Coordination in Offshore transmission – an assessment of regulatory, commercial and economic issues and options

A report by Redpoint Energy Limited

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Contents

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1 Executive summary

Introduction

Redpoint Energy was commissioned by the Office of Gas and Electricity Markets (Ofgem) to prepare a report on the regulatory framework, commercial arrangements and economic incentives for coordination in offshore transmission. Its purpose is to help Ofgem and the Department of Energy and Climate Change (DECC) identify potential barriers to achieving coordination in offshore transmission and to assess the potential costs and benefits of additional measures to address these barriers, but it does not necessarily represent Ofgem and DECC's views or conclusions on these issues.

This report presents our assessment of options for the regulatory and commercial regime for offshore transmission. In undertaking this work, we have looked to identify the various types of risks to which consumers and industry are, or could be, exposed to in the development and operation of offshore generation and transmission. In developing our intervention options, we then seek to consider the parties best placed to manage these risks and how risks and rewards should be allocated.

We have sought and benefited from the views of a number of industry participants both on a bilateral basis and through the various Offshore Transmission Coordination Group (OTCG) meetings and expert workshops convened by Ofgem and DECC.

Background

The Government has set an ambitious target for the deployment of renewable energy for 2020, by which time it has committed to meeting 15% of the UK's energy needs from renewable sources. The Government's strategy to meet this target requires about 30% of UK electricity to come from renewables by 2020. Offshore generation is likely to be an important part of meeting Government renewable electricity targets. However, considerable uncertainty remains over the precise quantity and timing of offshore development as this will be driven by commercial decisions that factor in future development cost, the level of subsidy available and any planning, technological or supply chain constraints. For example, the four scenarios used for this study project between 15 GW and 45 GW of offshore generating capacity by 2030, and the 2011 Offshore Development Information Statement (ODIS) includes a 'sustainable growth' scenario with 67 GW of capacity by 2030.

Where significant development of offshore generation resources is undertaken, coordinated and integrated offshore transmission grids offer economic benefits versus individual point to point connections, interconnections and associated onshore reinforcements.

In this context, Ofgem and DECC are jointly undertaking an Offshore Transmission Coordination Project to consider whether additional measures are required to deliver coordinated networks. The nature of offshore generation projects to date has meant that transmission has typically been radial, point-to-point connections, and under these circumstances the competitive aspects of the offshore regime have generated benefits by attracting new and low cost sources of capital, as well as innovative approaches to minimising operating and maintenance costs. The Offshore Transmission Coordination Project was created to consider whether the regime might need to adapt to accommodate more complex Round 3 projects. To date, 5 GW of transmission capacity (of the 8 GW expected from Rounds 1 and 2) has already entered the Offshore Transmission Owner (OFTO) tender process, so much of the capacity to be tendered under the enduring regime will be from Round 3.

Where significant development of offshore generation resources is undertaken, coordinated and integrated offshore transmission grids offer economic benefits versus individual point to point connections, interconnections and associated onshore reinforcements.

The benefits and risks of coordination

A coordinated approach to developing transmission networks requires that expansion takes into account the full range of developments on the network, trading off the benefits and risks from coordination to arrive at an optimal design. Four key types of coordination have been identified through the work for the Offshore Transmission Coordination Project:

- coordination within wind farms (or within zones that are being developed by a single developer),
- the use of offshore transmission links to address constraints across transmission boundaries in the onshore network,
- coordination across different offshore zones, *and*
- linking with international interconnectors.

There are a range of benefits that could be accessed through a coordinated approach to the development of offshore transmission infrastructure, including reduced overall investment costs. There are also potential challenges and risks associated with developing coordinated offshore networks. These are listed in the table below.

Table 1 Summary of potential benefits and risk of coordination in offshore transmission

Potential benefits	Potential risks
reduced total capital expenditure, reduced operating expenditure, reduced local environmental impacts, fewer planning and consenting issues, reduced connection timing risk for generators once a coordinated network is established, increased transmission system flexibility and security of supply, *and* greater consistency with wider European developments (eg flexibility to link with other networks including international networks and the trade which may result).	stranding risks associated with anticipatory investment, technological challenges, increased project complexity, *and* potential temporary reduction in transmission system flexibility and security of supply for early phases.

