. This is typically debt with recourse to project level assets. Large developers are in a better position to obtain debt finance than small developers because they have stronger relationships with banks and are able to offer lenders more business.

After the wind farm is successfully operational, the developer has the option to retain the asset and generate income from the output (electricity and ROCs). At some point they may also choose to divest some or all of their stake, depending on the need to free up capital for other projects and/or realise returns on their investments.

Figure 8 – Key investment points for large onshore wind developers



3.2.4 Offshore wind

Offshore wind farms have significantly higher capital expenditure requirements due to higher technology costs, shipping costs and connection costs. They are also perceived by investors to be higher risk projects, and therefore the current set of offshore wind developments are generally being financed on balance sheet. They are not able to obtain debt financing from commercial banks as a consequence of their large capital requirements and level of risk. Consequently, offshore development is currently being undertaken mainly by utilities through internal funding, with a few large developers also active.

From a financing perspective, offshore development faces different challenges to onshore. On the one hand, the type of developers that undertake offshore projects may be in a better position to raise finance, as under the Renewable Obligation offshore projects benefit from strong policy support. On the other hand, the cost/risk profile of the project is not conducive to raising some types of finance.

Investment points for offshore wind projects are staged and will be unique to each project. As the funds are being sourced internally, investment decisions will match the individual financial priorities and circumstances of the sponsoring utility. However, the two key milestones remain similar to onshore – initial development funds and capital expenditure required for construction.

3.3 Financial bottlenecks in wind investment

Lack of finance has the potential to hinder development of a wind project, with this obstacle becoming more pronounced in recent times. Financial bottlenecks are affecting both onshore and offshore development. However, in comparison to some of the other constraints considered as part of this study, the current financial bottlenecks are unlikely to be the main binding factor in the long term, provided the freeze on wind project finance alleviates in the future.

Onshore development is facing challenges in raising both debt and equity as a result of the current credit crunch. All key investment points in the cycle have become more challenging, including equity for development, debt and equity for construction and debt for refinancing.

As illustrated by Figure 9, these issues are interlinked (challenges in raising debt impact negatively on the ability to raise equity and vice versa). Additionally, the supply chain has also been impacted due to financial issues, compounding problems for developers who are trying to reach financial close. This compounding effect means that developers need to address challenges on multiple fronts simultaneously.

Figure 9 – Interlinking between equity, debt and supply chain issues

Offshore development is largely equity financed due to its risk profile and many are funded using developers' own balance sheet capital. However, they are not immune to financial bottlenecks. It is still a challenging environment for the project sponsors to raise equity (be it for a specific project or to strengthen their balance in general). Additionally, projects need to gain approval from internal committees and will have to compete for funding from other parts of the business. This process is increasingly challenging in the current environment.

When evaluating projects internally, similar risk/return assessments are made by internal stakeholders as those that would be done by external counterparts. Since offshore projects are more reliant on policy support than onshore, via the Renewables Obligation, they are more susceptible to another dimension of risk (policy uncertainty).

3.3.1 Equity market issues

All projects are prone to equity market issues. Equity investors are looking for increasingly higher returns on wind farm projects to compensate them for the risk involved. This leads to higher discount rates and lower valuations. One method of amplifying equity returns on projects is to increase the amount of debt. However, debt is becoming more difficult to raise (see Section 3.3.2) and this further diminishes the levered return on equity.

The changing market conditions are creating a divergence on how developers and investors view risk and return. As mentioned above, equity investors currently have a higher assumption of project risk. While developers have also adjusted their risk expectations they have not done this to the same degree. Effectively, those looking to raise equity have not adjusted their valuation expectations in line with equity providers. This has created a buyer-seller valuation gap and is an obstacle to reaching agreement on financing deals.

Current holders of wind assets (financial players and utilities alike) are not able to release the equity locked in existing assets in order to undertake new projects because of the factors already mentioned. This constrains their ability to devote resources and progress activity on new development.

There is still uncertainty on the exact form of policy support mechanisms for wind. While there is some upside from improved levels of support, it is difficult to identify the material impact on the level of equity finance this would deliver. Again, different stakeholders will have different views on future policy support and this hinders the ability to reach equity agreements.

3.3.2 Debt Market Issues

Debt market issues manifest themselves in a number of different ways. Syndication required for large deals is more difficult because there are fewer banks in the market and this affects the ability to form a syndicate. Where single banks were issuing large loans individually, they were still able to spread their risk by re-selling portions on the debt market. This is more difficult for the same reason – that is, there are fewer banks open to re-purchase this debt.

Some banks that were previously financing small deals (in the order of £5m-£10m) such as Alliance & Leicester and Nord LB have ceased to provide renewable project finance. The banks that are still present may look at small deals but will tend to favour developers that have a portfolio of projects to offer. There are still the likes of Barclays, HSBC, SMBC and Fortis. However they are able to pick projects with the most compelling economics, i.e. those projects likely to pass credit committee approval, leaving some small projects unable to obtain debt.

Lenders are becoming increasingly selective about the deals they finance and are applying stricter lending criteria. These criteria can include stricter debt service cover ratios, debt covenants, target repayment profiles on top of basic payment profiles and off-take agreements that provide more certainty.

The spreads on debt margins are increasing, thereby raising the cost of debt. These spreads increase in line with bank's perception of project risk. For high risk projects, higher spreads are accompanied by lower gearing levels. Both of these factors lower the equity rate of return.

As a consequence of lowered risk appetites, some lenders are favouring projects with guaranteed cash flows, for example, those located in countries which use feed-in tariffs as their principal renewables support mechanism. This puts UK developers (of >5MW projects) comparatively disadvantaged.

3.3.3 Financial Supply Chain Issues

The impact of the slowdown has in turn affected the supply chain. This impact is exacerbated by general market conditions. Some supply chain costs have gone down (such as turbine costs[4]) whilst some have gone up (shipping for offshore construction).

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4 Some cost reductions may have been partially offset by adverse exchange rate movements.

The latter is due to general market conditions. In the case of shipping, for example, it is because there are fewer vessels to support offshore construction.

Developers, unable to reach financial close, are defaulting on their supplier payments and losing turbine deposits. This sets back the development of the project as developers have to go through the process again to secure supply agreements before they can seek finance.

Similarly, if a project is delayed for an extended period of time then planning consents and grid connection agreements may expire. In this case developers will have to reapply, resulting in lost time and additional costs.

3.3.4 Other issues

Currently, there is a lack of lucrative power purchase agreements (PPAs). The PPA market is dominated by the major vertically integrated energy suppliers, and they are extracting a greater proportion of value of the PPA for themselves. The less attractive the PPA, the more difficult it is for developers of generation projects to obtain finance. There is also a tendency for lenders to favour less risky (but consequently less lucrative off-take agreements). For example, PPAs that have floor prices are also likely to pass on less of the upside to generators.

3.3.5 Measuring the impact of financial bottlenecks

In the current market conditions a number of wind developers have been unable to reach financial close on projects, or re-finance existing portfolios. In the former case, this is the main reason why these projects have not been able to proceed with construction.

There is anecdotal evidence supporting this. However, this cannot be confirmed as there is no accurate way to determine exactly how many projects are being held back purely due to financial reasons. Developers are not obliged to report on this issue. Furthermore, it would not be in their interests to report difficulties while they are attempting to build confidence with investors.

There is a similar challenge determining how much projects are being held up on re-financing. Utilities may have multiple drivers for delaying re-financing of wind projects or wind portfolios and it is not possible to separate those delayed purely on financial grounds.

3.4 Modelling finance constraints

Our quantitative scenarios replicate the impact of each constraint on the speed and volume of project development. Below we outline the main assumptions relating to finance constraints in the modelling. We report first the assumptions in the core, High Feasible, scenario and then any alternative assumptions that are applied in sensitivity analysis.

3.4.1 High Feasible scenario

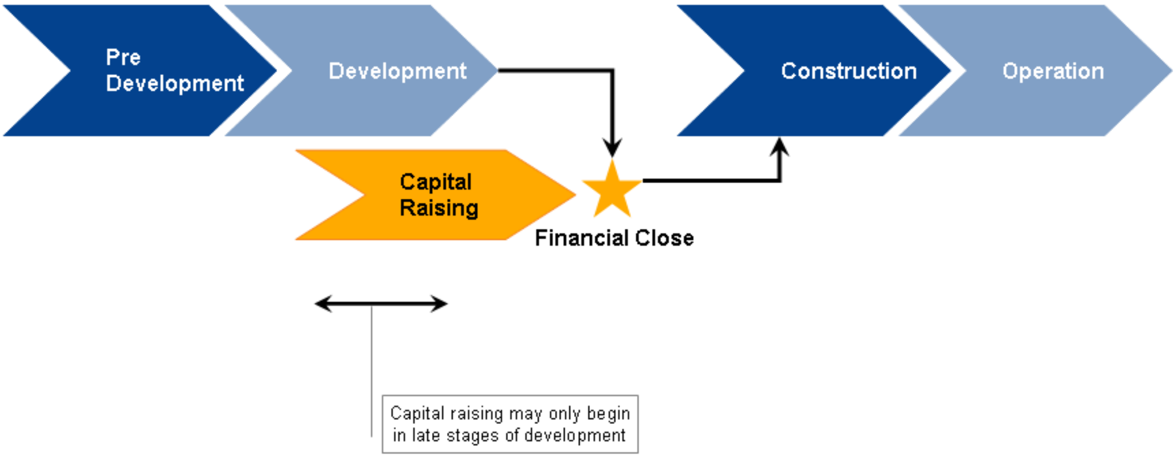
It is expected that financial bottlenecks will ease in stages. Already, there is some evidence of a thaw in the project finance market, with finance options re-opening to most developers. We project that this unfreezing will be followed by a period of time where lead times will be longer than pre-crisis, before eventually returning to pre-credit crisis levels from 2015 onwards.

The financial crisis is affecting different classes of developers in a different way (and to a different degree). This is due to the varying level of dependence that developers have on debt and equity markets. Consequently, IPPs are likely to be impacted to a greater extent than utilities.

In the midst of the crisis, developers have the option of selling development assets that are attractive to utilities or large energy companies (typically projects > 5 MW capacity) as a UK market for distressed assets has emerged.

Figure 11 summarises the financial lead times that we have assumed to create our trajectories of new wind investment in the UK to 2020. These lead times are the expected average time from when a developer begins discussions/negotiations with investors to the time that funds are committed (often referred to as the capital raising phase). In addition to longer lead times, developers need to be in a late stage of development before they can approach finance partners. The amount of overlap between development and capital raising is expected to vary during different stages of the crisis. This is because, before the crisis, there was more demand for investable projects, and financiers were open to starting discussions with developers earlier. Now the converse is true, and projects are competing for finance, financiers will only be willing to engage developers in late stages of development.

Figure 10 – Overlap between development and capital raising



The overlap assumed between the development and capital raising phases assumed for each stage of the credit crisis are shown in Figure 12. As can be seen, the overlap falls from 9 months before the end of the development phase to 3 months, to reflect the tighter market conditions, then rises again post-crisis.

The overall impact on project timescales depends on the combination of capital raising and overlap times. For example, during the unfreezing phase, capital raising is expected to take 9 months on average, but would only start 3 months prior to the completion of development, resulting in financial close being achieved 6 months after development completes. On the other hand, during post crisis years, capital raising is expected to take only 6 months and developers may begin approaching financiers up to 6 months prior to development completing. Therefore, financial close is expected to be reached soon after development completes.

Figure 11 – Assumed lead times used for the High Feasible trajectory

	Pre Crisis (until 2008)	Mid Crisis (2009)	Unfreezing (2010)	Post Crisis (2011 onwards)	2015 onwards
IPP (<= 5MW) - Onshore only	3 Months	Stalled	9 Months	6 Months	3 Months
IPP (> 5 MW) - Onshore only	3 Months	Some assets being sold	9 Months	6 Months	3 Months
Utility -Onshore/ Offshore	3 Months	9 Months	6 Months	6 Months	3 Months
Large Developer - Onshore only	3 Months	Some assets being sold	9 Months	6 Months	3 Months

There is a market in the UK for development stage wind assets. This change of ownership adds additional delay (≈ 3 months)

Figure 12 – Overlap between the end of development and capital raising

	Pre Crisis (until 2008)	Mid Crisis (2009)	Unfreezing (2010)	Post Crisis (2011 onwards)	2015 onwards
Overlap	9 Months	3 months	3 Months	6 Months	9 Months

3.4.2 Lack of project financing capacity scenario

The High Feasible assumptions reflect an optimistic view of market recovery. If enough lenders and investors exit the project finance market as a result of the crisis then the transition back to normal finance market operation may be more drawn out. As wind projects become attractive for investment again, financiers will be drawn back into the market but this gradual build up may extend the ‘unfreezing’ stage by an additional year (ending in 2011), though it is assumed that normal market operation is still resumed from 2015.

Our modelling indicates that in a pessimistic scenario this ramp down of financing capacity does not develop into a binding constraint. However, it is a risk that we have identified during the study.

4. PLANNING

4.1 Introduction

The planning system has a direct impact on investment in wind farms in the UK, affecting both the speed of investment and investor confidence. There have been significant delays in progressing wind farm applications through planning and, for onshore wind in particular, inconsistency in decision making on similar issues. Wind farm proposals can take up to 6 or more years from selection of the site through to a positive decision. Each proposal is decided on its facts and merits which can make it difficult to identify trends and timescales taken to get through planning. However there are some consistent themes and key constraints associated with wind farm proposals which we identify in this section.

The planning system in the UK plays a key role in the promotion of renewable energy and the delivery of targets. The UK planning system is plan-led with national planning policy on sustainable development, climate change and renewable energy being implemented in regional and local planning policy. Planning policy directly influences the decision making process. As with any development requiring planning permission, a renewable energy proposal is decided on its merits and each proposal is specific to its facts. Consideration of, and adherence to, relevant national and local policy and a balance of any environmental harm against the benefits of the renewable energy proposal must be undertaken by decision makers in accordance with general planning principles.

For onshore wind, Scotland has been the most successful to date in progressing wind farms through the planning system. Onshore proposals of under 50MW in England and Wales have been the least successful, mainly due to the time it takes to get through decision making at Local Planning Authority (LPA) stage (onshore wind applications requiring environmental impact assessment are taking an average of 14 months to be determined by the LPA when targets under relevant planning legislation indicate that they should be taking 16 weeks under the relevant planning legislation) and a high refusal rate. Unfortunately this appears to be getting worse rather than better[5]. In Northern Ireland whilst there has been a high approval rate for onshore wind, with very few appeals, applications have been taking about 3 years to proceed to determination.

Most of the applications for offshore wind proposals which have been determined to date have been successful with few refusals (although some were withdrawn prior to decision). These have taken about 4 and a half years to get from grant of the option to develop from the Crown Estate to a positive decision.

In order to address delays in the planning system in England and Wales, the Planning Act 2008 introduces a new regime for the determination of onshore wind farms of over 50MW and offshore wind farms of over 100MW by the setting up of the Infrastructure Planning Commission (IPC). This regime is described below and is expected to be instrumental in speeding up the decision making process for offshore wind in particular. Scotland is also undergoing a significant change to its planning system with the introduction of The Planning etc. (Scotland) Act 2006 which sets out a new planning regime for all development requiring planning permission in Scotland which also aims to improve efficiency in progressing applications through planning. Whether these new regimes do

5 See BWEA reports referenced below in Section 4.4.2

alleviate the delays for wind farm proposals remains to be seen as the new systems are not properly up and running yet and much of the Regulations supporting the IPC's functions has not yet been finalised (the IPC is expected to receive applications for renewable energy proposals from 1 March 2010 and the new Scottish system comes into force on 3 August 2009).

The planning system for under 50MW onshore proposals in England and Wales will not be directly affected by the new planning regimes and will remain the same. There is a lot of potential going forward for this size of proposal in England and Wales and therefore consideration of the timescales to date and reasons for delays in planning for these proposals (which have the worst record to date for approvals and timescales) are important when looking to future deployment and meeting 2020 targets. In addition, over 50MW onshore proposals going through the IPC will have to undergo detailed pre-application consultation with a soon to be approved list of statutory consultees, including the local planning authority, whose responses of objection or no objection will be taken into full consideration in the determination of the application. Therefore considering the reasons for delays and tensions encountered at a local level will remain important.

It is useful to consider why Scotland has had more success than England and Wales. We consider the reasons for this are that:

- Scotland has a more joined up planning system between the national level and local level with effective and positive engagement between the two;
- the statutory consultees in Scotland are very engaged and effective. Scottish Natural Heritage, for example, has driven many positive initiatives for wind energy;
- physically there is more room to accommodate more wind farms (less built up areas);
- since 2000 Scotland has had very effective national guidance transmitting directly to local decisions which has not been seen in England and Wales; and
- overall there is a political will in Scotland at all levels to make wind energy work.

This section covers:

- a brief overview of the current situation on how many projects have gone through the planning system and the approval and refusal rates recorded;
- an overview of the planning regime in the UK for wind energy proposals including the various consenting regimes, planning policy and what is involved for development requiring an environmental impact assessment, one of the key requirements of the decision making process;
- proposed recent changes to the planning regime going forward, including that proposed under the IPC;
- consideration of the timescales and approval rates of onshore and offshore wind in the UK according to both statutory guidelines, and that which occurs in practice, which then feed into the development of the trajectories for wind investment to 2020 as presented in Section 7; and
- identification of the constraints encountered in the planning process and reasons for delays and how changes to the planning process might assist to alleviate these constraints going forward.

4.2 The current situation – an overview

The BWEA published a report in July 2009[6] which concludes that there is an imbalance in the delivery of renewables across the UK.

- Scotland has already exceeded its 2010 renewable energy target of 18% of electricity to come from renewables with 25% of supply coming from renewables at present.
- Northern Ireland has a target for 12% of electricity to come from renewables by 2012 and almost the entire remainder of its 2012 target will be met via wind energy alone assuming onshore wind projects currently consented are built by 2012.
- Wales will fall significantly short of its 2010 target for 4TWh of electricity per annum to come from renewables, equivalent to approximately 1500MW installed capacity. To date only an additional 100MW of onshore wind has become operational since 2005 and in August 2008 the total installed capacity was 390MW.
- In England BWEA reviewed the regional targets of the English regions for 2010 which cumulatively are 4,554MW and concluded that this will be missed by a wide margin with an estimated 2,303MW of renewables capacity currently installed in England. With respect to the UK 2010 renewable energy target, Scotland and Northern Ireland's renewables capacity has bolstered the poor performance of England and Wales to date.

Planning constraints have been identified as a key concern for delivery and there are several factors that have led to delays in the planning system. It is important to consider these constraints when identifying the number of projects that can come forward to meet the 2020 targets because not all the constraints will be addressed under the new planning regimes in England, Wales and Scotland. This is because some constraints are simply inherent in the development consenting process (eg environmental constraints) and some constraints will not be affected by the new regimes (eg local decision making for under 50MW onshore proposals in England and Wales). The constraints themselves are discussed in more detail in Annex A and we have identified when we consider a particular constraint might be addressed or eased by the new regimes. The constraints are:

- Onshore wind;
  - timescales for implementation of National Policy down to local level;
  - environmental constraints;
  - resource issues for statutory consultees and LPAs;
  - preparation of an Environmental Statement (ES) and the EIA process leading to preparation;
  - LPAs not determining applications within statutory timescales;
  - low approval rates by the LPA for projects under 50MW;
  - increasing number of projects being legally challenged;
  - aviation issues;
  - costs involved in applying for planning permission and progressing an application through the planning cycle;

[6] England's Regional Renewable Energy Targets: Progress Report July 2009

- Offshore wind;
  - onshore grid;
  - navigation and fishing;
  - piling noise;
  - birds; and
  - offshore electricity transmission operator (OFTO).

4.3 Current planning regime

This section briefly outlines the current planning regime for wind farm proposals in the UK. As mentioned above The Planning Act 2008 and The Planning etc (Scotland) Act 2006 establish new regimes for certain types of on and offshore wind farm development but not all. An outline of the new regimes is set out below in the next section. The current regime will continue to apply to onshore wind farm proposals of under 50MW in England and Wales and onshore wind farm proposals of over 50MW in Scotland. Therefore application of the current regime for these proposals is relevant going forward.

The planning system in the UK is 'plan led', that is to say there is a hierarchical structure of guidance and plans covering national and local planning (in England this also includes regional planning). At present the overarching planning guidance for the deployment of renewable energy developments in the UK is set out in national planning policy statements applicable to each region/jurisdiction: England (PPS22), Wales (TAN8), Scotland (SPP6) and Northern Ireland (draft PPS18) which in turn must acknowledge the commitments on the part of the United Kingdom to targets for reducing CO2 emissions and achieving renewable energy targets.

Onshore wind developments which have a potential generating capacity up to and including 50MW must, unless material considerations indicate otherwise, be determined in accordance with the relevant policies of the adopted development plan comprising either saved policies in adopted Local Plans or adopted Development Plan Documents for the administrative area of the Local Planning Authority within which the proposal sits. For example, in England the development plan is made up of Regional Spatial Strategies and Development Plan Documents contained within the Local Development Framework. This will continue to be the case. Wind developments over 50MW are not strictly subject to adherence with the development plan, although the development plan policies will be a material consideration in the consideration of a planning application. Going forward in England and Wales these proposals will be considered in accordance with a new National Policy Statement which is discussed below.

The main legal framework and processes that a planning application is to follow are defined in the relevant Planning Act for the particular jurisdiction as discussed in the following sections.

It is important to note that each proposal is specific to its facts and particular issues as is the case with all planning applications. When determining a renewable energy proposal the decision maker, after having considered relevant national and local planning policy, representations from the local planning authority, statutory consultees and third parties, must weigh other material planning considerations including any environmental harm that might be caused against the renewable energy benefits of the proposal before reaching their decision.

4.3.1 Environmental Impact Assessment

Most[7] onshore wind farms and all offshore wind farms will require an Environmental Impact Assessment (EIA) under the relevant Regulations for England and Wales, Scotland and Northern Ireland. These Regulations and the need for EIA will continue to apply under the new planning regimes

The purpose of EIA is to identify and assess the likely significant environmental effects of the proposal. The results and conclusions of the EIA are set out in an Environmental Statement (ES) which must be submitted with the planning application.

Before making a planning application, a developer will usually ask the decision maker for their formal opinion on the information to be supplied in the ES and the scope of the EIA to be undertaken, i.e. a scoping opinion. In practice most developers prepare a draft scoping opinion to be agreed and discussed with the decision maker and following consultation with relevant statutory consultees (for example Natural England, Scottish Natural Heritage, Historic Scotland or Countryside Council for Wales etc).

4.3.2 Consent procedures for onshore wind

Annex A sets out in detail the stages that a developer of an onshore wind farm proposal will go through in the development cycle including planning. An overview of the key planning stages for an onshore proposal between 5 and 50MW in England and Wales is set out in Figure 13. In order to give an indication of the potential overall timescale for the planning process we have inserted timescales for each stage. For some stages the timescales are set by legislation, some timescales are indicated by guidance (for examples timescales if an application goes to a planning appeal) and some stages have no set timescales to be adhered to. In those latter circumstances we have made an assumption as to the average timescale that the particular stage might take. In addition it is important to note for all the High Feasible scenario timescales that even where timescales are set by legislation or guidance some can still be extended (for example, the period within which the local planning authority should determine an application).

As the Planning Act will not affect onshore proposals under 50MW in England and Wales, these stages and timescales will continue to apply. In Scotland and Northern Ireland the stages are currently the same but the timescales differ (going forward from 3 August 2009 the stages for Scotland will change and this is discussed in the next section).

More explanation as to what happens at each stage and how the timescales have been derived are set out in Annex A, however a brief explanation of the key planning stages to give context to Figure 13 is set out here:

- Pre-application (Scoping opinion and EIA) Stage: This period covers the developer selecting the site and preparing the planning application and EIA ready for submission. There is a statutory period of 5 weeks from the date of receipt of a request for a scoping opinion for the decision maker to issue a scoping opinion as to the scope of the EIA. There is no set timescale for the site selection/EIA/application preparation period and we have assumed a period of up to 2 years for a 5-50MW site.

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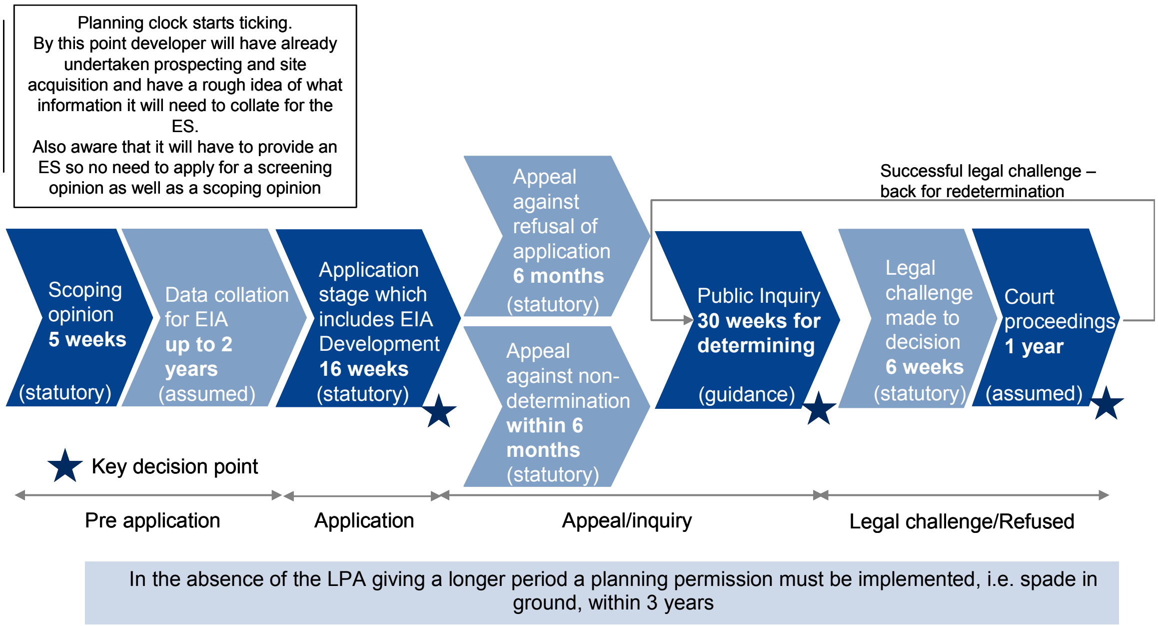
7 Any development which involves the installation of more than 2 turbines or the hub height of any turbine or height of any other structure exceeds 15 metres will require an EIA. For smaller proposals, however, a developer may want to request a screening opinion from the LPA to see if an EIA is required.

- Application Stage: The application is submitted to the relevant LPA and they have a set period within which to determine it. In England, Wales and N. Ireland this is 16 weeks. In Scotland it is 4 months. This period can be extended by agreement between the LPA and applicant (i.e. developer) in writing. If the LPA refuse the application or fail to determine it within the timescale an applicant can appeal to the relevant appeal body.
- Appeal Stage: An applicant can appeal within 6 months of the date of refusal of the application or within 6 months of the date that the application should have been determined by.
- Public Inquiry: Most wind farm appeals are heard by way of public inquiry (about 90%). In England, the Planning Inspectorate have issued guidance to the effect that a public inquiry should be held and determined within 30 weeks of the validation date of the appeal.
- Legal Challenge: In England and Wales an appeal decision can be challenged in the High Court (on certain grounds only) within 6 weeks of the appeal decision date (In Scotland it is by way of Judicial Review with no set timescale). There is no set timescale within which a challenge should be heard and determined but at present challenges take at least 1 year. If successfully challenged the decision is sent back to the relevant appeal body for re-determination. We estimate that about 10% of approved wind farms will be legally challenged.

As the Planning Act will not affect onshore proposals under 50MW in England and Wales these stages and timescales will continue to apply. In Scotland and Northern Ireland the stages are the same but the timescales differ. These timescales form the “potential” or High Feasible basis upon which the historical data set out below should be compared against for under 50MW onshore wind proposals.

Figure 13 – Planning process for a wind proposal between 5 and 50MW – timescales as per those under current guidelines for England[8]



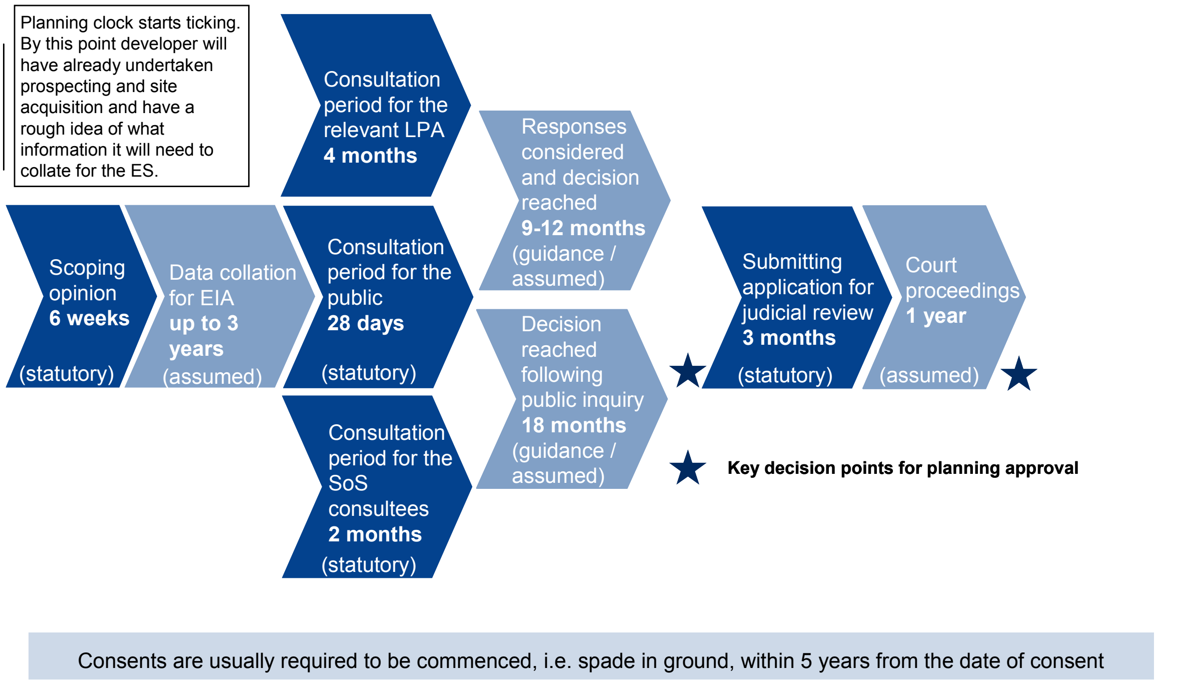
Source: Eversheds

Currently onshore wind proposals over 50MW, planning applications are submitted to, and determined by, the relevant Secretary of State under Section 36 of the Electricity Act 1989 for England, Wales and Scotland and Section 39 of the Electricity (Northern Ireland) Order 1992 for Northern Ireland. Apart from a specified consultation period there are no set timescales for determination by the Secretary of State of these applications. The LPA is consulted on the application. If they object a public inquiry is called. For England and Wales these proposals are due to be heard by the new IPC once established as discussed below in Section 4.4. For Scotland and Northern Ireland there will be no change to the current regime. Figure 14 summarises the key planning stages that a Section 36 Electricity Act 1989 application has to go through in England. It is important to note that there are no set timescales for the progress of a Section 36 application from submission through to determination although there are some set consultation timescales but otherwise the timescales are set out in guidance only or are driven by the Secretary of State. A legal challenge to a Section 36 decision is by way of Judicial Review to the High Court to be submitted within 3 months of the decision in England, Wales and N. Ireland with no set time period for submission to the Court of Session in Scotland.

These timescales form the potential High Feasible basis upon which the historical data set out below should be compared against for over 50MW onshore wind proposals in England and Wales.

8 For timescales for the other jurisdictions (Wales, Scotland and Northern Ireland) and the context behind these values, refer to Table 5.

Figure 14 – Planning process for a wind proposal ≥ 50MW – timescales according to those under the statutory guidelines for England



Source: Eversheds

4.3.3 *Consents procedures for offshore wind*

Under the Estate Act 1961, the Crown Estate's permission is necessary to place structures on or pass cables over the seabed and its foreshore. Potential developers also require statutory consents from a number of government departments responsible for the offshore wind development process. Currently there are two routes for obtaining consent for offshore wind farms in England, Wales and Scotland, but only when all the necessary statutory consents are obtained will the Crown Estate grant a lease for development.

- England, Wales and Scotland:

a) Application for operation and consent of a generating station under Section 36 Electricity Act 1989 which is submitted to the Department for Energy and Climate Change (DECC) and an application for a licence under Part 2 of the Food and Environmental Protection Act (FEPA) 1949 submitted to the Marine and Fisheries Agency. In Scotland applications are made to the Scottish Ministers.

b) An application for an Order under the Transport and Works Act 1992 provides an alternative route for territorial waters only.

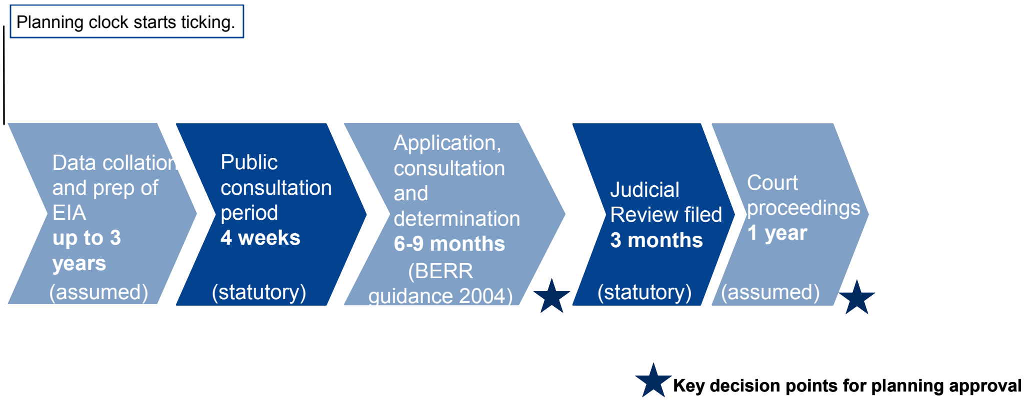
- Northern Ireland:

a) Application for operation and consent of a generating station under Section 39 Electricity (Northern Ireland) Order 1992 and an application for a licence under Part 2 of the Food and Environmental Protection Act 1949 both of which are submitted to the Department of Enterprise, Trade and Investment (DETINI).

For all jurisdictions, planning permission is also required for the onshore elements of the wind farm, for example, the substation. This can either be obtained by an application for deemed planning permission (under Section 90 of the Town and Country Planning Act 1990 for England and Wales and Section 57(2) of the Town and Country Planning (Scotland) Act for Scotland). This means that the permission will be deemed to be included in the Section 36 consent. Alternatively a totally separate application for planning permission under the relevant planning acts to the LPA within which the site sits can be made. In this case the determining authority for that element of the site will be the LPA. Offshore wind developers are also required to undertake an Environmental Impact Assessment of the proposal, which we discuss in the following section.

Figure 15 provides an illustration of the planning processes and timescales typically involved for an offshore wind farm located in England and Wales. For a more detailed list of steps, refer to Annex A. This diagram has limited use for the purposes of this report in terms of projecting forward. Going forward, there is only one proposed development that comes under this category, whilst any remaining Round 1 and all Round 2 and 3 projects will follow the process as set by the new planning regime (see Section 4.4).

Figure 15 – Planning process for an offshore wind farm <100MW – timescales as per those under the current guidelines for England & Wales



Source: Eversheds

4.4 Historic performance of planning regime

We have reviewed the historic performance of the planning regime to derive some illustrative summary statistics on timescales and rates of approvals and refusals that can be used as references for modelling and anticipated impacts of planning reform.

4.4.1 Timescales

Trying to determine an average timescale for the various key planning stages has been difficult due to the extremes in timescales between applications, the significant number of proposals still awaiting determination and the case by case issues relevant to each application. Referring to an average timescale without appreciation of the context and issues being encountered on specific applications does not give an accurate picture. However the averages set out in this report do give an indication of how long proposals have been taking to go through in general terms.

Due to planning procedures being slightly different depending on the size of the windfarm (and which jurisdiction it is located in i.e. England, Wales, Scotland and Northern Ireland), we have sub-divided the timescales into the following categories:

- Onshore wind;
  - less than 5MW;
  - between 5MW and 50MW;
  - greater than 50MW
- Offshore wind;
  - up to 100MW; and
  - greater than and including 100MW.

It has not been possible in the time available to track each and every planning application that has been submitted in the UK through the various stages of the planning cycle. We have therefore tracked a selection of applications for the 0-5MW and 5-50MW group and jurisdictions. Most of the under 50MW applications tracked were submitted in the period 2005-2007 to allow us to record how long it took a project to be determined including on appeal, hence the average timescales should be considered with this in mind.

The timescales for over 50MW applications are set out on the relevant DECC or Scottish Government website and we used the information here to reach the averages for these applications in England, Wales and Scotland. We have been able to review all applications. Therefore the average figures for this scale of project are as accurate as we could get. In relation to over 50MW applications in Wales none have yet been determined and the applications are quite recent. Therefore the Welsh figures for these proposals should be given little weight.

In the BWEA recent report: England's Regional Renewable Energy Targets: Progress Report (July 2009) it concludes that in England the average decision time for onshore under 50MW applications decided by the LPA between April 2006-April 2009 was 14 months (as opposed to the statutory timescale of 16 weeks) and for applications that are refused and go on to appeal the average decision time was 26 months, with an average approval rate for both appeals and local authority determined applications of 17.2 months. The BWEA also note that the wind industry suffers disproportionately with much longer decision times compared to all other types of major applications of which three quarters are determined in 13 weeks:

- the overall decision-making process is on the verge of reaching an average of 2 years. Between March 2007 and March 2008 only 7% of applications in England were determined within the statutory 16 week target; and
- the real problem with decision times stems from the local political decision-making process.

The BWEA report also comments on the timescales from consent to deployment of the wind farm.

- In the first five years of the UK industry, onshore wind farm projects were completed just over 6 months from the date of consent. Over the last five years projects have taken an average of nearly 28 months. The BWEA found there is little correlation with the size of the projects. What does affect the timescales are the discharging of any conditions attached to the consent that must be discharged by the local planning authority before construction can start, supply of turbines and grid connection.
- Offshore projects have been similar to onshore projects with projects being completed on average 28 months after consent. However not many offshore wind farms have been completed to date and the larger Round 2 schemes are likely to take longer to deploy. BWEA, after receiving information from Round 2 developers, say that the

time between consent and operation is likely to increase to between 30 and 45 months but this does all depend on the individual projects.

As stated above we reviewed a selection of under 50MW onshore applications submitted between 2005 and 2007 which have been determined to gain our average timescale per stage of the planning process. For over 50MW onshore proposals, we have reviewed the timescales of all applications which have been determined. In relation to offshore wind we have reviewed the timescales for all offshore applications which have been consented to date. The average timescales are set out in Table 6 below.

As stated above all under 50MW onshore proposals in England and Wales will continue to be progressed and determined under the same regime and won't be directly affected by the new IPC and there will be a large proportion of proposals in this category. This size of development has suffered most delay over the years. It is therefore useful to just highlight some detail behind the average timescales for under 50MW onshore proposals here to get an appreciation of the difficulties encountered including legal challenge as these are typical of the overall picture:

- 17 0-5MW onshore applications in England were selected between 2005 and 2007. 3 have yet to be determined and 1 was withdrawn. 9 of the applications were approved at local authority level and 4 were refused. Timescales for determining those applications ranged from 15 weeks to 2 years and 4 months. All 4 refusals were appealed: 2 of the appeals were approved, 1 appeal was withdrawn and 1 was refused. A legal challenge was made to one of the approved appeals. The appeal was approved on 1 May 2008 and the court hearing for the challenge was expected to be in early 2009, but at the time of writing (July 2009) there has been no decision. There was insufficient data available for us to review 0-5MW application timescales for Wales.
- 28 5-50MW onshore applications in England were selected between 2005 and 2007. All were determined by the local planning authority. 12 were approved and 16 were refused. Timescales for determining those applications ranged from 11 weeks to 125 weeks. Out of the 16 that were refused 9 went to appeal. Out of that 9, at the time of writing 1 is still awaiting an inquiry date and 2 await an inquiry decision. 4 were refused, 1 was approved and 1 was withdrawn. The 1 appeal that was approved is currently subject to legal challenge. Timescales from the local authority decision to an inquiry being called on appeal range from 8 months to 19 months.
- In order to give some indication of the delays that can be caused by a legal challenge it is worth setting out the timescales for the 1 appeal above (in the 5-50MW category) that was subject to a legal challenge: the application was submitted in November 2005, refused by the local planning authority on 31 January 2006, heard by public inquiry in October 2006 with permission being granted in February 2007. A legal challenge was submitted and heard at the High Court in July 2008. The challenge was successful and the decision was remitted back for re-determination with a further public inquiry starting in July 2009.
- 24 5-50MW onshore applications in Wales were selected since 2005. 10 are still to be determined by the LPA. All of those applications awaiting determination have been in the system for over 1 year with the longest still awaiting determination after 3 years. 14 have been determined of these 7 were approved and 7 were refused. Timescales for determination range from 12 months to 30 months. 6 went to appeal with only 1 being approved and 3 being refused. Timescales from application determination to inquiry ranged from 8 months to 18 months. Out of the applications approved it is interesting to note that none are operational yet and only 1 is currently in construction (this one was approved in March 2007).

- All over 50MW onshore proposals in Scotland will continue to be considered under the regime for Section 36 Electricity Act applications.

Table 5 provides a summary of the timescales based on historical data. As set out above we have not included figures for legal challenge as we did not have enough data to draw a reasonable average from. More detailed analysis of the figures from the pools of application in the various regimes reviewed are set out in Annex A.

Table 5 – Historic average onshore and offshore wind timescales

Type and size	Planning Stage and processes	Timescale (months)			
		Eng	Wales	Scot	NI
Onshore: 0-5MW	Pre-application: site selection and EIA Assumed timescale – not based on historical data	26.0	26.0	26.0	26.5
	Application: application submission to determination at application stage Based on the timescales of 13 applications in England. Insufficient data available to review Wales, Scotland and N. Ireland so English timescales assumed.	4.0	4.0	4.0	4.0
	Appeal/Inquiry Based on the timescales of 4 of the 13 applications that went to appeal.	13.5	13.5	15.5	24.0
Onshore: 5-50MW	Pre-application: site selection and EIA Assumed timescale – not based on historical data	25.3	25.3	25.3	25.5
	Application: application submission to determination at application stage Based on the timescales of a selection of applications reviewed in all 4 jurisdictions (see Annex A).	11.0	21.0	12.0	4.0
	Appeal/Inquiry Based on the timescales from the selection of applications reviewed (see Annex A)	14.0	16.0	15.0	60.0
Onshore: >50MW	Pre-application: site selection and EIA	37.5	37.5	37.5	37.5

Type and size	Planning Stage and processes	Timescale (months)			
		Eng	Wales	Scot	NI
	Assumed timescale – not based on historical data				
	Application: application submission to determination at application stage Based on the timescales of all applications submitted and determined without a public inquiry. NB No applications in Wales yet determined so figure for England has been used. N. Ireland is based on 2 applications only.	25.0	25.0	27.0	4.0
	Inquiry Based on the timescales of all applications submitted and determined following a public inquiry	10.0	10.0	24.3	n/a
Offshore: <100MW	Pre-application: EIA Based on historical data	29.0	29.0	14.0	37.0
	Application Based on historical data. Note however that there is only 1 offshore proposal in Wales and Scotland so the timescales have been based on that and there are no offshore proposals consented in Northern Ireland.	21.0	21.0	10.0	9.0

Source: Eversheds

4.4.2 Consents approval and refusal rates

Historic approvals and refusals rates for onshore and offshore wind have been derived mainly from BWEA data. There is no definitive approvals or refusals schedule therefore the information has been collated using data from various BWEA spreadsheets.

According to BWEA State of the Industry Report published in October 2008 since the industry began receiving decisions in 1991 the average onshore approval rate in the UK for all schemes has been 72%. However, since January 2006 only 67% of applications have been approved. The approval rate for the 33 applications over 50MW which had been decided up to October 2008 amounts to 85% by scheme but has fallen to 70% by scheme since January 2006. The BWEA states that whilst those statistics are impressive, given that almost half of the MW capacity so far determined in the UK is over 50MW determined under the Section 36 Electricity Act, the figures mask the true performance of the local planning system across the UK. The BWEA report also states that:

- Since January 2006 only 54% of 167 onshore wind farm applications have been consented at the local level (significantly less than all other major housing, office, retail and general industrial). Around 12% of the original applications are eventually consented at appeal, taking the UK wide approval rate for under 50MW applications to an average of 66% since January 2006.

- Northern Ireland has a 97% approval rate but these have taken a lot longer to actually get through the planning process with decisions in 2008 taking nearly 3 years from the date of submission and 26 proposals remain in planning undetermined (as of October 2008).
- In England only 40% of projects submitted are consented by the local planning authority with a further 11% being approved at appeal.
- In Wales and Scotland, only 56% and 57% of applications respectively are being awarded consent by the local planning authority.
- Of those applications determined at appeal over the last 5 years (to October 2008) an average of 50% are allowed and the BWEA found that the performance did not fluctuate to any noticeable degree across the four countries of the UK.
- According to overall approval rates taken from both local planning authorities and appeals since January 2006, 67% of schemes under 10MW were consented compared with 64% of schemes between 10MW and 50MW in size. Larger schemes are likely to take longer to be decided.

Table 6 below has been based on a review of BWEA data for applications submitted and determined. It does not however represent the most up to date figures and we are uncertain as to its completeness. We have seen statistics which certainly differ from our review set out below as indeed BWEA's own research above has done. Unfortunately there is no definitive list of all applications with approvals or refusal rates set out.

Table 6 – Approval and refusal rates for onshore projects in the UK

MW	Jurisdiction	No. of applications identified	No. of applications not determined or withdrawn	Approvals rate (%)	Refusals rate (%)
Onshore: 0-5MW	England	130	20	76%	24%
	Wales	38	3	71%	29%
	Scotland	57	20	92%	8%
	N. Ireland	21	8	100%	0%
Onshore: 5-50MW	England	204	61	65%	35%
	Wales	61	13	60%	40%
	Scotland	166	45	84%	16%
	N. Ireland	72	46	96%	4%
Onshore: >50MW	England	10	3	86%	14%
	Wales*			80%	20%
	Scotland	83	51	69%	31%
	N. Ireland*			100%	0%

*Due to a low number of applications in these areas, data for England has been used for Wales, while Northern Ireland uses percentages based on the High Feasible scenario

The above approvals rates do not highlight the particularly low approval rate encountered by proposals on appeal.[9] We have therefore reviewed all appeals submitted for onshore wind farms to date and reported on the number of refusals and approvals for each jurisdiction. The results are set out below.

9 Here the appeal is by a developer that has had its initial planning application refused.

Table 7 – Approval and refusal rates for onshore projects reaching the appeal stage

Size	Jurisdiction	No. of appeals identified	Approvals	Refusals
0-5MW	England	33	19	14
	Wales	3	-	3
	Scotland	5	-	5
5-50MW	England	36	13	23
	Wales	13	5	8
	Scotland	22	11	11

It is important to note that the proposals that get planning approval may not be constructed. Reasons for approved sites not being built can include lack of funding and the unavailability of a turbine within the parameters required for a particular permission (e.g. due to lack of supply or termination of the production of the particular turbine envisaged such that planning conditions attached to a planning permission cannot be met).

Conversely, an onshore wind farm proposal that is refused planning permission may not necessarily mean that the particular site is not suitable for future wind farm development. It may mean that a new layout or different size scheme might be more appropriate. However, it is more realistic to assume that it will not be acceptable for future development.

4.5 Reform of the planning regime in the UK

4.5.1 England and Wales – the Planning Act 2008

The Planning Act 2008 was introduced to try to alleviate and simplify the cumbersome and time-consuming regime for the determination of large infrastructure projects in England and Wales by introducing a single consent regime for what are defined as Nationally Significant Infrastructure Projects (NSIPs). It should be noted that the Conservative shadow administration has indicated an intention to review the IPC legislation should the Conservative Government come into power, but for the purposes of this project we have assumed that the IPC will go ahead in its current form.

This new, single consent regime provides for:

- the Government to produce National Policy Statements (NPSs) that will establish the national case for infrastructure development and set the policy framework for IPC decisions. These will integrate environmental, social and economic objectives including the Government’s climate change commitments to deliver sustainable development. They will be the primary consideration for the IPC in determining applications for development consent for NSIPs. It is anticipated that they will have a timeframe in principle of between 10-25 years depending on the sector they are to cover and the Government will consider whether a review is necessary every 5 years. The Government has recently announced (in its IPC Implementation route map July 2009) that the NPS covering renewable energy will be published in Autumn 2009 and therefore we cannot make any more comment on the detail or content of this NPS and how it will influence the deployment of wind farm applications through the IPC at this stage.

- a new duty – and greater onus – on promoters to ensure that proposals are properly prepared and consulted on before they submit an application for development consent by introduction of the legal requirement for a full and detailed pre-application consultation procedure. This effectively front-loads applications and moves a lot of the post-application process from the previous regime to pre-application. Applicants will have to ensure that their proposal is ready for consent at the time they submit the application.
- a new independent body, the Infrastructure Planning Commission (IPC), to take over responsibility for considering and deciding on NSIPs. As stated above decisions will be based primarily on National Policy Statements. The Government has recently announced that the IPC will be accepting renewable energy applications from 1 March 2010.

The Government hopes that the new regime will give promoters a clearer framework with a higher degree of predictability in which they can make investment decisions with more confidence. In most circumstances, cases will be decided within a year from application.

In the context of wind generation the IPC will determine:

- onshore wind farm proposals in England and Wales with an expected generating capacity of more then 50 MW;
- offshore wind farm proposals with a capacity of more then 100 MW (in waters in or adjacent to England or Wales up to the seaward limits of the territorial sea, or in a Renewable Energy Zone, except any part of a Renewable Energy Zone in relation to which the Scottish Ministers have functions); and
- the installation of an electric transmission line above ground if in England and Wales (in whole of in part) or partly in England and partly in Scotland (and then only to the extent that the above ground line is in England).

The detailed procedures and processes of the new regime are currently undergoing consultation in three tranches. We summarise the procedures here and discuss in more detail in Annex A. So far there has been consultation on the list of statutory consultees, pre-application procedure and the form of the application. Consultation on the decision making process was published in July 2009 after the writing of this report and has therefore not been taken into account in this report.

A consent for an NSIP will be set out in an Order for Development Consent. A Development Consent will include consent that would previously have to have been applied for separately for onshore and offshore wind farms[10]:

- Section 36 Electricity Act 1989 – onshore and offshore;

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10 For projects located in Wales the Planning Act still allows applications under the Transport and Works Act 1992 to be used for offshore generating stations in waters in or adjacent to Wales up to the seaward limits of the territorial sea.

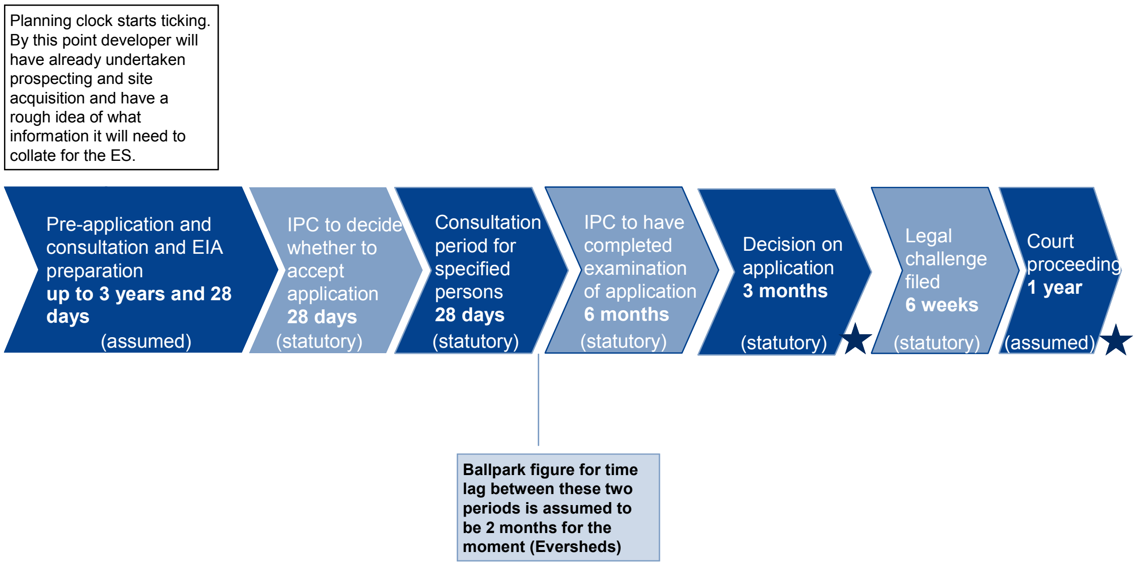
- Section 37 Electricity Act 1989 – electricity lines;
- Section 34 Coast Protection Act 1949 – offshore only; and
- Licence under Part 2 of the Food and Environmental Protection Act – offshore only.

Once submitted the application should be processed through to determination within 9 months. Figure 16 summarises the key stages and timescales within which the application should be progressed. To give context to this figure the key stages are summarised as follows (more detail is set out in Annex A):

- Pre-application: Whilst overall an application is expected to be progressed within 9 months the timing of the pre-application process should not be underestimated. There are no set timescales for this stage and the length of this pre-application process will depend on the particular proposal. For the purposes of the model we have assumed a period of 3 years although it is anticipated and hoped that the period may be quicker than this.
- Submission to IPC: On receipt the IPC must decide whether or not to accept the application within 28 days. (They will be looking to see that the pre-application procedures have been properly carried out and that all is in order ready for the IPC to proceed.)
- Consultation Period: The applicant must then give notice of the application to specified bodies/people which will be set out in the regulations giving a consultation period of 28 days for representations on the application to be made.
- Unknown timescale period: The IPC will then decide whether a single commissioner or a panel of commissioners (maximum of 3) will consider the application (going forward, the procedure varies a little depending on this) and will make an initial assessment of the principal issues arising on the application and after making that assessment they must hold a meeting. There are no set timescales for this step in the procedure. In the meantime and for the purpose of the model we have estimated a period of 2 months.
- Examination of application: The meeting held by the IPC is one to which the applicant and any person who has made a representation can attend to make representations about how the application should be examined (no evidence is heard at this stage). The date of this meeting effectively triggers the timescales for determining the application. The application can be determined in 3 ways: written representations; hearings about specific issues or open-floor hearing. People will be able to make representations. The aim is to avoid the long public inquiries that can take place at the moment (eg for the over 50MW proposals some last as long as 9 weeks and at a minimum at least a month). The IPC is under a legal duty to complete the examination of the application by the end of the period of 6 months from the date of the meeting. It is expected however that for a number of applications being heard at open-floor hearings that this period will be longer.
- Determination of the application: The IPC is under a legal duty to decide an application by the end of the period of 3 months from the end of the 6 month period above for examination. There is however provision in the Planning Act for the IPC which allows a later date to be set at the Secretary of State's discretion. There is also provision for the Secretary of State can intervene if they think they should determine the application.
- Legal Challenge: Once the application has been determined it can be subject to a legal challenge. There is no right of appeal. Any person wishing to make a legal challenge must do so within 6 weeks of the date of the decision. The challenge will

be to the High Court and as for challenges in the current system there is no set time period for determining legal challenges. For the purposes of the diagram we have assumed a period of 1 year but this is obviously not definitive.

Figure 16 – Planning process and proposed timescales for those wind projects which will be determined by the IPC



Once planning permission has been received, we assume that project must commence with construction i.e. spade in ground within 5 years as per the previous practice (this is still in discussion at present)

Source: Eversheds

4.5.2 Under 50MW projects in England

The Planning Inspectorate in England has recently published (4 April 2009) new guidance for the progress of appeals. The aim of this is to streamline the appeals process further and for public inquiries, the aim is to reduce the period between appeal submission and inquiry date and encourage earlier submission of statements of common ground between the LPA and the appellant to try to reduce the amount of inquiry time.

4.5.3 Killian Pretty Review

This review highlighted the need for reform to the planning system in England. The Government's response indicates that some recommendations will be taken on board. Until we know what the Government intends to do and when it is not possible to comment on whether the deployment of onshore or offshore wind farms will be affected by this.

4.5.4 Scotland

Scotland is currently undergoing the most significant modernisation of its planning system in over 60 years through The Planning etc. (Scotland) Act 2006 (referred to in this section only as the Act). The changes being introduced are substantial and are different to the new regime under the Planning Act in England and Wales. However both new regimes share the statutory duty for pre-application consultation prior to the submission of larger developments. The new regime is described in more detail in Annex A but key points are summarised below:

- A new hierarchy of developments has been created (see the Town and Country Planning (Hierarchy of Developments) Scotland) Regulations 2009 which came in effect on 6 April 2009. This splits development type into national, major and local developments. Wind farms over 20MW are classed as 'major' developments and wind farms under 20MW are classed as 'local' developments. National and Major Developments will need to undergo a specific pre-application consultation procedure with the public, consultees and LPA. Local Developments (which include onshore wind of under 20MW) do not need to under go this unless the LPA consider it appropriate. For Local Developments determination can be by way of a new provision known as a scheme of delegation. This means that the LPA can delegate an officer to determine the application as opposed to it being determined by Committee. If this scheme of delegation is taken up for a particular application and the application is refused the applicant can only request a review of the application by the LPA. If the LPA refuse it there is no right of appeal. The Electricity Act 1989 will still apply to applications over 50MW.
- Part 2 of the Act introduces a new development plan system and The Town and Country Planning (Development Planning) (Scotland) Regulations 2008 came into force in February 2008. These make provision for new development plan documents: Strategic Development Plans and Local Development Plans which will set out the policy framework for development of land in the areas for which they cover.
- The period within which appeals must be submitted to the Scottish Government has been reduced from 6 months to 3 months.

The Scottish Government has recently published their Renewables Action Plan.

4.5.5 Potential timescales consistent with revisions to planning reforms

Drawing on the above discussions, we have endeavoured to summarise how the reforms may affect the historic timeframes reported in Table 5. These are presented in Table 8 which replicates the information in Figure 13 for onshore wind under 50MW applications in England and Wales and Figure 16 for over 50MW onshore wind and over 100MW offshore wind applications in England and Wales.

Though a number of the timescales per planning stage are set out in weeks, the Tables report in months (rounded-up to the nearest month) to be consistent with subsequent modelling assumptions.

In setting out the planning stages and timescales we have not included a timescale for a legal challenge or judicial review. This is because the timescales for that stage are so individual and depend on a number of factors, not least the waiting time at the High Court for the matter to be heard that it was not considered helpful to add this into the model. In addition whilst legal challenges and judicial review are increasing they do not apply to the majority of proposals. However it is the *threat* of legal challenge which impacts on decision making and timescales as applicants and decision makers become ever more cautious and thorough in their approach to avoid any potential legal challenge from being made. This will continue to apply going forward with the new regimes and whilst the scenario assumes no legal challenges will be made this assumption represents an ideal outcome. There will be legal challenges to IPC decisions and these are particularly anticipated in the first few decisions. As the timescales and numbers of legal challenges likely to be made cannot be quantified to any useful degree it was decided for the purposes of the scenario to assume no legal challenges and this should be taken into account in interpreting the results from the model. We would suggest that if a legal challenge is made one should assume a period of 12 to 18 months for the matter to be heard at a hearing in the High Court. If the challenge is successful and the decision remitted back for re-determination one should assume an additional 12 months.

It should be noted that the timescale within which a planning permission must be implemented (or 'technical start') is set by the LPA for under 50MW onshore proposals and can vary. In the absence of any specific timescale the statutory period is 3 years from the date of permission and in the majority of under 50MW proposals this is the period given. Recent DCLG correspondence to Planning Officers has however indicated that this period should be extended given the problems with supply of turbines. Developers must satisfy any planning condition attached to the permission which must be discharged before they can start construction. These often require the submission of a detailed plan (eg construction method statement) to the LPA for their agreement. Reference is made to the development cycle set out in Annex A which discusses this in more detail. For over 50MW the period the decision maker has given from decision commencement of development has historically been 5 years. It is not known whether this will apply to IPC consents but for the purposes of the model and Table 5 we have assumed that it will.

Table 8 – Timescales assumed for onshore and offshore wind split into size and jurisdiction according to statutory guidelines, post IPC

Type and size of proposal	Planning Stage	Timescale (months) Eng	Wales	Scot	NI
Onshore: 0-5MW	Pre-application: site selection and EIA Assumed timescale	26.0	26.0	26.0	26.5
	Application: application submission to determination at application stage Statutory timescale for EIA	4.0	4.0	4.0	4.0
	Appeal/Inquiry Based on guidance notes or target timescales issued by the relevant appeal body for period from appeal submission to appeal decision	13.5	13.5	15.5	24.0
	Time period for implementing the planning permission This is the usual timescale granted and assumes no longer period set by LPA	36.0	36.0	36.0	36.0
Onshore: 5-50MW	See Figure 13 above				
	Pre-application: site selection and EIA Assumed timescale	25.3	25.3	25.3	25.5
	Application: application submission to determination at application stage Statutory Timescale (for EIA)	4.0	4.0	4.0	4.0
	Appeal/Inquiry	13.5	13.5	13.5	60[11]

[11] In the lack of any guidance notes this figure has been based on the average timescale from historical data. It should also be noted that there have been very few appeals to onshore wind farms in N. Ireland.

Type and size of proposal	Planning Stage	Timescale (months) Eng	Wales	Scot	NI
	Based on guidance notes or target timescales issued by the relevant appeal body for period from appeal submission to appeal decision				
	Time period for implementing the planning permission This is the usual timescale granted and assumes no longer period set by LPA	36.0	36.0	36.0	36.0
Onshore: >50MW	For England and Wales see Figure 16 (IPC Procedure). For Scotland see Figure 14 Section 36 Electricity Act (assumed similar timescales for N. Ireland)				
	Pre-application: site selection and EIA and pre-application consultation Assumed timescale	37.5	37.5	37.5	37.5
	Non-IPC Application (i.e. applications over 50MW in Scotland and N. Ireland): application submission to determination at application stage Statutory Timescale for England and Wales and indicative guidance timescales for Scotland which have also been applied to N.Ireland where no guidance timescales are given.	n/a	n/a	4.0	4.0
	Public Inquiry Assumed timescale based on historical data average	n/a	n/a	18	24
	IPC: Application period to public meeting Based on statutory period of 1 month for validation, 1 month consultation and assumed period of 2 months until public meeting	4.0	4.0	n/a	n/a
	IPC: From Public Meeting to determination	9.0	9.0	n/a	n/a

Type and size of proposal	Planning Stage	Timescale (months) Eng	Wales	Scot	NI
	This timescale includes the 3 month examination and consideration periods set in the Planning Act but it likely to be increased depending on the issues to be discussed and any open-floor hearing. A simplistic view on timescales for this period has been assumed.				
	Time period for implementing the planning permission This is the timescale normally granted for current Section 36 Electricity Act consents and is assumed for wind farm IPC development consents for the purposes of the model.	60.0	60.0	60.0	60.0
Offshore: <100MW	Pre-application: EIA Assumed timescale	37.0	37.0	37.0	37.0
	Application Assumed timescale based on current situation	9.0	9.0	6.0	9.0
	Time period for implementing the planning permission Assumed timescale based on current situation	60.0	60.0	60.0	60.0
Onshore (>50MW and offshore (>100MW) according to IPC	Pre-application consultation	37.5	37.5	n/a	n/a
	Submission of application to IPC This includes 1 month review of application to acceptance and 1 month consultation period	2.0	2.0	n/a	n/a
	Period awaiting calling of Public Meeting Assumed	2.0	2.0	n/a	n/a
	Consideration and Determination period This timescale includes the 3 month examination and consideration periods set in the Planning Act but it likely to be increased depending on the issues to be discussed and any open-floor hearing. A	9.0	9.0	n/a	n/a

Type and size of proposal	Planning Stage	Timescale (months)			
		Eng	Wales	Scot	NI
	simplistic view on timescales for this period has been assumed.				
	Time period for implementing the planning permission This is the timescale normally granted for current Section 36 Electricity Act consents and is assumed for wind farm IPC development consents for the purposes of the model.	60.0	60.0	60.0	60.0

Source: Eversheds

Until the IPC is up and running it is difficult to predict exactly how long applications will take to go through to determination. Set timescales have been given for certain stages in the application process and these are described in more detail in Annex A and have been used in the above table for the purposes of the model. However applications for wind energy may well also include an application for compulsory purchase and other applications for consents that can be made within the same overall application for Development Consent.

The inclusion of these will increase the timescales to determination and the length of open-floor hearings. The intention of the IPC is to ensure decisions on major infrastructure proposals are reached faster than they are at present for the purposes of the study we can only assume that this will be the case. The reality will not be known until after applications have progressed through the IPC. In addition we cannot predict whether approval rates will increase or not however given the increased importance being placed on renewable energy by the Government and proposals suggested in the Renewable Energy Strategy and Renewables Action Plan it has been assumed in the High Feasible scenario that approval rates will increase.

4.6 Modelling planning constraints

Planning constraints are implemented in the model during the pre-development and development phase of the project cycle. In general, there are two categories of planning constraint:

- the time taken for the planning application and related processes (e.g. determination or appeal) for a particular project; and
- the probability that a project is granted planning consent.

As the time taken for a particular project to progress through planning is dependent on the stage at which planning consent is granted, we also define the proportion of wind generation projects that are successful at the alternative stages of the planning cycle i.e.

- Pre-Application;
- Appeal/inquiry; and
- Refusal (Lost).

Planning constraints are defined at the regional level (i.e. England, Wales, Scotland and Northern Ireland) and by technology band in order to reflect the different strength of the barriers across these dimensions in reality. To account for changes in legislation, planning times are also defined in each year to 2020. Therefore a 50MW offshore project entering planning in 2009 could spend a different time in planning to a 50MW offshore project entering planning in 2015. In our modelling we introduced new timelines for certain technology bands based on the anticipated date the IPC will start receiving applications for wind energy proposals which is due to commence in March 2010.

The following sections present further details on the two planning scenarios that have been modelled.

4.6.1 Planning constraints in the High Feasible scenario

Constraints under the High Feasible scenario broadly reflect favourable conditions for planning phase. Planning times under the High Feasible scenario are taken from those set out under legislation or planning guidance notes and assume that successful planning reform has taken place. To this end, it has been assumed that all projects are granted planning permission and that these projects pass through planning at the first stage (Application) for onshore sites and at the appeal stage for offshore sites. This is only an assumption designed to reflect a benign planning regime. The indicator methodology will highlight whether the assumptions prove optimistic.

Table 9 presents a summary of the planning constraints that have been implemented under the High Feasible scenario. It can be seen that in general there is little variation in the average number of months individual projects are expected to spend in planning. The reason for this is that all projects are assumed to pass through planning at the application stage. Although we cannot determine whether or not there will be a legal challenge, we assume that all projects will gain approval at the application stage. Therefore there is no variation in the time taken for planning between projects in identical technology bands in a given region. The reason for the existence of a range is the difference between regional planning times for a given technology band.

Table 9 – Summary of planning constraints implemented in the model under the High Feasible scenario

	Technology Band	Average time in planning (months)	Range (months)	Probability of success	Range
Onshore	0-5MW	30.00	30.0-30.5	100%	0.00
	5-50MW	29.00	29.3-29.5	100%	0.00
	>50MW	42.00	0.00	100%	0.00
Offshore	<100MW	46.00	44.5-47.5	100%	0.00
	>100MW	46.00	44.5-47.5	100%	0.00

Table 10 shows the proportion of projects allocated to the stages of planning under the High Feasible scenario. As mentioned, all onshore projects are assumed to pass through planning at the application stage. As offshore projects must go through a different planning process to onshore projects (see Annex A), for modelling purposes all offshore sites have been allocated to the second phase of the planning cycle.

Table 10 – Proportion of projects allocated to stages of planning by region and technology band under the High Feasible scenario

Onshore/Offshore	Country	Size category	Application	Appeal/inquiry	Lost
Onshore	England	1MW to 5MW	100%	0%	0%
Onshore	Wales	1MW to 5MW	100%	0%	0%
Onshore	Scotland	1MW to 5MW	100%	0%	0%
Onshore	Northern Ireland	1MW to 5MW	100%	0%	0%
Onshore	England	5MW to 50MW	100%	0%	0%
Onshore	Wales	5MW to 50MW	100%	0%	0%
Onshore	Scotland	5MW to 50MW	100%	0%	0%
Onshore	Northern Ireland	5MW to 50MW	100%	0%	0%
Onshore	England	Over 50MW	100%	0%	0%
Onshore	Wales	Over 50MW	100%	0%	0%
Onshore	Scotland	Over 50MW	100%	0%	0%
Onshore	Northern Ireland	Over 50MW	100%	0%	0%
Offshore	England	Less than 100MW	0%	100%	0%
Offshore	Wales	Less than 100MW	0%	100%	0%
Offshore	Scotland	Less than 100MW	0%	100%	0%
Offshore	Northern Ireland	Less than 100MW	0%	100%	0%
Offshore	England	Greater than 100MW	0%	100%	0%
Offshore	Wales	Greater than 100MW	0%	100%	0%
Offshore	Scotland	Greater than 100MW	0%	100%	0%
Offshore	Northern Ireland	Greater than 100MW	0%	100%	0%

4.6.2 *Planning constraints under the Alternative scenario*

Planning constraints implemented under the Alternative scenario reflect planning times and allocation derived from historical data. Under the Alternative scenario, we have modelled the fact that not all onshore projects receive planning permission and hence revert to residual resource status. We term this 'Residual Resource', which implies that a project that has been refused planning permission is not available to be developed in the future.