Using data from the asset delivery work stream, we undertook a cost–benefit analysis across four different generation scenarios designed to assess the impact of differing UK-wide delivery of renewable targets on the likely offshore transmission requirements. These cover a broad range of deployment scenarios for offshore generation (15 GW to 45 GW installed capacity by 2030). Results from the cost-benefit analysis shown in the table below demonstrate that the benefits from a coordinated build increase significantly with the total volume of generation capacity under central case assumptions. Under Scenario D, there are net present value benefits of almost £3.5 billion from a coordinated build if perfect foresight is assumed. However, under Scenario A there are only £500 million in net present value gains. This is due to the reduced scope for coordination where there is less offshore generation. These results represent a saving of between 8% and 15% of the cost of a radial network.[1]

Table 2 Cost-benefit analysis of build-out of Round 3 zones

	NPV to 2030 £m (real 2011)		Reduction in cost from coordination	
	T1 (radial)	T2 (coordinated)	NPV £m (real 2011)	As a proportion of radial NPV
Scenario A	£5,784	£5,290	£494	8.5%
Scenario B	£12,468	£11,396	£1,072	8.6%
Scenario C	£19,275	£16,908	£2,367	12.3%
Scenario D	£23,976	£20,483	£3,493	14.6%

This cost-benefit analysis should be considered in the context of the risks described above. For example, stranding risks have not been quantified in the cost-benefit analysis. Analysis from specific case studies of Round 3 zones shows that stranding risk can be significant for specific assets. In the West of Isle of Wight zone for example, a 50% increase in investment is required during the first stage of build to achieve a coordinated solution, creating significant stranding risk of more than £100 million on just over £200 million of assets. Including stranding risk in the analysis would reduce the benefits from coordination, though this can be mitigated in part if the approach adopted to anticipatory investment ensures that the risks are effectively managed.

We have undertaken a number of sensitivities on our central case assumptions. Overall, our sensitivities demonstrate that the main results are robust to changes in key parameters relating to discount rates and costs of capital.

Potential barriers to delivering coordination under the current arrangements

We have assessed the key potential barriers to developing a coordinated transmission network under the current regime and based on this we have produce a summary 'problem statement' shown below that has formed the basis for considering changes to the regulatory regime.

[1] The cost-benefit analysis is based on the underlying capital cost and timelines developed by the Asset Delivery work stream, but adds additional information on the full lifetime cost of these assets. This includes the cost of capital (used to annuitise capital costs), depreciation, and operating and maintenance costs. The asset delivery work stream found that there could be aggregate capital expenditure savings from coordination of between 8% (scenario A) and 16% (scenario D).

Table 3 Summary of barriers: the problem statement

Problem	Commentary
Anticipatory investment process uncertainty	Lack of clarity on process and adequacy of existing tools to give certainty on funding for anticipatory investment to keep open desirable coordinated outcomes.
Network optimisation	An optimised network would allow a given volume of generation and demand to be connected efficiently and economically including a coordinated approach where this is beneficial (taking into account current and future consumers). The National Electricity Transmission System Operator (NETSO) has a key role in ensuring coordinated network developments, but there are 3 key constraints or challenges to the development of an optimised network, including a) Onshore/offshore interactions including whether the NETSO's role could be improved b) Lack of vision for a coordinated network, including whether the process for short- and medium-term planning decisions could be better informed by improvements to the long-term vision and c) The ability to add sufficient incremental capacity to the offshore network over time, as further needs evolve.
Risk–reward profile of coordinated investments	Even if there is an adequate anticipatory investment structure, it is not clear whether the risk–reward profile (given TNUoS charging and user commitment rules) for coordinated investments will be acceptable for generators.
Interconnector-OFTO regulatory interface	Uncertain/possibly inadequate regulatory framework for interconnector-OFTO connections
Planning and consenting barriers to anticipatory investment	Planning/wider consenting process for anticipatory investment needed to facilitate coordination can be unclear (IPC guidance could prevent consenting beyond firm need) or can involve multiple applications
Technology risks and asset incompatibility	There could be a need for some standardisation to help ensure interoperability and extendibility, particularly if many players and manufacturers are involved. Some of the technology that is key to unlocking cost savings (and means coordination becomes beneficial) is not yet available and the supply chain is relatively small.

Possible measures to address barriers to coordination

We have developed a 'long list' of intervention measures across the regulatory, commercial and incentive arrangements that could address issues with coordination in offshore transmission identified above. The intervention measures have been developed through input from our own analysis, OTCG meetings and workshops and stakeholder responses to previous Ofgem and DECC consultation.