Table 11 presents the average planning times that each technology band can be expected to spend in planning under the Alternative scenario. The range of planning times increases significantly as we now take into account projects that need to go through other stages of the planning cycle and the historical data that shows more variation between regions. In contrast to onshore sites, offshore sites have much less of a range in planning times. This is because in the absence of historical data, we have assumed that all offshore sites pass through planning at the appeal stage.

Table 11 – Summary of planning constraints implemented in the model under the Alternative scenario

	Technology Band	Average time in planning (months)	Range (months)	Probability of success	Range
Onshore	0-5MW	35.00	30.5-38.5	85%	71%-100%
	5-50MW	47.00	32.1-59.7	76%	60%-96%
	>50MW	66.00	53.9-74.6	84%	69%-100%
Offshore	<100MW	47.00	44.5-47.5	100%	0.00
	>100MW	47.00	44.5-50.0	100%	0.00

Table 12 shows the proportion of projects allocated to a given stage of planning under the Alternative scenario. The percentages are derived using historical data and are representative of a business as usual scenario for the planning regime. It can be seen that under the Alternative scenario, some onshore projects will go to appeal/inquiry, which will take longer and some will be refused planning permission. Projects refused planning permission are modelled as having gone through the appeal stage before being rejected and then revert to Residual Resource.

Table 12 – Proportion of projects allocated to stages of planning by region and technology band under the Alternative scenario

Onshore/Offshore	Country	Size category	Application	Appeal/inquiry	Refused
Onshore	England	1MW to 5MW	71%	6%	24%
Onshore	Wales	1MW to 5MW	69%	3%	29%
Onshore	Scotland	1MW to 5MW	89%	3%	8%
Onshore	Northern Ireland	1MW to 5MW	100%	0%	0%
Onshore	England	5MW to 50MW	54%	11%	35%
Onshore	Wales	5MW to 50MW	57%	4%	40%
Onshore	Scotland	5MW to 50MW	73%	11%	16%
Onshore	Northern Ireland	5MW to 50MW	96%	0%	4%
Onshore	England	Over 50MW	0%	86%	14%
Onshore	Wales	Over 50MW	50%	30%	20%
Onshore	Scotland	Over 50MW	59%	10%	31%
Onshore	Northern Ireland	Over 50MW	75%	25%	0%
Offshore	England	Less than 100MW	0%	100%	0%
Offshore	Wales	Less than 100MW	0%	100%	0%
Offshore	Scotland	Less than 100MW	0%	100%	0%
Offshore	Northern Ireland	Less than 100MW	0%	100%	0%
Offshore	England	Greater than 100MW	0%	100%	0%
Offshore	Wales	Greater than 100MW	0%	100%	0%
Offshore	Scotland	Greater than 100MW	0%	100%	0%
Offshore	Northern Ireland	Greater than 100MW	0%	100%	0%

4.6.3 Comparison of scenarios

The High Feasible and Alternative scenarios differ in three ways:

- On average, projects spend less time in planning under the High Feasible scenario than under the Alternative scenario. The is because the Alternative scenario uses historical planning timescales which are longer than the timescales set out under legislation or planning guidance notes and the assumption that not all projects pass through planning at the first stage.
- Secondly, the range of average planning times per region is far greater in the Alternative scenario than in the High Feasible scenario. This is because under the Alternative scenario all projects are assumed to go through planning at the application stage, while the High Feasible scenario uses historical data to allocate a proportion of projects to appeal and inquiry stages of planning. As it takes a longer time to go through pre application and appeal/inquiry, the range of planning times increases. This effect is compounded as different regions have different timescales associated with appeal and inquiry.
- The Alternative scenario models projects that get refused planning permission. There can be a variety of reasons for this rejection, but we have modelled it as taking place after the appeal/inquiry stage. Once a project is refused planning permission, it reverts to residual resource status and cannot be redeveloped.

5. SUPPLY CHAIN

5.1 Introduction

The supply chain can be defined as the engineering and manufacturing infrastructure and resources that support the construction of onshore and offshore wind farms. This covers items such as turbine manufacture, balance of plant manufacture which refers to sub-systems that are not part of the turbine itself but essential for operation, availability of specialist installation vessels and engineering resource.

In relation to where the supply chain constraint sits in the overall project cycle, we have assumed that this particular constraint lies between the end of the development phase (i.e. post financial close – see Section 3) and the beginning of the construction phase. The supply chain, therefore, has the potential to limit the capacity of turbines going into construction and hence limit the total operational wind generation in the UK.

For the purposes of this study, we assume that capacity that has gone through the development stage waits in the supply chain phase until sufficient resources are allocated to begin construction. In reality, this could imply that the predicted rate of return would need to be higher for investment in a project that was not guaranteed supply chain capacity. Alternatively it might mean that finance is only granted when a vessel slot has been secured. Such issues have been deemed out of the study scope.

Due to time constraints during the project, the majority of the analysis associated with supply chain constraints has been based previous studies and discussions with both DECC and the BWEA. This includes the SKM report 'Quantification of Constraints on the Growth of UK Renewable Generating Capacity' and the Douglas Westwood report 'Supply Chain Constraints on the Deployment of Renewable Electricity Technologies' produced as part of the 2008 Renewable Energy Strategy and the more recent study by BVG Associates on how to improve delivery of UK offshore wind.

This section provides:

- an overview of the key issues affecting the capacity of the supply chain;
- details of the measures that are necessary to alleviate the constraints for offshore and onshore wind deployment; and
- the supply chain assumptions used for the development of the trajectories for wind investment to 2020 as presented in Section 7.

5.2 Current status

According to our database of projects that are under construction, at present there is around 0.85GW of onshore wind being constructed and 1.3GW of offshore wind. This equates to a build rate or supply chain capacity of 0.85GW per year for onshore wind (assuming a one year build time) and 0.65GW per year for offshore wind (assuming a two year build time).

These figures are higher than the present situation as stated by SKM which reported that the average build rate for onshore wind sites was 450MW/year over the last four years and 350MW/year for offshore. From further discussions with both the BWEA and DECC, we view that these higher figures are in line with current estimates for supply chain capacity and have therefore used them as a basis for any analysis on supply chain constraints (see Section 5.5).

5.3 Key issues currently affecting supply chain development

The key issues currently affecting supply chain development have already been well documented in the SKM and BVG reports, therefore the following is only a summary of the relevant issues for onshore and offshore wind.

5.3.1 Onshore wind

Given the more mature status of the onshore turbine market, supply chain issues are not generally seen to be as severe as for offshore sites (see Section 5.3.2). According to SKM the key constraint is the availability of wind turbines, whilst Douglas Westwood and the BWEA view that supply chain has developed in response to the number of projects that can be accommodated by the currently constrained transmission network (see Section 6). It is likely that, if the large backlog of projects created by the delay in the reinforcement of the transmission network were to be released, the supply chain would not be able to adjust immediately due to the unavailability of wind turbines and skilled engineering resources.

There has been some slight easing in turbine availability due to the downturn in the US wind market and the relocation of manufacturing facilities to the US which has led to a fall in the demand for exports from Europe. However, this is unlikely to completely ease turbine availability for the UK and will therefore still be one of the main supply chain constraints for the time being.

There are reported to be some issues surrounding physical access (i.e. the turbine and mast) to certain onshore wind sites (typically in Wales) that limit the capacity of wind turbine that can be installed (reported to be around 0.85MW). Information from wind developers indicates that most developers who plan large projects (that are more capital intensive) pay for additional works to be carried out to improve transportation access. Therefore this issue can be seen to only affect small scale developments and are not expected to impinge significantly on the overall operational capacity potential for onshore wind.

5.3.2 Offshore wind

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

5.3.2.1 Turbine manufacture

Turbine manufacture includes all sub-systems that are required to produce the turbine itself. This includes items such as turbine blades, gearboxes and bearings, castings and forgings (e.g. for the hub) and the turbine towers. Manufacturers typically provide the entire turbine to a developer, however, there are a number of sub-components that have to be supplied to the turbine manufacturer. The market for these sub-components is often global, with suppliers not just dedicated to the production of wind turbines.

Both the BVG report and SKM report that the availability of wind turbines as a whole is a key constraint for the offshore wind supply chain. Assuming that the average size of wind turbines is 5MW[12] over the period 2009-2020, and the total capacity in development and resource for offshore wind is 39.2GW, then the UK would require around 7800 turbines to facilitate this potential. Given that there is currently 598MW of offshore wind operational, this will require a large increase in the supply of key turbine components for the UK market. Interestingly, the BVG report does not forecast any issue in component supply but rather the limit of the capacity of turbine manufacturers. Issues are also raised regarding the fact that offshore turbines are still under development in terms of design and could suffer from initial problems associated with all new technology (most designs have been adopted from onshore turbines and are therefore not suited to the harsher maritime climate – as demonstrated when DONG needed to replace all gearboxes on the Horns Rev wind turbines due to corrosion).

5.3.2.2 Balance of plant manufacture

Balance of plant sub-systems covers such items as foundations for turbine construction, cables to connect the wind site to the transmission network, and substations to transform the energy output of the turbine to match grid requirements.

Both the SKM and BVG reports agree that the main constraint regarding balance of plant manufacture is the supply of subsea cables. The Crown Estate estimate that 7700km of cable (3000km HVAC and 4700 HVDC) will be required for Round 3 projects, and currently no cable factories are located in the UK. This impact is further compounded by supply being booked for the next 5 years and at present there only being three offshore cable suppliers within Europe, although there is some evidence to suggest that other manufacturers are trying to break into the market.

5.3.2.3 Installation and commissioning resources

For the purposes of this study, installation and commissioning resources covers those items necessary to construct and commission wind turbines and windfarms. For offshore, this includes the development of construction ports and specialist vessels for turbine and foundation installation.

According to SKM, BVG, Douglas Westwood and the BWEA, the key constraint affecting offshore wind is the current lack of installation vessels. At present it is estimated that only two vessels are available for use to install turbines at offshore sites in the UK, although market data would suggest that there is interest in the construction of new vessels and an additional two are expected to be in service by 2011.

The other issue is a general lack of construction facilities/ ports in the UK at present. Although some ports are used for offshore farms, the scale of Round 3 projects makes a dedicated series of ports important. The availability of construction ports is being addressed via the DECC document 'UK Ports for the Offshore Wind Industry: Time to Act'.

[12] The BVG report states that the average size of new offshore turbines in 2020 will be just under 6MW. Therefore 5MW is a sensible projection for the average offshore turbine capacity to 2020.

5.4 Measures needed to alleviate supply chain constraints

There are several adaptive measures that can be taken in order to alleviate the key supply chain constraints highlighted in the previous Section. Due to the long lead times to deliver additional supply chain capacity, the key to attracting investment in the supply chain is transmitting clear market signals that additional supply chain capacity is required for offshore wind. Arguably, this is already happening to a certain extent as a result of the Offshore Energy SEA, the Scottish and Northern Irish SEAs, Round 3, and the Crown Estate's Scottish Territorial Waters project.

As discussed in Section 5.3.1, the main investment required to relieve onshore wind supply chain constraints would be the building of a new turbine production plant, preferably in the UK. The construction of a plant capable of delivering an additional 450MW of onshore turbines to the UK each year is expected to take 2 years to build. This additional capacity would equate to a rate of production of one hundred and fifty 3MW turbines a year.

There is also the option of importing turbines from abroad, which is the present case. However, due to other European countries ramping up their wind generation to meet their own 2020 renewable energy targets, the UK will need to compete strongly for resources in the future. In addition, China and India are beginning to absorb substantial proportions of supply chain capacity for turbine components due to a growing home market.

These two countries are beginning to develop their own manufacturing industry for wind turbines, thus, there exists the future potential for Chinese turbines to be imported into the UK market. The main hurdle such exports face is to overcome the reliability and efficiency (technology) gap that exists between Chinese manufacturers and companies like Vestas. The BVG report states that Chinese manufacturers are expected to establish this level of reliability at some time after 2015, implying that there is limited scope for including the effect of imported Chinese turbines.

As the offshore wind industry is relatively under developed compared to the onshore wind generation market, there are more areas of the supply chain that require investment in order to increase the capacity of the supply chain, including:

- Offshore specialist installation vessels: specialist installation vessels are estimated to cost between £50million and £150 million (depending on whether or not vessels are converted from current oil and gas installation vessels or ordered as new) and have a delay of three years between the date of ordering and the date of entering service. The Doulas Westwood report states that the construction time for a new vessel could be up to 4 years. Both of the aforementioned timescales are for new build vessels. According to the BVG report, the time taken to convert vessels is nine months.
- Offshore wind turbine construction and assembly facilities: additional dedicated offshore turbine facilities, such as the Clipper factory in North East England, would relieve dependency on imports and would leave UK developers less exposed to competition from EU firms and the effects of exchange rate fluctuations. In addition, there could be benefits in promoting the offshore wind industry in the UK, particularly with the current trend for vertical integration of manufacturing companies for what is still a developing technology. It is not clear how much an offshore facility would cost, but it is estimated that the Clipper factory will produce 200 turbines by 2014. This equates to an additional supply of 1GW of offshore capacity per year for the UK market.
- New cable production facilities: new cable production facilities are expected to take three years to build and cost £35million. The construction of a dedicated UK cable

production facility is likely to require luring one of the three companies that currently have the intellectual capital rights to produce HVDC or HVAC cable.

- Port facilities: a new facility for the assembly of offshore turbine sub-systems is estimated to cost £15million and take two years to construct. The UK government has recently released a consultation to identify the most suitable UK ports for conversion to accommodate offshore wind turbines.

These various investment measures are taken account of when modelling our trajectories of wind investment out to 2020 as discussed in the next section.

5.5 Modelling supply chain constraints

In deriving our trajectories of wind investment to 2020, we have considered how supply chain capacity develops under two different scenarios – 'High Feasible' and 'Alternative'. The High Feasible scenario assumes a supply chain capacity that expands in response to the anticipated deployment of wind generation, whilst the Alternative scenario assumes a supply chain constraint that represents business as usual with some expansion in certain areas of the supply chain albeit at a lower rate of expansion than under the Alternative scenario.

Supply chain constraints are modelled at the UK level as a volume constraint, split into onshore and offshore categories. The constraint is applied in the model between the development phase and the construction phase. Therefore once projects have completed the development phase, the cumulative capacity entering the supply chain for a given year is calculated. The proportion of the UK wide supply chain allocated to an individual region (England, Scotland, Wales and Northern Ireland) is determined by the total capacity awaiting construction in that region. In the event that insufficient supply chain capacity exists for all capacity in a region to enter construction, surplus capacity is rolled over to the following year.

5.5.1 Supply chain under the High Feasible scenario

For the High Feasible scenario we have assumed that supply chain capacity is broadly in line with the SKM high growth scenario for onshore and offshore wind as taken from their 2008 report, but altered to take account of current rates of construction build (see Section 5.2).

Table 13 presents the increase in supply chain capacity that has been assumed for onshore wind. It shows a steady increase in the capacity of the onshore wind supply chain taking place until 2019, at which time the onshore supply chain is capable of constructing 1.5GW of new capacity per year. This figure is equivalent to an additional two turbine factories being built in the UK.

There have been some questions as to what would sustain the onshore wind industry post 2020 given that the amount of onshore wind being developed per year by this time would be lower than that being developed in the period up to 2020. Discussions with DECC have indicated that a combination of re-powering of onshore sites, exports and new build offshore is likely to sustain this supply chain post 2020.

Table 13 – Supply chain capacity for onshore wind under the High Feasible

Supply chain capacity (MW)	2008	2010	2014	2015	2017	2020
Turbine availability	450	850	1000	1100	1300	1500
Engineering resource	450	850	1000	1100	1300	1500
Overall supply chain constraint	450	850	1000	1100	1300	1500

Source: SKM and Pöyry Energy Consulting

Table 14 presents the assumptions used for increasing the supply chain capacity for offshore wind to 2020. It shows an additional ten offshore vessels are in service by 2020. As each specialist vessel is capable of installing 175MW/year, this relates to an installation rate of 2.275GW per year in 2020. Moreover this is more than one third of all vessels expected to be deployed in Europe to 2020 (BVG expect 35 installation vessels to be operational in Europe by 2020). For the purposes of this study, the rate of installation per vessel has been taken as that given in the SKM report of 175MW/year. The dominant constraint in determining the rate of installation is the weather- the BWEA report that in favourable conditions, vessels are capable of installing up to 2MW per day. This is to be contrasted with the numerous reports of wind farms being severely delayed due to weather conditions. The rate of installation derived by SKM assumes that vessels can operate in a 170 day window and require 3.5 days to install a 3.6MW turbine. However, given that many Round 3 sites are further offshore than current wind farms and therefore in rougher seas, it can be expected that the operating window will reduce. In order to balance this against expected improvements in technology and installation methods, this study has assumed a rate of installation of 175MW/year per vessel to 2020.

Table 14 also demonstrates that the supply chain capacity of the other components is assumed to move in tandem with the build rate of the installation vessels. Assuming that new vessels cost £150million, this would translate into a required investment of £1.65billion; even if vessels cost £50 million, £550million of investment would still be required by 2020. Given the other elements of the offshore supply chain cost less to upgrade and crucially the fact that most large offshore wind developments in Round 3 are likely to be constructed by large utilities, rather than IPP's, it seems unlikely that investments in the other areas would not be triggered.

Finally, we assume that the utilities involved in the large offshore projects will also be able to source wind turbines on the international markets with little problem, partly due to the size of order they are likely to be making given the size of the Round 3 projects.

Table 14 – Supply chain capacity for offshore wind under the High Feasible scenario

Supply chain capacity (MW)	2008	2010	2014	2015	2017	2020
Installation vessel availability	350	700	1225	1400	1750	2275
(No of vessels)	(2)	(4)	(7)	(8)	(10)	(12)
Cable availability	350	700	1225	1400	1750	2275
Turbine availability	350	700	1225	1400	1750	2275
Engineering resource	350	700	1225	1400	1750	2275
Overall supply chain constraint	350	700	1225	1400	1750	2275

Source: SKM and Pöyry Energy Consulting

5.5.2 Supply chain under the Alternative scenario

The supply chain capacity available for onshore and offshore wind construction under the Alternative scenario presents a more pessimistic case for expansion. In general, it is in line with the medium growth scenario from the SKM report, but altered to take account of current rates of construction build (see Section 5.2).

Table 15 shows how the key components of the onshore supply chain evolve to 2020. The additional 50MW of capacity in 2014 relates to an increase in imports of onshore turbines. In general this scenario is reflective of a situation where very little investment in the supply chain for onshore wind takes place due to market anticipation of extended delays for onshore wind projects receiving transmission access.

Table 15 – Supply chain capacity for onshore wind under the Alternative scenario

Supply chain capacity (MW)	2008	2010	2014	2015	2017	2020
Turbine availability	450	850	900	900	900	900
Engineering resource	450	850	900	900	900	900
Cable availability	450	850	900	900	900	900
Overall supply chain constraint	450	850	900	900	900	900

Source: SKM and Pöyry Energy Consulting

Table 16 presents the assumptions used for increasing the supply chain capacity for offshore wind to 2020 under the Alternative scenario. Under this scenario, it is assumed that a total of 6 vessels are in service by 2020 reflecting a more cautious market to the deemed growth in offshore wind developments in the UK. As each specialist vessel is capable of installing 175MW/year, this relates to an installation rate of 1.05GW per year in 2020. This would be around 16% of the total number of vessels expected to be deployed in Europe by 2020.

Table 16 – Supply chain capacity for offshore wind under the Alternative scenario

Supply chain capacity (MW)	2008	2010	2014	2015	2017	2020
Installation vessel availability	350	700	1050	1050	1050	1050
(No of vessels)	(2)	(4)	(6)	(6)	(6)	(6)
Cable availability	350	700	1050	1050	1050	1050
Turbine availability	350	700	1050	1050	1050	1050
Engineering resource	350	700	1050	1050	1050	1050
Overall supply chain constraint	350	700	1050	1050	1050	1050

Source: SKM and Pöyry Energy Consulting

5.6 Potential for further relaxation of supply chain constraints

Given that supply chain capacity is one of the key facilitators of wind generation deployment in the UK, it is necessary to investigate the potential that exists for the supply chain in the UK to expand to a higher level than assumed in the High Feasible scenario. To this end we have received input from DECC and evaluated reports from the BWEA, BVG associates and Douglas Westwood to scope out what it might be possible for the supply chain to achieve under favourable conditions.

The BWEA report 'UK Offshore Wind: Charting the Right Course', identifies nine offshore vessels that are currently under construction or on order. This is in addition to the five or six vessels currently targeting the UK market. On the assumption that all vessels will be commissioned for UK operations, and that the installation rate is 175MW/year, the UK will have a dedicated installation capacity of 2.625GW/year when these vessels enter service.

The report from BVG associates projects by 2020, the European requirement for offshore turbines is in excess of 1600 per year at a cost of £9 billion, implying that 35 installation vessels will be operational in Europe 2020. As the report looks at the offshore supply chain from a European perspective, it is difficult to identify the total number of vessels available for the UK market. Assuming that each vessel were capable of installing 175MW/year, this would imply that a total of 6.125GW of offshore wind could be installed per annum in Europe by 2020. In addition, the report also projects the total number of turbines available in the European market to be in excess of 1600 units. Assuming an average turbine capacity of 5MW, this would equate to a rate of installation of 8GW/year throughout Europe by 2020. The study also identifies that the rate of installation of offshore wind in the UK could reach 6.5GW/annum by 2020 with a cumulative installed capacity in excess of 32GW by 2020.

In conclusion, it appears that the UK has the potential to increase the capacity of the supply chain above that set out under the High Feasible scenario. However, the investment case must still be made for the vessel to be ordered 3 years in advance of delivery (as quoted by the BWEA and SKM). Therefore clear market signals are essential to stimulate investment in offshore vessels.

6. TRANSMISSION

6.1 Introduction

After many years of relative stability in terms of the transmission infrastructure and the patterns of generation connected to it, issues relating to transmission investment and transmission access have come to the fore in recent years with the increase of applications for wind connection in (electrically) remote regions. This pressure on the transmission system and the arrangements for accessing it are expected to continue with the anticipated development of offshore wind generation. The uncertainty associated with transmission extends to connection applications for other classes of generator (including nuclear and other conventional generation), as the transmission system is forecast to become increasingly constrained over time.

In this context, developments in respect of the transmission system's capability, and also the arrangements for allocating access to it, are important factors for the future deployment of wind generation. Developments in these regards are both complex and numerous. Given this, we seek to provide an overview of the most pertinent issues relating to transmission and to explain how these issues have been incorporated into the modelling framework.

This section provides:

- an introduction to the existing transmission system;
- an overview of the initiatives and developments which are expected to shape the transmission system and transmission access arrangements in the future; and
- the transmission assumptions used for the development of the trajectories for wind investment to 2020 as presented in Section 7.

6.2 Current status

National Grid expresses the capability of the system in terms of feasible bulk power transfers across defined system boundaries. These boundaries represent some of the main historical weaknesses on the system where it has limited ability to handle bulk power transfers. The boundary between England and Scotland (the Cheviot boundary) is a particularly significant pinch-point on the system and these circuits are already operating at their maximum capability.

In cases where there is insufficient transmission capacity to accommodate available generation, National Grid, as GB System Operator, has to take constraint management actions to reduce generation in a constrained area (e.g. to the north of the Cheviot Boundary) and replace it with generation in an unconstrained area (e.g. to the south of Cheviot Boundary). The cost of transmission constraint management has increased considerably in recent years and is expected to continue to increase in the short-term at least. This is particularly the case in relation to the Cheviot Boundary. Constraint costs are shown in Table 17.

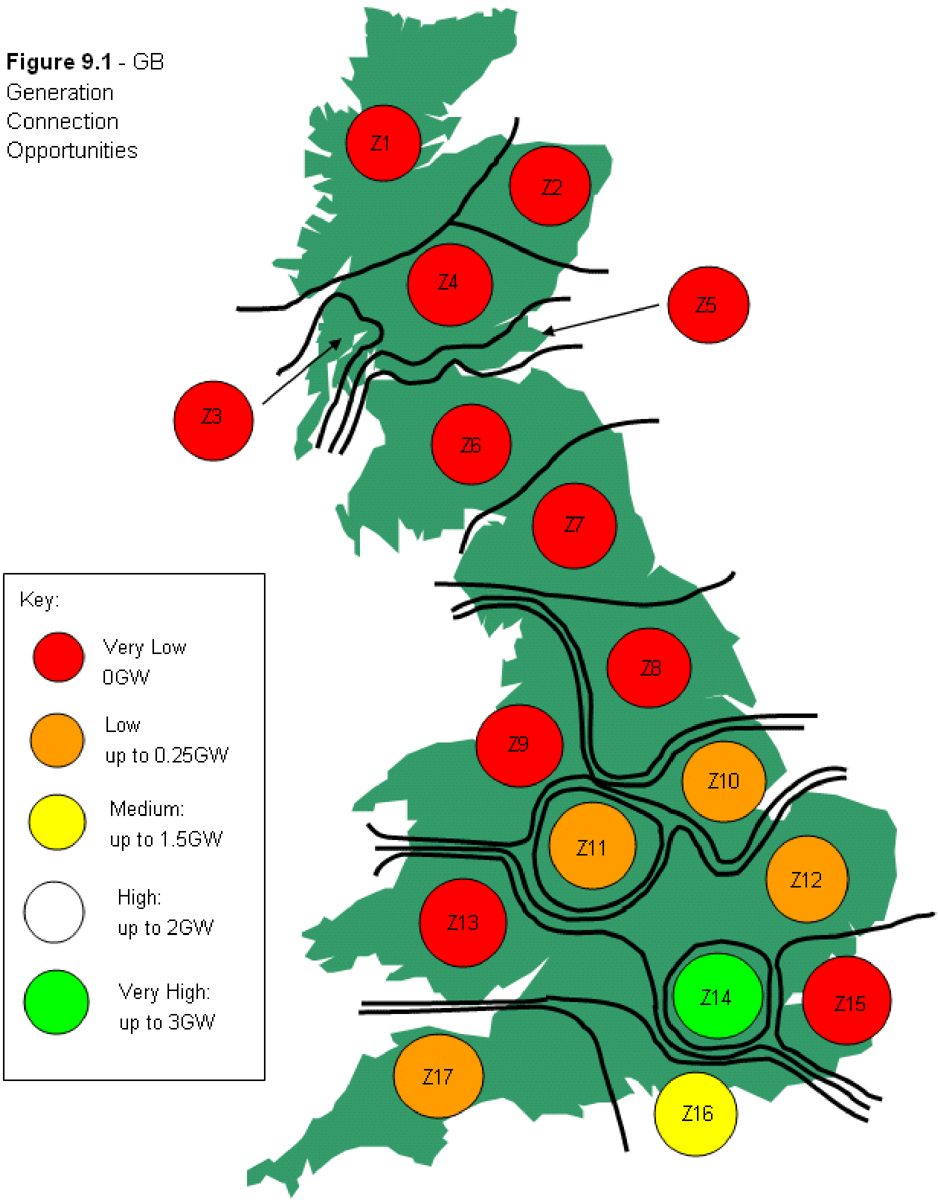
Table 17 – Transmission constraint costs (money of the day)

£m	2005/06		2006/07		2007/08		2008/09		2009/10
	Forecast	Actual	Forecast	Actual	Forecast	Actual	Forecast	Latest Forecast	Forecast
England & Wales	15	13	15	28	24	29	24	161	139
Cheviot	11	44	17	25	30	22	70	81	70
Within Scotland	10	26	25	55	29	20	35	65	50
TOTAL	36	84	57	108	82	70	124	307	259

Source: National Grid, Ofgem

The capabilities of the existing transmission system can also limit the ability of new generation plant to connect to and access the system. Access to the system is currently allocated within the limits of the system's capability. This means that when a generation connection requires transmission reinforcement, this work is completed before the generator is able to access the system. This is an 'invest and connect' model of transmission access. In this context, Figure 17 shows the generation connection opportunities based on the capability of the existing transmission system. There are effectively no opportunities for new connection in Scotland and northern England, linked to limitations of the system to accommodate flows in these areas. Opportunities for connection are generally enhanced in more southerly areas of Great Britain (although there are still areas where opportunities are very low). Overall, however, opportunities for new connection are limited, with prospects only rated by National Grid as 'medium' or above in two cases.

Figure 17 – Existing generation connection opportunities



Source: National Grid Seven Year Statement 2009/10

In order to accommodate the connection of additional generation, particularly of the scale envisaged, and to alleviate the existing constraint issues, there is a requirement for network reinforcement and for revisions to the arrangements for allocating transmission access. Developments in these regards are being progressed at present and the next Section provides an overview of the most pertinent initiatives.

6.3 Ongoing transmission related initiatives and developments

6.3.1 Identified transmission investment requirements

The need for additional transmission capabilities to accommodate anticipated generation connections is widely accepted. Several studies have been undertaken which seek to assess the potential scale of investment required. This Section highlights the key requirements arising from these studies and explores their implications for transmission investment.

6.3.1.1 ENSG Report

Following the publication of the UK Renewable Energy Strategy in June 2008, the Electricity Networks Strategy Group (ENSG)[13] asked the transmission licensees to complete a study to:

- develop electricity generation and demand scenarios consistent with the EU target for 15% of the UK's energy to be produced from renewable sources by 2020; and
- identify and evaluate a range of potential electricity transmission network solutions that would be required to accommodate these scenarios.

A report based on the study was published in March 2009[14]. The total cost of the onshore reinforcements proposed by the ENSG is £4.7bn. This will result in an onshore network that can accommodate 34GW of onshore and offshore wind generation, plus a further 11GW of nuclear generation. The study outlines the cost of transmission reinforcement required to accommodate 34GW of wind capacity (on a £ per kW of installed capacity basis) of £145/kW on average[15]. Table 18 outlines the transmission reinforcement projects identified in the ENSG report. The study concludes that the onshore transmission reinforcements can be delivered to the required timescales, on the assumption that they are taken forward in a timely manner and that the planning consent process facilitates network development.

13 The ENSG is a cross industry group jointly chaired by the Department of Energy and Climate Change and Ofgem.

14 'Our Transmission Network: a vision for 2020', ENSG, March 2009.

15 This drops to £129/kW if the additional nuclear capacity that is able to connect as a result of the onshore reinforcements is also included.

Table 18 – Onshore transmission reinforcements identified by ENSG report

Region	Reinforcement	Online	Installed wind capacity accommodated (GW) Min	Max	Total cost (£m)	Cost per kW installed wind capacity (£/kW)
Scotland Stage 1	North of Scotland, incremental Scotland and Western HVDC link	2015	8	8	1,565	196
Scotland Stage 2	North of Scotland and Eastern HVDC link	2018	4	4	1,150	288
Wales Stage 1	North Wales and Central Wales	2015 - 2017	4	6	575	96 – 144
English East Coast - Stage 1	Humberside and East Anglia	2017	7	11	910	83 – 130
London	London	2015	1	2	190	95 – 190
South West	South West	2017	2	3	340	113 – 170
TOTAL / AVERAGE			26	34	4,730	145 – 186

Source: ENSG

6.3.1.2 Crown Estate Report

While the ENSG report focuses on onshore transmission reinforcement required to accommodate anticipated generation connections, a report commissioned by the Crown Estate[16] focuses, in the main, on the offshore transmission investment required to deliver up to 25GW of Round 3 offshore wind generation projects.

Table 19 outlines the transmission reinforcement projects identified in the Crown Estate report. The total cost of the transmission investment projected in the report is £10.4bn. This equates to a cost per kW of installed capacity of £403/kW on average across the projects. Approximately £500m of the overall investment cost relates to onshore network

16 'Round 3 Offshore Wind Farm Connection Study', The Crown Estate, December 2008.

reinforcement, covered by the ENSG report. If this is stripped out, to avoid double counting, the specific offshore transmission investment costs relating to Round 3 are £9.8bn and the cost per kW of installed Round 3 capacity falls to approximately £380/kW.

Table 19 – Transmission investment for Round 3 offshore wind projects as identified by Crown Estate report

Region	Connection point	Installed wind capacity accommodated (GW)	Total cost (£m)	Cost per kW installed wind capacity (£/kW)
Moray Firth	New substation on coast	0.5	193	386
Firth of Forth	Torness	0.5	150	300
Dogger bank	Creyke Beck	1.2	5,910	477
	Creyke Beck	1.2		
	Creyke Beck	1.2		
	Keadby	1.2		
	Keadby	1.2		
	Killingholme	1.2		
	Killingholme	1.2		
	Killingholme	1.2		
Norfolk	Sizewell	1.2	1,728	349
	Sizewell	1.2		
	Norwich	1.2		
	Norwich	1.2		
Hastings	Bolney	1.2	184	368
Isle of Wight (west)	Chickerell	0.5	175	350
Bristol Channel	New substation on coast	0.5	430	287
Irish Sea	Deeside	1.5	1,632	329
	Deeside	1.2		
	Wylfa	1.2		
	Stanah	1.2		
TOTAL		25.8	10,402	403

Source: Crown Estate

6.3.1.3 Summary

On this basis, a considerable amount of transmission investment is required in order to accommodate anticipated wind generation capacity over the coming years. The total cost of the envisaged onshore transmission network reinforcement and offshore transmission network development to deliver an adequate system is estimated to be in the region of £14.5bn.

6.3.2 Developments to the transmission investment regulatory environment

The ENSG and Crown Estate reports combined suggest that an unprecedented level of transmission investment is required during the course of the next decade in order to enable the anticipated levels of wind generation to connect to and be integrated into the system. For any transmission investment to be undertaken, it must be funded. In this context, the regulatory arrangements are of critical importance to the actual delivery of transmission investment.

A step change in the regulatory approach towards transmission investment funding is required in order to ensure that the necessary infrastructure is delivered. Some initiatives are being undertaken which represent a move towards a more progressive regulatory framework. This Section focuses upon the transmission investment regulatory framework and developments to it.

6.3.2.1 Price controls and RPI-X@20 review

The existing transmission price control runs until 31 March 2012. After this, there are two further five year price control applicable for the period to 2020; the first beginning on 1 April 2012 and the second beginning on 1 April 2017. These dates represent key policy milestones for the implementation of future transmission regulatory funding arrangements. It is critical that appropriate funding arrangements are in place for the price control period beginning on 1 April 2012, in order to ensure that transmission investment is progressed during the middle of the next decade and so is in place ahead of 2020.

The price control beginning 1 April 2012 is expected to be shaped by the conclusions of Ofgem's RPI-X@20 review. The RPI-X@20 review is intended to ensure that the price control framework is fit for purpose in the context of the future energy markets, within which network regulation will increasingly focus on facilitating efficient investment to achieve environmental targets and ensure security of supply as well as on the achievement of efficiency gains. Completion of the RPI-X@20 review process on schedule represents a key policy milestone for the delivery of an appropriate transmission system to accommodate anticipated onshore and offshore wind generation.