The intervention measures represent a mix of incremental changes that could be implemented while still maintaining the existing OFTO tender process, and more substantive changes to the regime that could potentially deliver greater coordination, but would require in some cases wholesale changes to the existing arrangements and could entail substantial risks as well as the erosion of benefits from ongoing competitive pressures.

Table 4 Linking of problems and potential solutions

Potential problem	Potential solutions					
Anticipatory investment process uncertainty	Clarify regulatory arrangements	Enhanced AI process – pre-approved	Enhanced AI process – contracted			
Network optimisation	Relax 20% cap	Extended ODIS	Expanded NETSO role	TO delivery of active network	Regional OFTO	Central authority blueprint
Risk-reward profile of coordinated investments	Clarify regulatory arrangements	Sharing of risk with consumers and/or OFTOs	Open season arrangements	Consumers underwrite		
Interconnector-OFTO regulatory interface	Regulatory compatibility					
Planning and consenting barriers to anticipatory investment	Facilitate anticipatory investment in planning process					
Technology risks and asset incompatibility	Standardisation of operating parameters	Standardisation of assets	Sharing of new technology risks			

Illustrative policy packages to promote coordination

We have developed illustrative policy packages through consideration and analysis of the various intervention measures described above and their capacity to address the identified problems in the current regime. The packages combine a number of different policy measures and represent different approaches to the offshore transmission regulatory and commercial regime and the treatment of risk and reward.

They are presented for illustrative purposes and to facilitate qualitative analysis, but are just four of many different combinations of the solutions presented and do not necessarily represent our view of the 'optimal' or best response. The precise elements that are taken forward could be taken from across these packages or include measures not included in any of the illustrative packages. This will be for Ofgem and DECC to determine, as per their respective responsibilities and through consultation with stakeholders as appropriate.

Table 5 Summary of straw man packages

Policy lever	Package 1 – Inform and enable	Package 2 – Market led evolution	Package 3 – Regional monopoly	Package 4 – Blueprint and build
Theme	Incremental reforms to the current regime	As for Package 1, but with sharing of technology and stranding risks between consumers and generators	Facilitated regional monopolies (appointed through a competitive process) designed for coordinated build out with risk sharing between investors and consumers	Central direction and blueprinting for coordinated build out with consumers bearing the risk (and subsequent reward)
Role of centralised body in coordination planning	Provision of information to facilitate coordination	Light touch – vision for build, design only for 'no regrets' investments	Light touch design with a regional focus	Complete blueprint by a central body with oversight
Who decides whether coordination is beneficial	Generators and/or NETSO through connection offer	Generators and/or NETSO through connection offer	Regional OFTO, informed by generators	Central body
Anticipatory investment process	Guidance to clarify what forms of anticipatory investment will be given regulatory approval	Clarification as well as pre-approval of specific low cost anticipatory investments; risks shared between consumers and generators through changes to user commitment	Regulatory approval of regional OFTO plans as per the onshore regime; risks shared between consumers and generators through changes to user commitment and regular price controls	Anticipatory investment allowed as set out in blueprint; risk largely borne by consumers through user commitment and charging
Degree of competition (initial and subsequent)	Tender-based competition for build	Tender-based competition for build	Competition for regional monopolies	Tender-based competition for build out of each component
Technology innovation and investment	Generator/OFTO responsibility	Sharing of new technology risks through support mechanism	Sharing of new technology risks through support mechanism	Sharing of new technology risks through support mechanism
Consistency with broader developments	Retain flexibility to adapt to broader changes, such as shift to CfD support under EMR and potential changes to TNUoS and user commitment under TransmiT[2]	As for package 1	Regional OFTO mirrors onshore, price regulated regime, making RIIO framework applicable in the medium term, though competition is being introduced for some onshore assets.	Blueprint to incorporate international developments such as North Sea Grid and linking of offshore transmission with interconnectors

[2] CfD: Contracts for Difference. EMR: Electricity Market Reform. TNUoS: Transmission Network Use of System charges.