6.3.2.2 Enhanced transmission investment incentives

Within the scope of the existing transmission price control, Ofgem has recently implemented a transmission investment incentive framework which allows and encourages the transmission licensees to make anticipatory investment (i.e. ahead of user commitment) where efficient to do so. This signals a step-change in Ofgem's approach to a position in which anticipatory investment is encouraged in principle. Specifically, the transmission businesses now have a £12.5m allowance for particular pre-construction activities associated with transmission reinforcement works for the financial year running from 1 April 2009 to 31 March 2010. These allowances are viewed as short-term measures. Ofgem intends to consult on further, longer-term measures in the remainder of 2009 before implementing further measures with effect from 1 April 2010. These measures may include anticipatory allowances to fund construction works, which would enable further progress to be made in the final two years of the current price control.

6.3.2.3 Offshore transmission regulatory framework

Ofgem and DECC have developed a regulatory regime for offshore transmission. At the centre of this is tender process via which Offshore Transmission Owner (OFTO) licences are to be allocated. The key features of the regime are outlined in brief in Annex B.

The success of OFTO regime is critical to the connection of a considerable amount of offshore generation, however, it is, as yet, untested. Future tender rounds will include the enduring projects, for which the offshore transmission infrastructure is yet to be developed. These future tender rounds will be the real test of the new regime and the results will need to be closely observed to determine whether it is working as intended or if revisions to the regime are required.

6.3.3 Development of transmission access arrangements

Following the conclusion in June 2008 of the BERR/Ofgem Transmission Access Review (TAR), industry participants have raised several Amendment Proposals to the Connection and Use of System Code (CUSC) which, if implemented, would revise the GB transmission access arrangements. This study does not seek to review or discuss these proposals in detail. Instead, it seeks to identify the key issues associated with the broad transmission models being considered given their implications for wind generation deployment. A brief overview of the Amendment Proposals is, however, provided in Annex C.

The package of CUSC Amendment Proposals present three models for reform. A further model (the 'fourth model') has also been suggested, but this has not been progressed through the CUSC governance process. The four generic models are summarised below.

6.3.3.1 Evolutionary change

This is an incremental model of reform, offering revisions to the existing arrangements to better define access rights and to increase options for trading/sharing rights. Whilst this is expected to offer improvements, it is expected to have limited benefits in terms of the connection of new entrants, including wind generation.

6.3.3.2 Connect and manage

Under connect and manage, generators seeking to use the transmission system are given a firm connection date and can access the system from this point regardless of whether or not the system has been adequately reinforced to accommodate those generators. Effectively, this enables transmission connection to occur concurrently with the development of the generation project itself, with the result that both processes are dove-tailed to a common end-date (i.e. the connection process is subsumed within the generation project timetable).

Connect and manage arrangements would alter the balance of risk between National Grid and generators seeking a connection. Through connect and manage, the quantity of access rights allocated is driven by demand (generators' requirements) rather than supply (system capability). In addition, generators have greater certainty as to the date of connection and can achieve an advanced connection date. If, following connection, the generator is affected by constraint actions because the system has not been appropriately reinforced, the generator is financially compensated. This provides further certainty for the generator.

Conversely, connect and manage transfers risk onto National Grid. The traditional 'invest then connect' model enables National Grid to ensure that the system is adequately reinforced before connecting a generator. However, under connect and manage, system capability is not a requirement for access allocation. In the short-term, National Grid may, therefore, have to incur operational costs associated with constraint management.

The balance between the constraint costs and the long-term costs of reinforcing the system provides a clear signal of the need for investment. Where the constraint costs are expected to be higher than long-term costs, National Grid would be expected to reinforce the system, and vice versa. The commercial incentive to avoid potentially high constraint costs encourages National Grid to invest. However, National Grid is now investing to follow demand for access rather than investing ahead of demand. The implication is that under connect and manage generators will be able to connect earlier than at present and transmission investment will be delivered to mitigate exposure to constraint costs.

'Interim' connect and manage arrangements have been in place as of 8 May 2009, following Ofgem's direction to grant derogations from the requirements for parts of the transmission infrastructure to comply with the usual system standards. These arrangements are expected to remain in place until decisions in relation to the CUSC Amendment Proposals referred to above are taken. 450MW of capacity has already been identified for connection advancement, with the prospect of more capacity following suit.

6.3.3.3 Auctions

Under this model, long-term entry capacity access rights are allocated via auction mechanisms to bidding generators.

Auctioning, depending upon the particular design features, is an efficient method by which to allocate a scarce resource; the bidders with the highest valuation are allocated the resource. As at present, the quantity of access rights allocated would, in the main, be limited by the system capability. Additional capacity over and above this level could be made available if the prices signalled by users (existing generators and potential connectees) are considered to be sufficient to justify additional investment. However, this decision would be taken by National Grid in its assessment of auction bids. Therefore, the quantity of access rights allocated is essentially based on the system capability and within National Grid's control.

However, there is the potential for the auction process to be complex, which may create a barrier to new wind generations projects. In addition, uncertainty exists in respect of the quantity of access rights that a bidder may secure (if any) through the auction and the associated price. The possible consequences are that bidders may be unsuccessful in securing access rights or may even be dissuaded from participating in the auction given the risk involved. The implications may manifest through lower actual generation connection and/or slower generation connection. By implication, this suggests lower renewable output.

6.3.3.4 'Fourth model'

Under this model, access rights are allocated through iterative rounds in which generators declare their access requirements over a number of years and, based on submissions received, National Grid determines fixed prices for each generator for each year. the generator is prepared to pay the quoted fixed price, it secures long-term rights to meet its requirements. If generators do not secure long-term rights for any or all of their output, they can instead procure rights released in the short-term.

As things stand, this model is the least developed of the possible solutions and so uncertainty remains as to the exact details.

6.3.3.5 Current status

With the exception of the 'fourth model' all the constituent CUSC Amendment Proposals are with Ofgem for decision. However, given its concerns that the industry process has not enabled the 'fourth model' to be progressed, Ofgem has recommended that the Secretary of State now takes its powers under the Energy Act 2008 to facilitate reform of the transmission access arrangements[17]. As part of the Renewable Energy Strategy published on 15 July 2009, the Secretary of State announced that he will intervene to deliver transmission access reform within the next 12 months. This is the next key step for the development of enduring transmission access arrangements.

6.4 Modelling transmission constraints

The issues affecting transmission are complex and broad ranging in nature. The modelling framework seeks to reflect these issues in a simplistic manner, focusing on variations in transmission reinforcement timescales and the implications of variations in potential transmission access arrangements. These transmission issues can manifest in two possible forms; generation constraints (MWh) and/or generation capacity build (MW). The means by which the transmission issues have been implemented within the model for the different scenarios are described in the Sections below.

6.4.1 'High Feasible'

6.4.1.1 Transmission reinforcement

In the 'High Feasible' scenario, the transmission reinforcement programme identified in the ENSG Report is assumed to be delivered. The backdrop for this assumption is that there appears to be political and regulatory support for ENSG process and recommendations and, as discussed in Section 6.3.2, there are indications that the regulatory arrangements linked to transmission investment are being changed to enable investment. Table 20 sets out the assumed transmission reinforcement completion dates.

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17 'Transmission Access Review – Third Progress Update', Lord John Mogg letter to Ed Milliband, 25 June 2009.

Table 20 – Transmission reinforcement programme used for the 'High Feasible' scenario

Region	Reinforcement	'High feasible' completion date
Scotland Stage 1	North of Scotland	2015
Scotland Stage 1	Incremental Scotland	2015
Scotland Stage 1	Western HVDC link	2015
Scotland Stage 2	North of Scotland	2018
Scotland Stage 2	Eastern HVDC link	2018
Wales Stage 1	North Wales	2017
Wales Stage 1	Central Wales	2015
England East Coast	Humberside	2017
England East Coast	East Anglia	2017
London	London	2015
South West	South West	2017

Source: ENSG

The delivery of offshore wind generation projects is closely linked to the completion of the onshore transmission reinforcement works outlined by the ENSG (i.e. the onshore transmission works can be considered as an enabler for the offshore projects). The completion dates for the Round 3 offshore projects identified in the Crown Estate are, therefore, assumed to be closely related to the completion of the onshore reinforcement works. The mapping between Round 3 projects and ENSG reinforcement works are shown in Table 21.

Table 21 – Mapping between Round 3 projects and onshore transmission reinforcement works for the 'High Feasible' scenario

Zone	Match with ENSG reinforcement project	'High feasible' completion date
Moray Firth	Scotland Stage 1/2	2015
Firth of Forth	Scotland Stage 1	2015
Dogger bank	England East Coast	2017
Hornsea	England East Coast	2017
Norfolk	England East Coast	2017
Hastings	London	2015
Isle of Wight	South West	2017
Bristol Channel	South West	2017
Irish Sea	Scotland Stage 1	2015

6.4.1.2 Transmission access arrangements

Under the 'High Feasible' scenario, we assume that a connect and manage model is implemented on an enduring basis. As under the existing interim connect and manage model, this enables connection to be advanced. Effectively, this enables transmission connection to occur concurrently with the development of the generation project itself, with the result that both processes are dove-tailed to a common end-date (i.e. the connection process is subsumed within the generation project timetable).

One implication of connect and manage referred to above is the potential for generation to be constrained off in cases where the system cannot accommodate generation delivered against the allocated access rights. We have taken account of this by assuming that 15% of Scottish wind generation output is constrained down under the 'High Feasible' scenario up until 2015 when the first tranche of Scottish transmission reinforcement projects proposed by the ENSG are expected to be completed.

The reduction of 15% is based on assumptions used by National Grid in its assessment of the potential impact on costs and volumes if it were to implement CAP148 (which also proposed a connect and manage approach transmission access). The modelling of CAP148 suggested that while Scotland had traditionally been modelled as two constrained zones, each active 10% of the time but out of phase with each other, this should be simplified to assume a constant percentage across the whole country. To simplify the modelling it was therefore decided that the whole of Scotland should be consistent with active constraints 15% of the time (this increase took into account the phasing). On this basis, a 15% reduction in generation output is assumed for Scottish generation.

6.4.2 'Alternative'

6.4.2.1 Transmission reinforcement

In the 'Alternative' scenario, the delivery of the ENSG transmission reinforcement programme is assumed to be delayed. The rationale for this is that the identified onshore transmission investment programme is very ambitious, representing a step change in investment on the transmission network that is significantly higher than has been achieved over the last 10 years. The programme also presents operational issues (e.g. significant numbers of possibly conflicting transmission outage requirements for the projects) and requires the development of new technologies (e.g. HVDC technology is in its infancy). Given the challenges linked to delivering this programme, it is appropriate to consider a revised, more feasible investment programme. Based on the experience of Energyline in respect of actual transmission investment projects, the revised investment programme is shown in Table 22. This is used in the 'Alternative' scenario.

Table 22 – Transmission reinforcement programme used for the 'Alternative' scenario

Region	Reinforcement	'High feasible' completion date	'Alternative' completion date
Scotland Stage 1	North of Scotland	2015	2015
Scotland Stage 1	Incremental Scotland	2015	2015
Scotland Stage 1	Western HVDC link	2015	2015
Scotland Stage 2	North of Scotland	2018	**2019**
Scotland Stage 2	Eastern HVDC link	2018	2018
Wales Stage 1	North Wales	2017	**2019**
Wales Stage 1	Central Wales	2015	**2017**
England East Coast	Humberside	2017	**2018**
England East Coast	East Anglia	2017	2017
London	London	2015	2015
South West	South West	2017	**2019**

Source: ENSG, Energyline, Pöyry Energy Consulting

As in the 'High Feasible' scenario, the completion of ENSG works is assumed to impact upon the delivery of Round 3 projects. The delayed ENSG timetable within the 'Alternative' scenario has a consequential impact upon the Round 3 project completion dates. The mapping between Round 3 projects and ENSG reinforcement works are shown in Table 23.

Table 23 – Mapping between Round 3 projects and onshore transmission reinforcement works for the 'Alternative' scenario

Zone	Match with ENSG reinforcement project	'High feasible' completion date	'Alternative' completion date
Moray Firth	Scotland Stage 1/2	2015	**2019**
Firth of Forth	Scotland Stage 1	2015	2015
Dogger bank	England East Coast	2017	**2018**
Hornsea	England East Coast	2017	**2018**
Norfolk	England East Coast	2017	2017
Hastings	London	2015	2015
Isle of Wight	South West	2017	**2019**
Bristol Channel	South West	2017	**2019**
Irish Sea	Scotland Stage 1	2015	2015

Source: ENSG, Energyline, Pöyry Energy Consulting

6.4.2.2 Transmission access arrangements

The transmission reinforcement assumptions in the 'Alternative' scenario are the same as under the 'High Feasible' scenario. That is, we assume that connect and manage arrangements will apply, thereby enabling the grid connection process to be completed in line with the generation project development timetable.

6.4.3 'Auction'

6.4.3.1 Transmission reinforcement

The transmission reinforcement assumptions in the 'auction' scenario are the same as under the 'Alternative' scenario.

6.4.3.2 Transmission access arrangements

We model the impacts of auctioning in two ways; first, the time taken to secure a connection and second, the impact of complex auction arrangements on the appetite for new projects to proceed and ability of new projects to secure access rights.

Unlike connect and manage models, under the 'auction' model connections are only progressed when the system has sufficient capability to accommodate the additional generation. As transmission reinforcement projects can take up to 3 years depending on the circumstances (as outlined in Annex E), we include a 3 year connection timeline within the overall project scenario. This can be progressed concurrently with other elements of the generation project. In cases where other elements of the generation development are cumulatively greater than 3 years in duration, the connection timeline is not binding. Only in cases where all other elements of the generation development cumulatively take less than 3 years will the transmission connection timeline be binding.

Given the potential for an auction process to be complex and to create uncertainty over the likelihood, or cost, of acquiring access rights (i.e. price and volume risk), some onshore projects may be deterred from progressing to development. Consequently, we assume a percentage reduction in onshore wind capacity entering development under the 'auction' scenario relative to the High Feasible and Alternative scenarios in order to reflect those projects that opt not to proceed given the risks of a complex auction process.

The percentage development capacity reduction varies by region and time to reflect the expected supply-demand balance for access rights. This depends upon the extent to which the region is currently constrained and the timing of the ENSG reinforcement projects which are expected to alleviate these constraints.

To elaborate further, on the basis that constraints are more prevalent in Scotland and northern England we have initially assumed a 30% capacity reduction in Scotland and a 15% capacity reduction in northern England. The capacity reduction percentage is reduced to zero as relevant onshore transmission reinforcement programmes (based on the delayed ENSG timescales from the 'Alternative' scenario) are completed. In Scotland, we have assumed a phased decrease in the capacity reduction factor in line with the multi-stage reinforcement programme. The assumptions are set out in Table 24.

Table 24 – Assumed onshore wind capacity restrictions

<table>
<tr><th></th><th>2009</th><th>2010</th><th>2011</th><th>2012</th><th>2013</th><th>2014</th><th>2015</th><th>2016</th><th>2017</th><th>2018</th><th>2019</th><th>2020</th></tr>
<tr><td>Northern</td><td colspan="6">15%</td><td colspan="6">0%</td></tr>
<tr><td>North West</td><td colspan="6">15%</td><td colspan="6">0%</td></tr>
<tr><td>Yorkshire</td><td colspan="9">15%</td><td colspan="3">0%</td></tr>
<tr><td>North Wales & Mersey</td><td colspan="10">15%</td><td colspan="2">0%</td></tr>
<tr><td>East Midlands</td><td colspan="12">0%</td></tr>
<tr><td>Midlands</td><td colspan="12">0%</td></tr>
<tr><td>Eastern</td><td colspan="12">0%</td></tr>
<tr><td>South Wales</td><td colspan="8">15%</td><td colspan="4">0%</td></tr>
<tr><td>South East</td><td colspan="6">15%</td><td colspan="6">0%</td></tr>
<tr><td>London</td><td colspan="12">0%</td></tr>
<tr><td>Southern</td><td colspan="12">0%</td></tr>
<tr><td>South West</td><td colspan="12">0%</td></tr>
<tr><td>South Scotland</td><td colspan="6">30%</td><td colspan="3">15%</td><td colspan="3">0%</td></tr>
<tr><td>North Scotland</td><td colspan="6">30%</td><td colspan="4">15%</td><td colspan="2">0%</td></tr>
<tr><td>Northern Ireland</td><td colspan="12">0%</td></tr>
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7. ILLUSTRATIVE TRAJECTORIES FOR INVESTMENT IN NEW WIND CAPACITY TO 2020

7.1 Introduction

The previous sections have examined in detail the various constraints which can affect the growth of onshore and offshore wind generation to 2020 and how they can be relieved.

To investigate the combined impact of announced and anticipated developments in the environment for wind deployment, we have developed a simulation model of national deployment potential that produces trajectories of annual capacity growth by technology type (onshore/offshore) and location (England, Wales, Scotland, Northern Ireland).

Though there are numerous possible scenarios, for the purposes of this study we have examined trajectories for investment in new wind capacity to 2020 under two different scenarios.

The first, the 'High Feasible' scenario, is characterised by a regulatory and policy environment in which any proposed developments are implemented on time and operate according to defined timescales, and a market environment where supply chain investment and financing conditions undergo changes to develop the massive potential of the UK's wind resource. The second 'Alternative' scenario represents a situation whereby proposed regulatory and policy developments are delayed by a few years, due to unforeseen circumstances, and where financing conditions and supply chain investments do not respond in time to policy signals provided by Government.

This Section presents:

- a brief overview of the simulation model and the generic input assumptions used to create the trajectories of annual wind capacity growth;
- the key results from the High Feasible scenario and the Alternative scenario; and
- a qualitative discussion on the results of running some alternative scenarios.

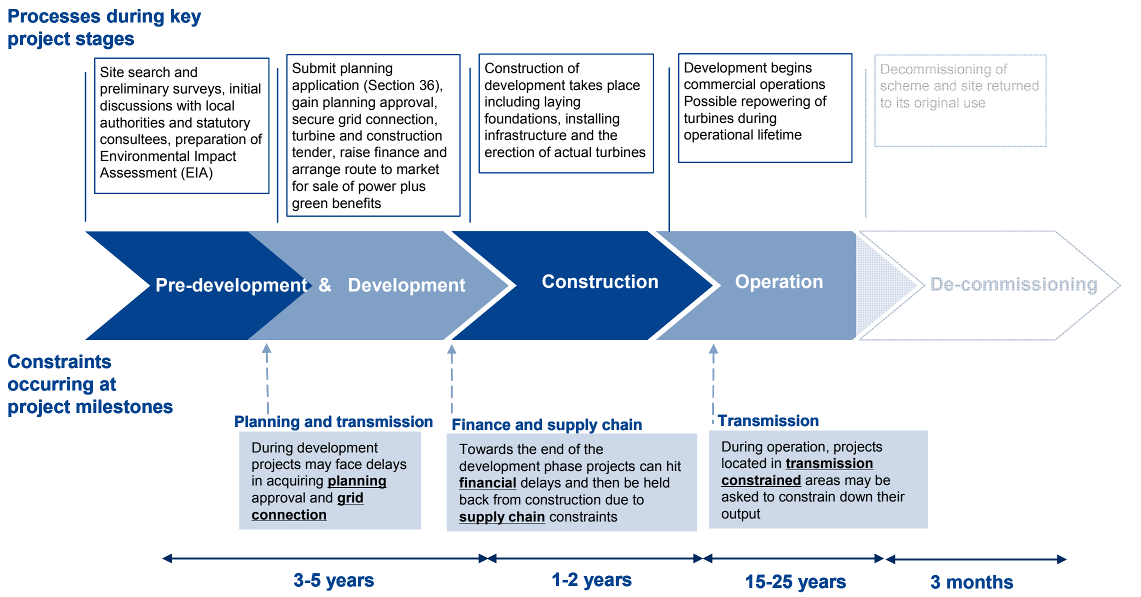
In Section 8 we use some of this analysis described in this section to help create a useful set of indicators that will inform policymakers of the progress against targets.

7.2 Overview of modelling methodology

This section explains how we have modelled wind generation deployment in the UK.

Figure 18 highlights the sequential nature of the project cycle and this is reflected in the model. The three phases of the project cycle are; pre-development and development, construction and operation. Therefore in order to reach operation, wind sites must pass through all previous stages. The rate of progress through the phases is dependent on the constraints we have applied in the model. The following paragraphs explain the position of the constraints relative to the phases of the project cycle.

Figure 18 – Project cycle basis for model development



Pre development and development. The pre-development and development stages have a number of constraints applied to them. These include certain aspects of transmission constraints, planning constraints and finance constraints. Most of these constraints are implemented as time constraints in the model, although there is also a loss rate associated with planning (which we have termed as residual resource).

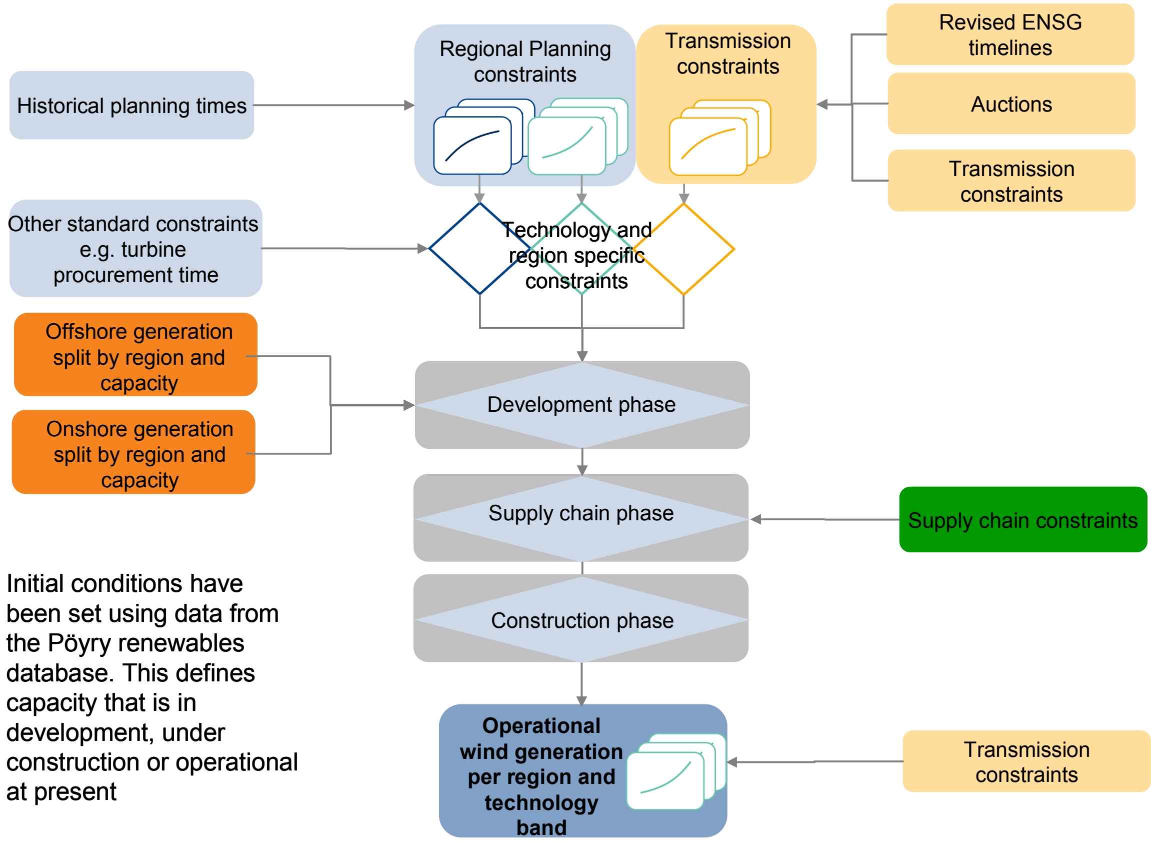
In order to move from the pre development and development stage to the construction stage, sufficient supply chain capacity must be in place. Therefore the model applies a supply chain constraint between the development phase and the construction phase. The supply chain capacity is defined at the UK level and is split by onshore and offshore categories. In addition, the supply chain constraint is modelled as a volume constraint that is applied to all capacity awaiting construction. The proportion of the supply chain that is allocated to a given region is defined by the capacity of wind generation awaiting construction. In the case where there is insufficient capacity in the supply chain to cope with projects awaiting construction, capacity is held back from entering the construction phase and is rolled over to the following year.

Construction. The construction period commences once a project has been allocated sufficient supply chain capacity. The standard assumption used in this model is 1 year for onshore sites and 2 years for offshore sites.

Operation. Once constructed, a wind farm is operational for a period of around 15-25 years, depending on technology and location. We model one type of transmission constraint in terms of generation output which is reflected through the load factor attributable to operational turbines in a given area. Load factors can be varied over time and also by region to reflect the characteristics of wind generation.

Figure 19 presents an overview of the model and highlights the sequential nature in which constraints are applied to the development phase, supply chain phase, construction phase and operational phase.

Figure 19 –Schematic of model



7.3 Limitations of the modelling methodology

One of the key limitations of this modelling approach is the absence of feedback modelling. This means that capacity enters development on a certain date regardless of the amount of capacity awaiting construction. In reality, a backlog of capacity awaiting construction may deter developers from developing new projects until the backlog has cleared. As this model does not consider such feedback dynamics, it is likely that in reality, the capacity sitting in the supply chain has the potential to be significantly lower, although this will not improve the outcome, only shift where the constraint lies.

7.4 Approach to creating wind trajectories

There are essentially four integral steps to creating our wind trajectories using our simulation model of national deployment potential:

- identify the onshore and offshore wind resource available in the UK;
- identify the key stages of the project cycle and their corresponding timescales (see Section 2);
- research the constraints that can affect these stages, by either impeding their progress or revising downwards their original capacity (see Sections 3, 4, 5 and 6); and

- calculate how much capacity passes through each of the key project stages each year to 2020.

The first and last steps are outlined below.

7.4.1 Identifying UK onshore and offshore wind resource

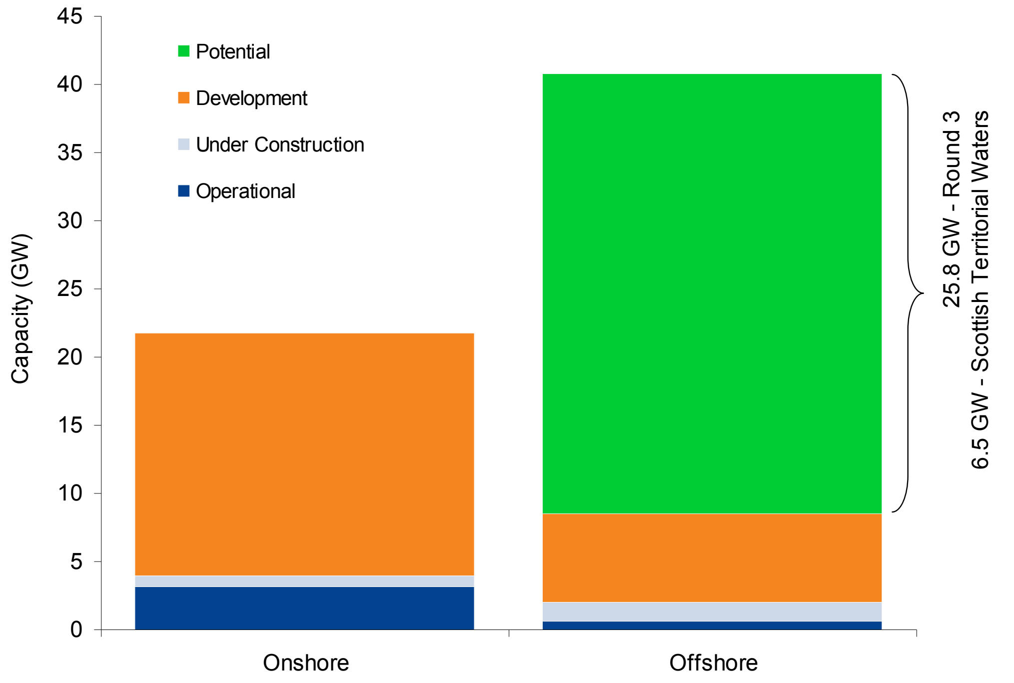
Figure 20 presents the basis for our UK onshore and offshore wind resource used for this study, broken down into:

- potential resource – capacity estimated to be available associated with areas that are undeveloped, but has been recognised as having the potential to be used for generation from wind;
- development – collective name given to the group of processes involved during the pre-development and development stages of the project cycle (see Section 2);
- under construction – refers to projects that are under construction, thus have completed the development phase and have been allocated sufficient resources to begin construction; and
- operational – projects that are currently operating and producing electricity.

The basis of these numbers is a combination of our own renewables database which holds a list of all known wind projects (operational, under construction or currently in development), and potential offshore resource as identified by Round 3 and that in the Scottish Territorial Waters.

It is clear from Figure 20 that we do not have onshore wind capacity classed as ‘potential’. The latest Green-X data suggests that onshore wind potential in the UK is just under 14GW, which is far less than the total capacity (18GW) of projects that are classed as ‘in development’ based on the data in our renewables database. Obviously we do not expect all of the projects ‘in development’ to become operational, nor do we consider the Green-X volume to be additional to the ‘in development’ capacity, as Green-X will have used a particular threshold, for example, based on wind speed, to determine their potential. Consequently, rather than double count these two separate volumes, we have used the higher of these two values as our basis for onshore wind potential.

Figure 20 – Breakdown of UK onshore and offshore wind resource



On this basis, we then further split onshore and offshore wind into the various jurisdictions – England, Wales, Scotland and Northern Ireland – and by a number of different size categories, to allow us to properly model the impact of the planning timescales and constraints that differ along these dimensions (see Section 4):

- Onshore wind;
  - small (less than or equal to 5MW);
  - medium (5MW<X<50MW);
  - large (greater than or equal to 50MW);
- Offshore wind;
  - large (greater than or equal to 100MW); and
  - medium (less than 100MW).

In addition, the capacity is broken down between the fifteen ‘transmission zones’ based on the old distribution areas to enable the accurate modelling of transmission constraints.

7.4.2 Modelling capacity through the various stages of the project cycle

All offshore and onshore wind generation projects are classified according to the stage of the project cycle that they are in – .i.e. resource, development; construction; and operation. The following paragraphs explain the terms in more detail.

Resource. This refers to the capacity estimated to be available associated with areas that are undeveloped, but have been recognised as having the potential to be used for generation from wind. Examples of such areas include the round 3 offshore zones and those in Scottish territorial waters.

Development. The collective name given to the group of processes wind farms must go through in order to be built. This includes the time taken to raise initial finance, the time for turbine procurement, the time to go through all relevant stages of planning, the time taken to raise capital and the time taken to reach financial close.

Construction. This refers to projects that are under construction at present. This implies that projects have completed the development phase and have been allocated sufficient resources to begin construction.

Operational. This term refers to projects that have already been constructed and are currently operating.

7.5 High Feasible scenario

As discussed in the introduction, the High Feasible is characterised by a regulatory and policy environment in which any proposed developments are implemented on time and operate according to defined timescales. These include:

- planning regulations, including those under the proposed IPC for England and Wales (see Sections 4.5 and 4.6);
- access to transmission infrastructure assuming Ofgem's proposed 'connect and manage' process (see Section 6.3.3.2); and
- investment in offshore transmission connection assets as specified by the Crown Estates in their Round 3 Connection Study and the ENSG (see Section 6.3).

The market environment under the High Feasible scenario is defined by:

- financing conditions under the current credit crisis continuing until the end of 2010 and then assuming slightly longer lead-times to financial close until 2015 before moving to a position seen pre-crisis to 2020 (see Section 3.4 and Figure 11); and
- required investment in the supply chain as identified by SKM in their high growth scenario, but revised slightly to account for the current situation (see Section 5.5.1).

The following section presents the key results from running this scenario through our model.

7.5.1 Key results

Figure 21 illustrates that if regulatory changes occur to time and are effective, projects were awarded planning approval within statutory guidelines and investment in supply chain capability occurs according to the predictions by SKM and BVG Associates (reflecting considerable high growth), then by 2020 the UK's onshore and offshore wind capacity may develop as shown. Under these circumstances, there is the potential for the UK to deliver 27GW of onshore and offshore wind by 2020, in line with existing projections underpinning the EU renewable energy target.

Figure 21 also shows that for onshore wind, installed capacity increases steadily, in line with the supply chain constraint. In comparison, offshore wind capacity increases at a faster rate post 2015, due to the larger Round 3 projects starting to complete the various development processes, matched by a supply chain that has geared up to facilitate their construction.

Figure 21 – Total installed wind capacity for the UK under the High Feasible scenario

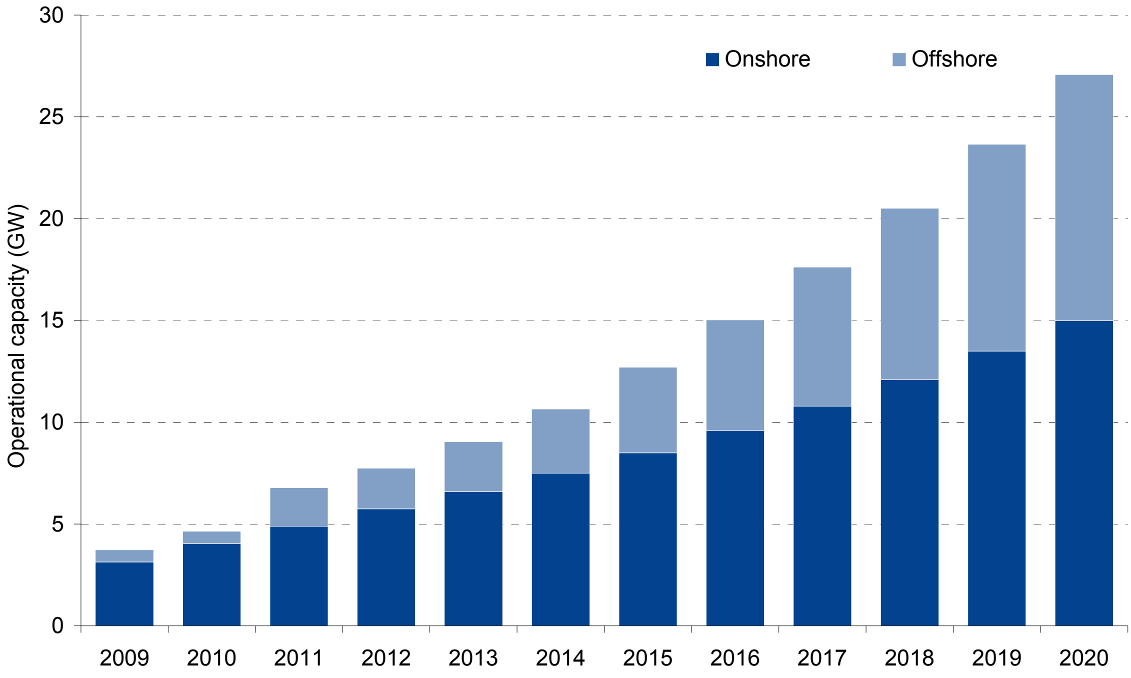


Figure 22 presents the equivalent onshore and offshore wind generation each year to 2020, which is projected to reach approximately 76TWh. In deriving this figure, we have assumed that onshore wind load factors average around 30% before dropping to 28% in 2015, reflecting the fact that the windiest sites will all have been developed. We have also assumed a 15% reduction in the load factor of sites located in Scotland until 2016. This reflects the impact of the connect and manage scheme on these particular projects, until such time as the ENSG reinforcements can help relieve transmission constraints (see Section 6.3.1.1).

For offshore we have assumed a load factor which increases from 35% to 37% post 2010, reflecting the use of sites located further away from the coast that have higher wind speeds.

Figure 22 – Generation from onshore and offshore wind under the scenario

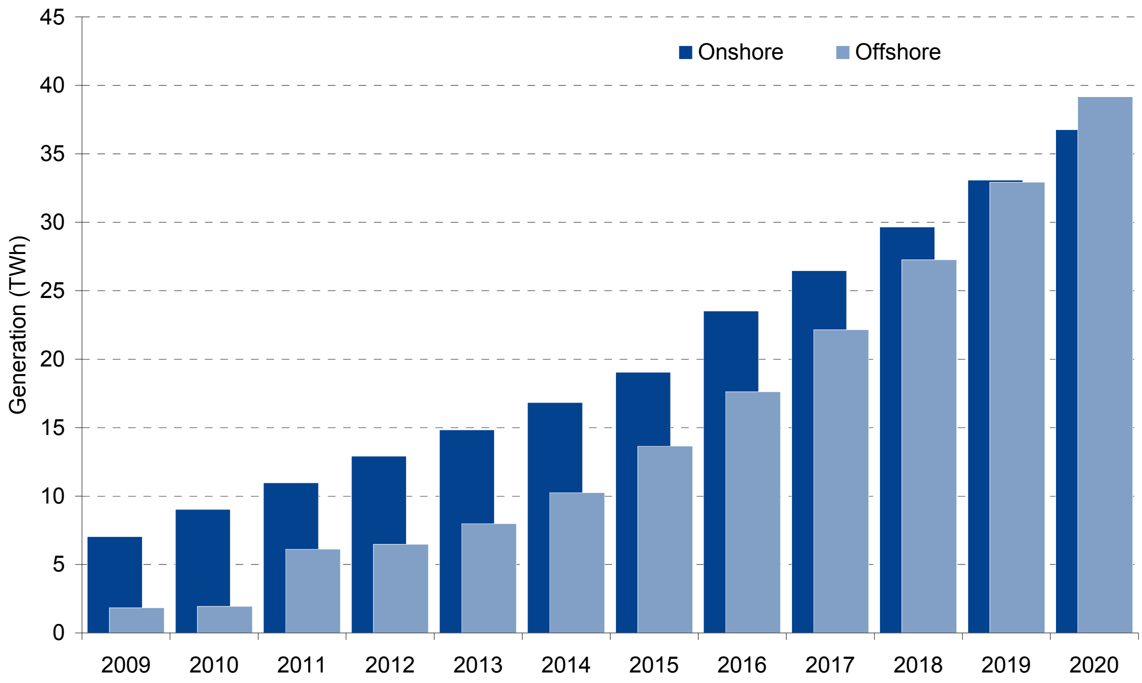


Figure 23 shows how the onshore wind resource is divided between the various categories – development, supply chain, construction and operation – per year to 2020. It illustrates that the main constraint holding back deployment of all projects in the development stages is the supply chain. This is also the case for offshore wind as illustrated by Figure 24, which again shows the supply chain holding back potential projects from undergoing construction.

In comparing the two development profiles, offshore wind is rather more staged than that of onshore wind reflecting the timing of Round 3 developments.

Figure 23 – Capacity per phase for onshore wind under the High Feasible scenario

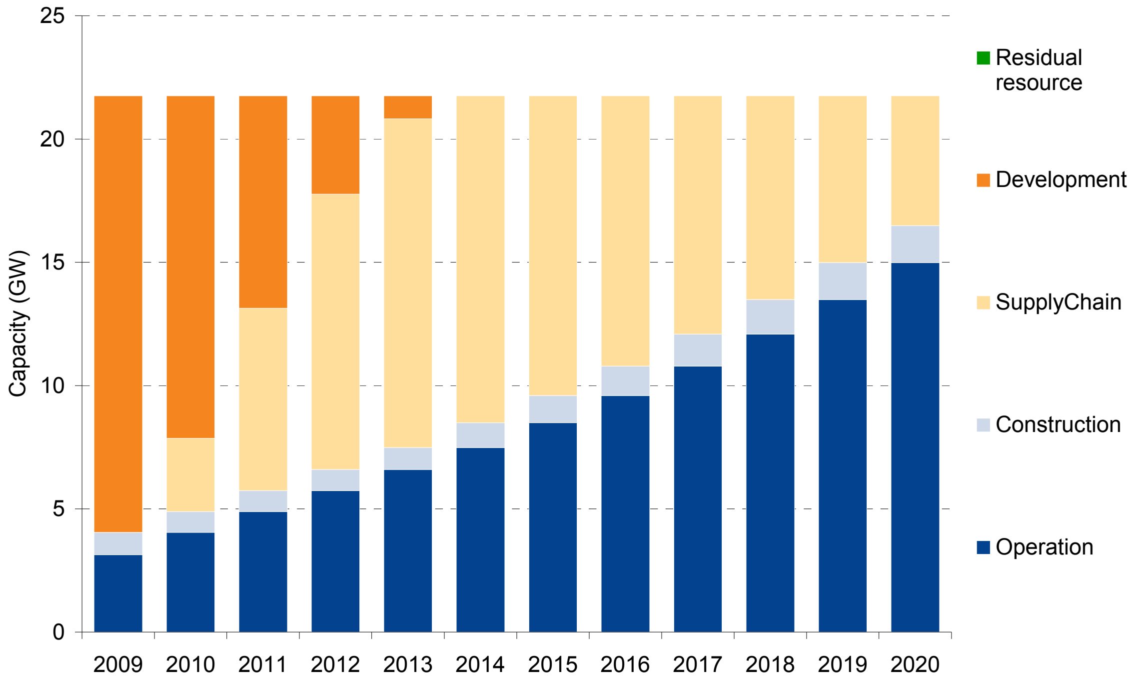
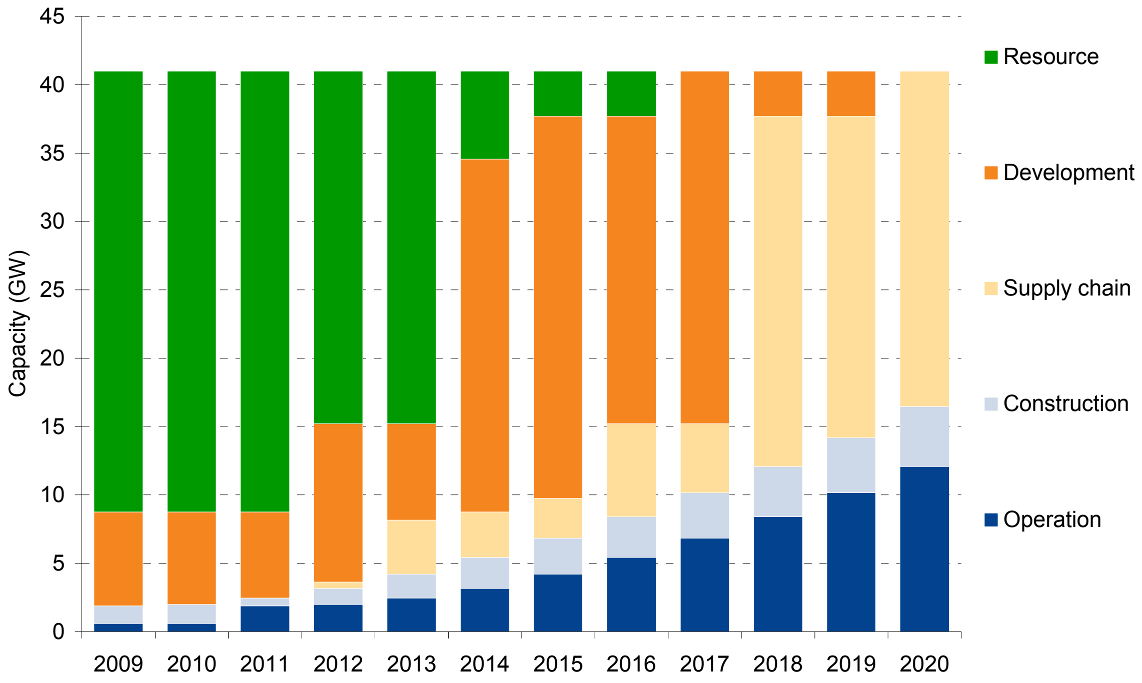


Figure 24 – Capacity per phase for offshore wind under the High Feasible scenario



7.6 Alternative scenario

Compared to the High Feasible scenario, the Alternative scenario is characterised by a regulatory and policy environment where milestones are not met on time:

- delays in planning timescales are based on historical data and refusal rates (see Sections 4.4.1 and 4.4.2);
- access to transmission infrastructure assumes Ofgem's proposed 'connect and manage' process (see Section 6.3.3.2); and
- revised timelines for investment in offshore transmission connection assets are observed (see Section 6.4.2.1).

The market environment under the Alternative is defined by:

- financing conditions under the current credit crisis continuing until the end of 2010 and then assuming slightly longer lead-times to financial close until 2015 before moving to a position seen pre-crisis to 2020 (see Section 3.4 and Figure 11); and
- required investment in the supply chain as identified by SKM in their medium growth scenario, but revised slightly to account for the current situation (see Section 5.5.2).

Table 25 presents a summary of the differences between the two scenarios.

Table 25 – Comparison of the underpinning assumptions between the High Feasible and the Alternative scenarios

	Base finance	Lack of PF capital	Connect and manage	Complex auction of transmission access	Original ENSG timelines	Revised ENSG timelines	SKM high growth supply chain (revised)	SKM medium growth supply chain (revised)	Statutory planning timescales	Historical planning timescales
High feasible	x		x		x		x		x	
Alternative	x		x			x		x		x

7.6.1 *Key results*

Figure 25 illustrates that, under these less favourable assumptions, by 2020 the UK's onshore and offshore wind capacity may only reach 22GW of onshore and offshore wind by 2020, around 5GW below the targeted level of wind capacity.

Figure 25 – Total installed wind capacity for the UK under the Alternative scenario

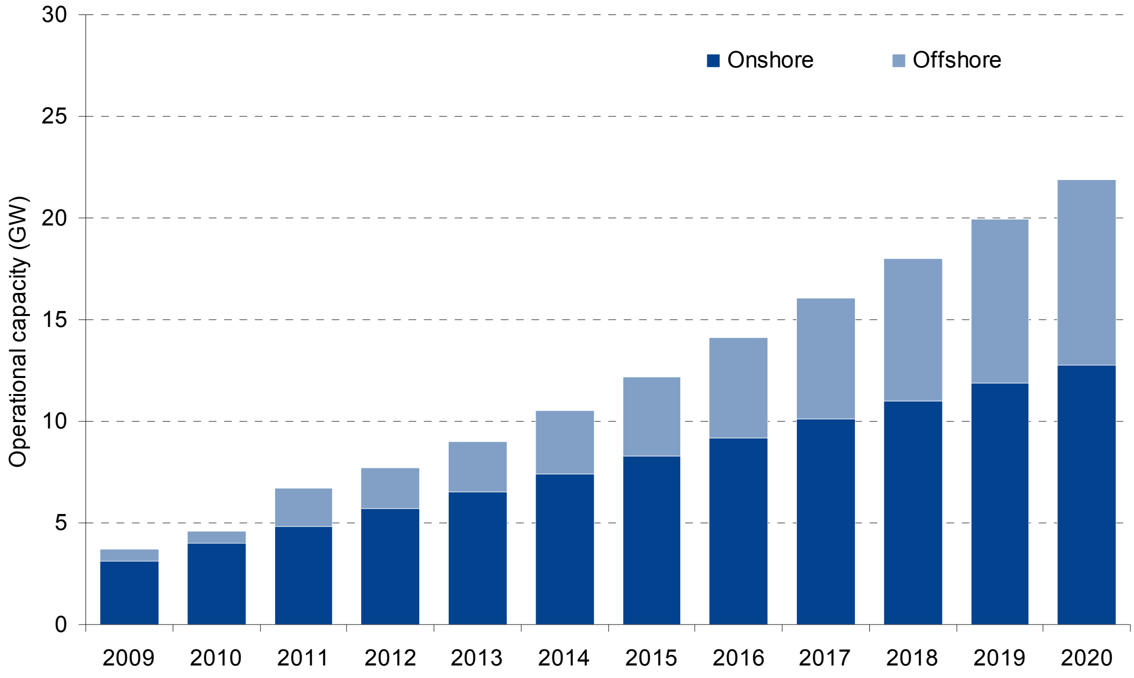


Figure 26 illustrates the trajectory of generation from operational wind generation in the UK to 2020 split by onshore (dark blue) and offshore (light blue) sites for each year to 2020. Under the Alternative trajectory, total generation from operational wind sites is expected to reach approximately 60.9TWh. The contribution of offshore wind to total generation is boosted by the higher average capacity factor. In addition, given that connect and manage regime is in place, there is a boost in onshore wind generation in 2016 due to the 15% transmission constraint being removed in Scotland.

Figure 26 – Generation from onshore and offshore wind under the Alternative scenario

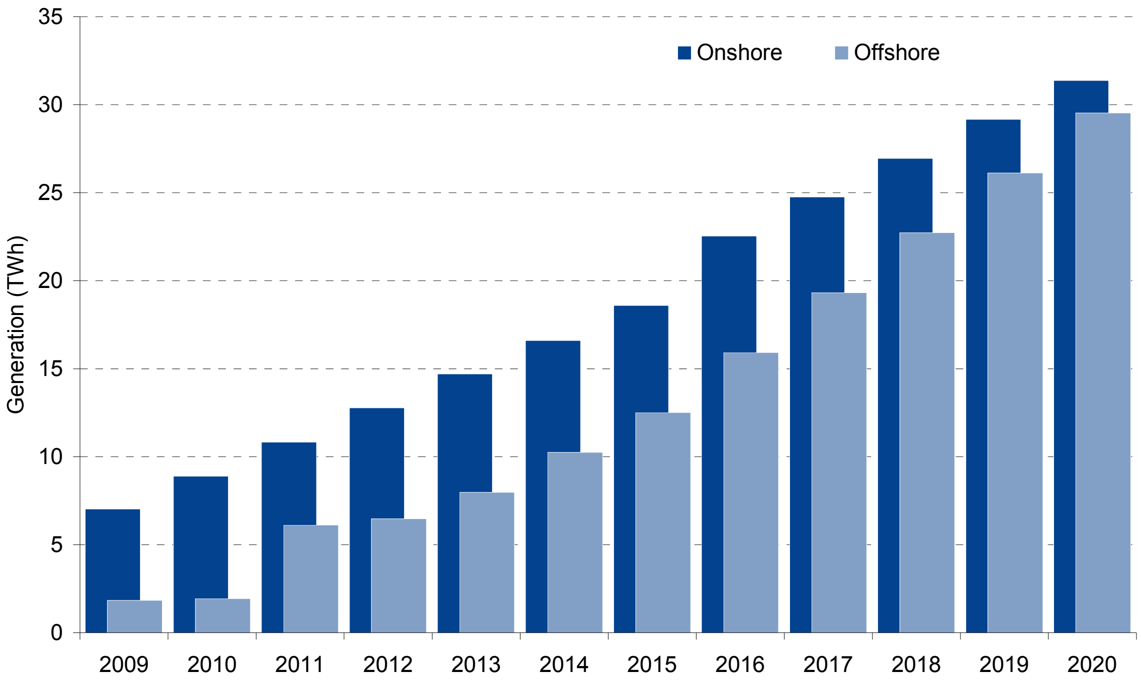


Figure 27 shows the capacity per phase for onshore wind sites in the UK to 2020. The initial conditions reflect those taken from the renewables database. It also shows the effect of introducing the updated planning constraints which mean that some onshore capacity is lost in the planning phase. This capacity is termed as residual resource as it cannot be recycled and be developed as it is likely that sound legal objections would have been made in order for the site to be rejected. Residual resource reaches a maximum of 3.1GW in 2019.

The time taken for development is greater than in the core scenario as not all projects are assumed to complete planning at the first stage. Therefore some projects that are effectively going through legal proceedings before being rejected are classified as being in development to 2018.

The supply chain begins to bind in 2010 and binds in each subsequent year, with the backlog of projects reaching a maximum of 8.4GW in 2013. The corresponding supply chain capacity for onshore wind is 450MW in 2009 before increasing to 900MW in 2015 with the construction of a new onshore turbine factory dedicated to the UK.

As a result, it is clear that for onshore wind under the Alternative trajectory, supply chain constraints are the main binding factor from 2010 to 2020.

Figure 27 – Capacity per phase for onshore wind under Alternative trajectory

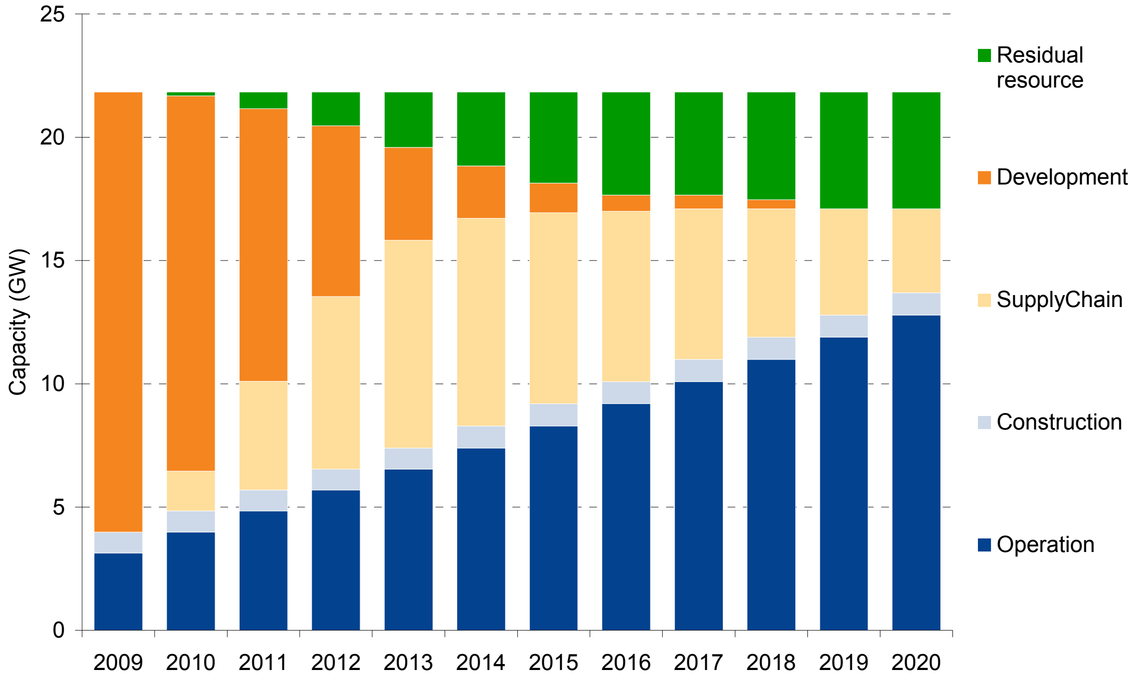
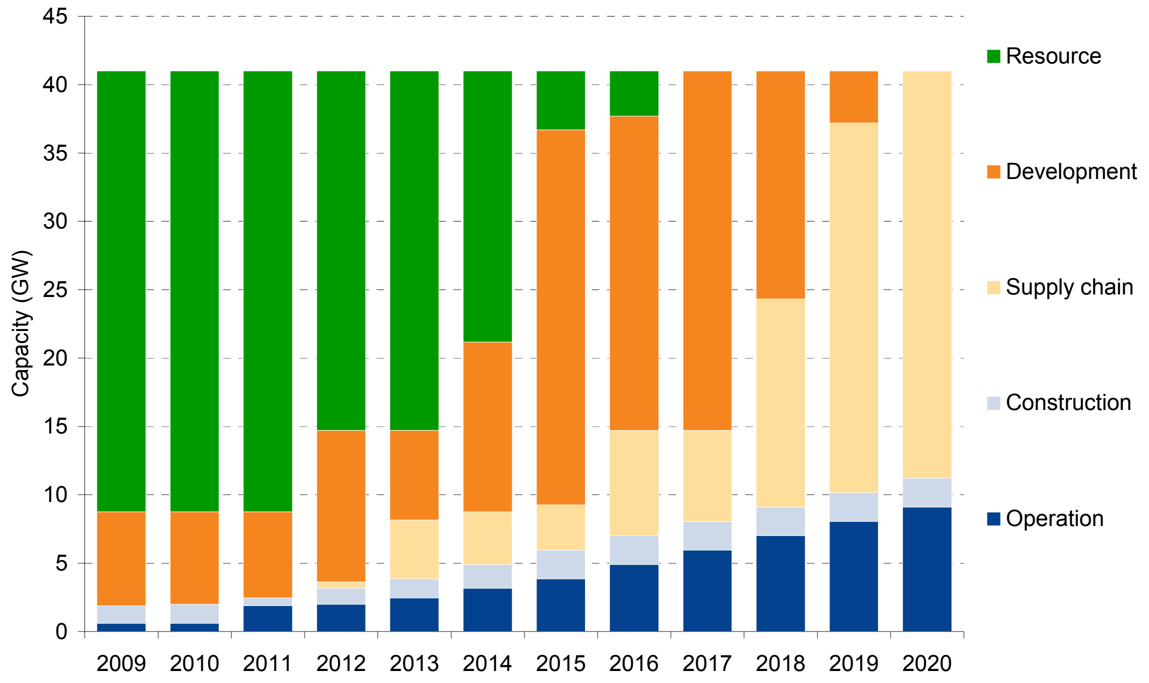


Figure 28 shows the distribution of wind generation in each phase for offshore wind to 2020. The number of offshore sites under development increases to a maximum of 26.2GW in 2017 before decreasing to zero in 2020 and reflects the staged nature with which offshore wind is expected to enter development. For the first three years of the Alternative trajectory, offshore wind is limited by constraints in the development phase. From 2012 onwards the supply chain limits the rate at which offshore wind generation enters operation. The amount of offshore wind generation capacity constrained by the supply chain reaches a maximum of 24GW by 2020, when all offshore resource has passed through the development stage. Under the Alternative trajectory, the rate of construction increases from 0.7GW/year in 2009 to 1.05GW/year in 2020. This implies that a total of 6 vessels installing turbines at the rate of 175MW/year will be dedicated to the UK by 2020.

In conclusion, it appears that the main binding constraint for offshore wind under the Alternative trajectory is the supply chain.

Figure 28 – Capacity per phase for offshore wind under Alternative trajectory



7.7 Comparison of scenarios

The objective of this Section is to compare the results of the Alternative and High Feasible trajectories and to explain the reasons for any difference between the results. Table 26 presents a comparison of the two trajectories in terms of installed capacity (GW) and generation (TWh). It can be seen that under the Alternative trajectory, there is less installed capacity of onshore and offshore wind and as a result less generation from wind.

Table 26 – Comparison of scenarios

	units	Statutory ideal	Realistic	Difference
Total installed capacity	GW	27.0	21.8	-5.2
Onshore installed capacity	GW	14.9	12.7	-2.2
Offshore installed capacity	GW	12.1	9.1	-3.0
Total Generation	TWh	76.0	60.9	-15.1
Offshore generation	TWh	39.2	31.4	-7.8
Onshore generation	TWh	36.8	29.5	-7.3

The main driver for the difference in operational onshore capacity between the High Feasible and Alternative scenarios is the supply chain. This is mainly due to insufficient capacity in the supply chain under the Alternative trajectory to provide the additional 2.2GW of operational capacity that would deliver the installed capacity of 14.9GW of onshore wind. This implies that the constraints placed on the system in terms of realistic planning times, increased times for transmission access and the creation of residual resource would not stop a sufficient amount of capacity passing through the development phase to meet the target. This is not to say that the issues surrounding residual resource in particular will not affect onshore wind generation deployment at all, in fact this will play a key role in the total amount of exploitable onshore wind resource, but rather that they are not key constraints to meet the trajectory set in the High Feasible scenario. The supply chain constraint is due to the limits on the rate of build in terms of MWh/year, which are far below that deployed in the High Feasible scenario.

The main driver for the difference in operational offshore wind capacity between the trajectories generated under the High Feasible and the Alternative scenarios has also been found to be the supply chain. In general, the two trajectories are very similar up until 2014. Under the High Feasible scenario, a large amount of resource moves into development, while in the Alternative scenario trajectory this happens in 2015. This is due to the impact of the revised ENSG timelines which cause a delay in the development of offshore wind sites due to owners knowing that transmission connection will not be available. As a result there is still 16GW of capacity in development in 2018 under the Alternative scenario compared to 3.3GW under the High Feasible. In order for the Alternative scenario to meet the target set in the High Feasible scenario, an additional 3GW of operational offshore wind capacity needs to be made available. It can be seen from Figure 28 that the supply chain constraint for the Alternative scenario is in excess of 3GW from 2013 and reaches 29GW in 2020. This indicates that sufficient capacity will pass through the development stage but there will not be sufficient construction resource to produce operational wind farms. As in the onshore case, the supply chain constraint is a result of the limitations placed on the amount of capacity entering construction due to resource constraints.

7.8 Alternative scenarios

This Section provides a brief overview of the alternative trajectories that have been modelled as part of the study. Table 27 shows the main differences between the trajectories that were run in addition to the High Feasible and the Alternative scenarios. A summary of the alternative scenarios is presented in Table 28 alongside the deployment of wind generation. Further results can be found in Annex D.

Under the auction scenario, it is assumed onshore wind generators need to bid for transmission access instead of being guaranteed access (or financial compensation) under the ‘connect and manage’ scheme. The result is that a number of wind generators do not take potential projects into development, therefore reducing potential capacity entering planning. While this means that less onshore generation capacity can potentially be deployed, Table 28 shows that there is no significant difference in generation or installed capacity by 2020. This is because, over the period to 2020, the supply chain constraint is still binding given the modelling assumptions – though the volume of capacity in development falls it still exceeds the capability of the industry to construct and connect it.

The poor finance scenario includes an extension of the unfreezing period due to the financial crisis. There is no real effect on installed capacity or generation, mainly because the time to raise finance associated with the unfreezing period is less than the time step of the model.

Table 27 – Summary of scenarios

	Base finance	Lack of PF capital	Connect and manage	Complex auction of transmissi-on access	Original ENSG timelines	Revised ENSG timelines	SKM high growth supply chain (revised)	SKM medium growth supply chain (revised)	Statutory planning timescales	Historical planning timescales
High feasible	X		X		X		X		X	
Alternative	X		X			X		X		X
Supply chain constraint and poor finance		X	X			X		X		X
Auction for transmission access	X			X		X		X		X
Worst Case*		X		X		X		X		X

Table 28 – Summary of scenario results

	Units	High feasible	Alternative	Auction	Poor Finance	Worst case
Total installed capacity	GW	27.0	21.8	21.7	21.8	21.7
Onshore installed capacity	GW	14.9	12.7	12.6	12.7	12.6
Offshore installed capacity	GW	12.1	9.1	9.1	9.1	9.1
Total generation	TWh	76.0	60.9	60.5	60.9	60.5
Offshore generation	TWh	39.2	31.4	31.0	31.4	31.0
Onshore generation	TWh	36.8	29.5	29.5	29.5	29.5

7.9 Impact of individual constraints on the deployment of wind generation

So far, this study has presented the trajectories of wind deployment associated with different scenarios. Therefore the effect of individual constraints on the deployment of wind generation requires further explanation. This Section presents the results of a univariate sensitivity analysis using the High Feasible scenario as a benchmark.

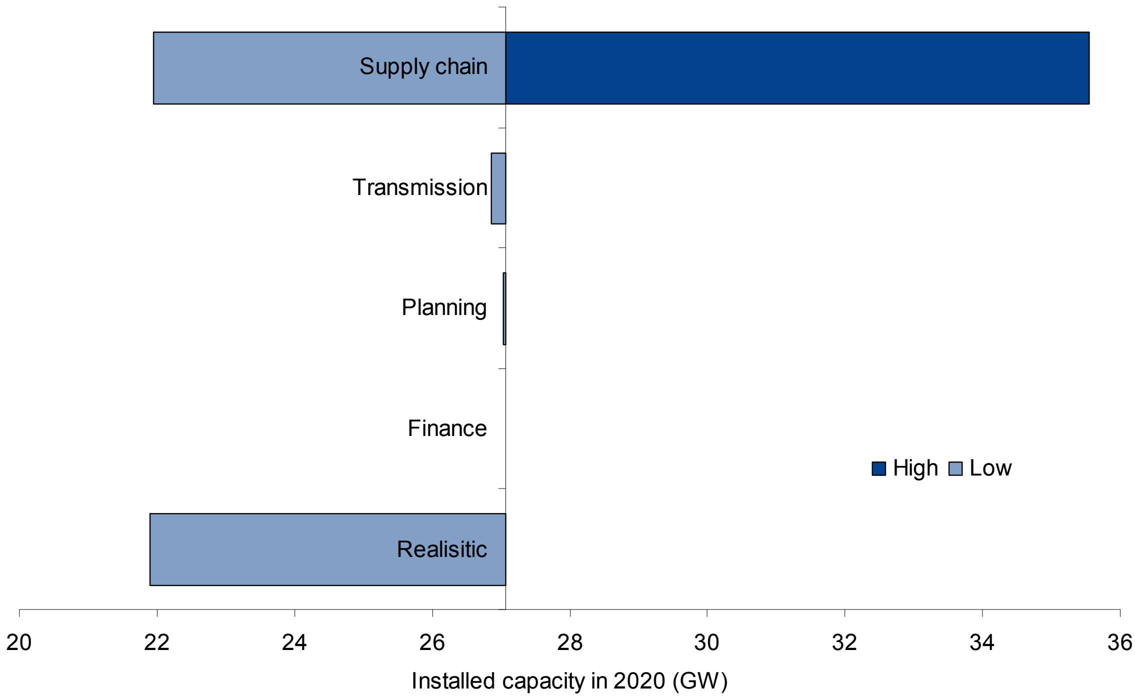
Table 29 – Input assumptions for sensitivity analysis

	Low	High
Planning	Historical planning times	High Feasible planning times
Transmission	Connect and manage Original ENSG timelines	Auctions, Delayed ENSG timelines
Finance	Long unfreezing period	Short unfreezing period
Supply chain	Medium SKM growth scenario	High SKM growth +0.5GW

The inputs shown in Table 29 have been individually transposed onto the High Feasible scenario to enable us to determine the impact that each of the constraints has the deployment of wind generation in the UK by 2020.

The results of the sensitivity analysis are seen in Figure 29. The chart plots the total capacity of deployed wind generation under the High Feasible scenario with constraints applied as per Table 29. The chart shows that the supply chain has the greatest impact on the capacity of deployed wind generation. As mentioned in Section 7.3, although the supply chain is a key determinant of the capacity of wind generation deployed, the modelling approach accentuates the impact it has by not considering the feedback that is likely to take place in the event of a severe supply chain backlog developing.

Figure 29 – Results of sensitivity analysis



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8. PROGRESS INDICATORS

8.1 Introduction

This Section of the report draws on the analysis undertaken in previous Sections to develop a set of indicators to help the CCC monitor progress in the deployment of wind generation for the UK to 2020. The indicators have been selected as a result of the contribution they have made in the scenario analysis in Section 7.

The progress indicators must enable the CCC to:

- compare the installed capacity and generation from wind in the current year with that consistent with a benchmark deployment trajectory (based on the High Feasible scenario);
- compare the projected installed capacity and generation from wind in 2020 given the current market position with that expected from the benchmark trajectory; and
- identify the drivers of the differences between wind deployment in the benchmark and current out-turns.

The reason for introducing a comparison between the current position and the 2020 position relative to the benchmark High Feasible scenario is to encompass one-off events (e.g. a low wind year) that may affect the short-term position, but not adversely affect long-term goals. As a result, indicators have been split into two groups: core indicators and underpinning indicators.

The following Sections present the core indicators and the underpinning indicators in detail along with the method used to identify key constraints and a set of rules for getting back on track.

8.2 Core indicators

Core indicators are used to assess the current position of wind generation deployment in any one year relative to the trajectory that is required to deliver the High Feasible. Given that the purpose of the indicators is to measure the deployment of wind generation in the UK, the core indicators are measures of installed capacity both in the current year and in 2020 along with the expected generation from wind. The former facilitates a comparison between the High Feasible and the current position, whilst the latter shows whether 2020 targets set by the High Feasible are expected to be met.

The following core indicators have been defined:

- operational capacity in current year;
- projected operational capacity in 2020;
- generation in current year;
- projected generation in 2020;
- % of demand met by wind;
- % of generation met by wind; and
- average load factor of installed capacity.

Operational capacity in the current year compares the operational capacity in the current position with that in the High Feasible. The result gives an indication of how far ahead or behind wind generation deployment is relative to that required to meet the High Feasible. Generation in the current year relates to the contribution that wind makes to the total generation portfolio. Two further related parameters that can be derived are the proportion of demand met by wind and the proportion of system generation provided by wind. These parameters are determined by the average load factor of wind generation which is a function of the split between onshore and offshore wind.

We anticipate that current year performance data would be obtained from existing UK government sources feeding into the Digest of UK Energy Statistics (DUKES) reports. The projected 2020 position would be derived by the CCC using the wind trajectory model developed as part of this project.

8.3 Underpinning indicators

Underpinning indicators help to identify the cause(s) of any difference in wind generation deployment between the current position and the High Feasible. This Section presents the underpinning indicators that determine the value of the core indicators. Underpinning indicators were chosen on the basis of those which were found to have the greatest impact on the GW of installed capacity and TWh of generation in the scenario analysis. In summary, the underpinning indicators can be split into three groups:

- Policy milestones/deliverables;
- Development and Planning; and
- Supply chain.

8.3.1 Policy milestones/deliverables

Underpinning indicators covering policy milestones/deliverables include ENSG timelines for transmission reinforcement dates and the implementation of CAP 164. The ENSG timelines for transmission investment cause offshore wind projects in certain regions to be delayed. The implementation of CAP 164 results in a 15% reduction in generation in Scotland to 2015 due to limits on transmission access in auction. These constraints can be relieved by implementing plans to ensure adequate investment is forthcoming to ensure resources are available for planned extensions. Data on the current position in relation to these policy milestones is expected to be available from the relevant organisation (e.g. Ofgem, ENSG, DECC, etc).

8.3.2 Development and Planning

Underpinning indicators for planning times include the average time taken for planning applications, the proportion of successfully approved projects (i.e. those that make it through planning) and capacity of new planning applications (in a given year and in terms of cumulative planning applications). Planning time constraints are relieved by implementing methods to reduce the time taken for a legal process to run (e.g. the IPC in England and Wales).