We have undertaken a qualitative assessment of the illustrative policy packages against criteria agreed with Ofgem and DECC and which have been tested with stakeholders through the OTCG process. While qualitative, the method has enabled an assessment of different packages and identification of key risks, strengths and weaknesses in each package. In summary, our qualitative assessment shows:

- Packages 1 and 2 perform well by delivering potential benefits associated with a more coordinated build of offshore transmission infrastructure through potentially bringing forward 'low regrets' anticipatory investment without involving significant risk compared with current arrangements.
- Package 1 involves incremental changes to the current regime and offers potential benefits with few risks.
- Package 2 also involves largely incremental changes to the current regime but could deliver greater benefits from coordination, although this needs to be set against greater risks. The main risks associated with this market led package relate to greater stranding risk (in particular, where some of this falls on consumers) and additional complexity from an expanded central agency role and provision for open seasons.
- Packages 3 and 4 offer greater certainty in realising the potential benefits from increased coordination, but these are likely to be outweighed by greater risks for consumers (in particular, increased stranding risk) and potential disruptions to the existing regime.
- Package 3 would involve significant changes from the existing regime to institute regional monopolies and considerable complexity in the tender system to appoint regional OFTOs. This could disrupt existing developments and even compromise timely build of offshore generation in the near term, as well as compromise benefits from competition.
- Package 4 is assessed as offering the greatest certainty for supply chains, generators (with follow-on benefits to timely build of offshore generation) and economic benefits from coordination, but these benefits come at the risk of substantial costs for developers and consumers given that, in the absence of perfect foresight, there could be significant asset stranding if building to a relatively inflexible blueprint. There will also be considerable complexity for the central body in developing the blueprint, with attendant losses of flexibility to respond to changes in build if projections on which the blueprint is based turn out to be incorrect.

Looking across the assessment of the illustrative policy packages, where modest assumptions are made on the development of offshore generation and/or the outlook is highly uncertain the incremental changes in packages 1 and 2 offer benefits versus the current arrangements with relatively low implementation and stranding risk. Where significantly more ambitious development of offshore generation is expected with some certainty, then packages 3 and 4 can offer significant benefits but at significantly increased regulatory, implementation and stranding risk and with major changes required to the current arrangements with the commensurate disruption and potential risk to current investment plans that this would entail.

Key conclusions

In summary, our key conclusions include:

- The current arrangements are likely to deliver some coordination, but the extent will be limited by the barriers identified above, namely:
  - Some coordination within wind farms is likely, but will be constrained by barriers associated with uncertainty about the anticipatory investment process, user commitment, potential planning barriers, technology risks and asset incompatibility,
  - The use of offshore coordination to increase onshore boundary capacity will be constrained by generators' unwillingness to sign connection offers where they might be exposed to additional costs such as from additional infrastructure built offshore,
  - Coordination across different offshore zones is possible, but would be constrained by the same barriers as for coordination within wind farms and requires cooperation of multiple parties, *and*
  - Linking with international interconnectors is not facilitated by the current regulatory arrangements.
- At a minimum, regulatory arrangements for anticipatory investment offshore should be clarified through issuing guidance regarding the treatment of anticipatory investment when calculating transfer values under generator build, and perhaps a more explicit *ex ante* approval and funding process for more significant anticipatory investment.
- Changes to user commitment (such as those set out as part of Connection and Use of System Code Modification Proposal (CMP) 192) and adaptation of the existing offshore charging methodology to accommodate coordinated developments could help to address problems with generator reluctance to accept coordinated connection offers.
- Regulatory arrangements should be developed to allow regulatory compatibility between offshore transmission and international interconnectors.
- Anticipatory investment should be facilitated in the planning process, in particular by removing barriers in the interpretation of Infrastructure Planning Commission (IPC) guidance on associated development.
- Standardisation of voltage and control systems at a UK - or EU - level should be advanced through a transparent and consensus-based process involving key industry participants. This process should take into account broader developments at a European level, including through the North Seas Countries' Grid Initiative.
- Significant uncertainty about future build of offshore generation poses a fundamental challenge for a more centralised approach to planning and building a coordinated offshore network.

2 Introduction and objectives

2.1 Introduction

In April 2011, Redpoint Energy was commissioned by Ofgem to prepare a report on the regulatory framework, commercial arrangements and economic incentives for coordination in offshore transmission development. Its purpose is to help Ofgem and DECC identify potential barriers to achieving coordination in offshore transmission, and to assess the potential costs and benefits of additional measures to address these barriers.

This report presents our assessment of options for the regulatory and commercial regime for offshore transmission. We describe below the background to this report, the objectives and approach taken, and the structure of the report.

2.2 Background

The Government has set an ambitious target of meeting 15% of the UK's energy needs from renewable sources by 2020. The Government's strategy to meet this target requires about 30% of UK electricity to come from renewables by 2020. In order to achieve such a substantial deployment of green energy in this timeframe, the Government has established a policy framework to support investment in renewable generation.