The average time taken for planning is broken down by onshore/offshore, region and turbine capacity band. The time taken in planning is the key determinant for the time a project spends in the development phase.

The proportion of approved projects relates to the amount of projects that do not make it through planning due to legal objections. This reduces the total resource available for wind generation for onshore sites. The assumption of the High Feasible is that no projects are lost in planning, however, this does not hold under other scenarios which are based on historical data.

The capacity of new planning applications is defined as the capacity of wind generation entering the planning stage per year. In the scenarios modelled in this report, capacity submits planning applications after set periods in pre-development. For onshore wind, all modelled potential resource is already assumed to be at least in pre-development, whereas that for much of the offshore wind potential is linked to transmission developments. Both create artificial measures of planning applications that lead to significant capacity bottlenecks in the supply chain (partly due to the limitations acknowledged in Section 7.3). Since the trajectories can be achieved without all the capacity entering planning in line with the timescales in any given scenario, the metric against which capacity entering planning is measured is that required to maintain future volumes of construction as modelled in the scenario.

Furthermore, in addition to considering the annual capacity of applications we also consider cumulative capacity of applications since 2009, as this will highlight whether poor performance against the annual benchmark represents a fundamental problem or is associated with a different profile of applications across time.

The initial market position in the modelling was based on our in-house renewables database that collates publicly available information from sources such as the BWEA's UK Wind Energy Database (UKWED), DUKES, the ROC register and supplements this with company-specific information and trade press reports (for example, RE News).

To measure the capacity and timing indicators for planning and development suggested above, the CCC will need to develop and maintain its own project database or access an existing database. As has been illustrated through the planning discussions earlier in this report, the information is largely available, though would need to be verified and reviewed at regular intervals.

Information on the capacity of projects currently within the formal planning process can be verified from the relevant authorities and over time the relevant authorities can also notify new projects applying for planning and the outcome of open planning applications (covering success, time of decision and any additional conditions of consent such as limitations on the capacity at the site). As this information is received and updated it will allow the CCC to measure several underpinning indicators:

- the annual capacity of projects entering planning;
- the success rate for planning decisions in a given year; and
- the average length of time that projects approved in a given year were in the planning process.

Information on the capacity currently subject to pre-development activities is likely to be less reliable, although using established and credible industry databases such as UKWED and market intelligence can provide a broad indication of future potential capacity development.

8.3.3 Supply chain

Indicators covering the supply chain include physical investments, the capacity currently under construction and the average construction period. In general these indicators require investment in additional resource in order to meet the High Feasible.

Physical investments in the supply chain are the collective name for the number of factories dedicated to producing onshore wind turbines and the number of vessels available for offshore sites. As stated in the Section 5, these supply chain constraints are deemed to be the key components in terms of delivering investment in the wider supply chain.

Capacity currently under construction effectively measures the capacity of the supply chain at a given year and therefore acts as a metric to gauge if the rate of build is sufficient to meet the targets set by the High Feasible.

The average construction period refers to the time taken for a project to enter operation once sufficient resource has been committed to begin construction. If the average construction period increases, projects will enter operation at a later date and vice versa if the construction period decreases.

Once more, information on projects under construction can be obtained directly from developers or existing market information databases – for example, UKWED.

8.4 Traffic light approach

The objective of the traffic light approach is to enable the CCC to identify the most important underpinning indicators and evaluate the impact they have on meeting the target for wind generation set under the High Feasible. This is done by:

- flagging up instances where core indicators fall outside a defined tolerance of the High Feasible; and
- flagging up instances where underpinning indicators fall outside a defined tolerance of the High Feasible.

The traffic lights compare the performance of the indicators under the High Feasible and the current position. The colour of the traffic light is dependent upon the performance of the system relative to the High Feasible. Table 30 presents the sensitivity bounds that have been used for the indicator model. In general, global indicators are measured on a percentage basis, while underpinning indicators are measured in both percentage and time (months), depending on which metric is more appropriate.

Table 30 – Sensitivity bounds for the Indicator model

Traffic light colour	% constraint	Time constraint (months)
Green	≥0	≥0
Amber	0<x≤-10	0<x≤-12
Red	<-10	<-12

Figure 30 presents an example of the traffic light approach using the core indicators to compare the High Feasible with the Alternative trajectory in 2009. Although no problems are reported with the current position, the projected performance of the Alternative trajectory compared to the High Feasible in 2020 is flagged up as a problem indicating that the underpinning indicators need investigating along with projections for the two scenarios.

Figure 30 – Example of core indicator traffic light monitoring

		Units	Current position	HighFeasible	Traffic Light
Global Inputs	Current year	year	2009		
Core Indicators	Total installed wind capacity in current year	GW	3.73	3.73	
	Total generation in current year	TWh	8.86	8.86	
	Projected installed capacity in 2020	GW	21.90	27.08	
	Projected generation in 2020	TWh	60.90	75.94	
	Load factor in current year	%	27%	27%	

8.5 A set of rules for getting back on track

It is clear from the scenario analysis and the work on key indicators that sufficient supply chain capacity is critical if the High Feasible is to be realised. This Section presents a set of rules related to the onshore and offshore supply chain which quantify the additional supply chain capacity required if the current position and trajectory have been found to be insufficient to meet the 2020 High Feasible.

The scenario analysis showed that the binding supply chain constraint for onshore wind deployment is the supply of turbines, while offshore wind deployment is determined by the number of installation vessels.[18] It is important to note that there is a delay between the decision to build additional supply chain capacity and the implementation of the additional capacity. This is due to the time taken for construction of a new vessel or turbine factory (this also applies to any element of the supply chain that requires investment).

18 If capacity is not fully utilised the focus may be on reducing time taken in planning or encouraging additional projects to enter development through increased policy support.

Figure 31 – Illustration of the delay effect in alleviating supply chain constraints

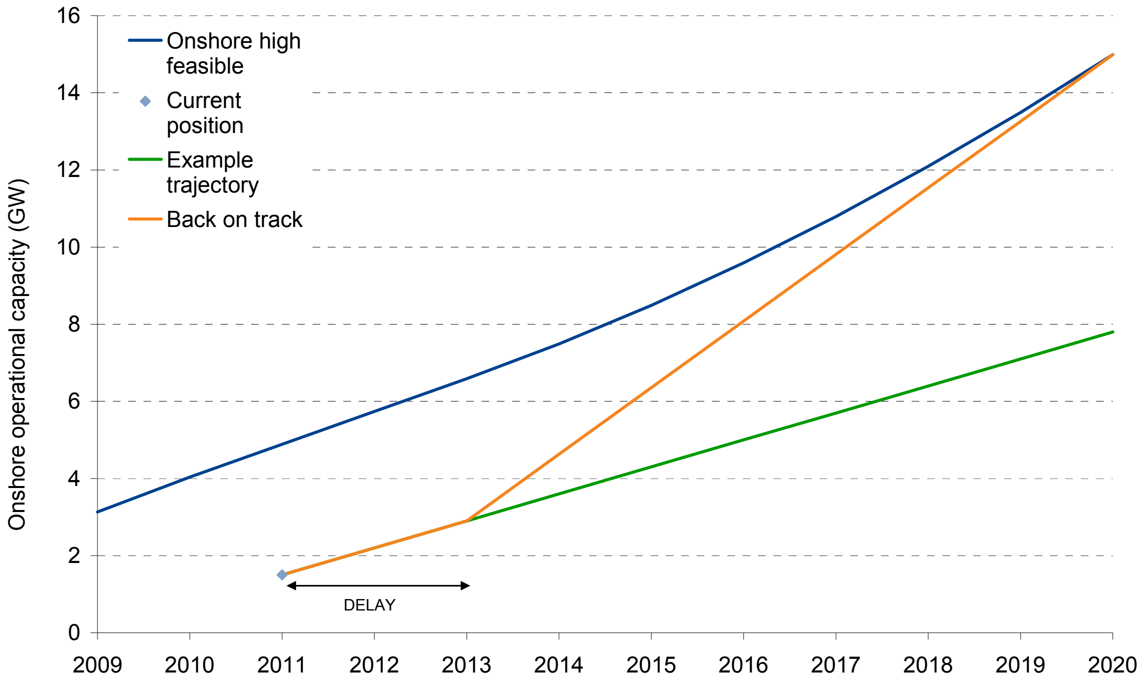


Figure 31 presents an example where the current position and projected trajectory is not expected to meet the target set by the High Feasible. Given a decision to invest in new supply chain capacity, the delay can be observed as the ramp in build rate does not happen for 2 years before it ramps up to meet the 2020 target. The delay also implies that more supply chain capacity must be invested in to ensure that targets are met due to the time lost waiting for manufacturing to be complete.

Therefore the rules for getting back on track can be summarised as follows:

- identify current position and trajectory of wind generation deployment;
- compare with trajectory for High Feasible to be met in 2020; and
- calculate new rate of build required in order to meet 2020 targets incorporating the delay in the time associated with the planned implementation and checking that there is sufficient capacity delayed by supply chain constraints.

From these rules, the required rate of construction can be derived for both onshore and offshore wind generation. Given a certain production capacity for turbine factories and installation rate for vessels, the number of additional units required of each can also be derived.

There are a few observations to add to complete this Section. Firstly, reducing the construction time (e.g. better manufacturing facilities) will reduce the delay, thereby reducing the additional supply chain capacity required. In addition, reducing the time of construction will enable a more flexible decision process i.e. given a build time of 2 years; vessels ordered in 2018 will not have any impact on the 2020 targets.

Increasing the construction time either due to demand will mean that extra capacity will need to be made available in order to get back on track. This has implications on the supply of vessels and relates back to fundamental questions of supply and demand which are outside the scope of this study.

8.6 Case study

The case study provides an example of how the indicators would work in practice by using the Alternative trajectory and comparing it to the High Feasible.

The High Feasible scenario is used as the benchmark against which market performance is assessed and the results of the Alternative scenario trajectory are used to represent a possible out-turn position in 2015 for the case study. Details of the scenarios can be found in Section 7. The sensitivity bounds are those set in Table 30; these bounds are subjective and can be altered by the CCC if desired. The example used in Figure 32 is for the year 2015.

Figure 32 – Illustrative traffic light table

		Units	Current position	HighFeasible	Traffic Light
Global Inputs	Current year	year	2015		
Core Indicators	Total installed wind capacity in current year	GW	12.14	12.70	
	Total generation in current year	TWh	31.24	32.68	
	Projected installed capacity in 2020	GW	21.89	27.08	
	Projected generation in 2020	TWh	60.87	75.94	
	Load factor in current year	%	29%	29%	
Underpinning Indicators					
Average planning period	All	months	58	41	
	Onshore	months	69	34	
	Offshore	months	48	49	
Average Development time IPP	All	months	61	44	
	Onshore	months	72	37	
	Offshore	months	51	52	
Average Development time VI	All	months	58	44	
	Onshore	months	70	37	
	Offshore	months	46	52	
Policy Milestone Indicators	Implementation of CAP164	year	2009	2009	
	ENSG transmission reinforcement dates				
	North Scotland Stage 1/2	year	2019	2015	
	South Scotland Stage 1	year	2015	2015	
	North East	year	2018	2017	
	Humberside/Yorkshire	year	2018	2017	
	Eastern	year	2017	2017	
	South East (London)	year	2015	2015	
	South East (Isle of Wight)	year	2019	2017	
	South West	year	2017	2017	
Supply chain indicators	Current capacity under construction	GW	3.00	3.73	
	Annual capacity required onshore planning	GW	0.00	1.33	
	Annual capacity required offshore planning	GW	5.96	1.85	
	Capacity of planning applications since 2009 (Onshore)	GW	11.38	7.50	
	Capacity of planning applications since 2009 (Offshore)	GW	12.72	7.34	
	Offshore supply chain capacity	GW	1.05	1.40	
	Onshore supply chain capacity	GW	0.90	1.10	
	Number of vessels for UK market (offshore)	no.vessels	6.00	8.00	
	Number of turbine factories (onshore)	no.factories	2.00	2.00	

In terms of core indicators, current operational capacity and generation are broadly comparable with the High Feasible scenario trajectory (evidenced by the 'amber' status in the table), but projections for installed capacity and generation in 2020 indicate the market is not expected to meet the targets set in the High Feasible scenario. To understand why this may be the case we look at the underpinning indicators.

A review of the underpinning indicators highlights major potential constraints in several areas, indicated by a 'red light':

- capacity under construction;

- annual capacity of onshore planning applications;
- average planning periods for projects; and
- delays in several planned transmission reinforcements.

Capacity under construction is at a lower rate than that required to meet the benchmark trajectory. Looking in more detail reveals that this supply chain constraint exists for both onshore and offshore projects. For offshore this is driven mainly by a slower deployment of installation vessels – only 6 are available to the UK market whereas it was envisaged that, by 2015, 8 vessels would have been available. This occurs against a background where planning applications for offshore are ahead of those that are required[19] suggesting that the supply chain is not responding quickly enough to market demands.

For onshore projects, the supply chain constraint is less evident – the number of turbine factories appears consistent with that in the High Feasible scenario. Indeed, it appears that the annual volume of projects entering planning is a major constraint for onshore development, with no new entry reported. Closer investigation of planning applications to date suggests that this is not a major concern. In this example, there is a much larger volume of capacity already in planning than needed to meet the benchmark trajectory (11.4GW relative to 7.5GW required by 2015). In actual fact, the indicators show that the major problem facing onshore projects in the medium-term is a lack of progress in reducing planning timescales – these are taking, on average, 3 years longer than expected under the revised planning system.[20]

From this snapshot, the CCC would be able to identify focus for policy interventions or changes that would not only relieve constraints but put the economy back on a trajectory to deliver the targeted capacity from the High Feasible scenario by 2020.

Figure 33 and Figure 34 illustrate revised trajectories that would get deployment back on track to meet the High Feasible targets for 2020. Though planning time appears to be the constraint, alleviating this would place more pressure on the supply chain, and Figure 33 shows that onshore capacity would need to expand by the equivalent of 2 factories assuming that the decision to build is made in 2015 (a two year build time and a production capacity of 450MW/year). This means that an additional 900MW of wind generation will be built between 2017 and 2020, which is enough to ensure compliance with targets under the High Feasible.

[19] This occurs despite some project developments being delayed as a consequence of the slippage in delivery on some transmission reinforcement projects.

[20] Since the indicators have additional levels of disaggregation (by region and scale), these can be investigated to ascertain whether the planning delays are generic or specific to a given region or size of project.

Figure 33 – Getting back on track for onshore wind

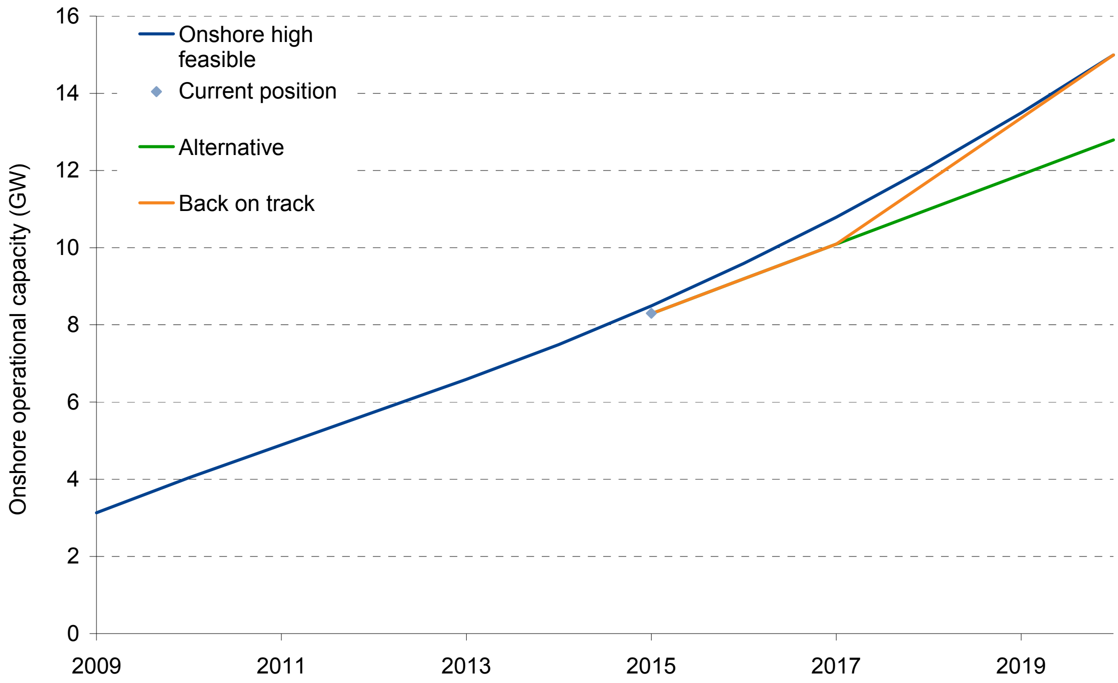
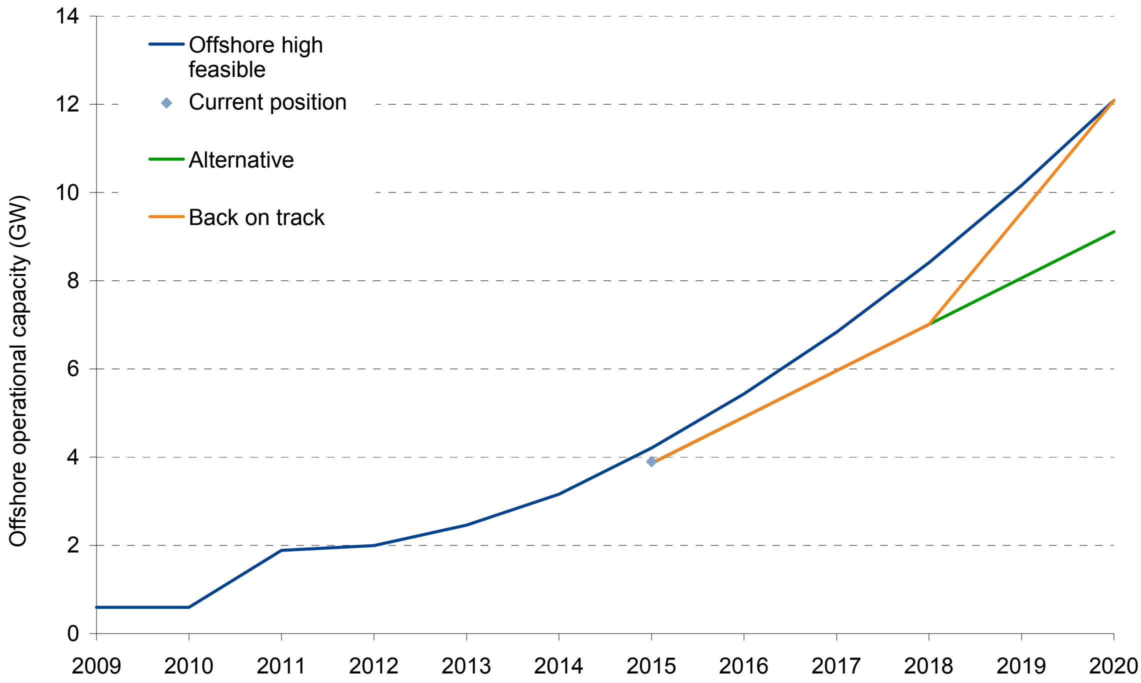


Figure 34 illustrates the trajectory offshore wind deployment must follow in order to meet 2020 targets. It shows that the supply chain capacity must increase by an additional 9 ships (1.6GW) that enter service in 2018 (assuming a three year build time and an installation rate of 175MW/year for new vessels). This compares to a total of 13 installation vessels in the High Feasible scenario. The total build rate in 2020 is then 5.2GW/year for offshore, which compares to a value of 4.4GW for the High Feasible. This overshoot is necessary to ensure that the 2020 target is met.

Figure 34 – Getting back on track for offshore wind



Not only has the case study shown how monitoring a set of indicators can highlight potential problems at an early stage, it has also reinforced the complex interactions between different stages of the project cycle. When addressing individual constraints, it is necessary to consider the knock-on effect these may have on pressures elsewhere in the chain – policy action needs to be effective in loosening the overall constraint on development potential rather than shifting the point where bottlenecks emerge.

It is also interesting to note the importance of revising projections of longer-term market performance to take account of observed changes in market conditions to identify appropriate corrective action. In this case study, there is little divergence between the actual and High Feasible position in 2015, but projecting future performance shows that slower growth in supply chain capacity, longer planning periods and delays in transmission reinforcement lead to significant divergence in the 2020 position. This leads to the conclusion that corrective action is necessary now.

If the same sensitivity constraints were kept, but projections were disregarded, it would be 2018 when the current year would be flagged up as falling behind the same year under the High Feasible. This effect is magnified by the delay incurred in providing additional supply chain capacity. In order to meet 2020 targets corrective action associated with the supply chain must be implemented before 2018 for onshore sites and 2017 for offshore sites, given the current constraints on developing supply chain capacity.

8.7 Interpreting the indicators

In the example shown, the main constraints on achieving the 2020 deployment consistent with the High Feasible scenario are limitations on supply chain capability and longer planning periods. This out-turn reflects the specific scenario assumptions, where the main differences are associated with slower supply chain capacity growth. However, in practice, the assessment will be based on actual market data. Identification of key constraints will require interpretation of the underpinning indicators as there are important dynamic feedbacks between the situation in the supply chain and the decision to proceed with a development. The following discussion illustrates the main observations that would indicate a primary problem at a particular stage.

8.7.1 Primary supply chain problem

Where the supply chain is the main problem, the monitoring system would show red for capacity under construction and potentially also for the average construction time – the latter would be more likely to manifest itself if the issue were lack of skilled labour as opposed to manufacturing capacity. Since the indicators also include specific infrastructure investments identified in the SKM scenarios, the position on UK infrastructure will also probably be red. However, the impact of this would depend on the extent to which the supply chain is a pan-European market, enabling UK developers to access European supply chain capability.

Under these circumstances, problems with other indicators – for example, the volume of planning applications and time in planning – may not be binding, and well functioning planning procedures may add to the bottleneck in supply chain (as discussed previously). Nevertheless, if the situation persists, then we may see planning applications (development) fall in the future as there will be a feedback into the cost of new projects – this would be a dynamic effect to monitor in following years.

8.7.2 Primary planning/development problem

With issues in the planning phase, we would expect the average planning period to be red, or the proportion of successful applications to be red, indicating an unsupportive planning system. Over a period of time, these problems may impact on decisions to proceed with developments and therefore we would see a fall off in the capacity of new applications and the cumulative planning applications since 2009.

The impact further down the project cycle (i.e. on the supply chain) may initially be to alleviate constraints, as fewer projects are demanding resource, but this could cause a longer-term problem for infrastructure development.

8.7.3 Primary transmission problem

Transmission constraints may manifest themselves in several ways. Initially, we would see policy milestones being missed associated with a failure to build network infrastructure on time. A consequence of this would be lower load factors of wind farms (though it should be noted that the latter on its own may just be a problem of wind speeds in a particular year or of the out-turn efficiencies of plant). Since delays to grid infrastructure may be known several years in advance, there may be knock-on effects on the speed of projects going into development (i.e. less planning applications each year), though this would depend on the nature of the enduring transmission access arrangements established and the implied incentives on developers to delay.

8.7.4 Primary financing problem

Our analysis does not monitor the time to financial close or the mix of developers active in the market, but we would anticipate ongoing financing problems to lead to delays in the average development time and/or the annual (and cumulative) capacity of planning applications falling. As in other areas, these problems earlier in the supply chain may mitigate potential supply chain constraints, but have detrimental impacts on the supply chain in the longer run as they reduce the incentive to invest in new infrastructure as there is not the volume of projects to support the new investment.

ANNEX A – PLANNING CYCLE FOR ONSHORE AND OFFSHORE WIND PROJECTS

A.1 Onshore wind

This section sets out the steps that a developer of an onshore wind farm proposal will typically go through during the planning process from start to finish when wanting to build an onshore wind farm. The table below incorporates both over 50MW proposals and under 50MW proposals (and states where there are key differences). The schedule is divided into key stages with a brief overview of what happens in each stage to inform the reader. This brief overview is not conclusive but is to give a general idea.

Not all proposals will go through and appeal and public inquiry at Stage 4. An under 50MW proposal can be appealed if it is refused or not determined at application stage. The vast majority of onshore wind farm appeals are heard by public inquiry. Proposals over 50MW can go to inquiry if the LPA raise an objection.

Table 31 – Planning cycle for onshore wind projects

Pre-application stage – Timescale for this period has been assumed to be 2 years for 0-50MW and 3 years for over 50MW + the statutory 5 week scoping period

Stage 1 – Site selection	Identification of potential sites for wind farm development. This would typically include (in no particular order) the following processes. ▪ Consideration of regional and local planning policy of renewable energy for the area. ▪ Identification/recording of wind speeds in the area which will include the need to erect an anemometer mast to record wind speeds. These anemometer masts will require planning permission so the planning application process for onshore wind under 50MW will apply. The anemometer mast will not (unless in very unusual circumstances) require EIA. Planning is usually granted within a short amount of time. ▪ Discussion and negotiations with landowner to agree option agreements to lease the land if the developer does not own the land. ▪ Initial identification of turbine layout and type of turbine that can be deployed (in terms of MW and height not specific make). ▪ Initial review of environmental constraints, for example: identification of areas statutorily designated for nature conservation or landscape, cultural heritage or hydrological value. ▪ Review of other constraints, eg access, aviation, proximity to residential dwellings. ▪ Review of number of turbines and MW which could be developed on the site and site layout. ▪ Review of finance for the proposal and viability.

- Review of grid connection.
- Initial discussions with key stakeholders to identify key concerns in relation to development of the site.

Stage 2 – EIA

If applicable (i.e. a small wind farm or single turbine) a screening opinion is sought from the Local Planning Authority for the area within which the site sits to see if EIA is required. For the majority of wind farm proposals EIA is required.

- Formal commencement of environmental impact assessment.
- Instruction of independent consultees to carry out EIA, eg landscape and visual, cultural heritage, noise, nature conservation, transport etc.
- A scoping opinion is sought from the Local Planning Authority (Under 50MW) or relevant Secretary of State (Over 50MW) as to the scope of the environmental impact assessment.
- Consultation with statutory consultees in relation to scoping opinion to identify areas of concern and need for in-depth surveying (eg with Natural England, Scottish Natural Heritage, Countryside Council for Wales, Environmental Agency, Scottish Environmental Protection Association, English Heritage, CADW, Historic Scotland.
- Consultation with Local Planning Authority.
- Consultation with public through public exhibitions and meetings.
- Design Iteration: the design and layout of the site will be modified in response to the environmental assessment being carried out to avoid sensitive areas and finalise layout.
- Carrying out of EIA: field studies and surveys – the number and length of surveying depends on the specific site and environmental sensitivities surrounding it.
- Preparing Environmental Statement.
- Preparation of other documentation ready for submission, for example, a Design and Access Statement and a Planning Statement.

Application stage

Stage 3 – Application Submission

- Submission of application to Local Planning Authority (LPA) for under 50MW or submission of application to relevant Secretary of State if over 50MW.
- Advertisement and consultation process with statutory consultees and public.
- For under 50MW applications in England, Wales and Scotland the Planning Officer at the LPA will write a report to Committee recommending approval or refusal of the application. The application will be determined by a Committee (they can either follow the Planning Officer’s recommendation or not). The Secretary of State has the discretion to ‘recover’ the application for determination by him rather than the Council.

- For over 50MW applications the relevant Secretary of State will consider the application and consultee responses. If the Local Planning Authority raises an objection to the application a public inquiry is more than likely to be called (ultimate discretion lies with the Secretary of State).

Decision

A Decision for Under 50MW should be made at this stage to either approve or refuse the application although some applications can remain underdetermined. For over 50MW proposals if the LPA object to the proposal a public inquiry is almost always called. If there is LPA objection the relevant Secretary of State can still call an inquiry if they consider it appropriate but they would normally determine the application on the papers having consideration to the evidence received.

For both under 50MW proposals if planning permission is granted it will be subject to planning conditions some of which will require action and further work on the part of the applicant to the satisfaction of the LPA before development of the wind farm can be begun.

Most wind farm permissions are granted for a period of 25 years from the date electricity is first transmitted to the grid. Under 50MW wind farm permissions must be implemented within 3 years of the date of the permission in the absence of any period set out in the permission. If there is no commencement of development (which has a set legal definition) within the required time period then the permission is lost. Over 50MW wind farm consents must be implemented within usually 5 years of the date of permission.

Appeal stage

For proposals under 50 MW only: the applicant has the option of submitting an appeal to the relevant body (see below) if the application is refused by LPA or not determined within the relevant time period (whether the set timescale above or any agreed extension of that period). The applicant has a period of 6 months from the date of refusal or the date that the application should have been determined by to lodge an appeal otherwise the right is lost.

Stage 4 – Submission of Appeal

An appeal is submitted to the relevant appeal body.

- England: Planning Inspectorate, Bristol.
- Wales: Planning Inspectorate, Cardiff.
- Scotland: Department of Planning and Environmental Appeals, Scottish Government.
- N. Ireland: Planning Appeals Commission.

The relevant appeal body determines how the appeal is dealt with after consideration from appellant and LPA. There are 3 modes of hearing an appeal: written representations; informal hearing; public inquiry. The majority of onshore wind farm appeals are heard by way of public inquiry (around 90%).

Once submitted the relevant appeal body will validate the appeal and issue formal letter confirming the commencement of this appeal. The date of this letter is called the Start Date or Relevant Date.

Inquiry stage

Different inquiry procedure rules apply to under and over 50MW applications but as the key stage are similar they have been dealt with as one for the purposes of this schedule.

Preparation Stages to Public Inquiry

The following documents need to be lodged by the appellant/applicant, LPA and any other main party to the inquiry:

- Statements of Case (outlining evidence to be brought, witnesses to be called and documents to be referred to).
- Statement of Common Ground (agreed between Appellant and LPA).
- Pre-Inquiry Meeting (Inspector (Eng/Wales/N). Ireland)/Reporter (Scotland), Appellant, LPA and members of the public discuss arrangements for inquiry, timetabling, scope of evidence and witnesses to be called).
- Core Documents (full copies of all documents to be referred to by witnesses in their evidence to be submitted to each main party to the inquiry).
- Proofs of Evidence (Eng/Wales)/Precognitions (Scotland)

Notices also have to be published confirming the date and venue of the inquiry. For wind farm proposals an appellant will need to bring evidence on at least 2 areas: planning policy and landscape and visual impact. Evidence is given by expert witnesses appointed by the appellant. Depending on the issues to be addressed some appellants might need to call as many as 10 expert witnesses. Inquiries for proposals over 50MW are likely to require at least 4 expert witnesses. Legal representation is also necessary.

Stage 5 – Legal Challenge

An increasing number of decisions are challenged either by way of legal challenge for under 50MW proposals in England, Wales and Northern Ireland or judicial review for under 50MW proposals in Scotland and all over 50MW proposals.

Stage 6 – Discharge of Conditions

A key factor in being able to implement the planning permission, that is begin construction, is to ensure that those planning conditions that must be discharged before development can commence are discharged. This can take some considerable time, if for example they are trying to reach agreement on aviation etc. These conditions state you have permission but subject to you getting agreement on a specific point before you can build. In the event that building commences before having satisfied the relevant conditions that need to be satisfied then the project is in breach of its planning permission. Sometimes conditions are discharged in good time but sometimes they can take a long time.

Source: Eversheds

A.2 Offshore wind

This section sets out the steps that a developer of an offshore wind farm proposal will typically go through during the planning process from start to finish when wanting to build an offshore wind farm. The schedule is divided into key stages with a brief overview of what happens in each stage to inform the reader. This brief overview is not conclusive but is to give a general idea.

Table 32 – Planning cycle for offshore wind projects

LEASE

Application process to the Crown Estate for the granting of a lease for the seabed of a specified zone. Beyond the territorial limit and within the Renewable Energy Zone an application for a Licence is required from the Crown Estate. The application process has occurred in Rounds and as such the majority of zone development options have been granted simultaneously.

PRE-APPLICATION

Preparation of an Environmental Statement to satisfy the EIA Regulations and preparation of an application for the offshore and if required, onshore works. This stage can vary in content and production time from project to project (for example if bird collision risk data is required if there is no existing baseline) and to the requirements of the individual zone. The majority of this time in this step is taken on preparation of the Environmental Statement.

APPLICATION

Application made for consents under s.36 EA 1989, Licence under FEPA 1985 and s.34 CPA 1949. Other consents which maybe required are TCPA s.57 or s.90 work, s.37 EA 1989 for cable lines and WRA 1991 s.109 for structures within a water course. An application under s.36 EA 1989 will be accompanied by the completed Environmental Statement.

CONSULTATION

Public Consultation Period. Administered by DECC. Any further information produced during this time which requires EIA will be advertised as SEI and require a further consultation period. This stage can trigger an Inquiry under s.36 Electricity Act for onshore and offshore works requested under s.90 TCPA.

DETERMINATION

Simultaneous grant of consent package applied for with s.36 application. Start date of the limitation period for legal challenge. Any Planning Permissions granted under s.57 TCPA (e.g.) for onshore substation works not granted deemed planning permission under s.90 TCPA will be subject to a 3 month Judicial Review limitation period from that Permission being granted.

A.3 IPC procedure and timescales

This section steps out in more detail the steps that a developer will take if it project is covered by the new planning regime whereby onshore wind projects over 50MW and offshore wind projects over 100MW will be determined by the Infrastructure Planning Commission (IPC).

A.3.1 Pre-application Consultation

Before an application is submitted to the IPC the applicant will have a statutory duty to go through certain pre-application consultations in relation to the proposal and will have to prepare environmental information. There is no set timescale given for this but we estimate that it could take as long as 3 years (and in some cases longer depending on what issues arise in this pre-application process)

The detail of what is involved in the pre-application consultation will be set out in regulations. Draft regulations and procedure are currently out to consultation (ending 19 June). These include the need to set out proposals for community consultation and adhere to them and also advertise the fact of the intended application in local and national newspapers. In addition an IPC consent will be given in a statutory Order which will set out all the elements of what is consented. The applicant is required to submit a draft Order with the application. Therefore the new IPC procedures are very "front-loaded" in that there will be an increased amount of work to be carried out prior to the application being submitted. The intention of this is to get the application as full and ready as possible for consent before it reaches the IPC.

A.3.2 Submission of the application to the IPC

Once an application is submitted to the IPC timescales start running. The IPC must decide whether or not to accept the application within 28 days. They will be looking to see that the pre-application procedures have been properly carried out and that all is in order ready for the IPC to proceed.