Offshore generation is likely to be an important part of meeting the Government's renewable electricity targets. For example, the UK Renewable Energy Roadmap[3] has set out a central range for deployment of between 11 GW and 18 GW by 2020, while the Committee on Climate Change (CCC) has projected[4] that there will need to be close to 13 GW of installed offshore generating capacity by 2020. Over a longer timeframe, some 55 GW of wind and marine generation capacity could be developed based on the current Crown Estate leasing programme, and announcements by DECC and the Scottish Government[5]. However, considerable uncertainty remains over the precise quantity and timing of offshore development. This will be driven by commercial decisions that factor in future development cost, the level of subsidy available and any planning, technological or supply chain constraints.

[3] DECC, *UK Renewable Energy Roadmap* (July 2011).

[4] Committee on Climate Change, *The Renewable Energy Review* (May 2011).

[5] National Grid, *Offshore Development Information Statement* (September 2011).

With significant development of offshore generation resources, overall synergies mean that coordinated and integrated offshore grids potentially have economic benefit versus individual point to point connections, interconnections and associated onshore reinforcements. Coordination (or integration[6]) involves taking an overarching view of the most efficient and economic design for the transmission network to serve different offshore generators, and four different types of coordination have been identified:[7]

- coordination within wind farms (or within zones that are being developed by a single developer),
- the use of offshore transmission links to address constraints across transmission boundaries in the onshore network,
- coordination across different offshore zones, *and*
- linking with international interconnectors.

The potential benefits of a coordinated grid include:

- reduced total capital expenditure,
- reduced operating expenditure,
- reduced local environmental impacts,
- fewer planning and consenting issues,
- reduced connection timing risk for generators once a coordinated network is established,
- increased transmission system flexibility and security of supply, *and*
- greater consistency with wider European developments.

These benefits need to be set against potential risks from coordination, including:

- stranding risks associated with anticipatory investment,
- technological challenges,
- increased project complexity, *and*
- potential temporary reduction in transmission system flexibility and security of supply for early phases.

The established offshore regime uses a competitive tender process as a method of economic regulation that promotes competition in network ownership. This regime is based on an extension of the role of National Grid as National Electricity Transmission System Operator (NETSO) offshore (including the requirement to produce an annual ODIS, as well as an extension of the requirement to develop the network in an efficient, coordinated and economical manner) and an extension of the arrangements whereby suppliers and generators make a request to NETSO for connection. Thus, as for onshore

[6] The terms coordination and integration are often used interchangeably by different parties. We use the term coordination in this report to refer to development of offshore transmission in a cost effective manner that takes into account the full range of developments on the network and the risks and uncertainties involved.

[7] TNEI and PPA, *Asset Delivery Work Stream Report*, Report for Ofgem (2011).

transmission, economic regulation of transmission assets is applied based on the potential for transmission networks to exhibit natural monopoly characteristics.

The key divergence from the onshore regime is the addition of a tender process to choose an OFTO for defined sets of transmission assets, with an associated revenue stream that is fixed for a significantly longer period (20 years) than onshore (5-8 years). Annual payments to OFTOs are set through the tender process, rather than through regular price control reviews as used onshore. The competitive aspects of the offshore regime have generated benefits by attracting new and low cost sources of capital for a given risk profile for the asset, as well as by encouraging innovative approaches to minimising operating and maintenance costs. Ofgem has estimated that the OFTO tender regime has already delivered £350 million in savings from competition[8]. The existing regime is described and reviewed in more detail in Appendix A.

In this context, Ofgem and DECC are jointly undertaking an Offshore Transmission Coordination Project to consider whether additional measures are required to deliver coordinated networks. The nature of offshore generation projects to date has meant that transmission has typically consisted of radial, point-to-point connections. The Offshore Transmission Coordination Project was created to consider whether the regime might need to adapt to accommodate more complex Round 3 projects.

To assist in this project, Ofgem and DECC have set up the Offshore Transmission Coordination Group (OTCG)[9] to provide advice and analysis in respect of developing a coordinated offshore and onshore electricity transmission network. The core areas identified as objectives for the group include:

- assessing constraints or drivers to the development of offshore transmission infrastructure,
- assessing grid configuration options, and
- assessing potential further regulatory options to achieve a coordinated grid configuration in an efficient manner.