Once the IPC accept the application the applicant must then give notice of the application (by way of advertisement in papers etc) to specified bodes/people which will be set out in the regulations. When they give notice to these people (consultees/the public etc) they must give them a period of 28 days within which the consultees can make representations on the application to the IPC (i.e. objections or support or issues of concern etc);

The IPC will then decide whether a single commissioner or a panel of commissioner (max 3) will consider the application (the procedure varies a little going forward depending on this. An initial assessment of the principal issues arising on the application will be undertaken. Once that has been done the IPC must call a public meeting. There are no set timescales for this step in the procedure. More detailed regulations will be published for consultation this year and they might give more of an indication as to how long this stage might take but nothing has been published yet. For the purpose of the model we have estimated a period of 2 months. It is not possible to comment further until draft regulations for consultation setting out the detail of what is proposed during this period are published.

A.3.3 Determination Period

The meeting held by the IPC is one to which the applicant and any person who has made a representation can attend to make representations about how the application should be examined (no evidence is heard at this stage). The date of this meeting kicks off the timescales for determining the application.

The application can be determined in 3 ways: written representations; hearings about specific issues or open-floor hearing. People can make representations to be considered. The aim is to avoid the long public inquiries that can take place at the moment (eg for the over 50MW proposals some last as long as 9 weeks and at a minimum at least a month).

The IPC is under a legal duty to complete the examination of the application by the end of the period of 6 months from the date of the meeting. (We have generalised this for the purpose of this report: if a single commissioner is hearing the application he has 3 months to examine it then he sends it to the IPC council who have 3 months to further examine the commissioner's findings. If a panel of 3 commissioners is hearing it they have 6 months to examine it – either way it is a 6 month period.)

The IPC is under a legal duty to decide an application by the end of the period of 3 months from the end of the 6 month period above for examination. There is however a provision in the Planning Act for the IPC which allows a later date to be set at the Secretary of State's discretion. Timescales for determining applications are more likely to be extended if there are revisions to the NPS being made during the period that the application should be considered. The detail of this discretion will be set out in regulations yet to be published or consulted upon – but will be during this year.

The Secretary of State can intervene if they think they should determine the application (the detail again will be set out in regulations yet to be published for consultation this year).

A.3.4 Legal Challenge of Decisions

Once the application has been determined it can be subject to a legal challenge. This can be either by the applicant (if the application is refused), the council or third parties who have an 'interest' (legally defined) in the application. There is no right of appeal. Legal challenges and judicial review and the timescale consequences of them to proposals are discussed later in this report.

Any person wishing to make a legal challenge must do so within 6 weeks of the date of the decision. The challenge will be to the High Court and will be placed in the normal court process in the queue with all the other claims the court has on. There is no set time period here for determining legal challenges. The Court has recently had a huge backlog and hearing dates for challenges were taking a year to be set from the date they were submitted. If the challenge was successful the application would need to be re-determined but only in relation to the area of dispute (unless circumstances had changed such that new issues had arisen since the last determination).

Average timescales from application determination to appeal determination

In order to give context and meaning to the average timescales used in the model (and in some cases to illustrate why the average figures for some categories should be treated with caution and do not reflect the actual historic experience to date) a schedule of the selection of proposals looked at to reach the average is set out below. The timescales for under 50MW proposals in England and Wales is important because the planning regime will continue to be the same.

0-5MW	**England**	17 applications were reviewed 9 of the applications were approved, 4 refused, 3 haven't yet been determined and 1 was withdrawn. In terms of statutory timescales some of these proposals will have required an environmental statement so the statutory date for determining the application would be 16 weeks from submission for

		the others would not have done so the date for determining the application would be 8 weeks[21] Out of the 13 applications that were determined the timescales for determining them were: 120 weeks (2 years 4m); 6 weeks; 15 weeks; 7 weeks; 36 weeks; 6 weeks; 7 weeks; 22 weeks 12 weeks; 11 weeks; 10 weeks. Out of the 4 that were refused all went to appeal. 2 were approved, 1 was withdrawn and 1 was refused. A legal challenge was made to one of the approved appeals. The application for this appeal was submitted on 19/1/07, it was appealed for non-determination and approved on appeal on 1/5/08. The court hearing to hear the legal challenge was expected to be early 2009.
0-5MW	**Wales**	Not enough data available
0-5MW	**Scotland**	Not enough data available
0-5MW	**N. Ireland**	Not enough data available

5-50MW APPLICATIONS

5-50MW	**England**	29 applications were reviewed. 28 were determined at application stage, 12 were approved, 16 were refused and 1 hasn't yet been determined. Timescales for determining the applications were (in weeks): 11, 18, 72, 32, 16, 77, 64, 21, 22, 28, 16, 28, 19, 104, 64, 14, 26, 29, 72, 104, 38, 9, 63, 55, 48, 14, 12, 44, 125. Out of the 16 that were refused 9 went to appeal. All went to public inquiry (1 is still awaiting an inquiry date). In terms of decisions 2 are awaiting an inquiry decision, 4 were refused, 1 was approved and 1 withdrawn. The one that was approved however has been the subject of a successful legal challenge and the decision is being re-determined at a second public inquiry starting in July this year.

21 As stated above both applicant and local planning authority can agree extensions of this period.

		In terms of timescales for that latter proposal: it was submitted on 10/11/2005 and determined on 31/01/2006 (refused), it went to appeal and was heard at a public inquiry in October 2006. Permission was granted on appeal in February 2007. A legal challenge was submitted within the 6 week period and heard in July 2008. It was successful – the decision was remitted back for re-determination with the inquiry in July 2009. Timescales from the application decision to the inquiry being called on appeal for the 8 appeals are: 8 m; 9 m; 1 yr 6 m; 1 yr 7m; 1 yr; 9m; 2 yrs; 9 m (and appeal withdrawn). Timescales from end of inquiry to appeal decision (approximate): 3m; 5 wks; 2 m; 3m; not known and the rest are still awaited.
5-50Mw	**Wales**	24 applications were reviewed (since 2005). 10 are however still to be determined by the Local Planning Authority. These proposals have been in the planning system for some time: 3 yrs 2m; 2 yrs 9m; 1 yr 3m; 1 yr; 1 yr 5m; 1 yr 1m; 1 yr 2m; 9m and 1 yr 2m. 14 have been determined. 7 of these have been approved, 7 were refused. 1 of the approved applications was "recovered" by WAG for their determination and was considered after inquiry. Timescales for determining the 14 applications were: 2 yrs; 2 yrs 2m; 1 yr 1m; 2 yrs 6m; 1 yr 5m; 2 yrs; 1 yr; 1 yr 6m; 2 yrs; 1 yr 3m; 1 yr 2m; 2 yrs 6m. 6 went to appeal (this includes the "recovered" application). Timescales from application determination to inquiry end date: 1 yr 3m; 1 yr 3m; 1 yr 6m; 8m; one appeal was withdrawn, one is awaiting an inquiry date. 4 appeals have been determined to date and only 1 was approved and 3 refused. Timescales from inquiry end to appeal decision: 5 wks; 5 wks; 9 wks; 9 ms (this was the recovered application determined by WAG). Out of the applications approved none are operational yet and only 1 is currently in construction (approved in March 2007).
5-50MW	**Scotland**	34 applications were reviewed (mostly submitted in the period 2005-2007) 6 of these applications are still to be determined. Submission dates for those applications yet to be

		determined are: 1/5/06; 15/6/06; 23/2/07; 1/1/06; 9/8/06; and 1/9/05. 1 was withdrawn and 19 applications were determined at application stage. 10 were refused and 9 approved. Timescales for determining the applications were: 66 wks; 48wks; 37 wks; 43 wks; 21 wks; 50wks; 45wks; 71 wks (dates for other applications not known). Out of the 10 refused 7 went to appeal (1 appeal was subsequently withdrawn) and 6 were appealed against non-determination. 1 appeal was heard by written representations (8 months from appeal submission to determination - appeal refused). The remaining 13 appeals were heard by public inquiry. 4 appeals are still awaiting a decision. 6 appeals have been refused and 5 approved. Timescales from application determination to inquiry: 1yr 3m; 2 yrs; 9m; 9m; 1yr 4m (timescales for other appeals not known). Timescales from inquiry to decision: 5m; 4m; 2 ½ m; 4m; 1m 2wks; 3m; 4m; (timescales for other appeals not known). Out of the applications approved only 2 are currently operational, the rest are awaiting construction (i.e. in the post consent stages).

50+ MW APPLICATIONS

50+ MW	**England**	10 applications to DTI/BERR/DECC were reviewed to get the average figures for the historic model[22]. 9 of the 10 applications have been determined, the other is still awaiting determination. All 9 of these applications have gone to public inquiry[23].

22 There have only been 12 Section 36 Electricity Act applications in England to date: one was submitted in 1993 and refused and one was withdrawn therefore these were discounted from the average.

23 Section 36 applications will go to inquiry if the Local Planning Authority object to the application.

		Timescales from application submission to start date of inquiry: 1 year 11 m; 3 years 2 m; 3 years; 2 years; 1 year 7m; 1 year 2 m; 2 years 1m; 1 year 5m. Timescales for length of inquires held: 4 weeks; 9 weeks (2 applications heard at conjoined inquiry); 3 weeks; 4 weeks; 4 weeks; 18 weeks (2 applications heard at conjoined inquiry); 12 weeks Timescales from end of inquiry to decision: 7 m 2 wks; 6 m 3 weeks (2 decisions at same time); 9 m; 10m; 3m 2 weeks; decision still awaited for conjoined inquiry); 11m. Overall timescale from application submission to inquiry decision: 2 yrs 8m; 4 yrs 4m; 4yrs 1m; 3 yrs 1m; 3 yrs 1m; 1 yr 10m; 2 yrs 5m. 3 of the 10 applications are still to be determined 6 were approved 1 was refused 2 of the approved schemes are operational: 1 - Application submitted 4/7/03 Operation dated 03/09 5 years 8 months from application to operation 2 - Application submitted 15/11/02 Anticipated operation date 09/09 6 years 10 months from application to operation Decision dates for those awaiting construction: 7/8/08 23/02/08 26/02/08 09/10/07
50+MW	**Wales**	7 applications in total for Wales (all applications ever submitted) to DECC

		Only 1 application has been determined and this was submitted in July 2000 and determined in February 2002 therefore we don't think this can be used as any idea as to how long applications will take going forward. Application submission dates for the 6 applications are: 27/3/09; 11/12/08; 09/05/08; 07/05/08; 30/11/07. There are therefore no timescales for Wales upon which to base the average figure and this is unknown. For the sake of providing a figure for model the average timescales for England have been assumed.
50+MW	**Scotland**	83 applications have been made to the Scottish Government 26 of these applications were subsequently withdrawn 57 applications were reviewed for timescales. 25 of those 57 applications are still to be determined therefore the average figure is based on the 32 applications which have been determined. In contrast to England 21 have been determined without going to public inquiry. 17 of those were approved and 4 were refused. Timescales for those determined without going to inquiry were: **31 weeks; 1 yr 8 m; 3 yr 2m; 1 yr 8m; 4 yr 9m; 5 yr 3m; 4 yr 3m; 1 yr 1m; 3 yr 3m; 3 yr 5m; 2 yr 10m; 1 yr 11m; 2 yr; 3 yr 1m; 1 yr 5m.** 11 applications went to public inquiry of which 5 refused at inquiry 3 approved at inquiry and 3 were awaiting decision 1 yr 3m; 2 yr 4m; 1 yr 4m; 1yr 3m; 1 yr 2m; 3 yr 5m; 3 yr 3m; 1 yr 3m (other timescales not known)

A.3.5 Planning Constraints

As identified above there are a number of constraints which have led to the delays in planning to date. Some of these constraints might be addressed or eased with the new regimes in England, Wales and Scotland but some will not be addressed either because they are inherent to applications for development generally (eg environmental constraints) or because the new regimes will not change them (eg local decision making).

A.3.6 Onshore wind

A.3.6.1 Timescales for implementation of National Policy down to local level

This is a particular issue for England and Wales. Development Plan documents usually cover a period of 10 to 15 years and take some time to be updated therefore many adopted Development Plan documents are historic and don't take account of the latest national policy guidance. It can be years before Development Plan documents are updated. For England and Wales, the fact of strategic national guidance and declarations of national intent in relation to renewable energy proposals does not alter the attitudes of local councillors at the LPA who determine under 50MW applications who tend to vote on their perception of local issues.

A.3.6.2 Environmental constraints

The number of turbines (and hence potential MW capacity) that can be deployed on a particular site is dependent on the environmental constraints present at a particular site and whether those constraints can be overcome. Some constraints are such that a very windy site with the potential to accommodate a larger number turbines would not get through planning due to the environmental issues that would be present should a proposal be built out: Not all sites are suitable for accommodating onshore wind farms.

The planning reforms will not influence this constraint.

Strategic national guidance in Wales (TAN8) which identified strategic search areas for major wind farm proposals to be located has led to significant delays in the deployment of wind farms. This is because a broad brush strategic environmental assessment of an area as was carried out for TAN8 cannot replace the more detailed site specific environmental assessment that developers need to carry out to demonstrate the acceptability of their proposal in environmental terms. For example TAN 8 did not take account of access issues and did not properly consider cumulative effects of having numbers of wind farms in one area. In addition much of the land identified was owned by the Forestry Commission so a tendering process for lease of the land by them had to be undertaken which increased the timescales. Site selection by developers considering the constraints of a specific site adopting a criteria based approach has been shown to the most effective means of identifying suitable sites for wind farms rather than a strategic approach.

A.3.6.3 Resource issues for statutory consultees and LPAs

The ability to engage in pre-application consultation can be limited by the lack of resource of statutory consultees of the LPA to deal with consideration of proposals in a timely manner or at all. Lack of pre-application consultation (whether in scoping or otherwise) can lead to further environmental information having to be provided once the application has been submitted to deal with concerns or inadequacies in information and may lead to the need to make amendments to the application.

Under the IPC developers will have a statutory duty to undertake a pre-application consultation with consultees, the LPA and the public. It is not yet clear whether there will be penalties for LPAs or consultees for not engaging with developers in a timely manner. Assuming that consultees and LPAs do properly engage in this process the post application period should be reduced. However the Planning Act and IPC effectively "front-loads" applications so this pre-consultation period could go on for some time especially if there are resource issues in dealing with applications coming forward. Time will tell whether overall the timescales will be improved.

A.3.6.4 Preparation of EIA

The EIA process can take some time to prepare for example if there are seasonal habitats surveys to complete or site specific issues to be overcome. A thorough and robust EIA is essential and this constraint will remain for all proposals going forward.

A.3.6.5 Application determination by LPAs

Timescales for LPAs in determining applications, particularly in the 5-50MW range is substantial (i.e. on average 14 months in England and Wales when it should be 16 weeks) and this is one of the key constraints. Because the IPC or Scottish reforms will not affect under 50MW proposals in England and Wales this constraint will remain for those applications.

Reasons that an LPA might not determine an application within the statutory timescales are:

- lack of resource to deal with multiple applications for wind farms in their area;
- lack of expertise/experience in dealing with wind farm applications (which do require specific technical expertise);
- lack of adequate environmental information from the developer and therefore request for further information required;
- drip feeding the developer with requests for all manner of extra information (whether necessary for EIA or the decision making process or not);
- requests for extensions of time from the developer (eg if they are in discussions with a consultee on an issue that could be resolved);
- engagement and discussion between LPA and developer on issues and objections;
- delay in waiting for stakeholder or consultee responses to be received and engagement with consultees; and
- depending on representations received the developer may make amendments to the application (within the defined (red line) boundary of the planning application) to try to overcome specific concerns. For example they might delete a turbine. Further EIA will need to be submitted and consulted upon.

A developer can submit an appeal for non-determination if an LPA is delaying in determining but submitting an appeal is expensive and some developers prefer to wait to see if the application is determined believing that it will be determined eventually and positively (particularly if they have been engaging in discussion and supplying further information). As stated above appeals can only be submitted within 6 months of the 16 weeks period for determination or the agreed extended date for determination. On other occasions the developer might want to submit an appeal shortly after the end of the determination date in the hope that they will get an approval on appeal.

In Scotland the period for submitting an appeal will fall from 6 months to 3 months. This might place a greater impetus on applicants to appeal quickly (as opposed to considering whether or not to appeal in more detail). It is likely to have a knock-on effect of increasing the number of appeals submitted to the Directorate of Planning and Environmental Appeals. In England and Wales the time period for submitting an appeal was dropped to 3 months and the planning inspectorate were inundated with appeals that they could not resource in a timely manner and this was one of the main reasons that the appeal period was reverted back to 6 months.

A.3.6.6 Low approval rates by the LPA for projects under 50MW

The approval rate for under 50MW proposals is low (BWEA have stated that for the period January 2006 to October 2008 the approval rate at LPA level in the UK was 62% with the figure being 72% based on all windfarms submitted into the system since 1992. As stated above we question way this has been calculated because it is our experience, having advised on a large number of wind farm appeals and applications since the first wind farm in 1992, that the approval rates by the LPA are a lot lower than this percentage). The approval rates appear to be getting worse.

For England and Wales in particular we do not believe there is any demonstrable link between positive national advice and approvals at a local level.

In England in particular there is a lack consistency in dealing with the same issues between decisions. Uncertainty in decision making and the approval rates on appeal affects the risk which investors are willing to take on a project.

A.3.6.7 Legal challenge or judicial review of decisions

An increasing number of consents are being legally challenged (or judicially reviewed depending on the application regime).

Timescales are affected and delay to the progression of the proposal will occur regardless of whether the challenge is successful or not, for example following the Little Cheyne Court Section 36 Electricity Act wind farm consent an application for leave for judicial review was submitted. An application for judicial review is a 2 stage process, first one must apply for leave to review and timescales are totally dependent on the court timescales. It took 18 months for the application to reach the first stage before the application was dismissed.

We do not think the delays caused by legal challenge due to the fact that challenges and judicial reviews are heard in the court system will get better with time and this constraint will remain.

A.3.6.8 Aviation

Issues with aviation has been a key reason for delays in the decision making process on a large number of applications and also in the post consent process when discharging planning conditions that must be discharged prior to planning permission being implemented. The BWEA has been particularly active in trying to resolve these delays and has engaged heavily with the aviation industry and DECC. BWEA has reviewed aviation concerns to applications for wind farms and concludes that half of all wind farm applications in the UK will face objections from aviation stakeholders on the grounds of radar interference, obstruction or impact to low flying. Many LPAs are not determining applications due to aviation concerns. The Memorandum of Understanding signed last year by various parties: BWEA, MOD and DECC is having some positive effects in terms of bringing forward solutions to the issue.

It is not anticipated that the new reforms will have an impact on this constraint.

A.3.6.9 Cost of applying for planning permission

The cost of putting together an application for an onshore and offshore wind farm should not be underestimated. The preparation of the EIA and other pre-application procedures can be very expensive. Application fees for onshore proposals are expensive (£250,000 a maximum fee) and should an inquiry be called on appeal the cost can be substantial to all parties to the inquiry.

It is not anticipated that the new reforms will have an impact on this constraint.

ANNEX B – OFFSHORE TRANSMISSION REGIME

B.1 Overview of regime

The proposed Offshore Transmission Owner (OFTO) regime has the following key features:

- OFTO licences will be granted for no less than 20 years;
- an OFTO licence holder will have a regulated revenue stream for a default period of 20 years;
  - shorter periods may be set if competition for the OFTO licence is considered to be sub-optimal;
  - after 20 years, the revenue stream can be re-tendered or extended on a case by case basis; and
- OFTOs will have incentives relating to the performance and availability of their offshore transmission assets (maximum exposure of an OFTO's annual revenue to the performance incentive is 10 per cent, while the availability level of 98% will be the default setting).

OFTO licences are to be issued via a competitive tendering process run by Ofgem. The enduring tender process (to apply to offshore transmission assets which will be constructed after April 2010) has the following key features:

- pre-conditions, including the signing of a Connection and Use of System Code (CUSC) bilateral connection offer and Crown Estate lease arrangements by the windfarm developer/s, must be satisfied before a tender can be initiated;
- there will be no OFTO of last resort; and
- there will be annual tender windows.

The proposed transitional tender process (to apply to offshore transmission assets which are in service or being constructed by April 2010) differs from the enduring process as follows:

- either a project is constructed or needs have achieved full financial close (or equivalent) in order to be eligible for the transitional scheme by the Go Active date (24 June 2009), if it has not achieved full financial close it must have done so by the Go-Live date (June 2010);
- developers will have comfort on funding for transitional projects such that they will be paid by the successful OFTO the greater of 75% of the ex-ante estimate of the Regulated Asset Value (RAV) or 100% of the efficient ex-post RAV; and
- there will be an OFTO of last resort if the tender process is unsuccessful, with the developer being appointed as the OFTO and having to ensure business separation.

B.2 Next steps

On 17 June 2009, Ofgem/DECC jointly unveiled the finalised regime for the tender process, following which the OFTO regime will reach 'Go-Active' on June 24 2009 and 'Go-Live' on June 2010. The first transitional tender process is expected to commence in summer 2009, and will involve tenders for those projects that have met the transitional qualification pre-conditions by a date specified by Ofgem, and subsequently met the tender entry pre-conditions. The second transitional tender process is expected to commence in mid-2010, and will involve tenders for those projects that have met the transitional qualification pre-conditions after 'Go-Active', and subsequently met the tender entry pre-conditions.

Table 33 indicates the projects that Ofgem expects to qualify for the first and second transitional tender rounds, based on information provided by project developers, together with indicative offshore project milestones. However, these projects are still required to meet all qualification pre-conditions in order to ensure that they qualify as transitional projects. Following this, each will need to meet the required tender entry pre-conditions before they enter the tender round.

Table 33 – Transitional tender rounds

Project	Developer	Size (MW)	Exp. Completion
Projects likely to qualify for the First Transitional Tender round			
Barrow	Dong Energy / Centrica	90	Operating
Robin Rigg	E.ON	180	Jul 2009
Gunfleet Sands(I & II)	Dong Energy	172	2009
Thanet	Vattenfall	300	-
Greater Gabbard	SSE / RWE Innogy	504	Mar 2011
Ormonde	Vattenfall	150	Nov 2010
Walney 1	Dong energy	178	-
Sheringham shoal	Statoil Hydro / Statkraft	315	Jun 2010
Projects likely to qualify for the Final Transitional Tender round			
London Array	E.ON / Dong / Masdar	1000	-
Lincs	Centrica	250	-
Gwynt y Mor	RWE Innogy	750	-
Docking Shoal	Centrica	500	-
Race Bank	Centrica	500	-
Walney 2	Dong Energy	183	-

Source: Ofgem, DECC and Pöyry Energy Consulting

ANNEX C – TRANSMISSION ACCESS RELATED CUSC MODIFICATIONS – SUMMARY OF PROPOSALS

C.1 CAP148: Deemed Access Rights to the GB Transmission System for Renewable Generators

Seeks to guarantee connection to the system for new renewable generation 3 years after the later of (a) the date on which the user signs a relevant bilateral agreement with NGET or (b) the date on which the project obtains its project planning consent. The firm connection date is subject to completion of local works and commissioning of the generator, but it is not contingent on completion of wider works to reinforce the transmission system.

C.1.1 Views expressed

CUSC Panel considers that none of the tabled options should be approved.

Ofgem is minded to reject CAP148.

C.2 CAP161: Transmission Access – System operator release of short term entry rights

Seeks to introduce a requirement on the System Operator (SO) to hold auctions for short-term transmission access rights.

Key features of the original proposal (which are varied to differing extents in the alternate(s)) are as follows:

- SO required to host auctions for short-term transmission access rights close to real-time:
  - 1 week capacity, allocated 5 weeks ahead.
  - 1 day capacity, allocated 2 days ahead.
  - Commercial Limited Duration Transmission Entry Capacity (CLDTEC) – from 7 weeks ahead to end of financial year.
- Auction assessment methodology to be specified by SO in a ‘SO Release Methodology Statement’ which would come under CUSC governance.
- Release would be based on economic criteria (i.e. if bid value > cost of providing the capacity, then SO accepts bid) except for CLDTEC which is allocated on a first-come first-served basis.
- Payment for successful bids is pay-as-bid.
- If access associated with short-term is withdrawn, compensation is provided to the holder at a buy-back price, subject to a maximum price that is consistent with BM data validation rules for bids, specified by the user in the auction process (backed up by the submission of BM bids at the price specified in the auction).

C.2.1 Views expressed

CUSC Panel supports WGAA1.

C.3 CAP162: Transmission Access – Entry overrun

Seeks to introduce commercial arrangements to allow a generator to export in excess of the entry rights conferred by its access holdings. There are several options for pricing overrun including simple multipliers (for instance of TNUoS or BSUoS) or ex-post pricing based on average observed costs.

Key features of the original proposal (which are varied to differing extents in the alternate(s)) are as follows:

- Enables parties to generate more than their TEC and pay and entry overrun charge.
- Export would be capped by local rather than wider transmission system capability limits.

C.3.1 Views expressed

CUSC Panel supports WGAA1.

C.4 CAP163: Transmission Access – Entry capacity sharing

Seeks to enable generators to share access rights between them.

Key features of the original proposal (which are varied to differing extents in the alternate(s)) are as follows:

- Enables generators to connect without wider transmission access rights if they can share rights with existing users.
- Intention to share access rights.
  - sharing arrangements would be set out in an agreement between National Grid and the relevant parties which sets out the hierarchy of entitlement to use access rights (e.g. Party A is the original holder (donor) and it has a sharing relationship with Party B (recipient), under which Party B can use the rights in the event that Party A is not using the rights). This avoids the need for notification to National Grid, enhancing flexibility close to real-time.
- Requires overrun arrangements (CAP162) to be in place to avoid one party being in breach of the CUSC.

C.4.1 Views expressed

CUSC Panel supports WGAA1.

C.5 CAP164: Transmission Access – Connect and manage

Seeks to provide generators that wish to connect to the transmission system with a fixed date for connection, after which they would be granted access or compensated if access is unavailable. Charging would be based on long-term incremental investment costs.

Key features of the original proposal are as follows:

- Provides any generator wishing to connect to the transmission system with a fixed date for receiving Transmission Entry Capacity (the ‘TEC effective date’). The TEC effective date is the later of the completion of local works or a period 4 years from the point that the connection request is made.

- The obligation is symmetrical, with generators being required to pay TNUoS charges from the TEC effective date for a minimum period.

Key features of the alternative proposal are as follows:

- A short term access product, Interim TEC (ITEC), will be available allowing generators to connect to the GB transmission system in advance of all necessary transmission reinforcement works being complete. This product will provide generators, the right to generate up to their TEC allowance providing they accept to be constrained from the system for a given period of 'X' hours without compensation.

C.5.1 Views expressed

CUSC Panel supports WGAA1.

C.6 CAP 165: Transmission Access – Finite long-term entry rights

Seeks to introduce finite, long-term entry access rights. These would be underpinned by a commitment from the generator to pay access charges and to provide financial security (which may be approximately 50% of the costs of access provision).

Key features of the original proposal (which are varied to differing extents in the alternate(s)) are as follows:

- Defines temporally finite, long-term entry rights (in yearly multiples) to access the transmission system.
- Long-term rights combined with long-term user commitment to pay the associated charges.
- Rights can be extended upon application.
- New generators (and existing generators requesting increased access rights) will be required to book a defined period of years of rights and provide the associated user commitment.
- The obligation is symmetrical, with generators being required to pay TNUoS charges from the TEC effective date for a minimum period.

C.6.1 Views expressed

CUSC Panel supports WGAA4.

C.7 CAP 166 Transmission Access – Long-term Entry Capacity Auctions

CAP166 proposes that all long-term entry access rights to the GB transmission system would be allocated by auction.

Key features of the original proposal are as follows:

- Long-term entry access would be released annually in blocks of whole financial years.
- Long-term entry access rights would be defined on a zonal basis, such that each User can share capacity between its power stations on a real time basis at a 1:1 exchange rate within these defined zones.
- Capacity would be allocated on a pay as bid basis up to a zonal baseline.

- The User commitment associated with long-term entry access rights would be a liability to pay the accepted bids.
- Outside of a specified period an incremental capacity release methodology would be developed to release capacity above the baseline to bids meeting a regulatory test.

Key features of the alternative proposals are as follows:

- CAP166 WGAA 1: rights are allocated to individual nodes (rather than within zones) via an auction which simultaneously clears across the whole network. The auction has the objective of maximising revenue subject to ensuring that limits on flows across pre-defined boundaries are not breached.
- CAP166 WGAA 2: introduces the concept of a reserve price that is reflective of both the Long Run marginal Costs of providing existing and incremental capacity and also the Short Run Marginal Costs of allowing an over-allocation of capacity across derogated system.
- CAP166 WGAA 3: features a Capacity-Duration Auction where access is allocated to all those that request it in a given year with the costs of providing such access being split into two charges; a long-run priced element which is designed to reflect the existing TNUoS charges for the costs of transmission infrastructure and a short-run priced element which reflects the forecast operational costs (in the form of transmission constraints) of providing access to a User in advance of any necessary transmission reinforcements being completed.

C.7.1 Views expressed

CUSC Panel considers that none of the tabled options should be approved.

C.8 CAP 168 Transmission Access - Under-use and reallocation of TEC

CAP168 seeks to introduce an under-use charge. That is, an access imbalance charge for under use of transmission access rights.

Key features of the original proposal (which are varied to differing extents in the alternate(s)) are as follows:

- The under use charge would apply to the difference between a generator's booked TEC (adjusted to reflect any relevant TEC trading) and its maximum access usage on at least three separate days throughout the year (not just the November to February 'triad' months).
- The under-use charge would only apply in generator TNUoS zones with a positive tariff.
- The under-use charge would be set based on a simple multiple of the relevant TNUoS generation tariff (a 1.5x multiple is proposed as a minimum, with the suggestion that this could be increased over time).
- The under-use charge will be additional to usual generator TNUoS charges.
- Revenue from under-use charges would be used to offset BSUoS or invested by the SO in operational enhancements.

C.8.1 Views expressed

CUSC Panel considers that none of the tabled options should be approved.

ANNEX D – ALTERNATIVE SCENARIOS

D.1 Complex Auction of transmission access scenario

Figure 35 – Total installed capacity for the UK under the auction scenario

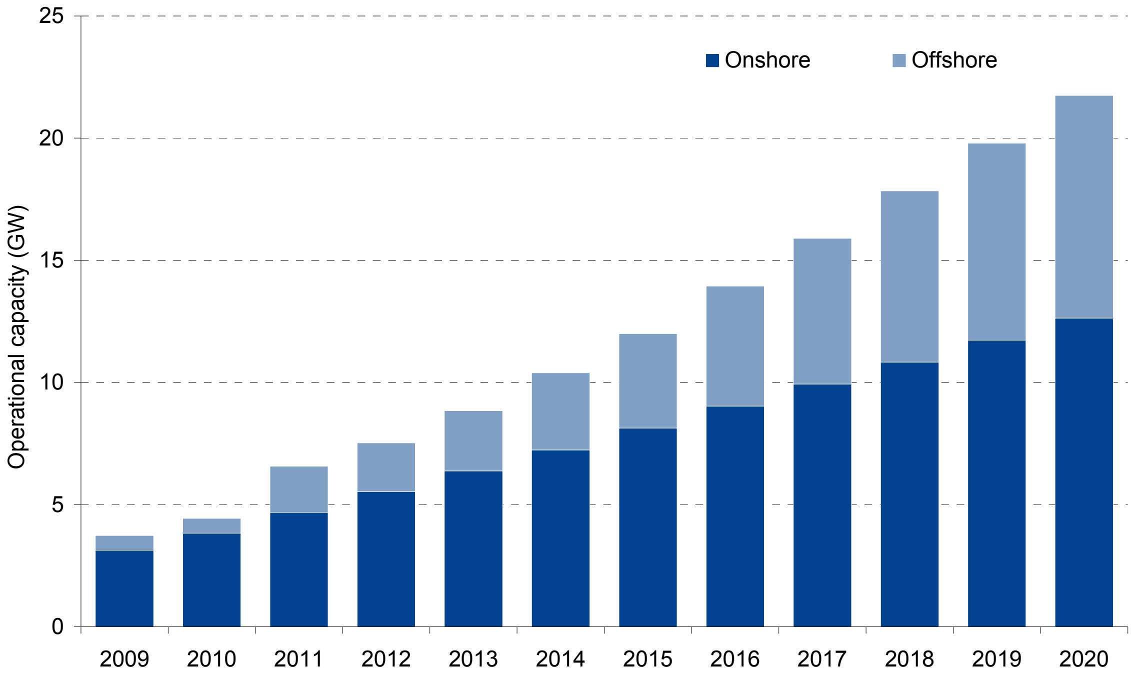


Figure 36 – Generation from onshore and offshore wind under the auction scenario

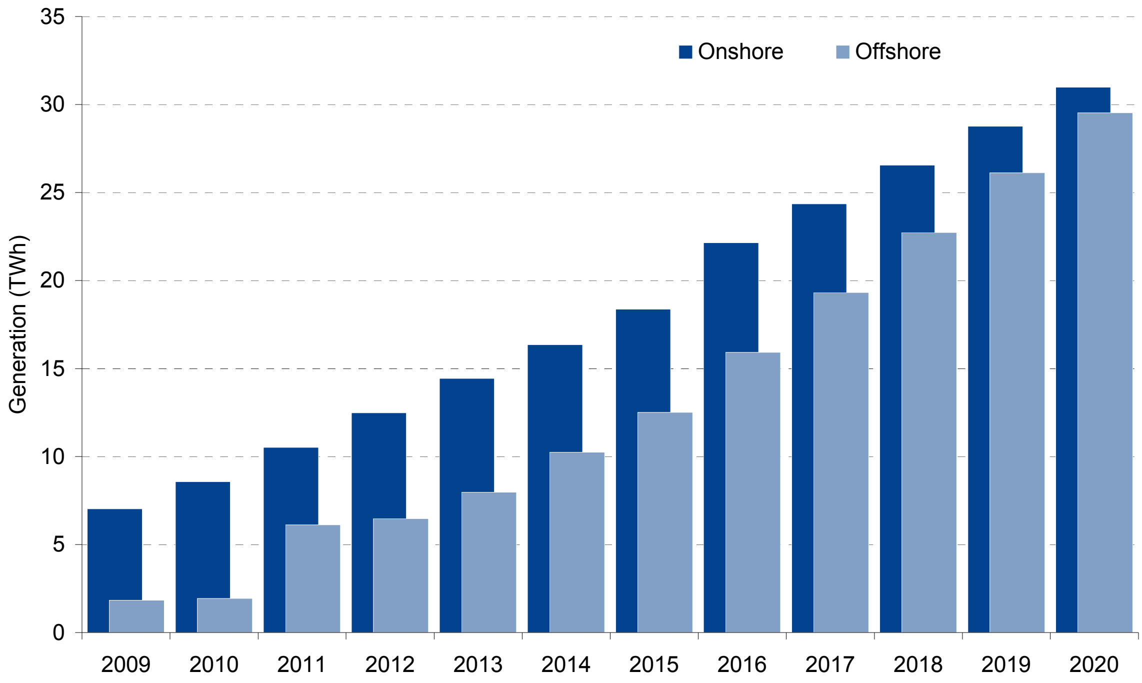


Figure 37 – Capacity per phase for onshore wind under the auction scenario

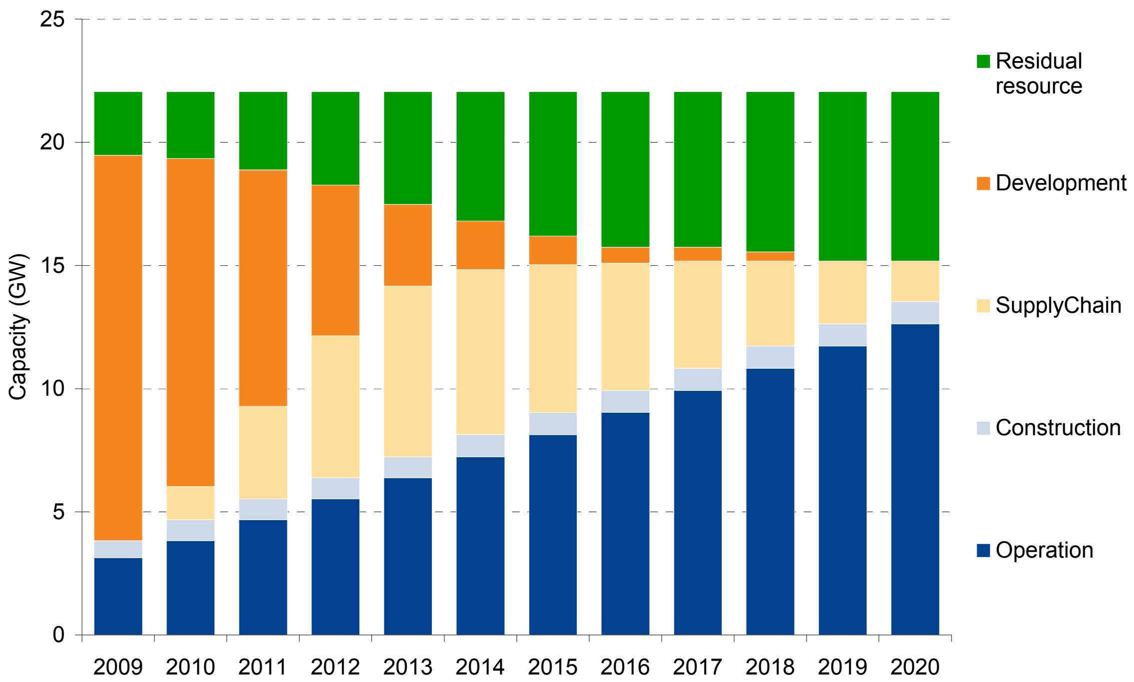
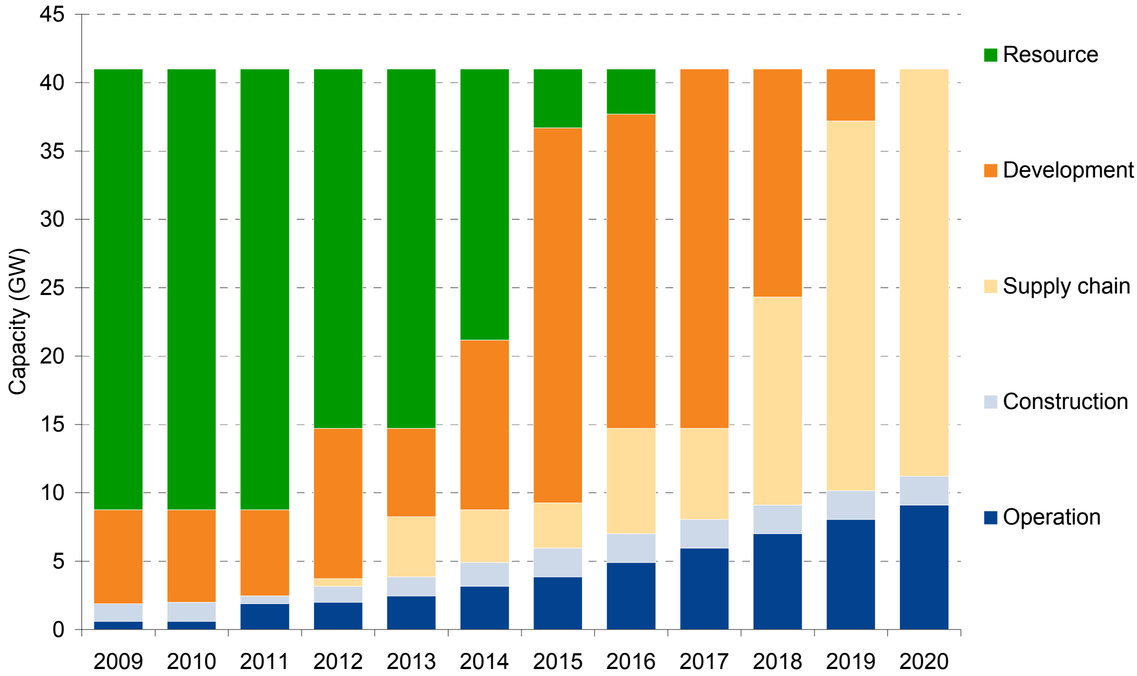


Figure 38 – Capacity per phase for offshore wind under the auction scenario



D.2 Difficult finance scenario

Figure 39 – Total installed capacity for the UK under the difficult finance scenario

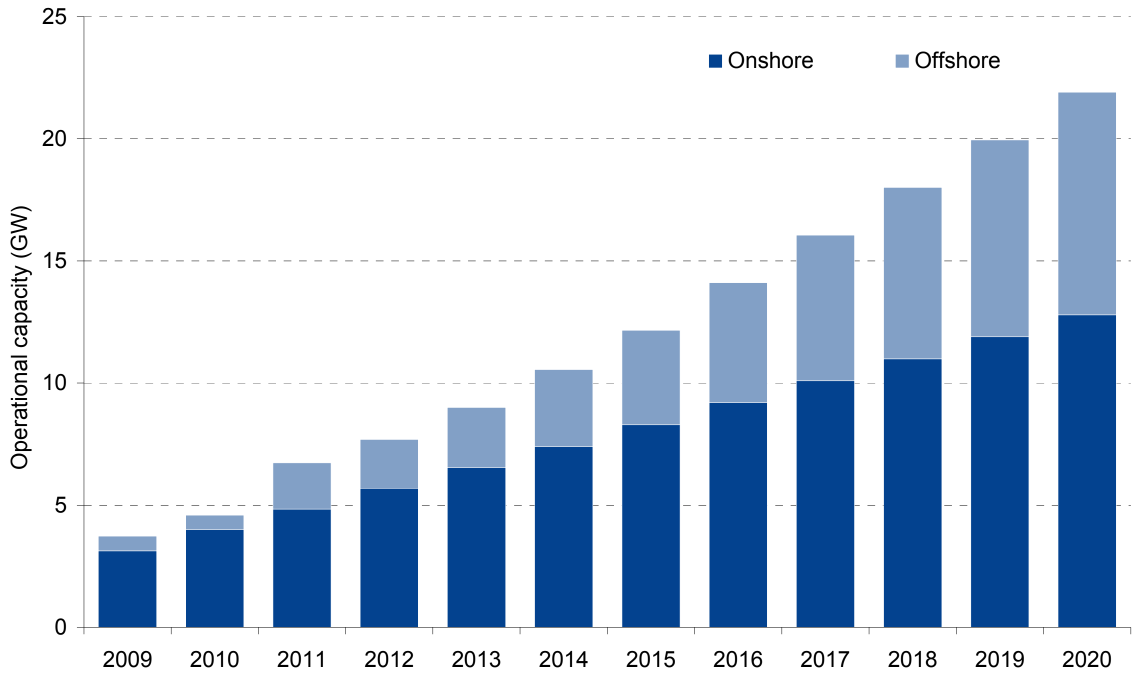


Figure 40 – Generation from onshore and offshore wind under the difficult finance scenario

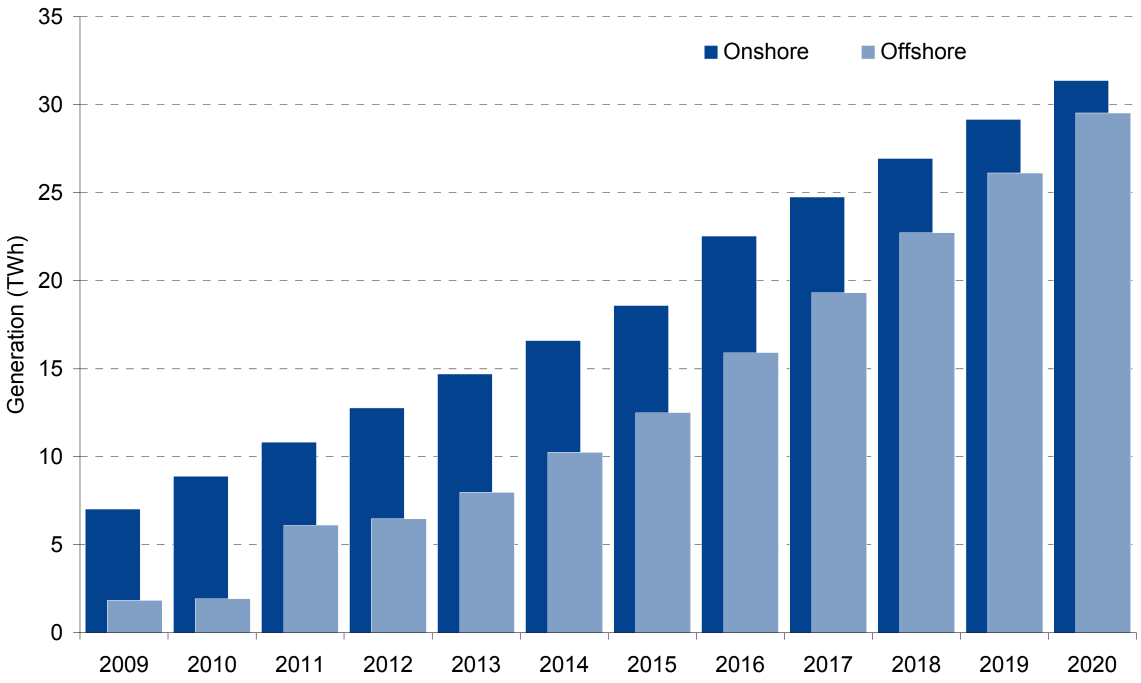


Figure 41 – Capacity per phase for onshore wind under the difficult finance scenario

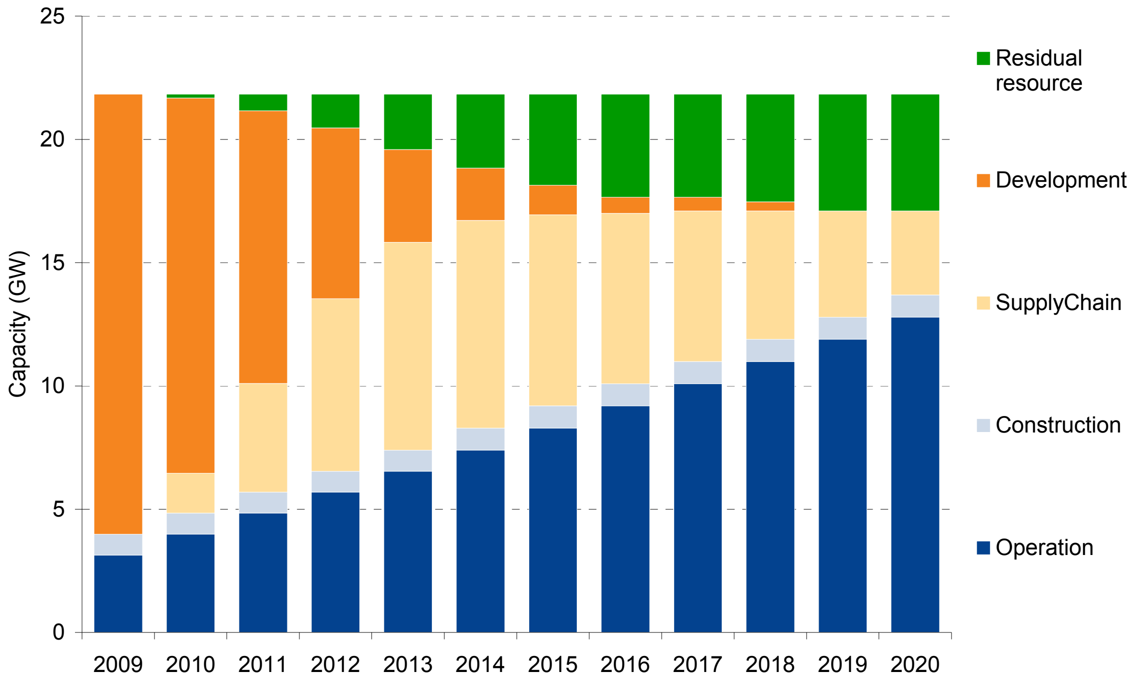
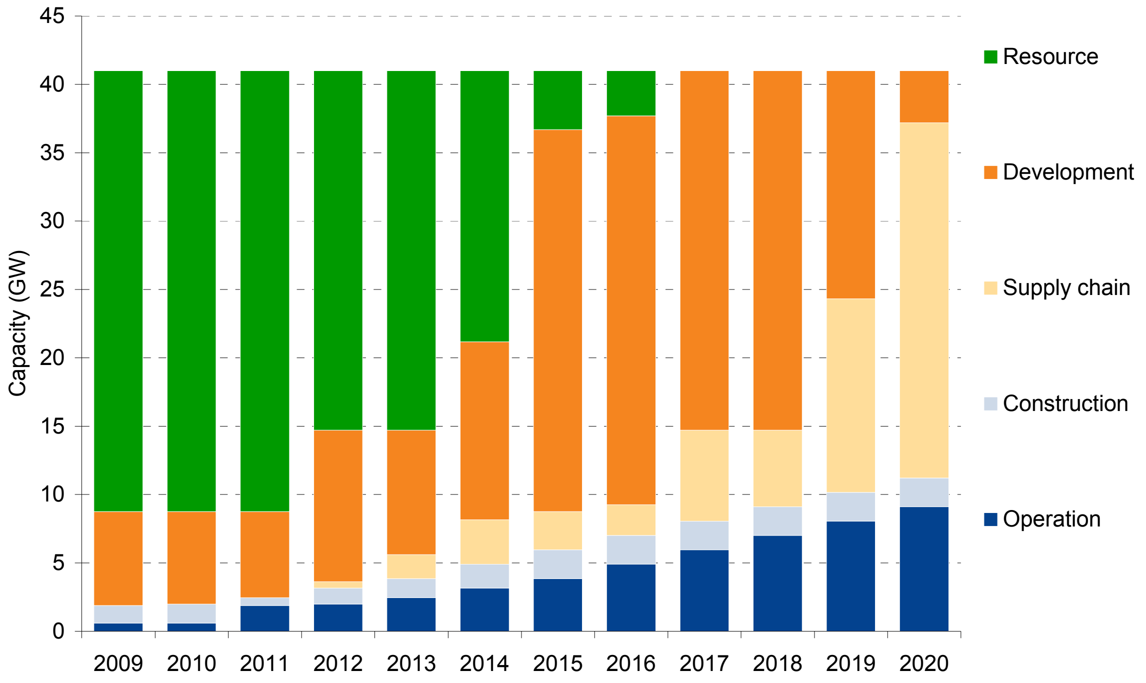


Figure 42 – Capacity per phase for offshore wind under the difficult finance scenario



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ANNEX E – 'TYPICAL' TRANSMISSION INVESTMENT PROJECT TIMELINES

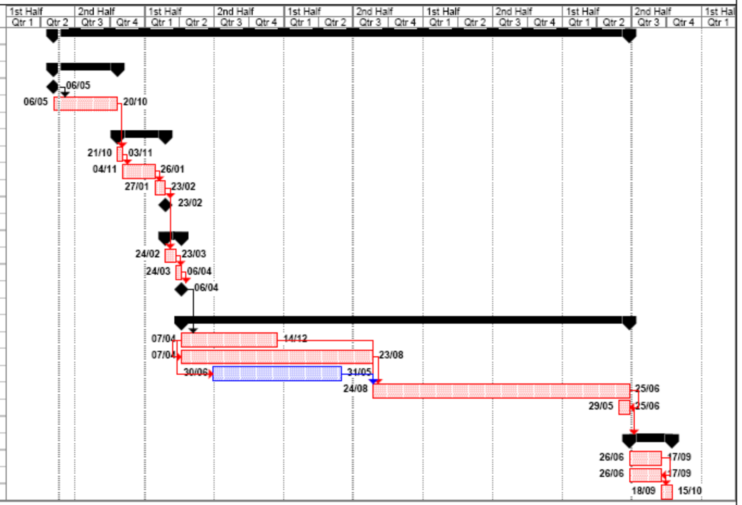
The generic project timelines for 'typical' onshore transmission investments are outlined below. These timelines are indicative. Actual timelines will vary depending upon the exact nature of the investment required.

- Figure 43 shows a project timeline for 'Overhead Line: Reconductoring' (780 days);
- Figure 44 shows a project timeline for 'Overhead Line: Up-rating/Refurbishment' (1080 days);
- Figure 45 shows a project timeline for 'Overhead Line: New Route' (1200 days); and
- Figure 46 shows a project timeline for 'Substation: Extension/New substation' (1080 days).

Figure 43 – Overhead Line: Reconductoring

Committee on Climate Change Proposal
Transmission Investment Cycle
Uprate
Overhead Lines Development
Issue 1

ID	Task Name	Duration	Start	Finish	Predecessors
1	**Project Cycle to Final Commissioning**	**1080 days**	**Wed 06/05/09**	**Tue 25/06/13**	
2					
3	**Investment Definition**	**120 days**	**Wed 06/05/09**	**Tue 20/10/09**	
4	Start Assessment	0 days	Wed 06/05/09	Wed 06/05/09	
5	Priority Assessment	6 mons	Wed 06/05/09	Tue 20/10/09	4
6					
7	**Development**	**90 days**	**Wed 21/10/09**	**Tue 23/02/10**	
8	Form Investment Team	2 wks	Wed 21/10/09	Tue 03/11/09	5
9	Option Definition & Development	3 mons	Wed 04/11/09	Tue 26/01/10	8
10	Investment Appraisal	1 mon	Wed 27/01/10	Tue 23/02/10	9
11	Stage 1 Investment Sanction	0 days	Tue 23/02/10	Tue 23/02/10	10
12					
13	**Project Design**	**30 days**	**Wed 24/02/10**	**Tue 06/04/10**	
14	Detailed Design & Equipment Spec	1 mon	Wed 24/02/10	Tue 23/03/10	10
15	Investment Appraisal	2 wks	Wed 24/03/10	Tue 06/04/10	14
16	Stage 2 Investment Sanction	0 days	Tue 06/04/10	Tue 06/04/10	15
17					
18	**Detailed Design & Delivery**	**840 days**	**Wed 07/04/10**	**Tue 25/06/13**	
19	Detailed Design	9 mons	Wed 07/04/10	Tue 14/12/10	16
20	Consents & Wayleaves	18 mons	Wed 07/04/10	Tue 23/08/11	19SS
21	Procurement	12 mons	Wed 30/06/10	Tue 31/05/11	19SS+3 mons
22	Site Construction	24 mons	Wed 24/08/11	Tue 25/06/13	19,21,20
23	Commissioning	1 mon	Wed 29/05/13	Tue 25/06/13	22FF
24					
25	**Scheme Closure**	**80 days**	**Wed 26/06/13**	**Tue 15/10/13**	**23**
26	Final Records	3 mons	Wed 26/06/13	Tue 17/09/13	
27	Financial Appraisal	3 mons	Wed 26/06/13	Tue 17/09/13	26FF
28	Closure Paper	1 mon	Wed 18/09/13	Tue 15/10/13	27



Project: Committee on Climate Chang
Date: Wed 20/05/09

Task | Critical Task | Progress | Milestone | Summary | Rolled Up Task | Rolled Up Critical Task | Rolled Up Milestone | Rolled Up Progress | Split | External Tasks | Project Summary | Group By Summary | Deadline

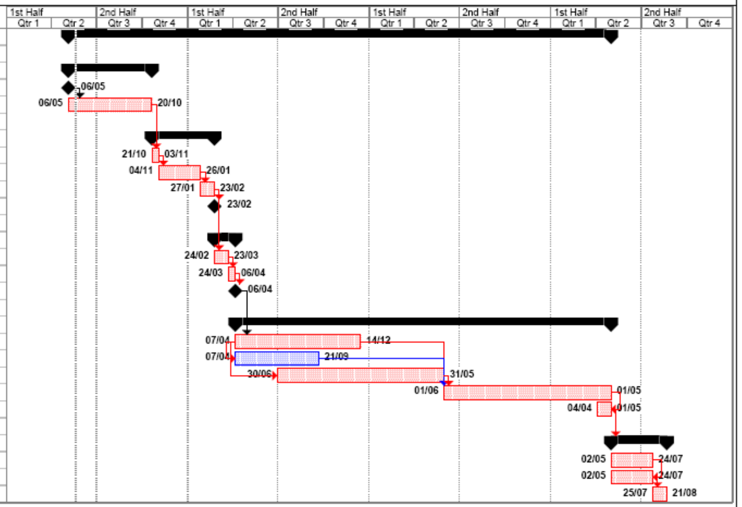
Page 1

Source: Energyline

Figure 44 – Overhead Line: Up-rating/Refurbishment

Committee on Climate Change Proposal
Transmission Investment Cycle
Reconductor
Overhead Lines Development
Issue 1

ID		Task Name	Duration	Start	Finish	Predecessors
1		**Project Cycle to Final Commissioning**	**780 days**	**Wed 06/05/09**	**Tue 01/05/12**	
2						
3		**Investment Definition**	**120 days**	**Wed 06/05/09**	**Tue 20/10/09**	
4		Start Assessment	0 days	Wed 06/05/09	Wed 06/05/09	
5		Priority Assessment	6 mons	Wed 06/05/09	Tue 20/10/09	4
6						
7		**Development**	**90 days**	**Wed 21/10/09**	**Tue 23/02/10**	
8		Form Investment Team	2 wks	Wed 21/10/09	Tue 03/11/09	5
9		Option Definition & Development	3 mons	Wed 04/11/09	Tue 26/01/10	8
10		Investment Appraisal	1 mon	Wed 27/01/10	Tue 23/02/10	9
11		Stage 1 Investment Sanction	0 days	Tue 23/02/10	Tue 23/02/10	10
12						
13		**Project Design**	**30 days**	**Wed 24/02/10**	**Tue 06/04/10**	
14		Detailed Design & Equipment Spec	1 mon	Wed 24/02/10	Tue 23/03/10	10
15		Investment Appraisal	2 wks	Wed 24/03/10	Tue 06/04/10	14
16		Stage 2 Investment Sanction	0 days	Tue 06/04/10	Tue 06/04/10	15
17						
18		**Detailed Design & Delivery**	**540 days**	**Wed 07/04/10**	**Tue 01/05/12**	
19		Detailed Design	9 mons	Wed 07/04/10	Tue 14/12/10	16
20		Consents & Wayleaves	6 mons	Wed 07/04/10	Tue 21/09/10	19SS
21		Procurement	12 mons	Wed 30/06/10	Tue 31/05/11	19SS+3 mons
22		Site Construction	12 mons	Wed 01/06/11	Tue 01/05/12	19,21,20
23		Commissioning	1 mon	Wed 04/04/12	Tue 01/05/12	22FF
24						
25		**Scheme Closure**	**80 days**	**Wed 02/05/12**	**Tue 21/08/12**	**23**
26		Final Records	3 mons	Wed 02/05/12	Tue 24/07/12	
27		Financial Appraisal	3 mons	Wed 02/05/12	Tue 24/07/12	26FF
28		Closure Paper	1 mon	Wed 25/07/12	Tue 21/08/12	27



Project: Committee on Climate Chang Date: Wed 20/05/09	Task	Milestone	Rolled Up Critical Task	Split	Group By Summary
	Critical Task	Summary	Rolled Up Milestone	External Tasks	Deadline
	Progress	Rolled Up Task	Rolled Up Progress	Project Summary	

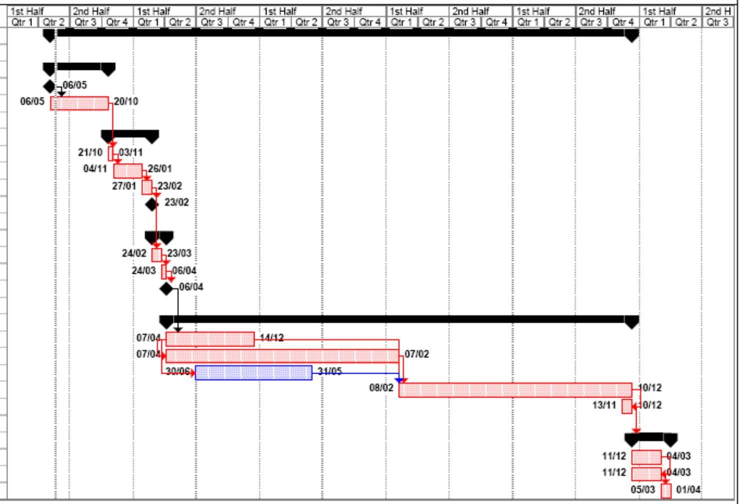
Page 1

Source: Energyline

Figure 45 – Overhead Line: New Route

Committee on Climate Change Proposal
Transmission Investment Cycle
New
Overhead Lines Development
Issue 1

ID		Task Name	Duration	Start	Finish	Predecessors
1		**Project Cycle to Final Commissioning**	**1200 days**	**Wed 06/05/09**	**Tue 10/12/13**	
2						
3		**Investment Definition**	**120 days**	**Wed 06/05/09**	**Tue 20/10/09**	
4		Start Assessment	0 days	Wed 06/05/09	Wed 06/05/09	
5		Priority Assessment	6 mons	Wed 06/05/09	Tue 20/10/09	4
6						
7		**Development**	**90 days**	**Wed 21/10/09**	**Tue 23/02/10**	
8		Form Investment Team	2 wks	Wed 21/10/09	Tue 03/11/09	5
9		Option Definition & Development	3 mons	Wed 04/11/09	Tue 26/01/10	8
10		Investment Appraisal	1 mon	Wed 27/01/10	Tue 23/02/10	9
11		Stage 1 Investment Sanction	0 days	Tue 23/02/10	Tue 23/02/10	10
12						
13		**Project Design**	**30 days**	**Wed 24/02/10**	**Tue 06/04/10**	
14		Detailed Design & Equipment Spec	1 mon	Wed 24/02/10	Tue 23/03/10	10
15		Investment Appraisal	2 wks	Wed 24/03/10	Tue 06/04/10	14
16		Stage 2 Investment Sanction	0 days	Tue 06/04/10	Tue 06/04/10	15
17						
18		**Detailed Design & Delivery**	**960 days**	**Wed 07/04/10**	**Tue 10/12/13**	
19		Detailed Design	9 mons	Wed 07/04/10	Tue 14/12/10	16
20		Consents & Wayleaves	24 mons	Wed 07/04/10	Tue 07/02/12	19SS
21		Procurement	12 mons	Wed 30/06/10	Tue 31/05/11	19SS+3 mons
22		Site Construction	24 mons	Wed 08/02/12	Tue 10/12/13	19,21,20
23		Commissioning	1 mon	Wed 13/11/13	Tue 10/12/13	22FF
24						
25		**Scheme Closure**	**80 days**	**Wed 11/12/13**	**Tue 01/04/14**	**23**
26		Final Records	3 mons	Wed 11/12/13	Tue 04/03/14	
27		Financial Appraisal	3 mons	Wed 11/12/13	Tue 04/03/14	26FF
28		Closure Paper	1 mon	Wed 05/03/14	Tue 01/04/14	27



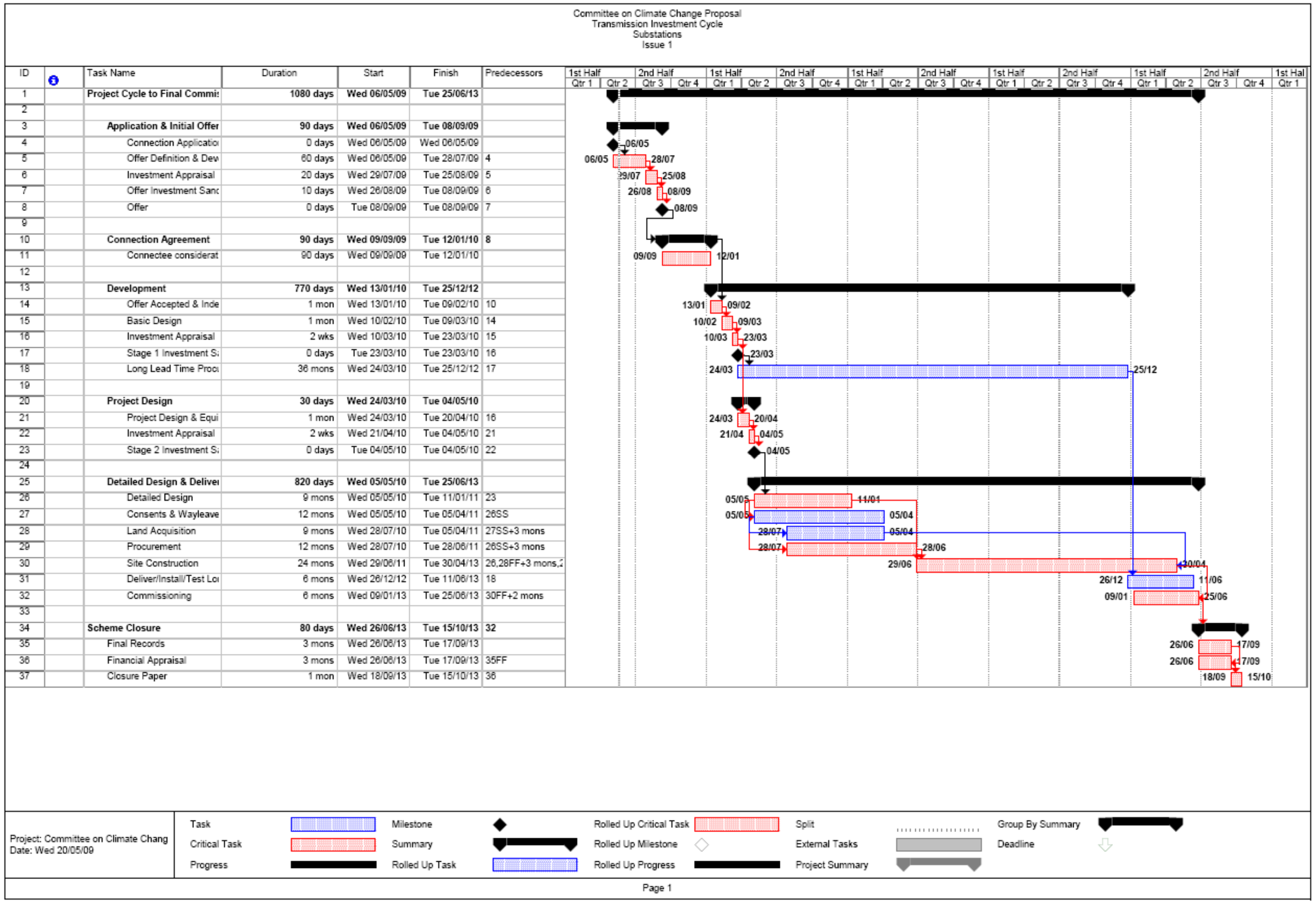
Project: Committee on Climate Chang
Date: Wed 20/05/09

Task | Milestone | Rolled Up Critical Task | Split | Group By Summary
Critical Task | Summary | Rolled Up Milestone | External Tasks | Deadline
Progress | Rolled Up Task | Rolled Up Progress | Project Summary

Page 1

Source: Energyline

Figure 46 – Substation: Extension/New substation



ID	Task Name	Duration	Start	Finish	Predecessors
1	**Project Cycle to Final Commi:**	**1080 days**	**Wed 06/05/09**	**Tue 25/06/13**	
2					
3	**Application & Initial Offer**	**90 days**	**Wed 06/05/09**	**Tue 08/09/09**	
4	Connection Applicatio	0 days	Wed 06/05/09	Wed 06/05/09	
5	Offer Definition & Dev	60 days	Wed 06/05/09	Tue 28/07/09	4
6	Investment Appraisal	20 days	Wed 29/07/09	Tue 25/08/09	5
7	Offer Investment Sanc	10 days	Wed 26/08/09	Tue 08/09/09	6
8	Offer	0 days	Tue 08/09/09	Tue 08/09/09	7
9					
10	**Connection Agreement**	**90 days**	**Wed 09/09/09**	**Tue 12/01/10**	**8**
11	Connectee considerat	90 days	Wed 09/09/09	Tue 12/01/10	
12					
13	**Development**	**770 days**	**Wed 13/01/10**	**Tue 25/12/12**	
14	Offer Accepted & Inde	1 mon	Wed 13/01/10	Tue 09/02/10	10
15	Basic Design	1 mon	Wed 10/02/10	Tue 09/03/10	14
16	Investment Appraisal	2 wks	Wed 10/03/10	Tue 23/03/10	15
17	Stage 1 Investment S:	0 days	Tue 23/03/10	Tue 23/03/10	16
18	Long Lead Time Proc	36 mons	Wed 24/03/10	Tue 25/12/12	17
19					
20	**Project Design**	**30 days**	**Wed 24/03/10**	**Tue 04/05/10**	
21	Project Design & Equi	1 mon	Wed 24/03/10	Tue 20/04/10	16
22	Investment Appraisal	2 wks	Wed 21/04/10	Tue 04/05/10	21
23	Stage 2 Investment S:	0 days	Tue 04/05/10	Tue 04/05/10	22
24					
25	**Detailed Design & Deliver**	**820 days**	**Wed 05/05/10**	**Tue 25/06/13**	
26	Detailed Design	9 mons	Wed 05/05/10	Tue 11/01/11	23
27	Consents & Wayleave	12 mons	Wed 05/05/10	Tue 05/04/11	26SS
28	Land Acquisition	9 mons	Wed 28/07/10	Tue 05/04/11	27SS+3 mons
29	Procurement	12 mons	Wed 28/07/10	Tue 28/06/11	26SS+3 mons
30	Site Construction	24 mons	Wed 29/06/11	Tue 30/04/13	26,28FF+3 mons,2
31	Deliver/Install/Test Lo	6 mons	Wed 26/12/12	Tue 11/06/13	18
32	Commissioning	6 mons	Wed 09/01/13	Tue 25/06/13	30FF+2 mons
33					
34	**Scheme Closure**	**80 days**	**Wed 26/06/13**	**Tue 15/10/13**	**32**
35	Final Records	3 mons	Wed 26/06/13	Tue 17/09/13	
36	Financial Appraisal	3 mons	Wed 26/06/13	Tue 17/09/13	35FF
37	Closure Paper	1 mon	Wed 18/09/13	Tue 15/10/13	36

Source: Energyline

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