Any changes to the existing regime will need to weigh the importance of avoiding significant disruption to the ongoing delivery of offshore generation.

Ofgem and DECC are seeking a range of evidence and analysis to inform the work of the Project, and a conclusions report will be developed for publication in winter 2011. In parallel, the Crown Estate and National Grid Electricity Transmission (NGET) have completed a joint feasibility study to look into the technical and practical feasibility and constraints of offshore transmission. There is close interaction with a range of industry stakeholders, and the OTCG has provided a forum to consider the full range of technical, regulatory and commercial issues.

To support their work, Ofgem and DECC appointed both technical and economic advisors who have focussed on two work streams, respectively:

- **Assessment of asset optimisation** broadly corresponding to consideration of grid configuration options to deliver coordinated and integrated offshore transmission, *and*
- **Assessment of regulatory, commercial and economic incentive issues and options**.

The latter is the subject of this report.

[8] Ofgem, *Three Bidders Selected to Run the First £700 Million of Transmission Links for Seven Offshore Wind Farms 2010*, Press Release (August 2010).

[9] The OTCG was formed in February 2011, following an open letter from Ofgem and DECC relating to the 'Coordinated offshore transmission development Stakeholder Community'.

The assessment of asset optimisation work has been undertaken by TNEI and PPA Energy. This work is a key input to the current study and is referred to as the 'asset delivery study'[10] throughout this report. Both work streams have worked closely together in their respective areas to ensure consistency between asset delivery scenarios and regulatory, commercial and economic intervention measures.

2.3 Objectives and approach

The overall objectives for assessing the regulatory, commercial and economic incentives in this study reflect Government and Ofgem objectives which require that the offshore transmission regulatory regime:

- **supports the timely build of offshore generation and wider sustainability,**
- **promotes reliability and security of supply,**
- **delivers economic benefits beyond those that could be expected to be the case under the current regulatory arrangements,**
- **ensures a fair and proportionate distribution of benefits, costs and risks, *and***
- **is deliverable and has a reasonable probability of being flexible in response to future (eg European) developments.**

Our approach is based on identifying the benefits, costs and risks of, and potential barriers to, coordination under the current regime, and developing additional measures that might be taken. From these we have developed a small number of illustrative 'policy packages' which represent combinations of measures and approaches to meet the objectives above.

In undertaking this work, we have looked to identify the various types of risks to which consumers and industry are, and could be, subject to with respect to the development and operation of offshore generation and transmission. In developing our intervention options, we then seek to consider the parties best placed to manage these risks, and how risk/reward should be allocated.

We have sought and benefited from the views of a number of industry participants, both on a bilateral basis and through the various OTCG meetings and expert workshops convened by Ofgem and DECC. However, we have not undertaken a full consultation of all relevant stakeholders. Our report therefore represents a description of our work and conclusions based on the available evidence and consideration and analysis of the key issues.

[10] Asset Delivery Work Stream – Final Report, November 2011, TNEI and PPA Energy.

2.4 Structure of report

The remainder of this report is structured as follows:

- in Section 3, we set out the potential benefits and risks from coordinated and integrated offshore transmission infrastructure,
- in Section 4, we present a cost-benefit assessment of a coordinated network build approach building on the asset delivery study,
- in Section 5, we assess the potential barriers and challenges to coordination under the current arrangements, culminating in a series of 'problem statements' associated with the current regime,
- in Section 6, we describe the intervention options which could promote greater coordination in the development of offshore transmission and address the potential barriers identified, *and*
- in Section 7, we propose illustrative combinations of intervention options that could function well as a package and facilitate coordination, thus addressing a number of problem statements ('policy packages'), and assess these qualitatively.

In addition, we include a number of supporting appendices which provide further detail, as follows:

- Appendix A sets out a review of current arrangement for the regulation of offshore transmission,
- Appendix B presents an analysis of risk allocation under the arrangements,
- Appendix C sets out the cost-benefit analysis approach and results of sensitivity analysis,
- Appendix D contains results from case studies of the Irish Sea, West of Isle of Wight and Hornsea zones,
- Appendix E summarises key features of the policy packages developed for this study, *and*
- Appendix F outlines the methodology and detailed results from qualitative analysis of the policy packages.

3 The benefits and risks of coordinated offshore transmission

3.1 Introduction

A coordinated approach to developing transmission networks requires that expansion takes into account the full range of developments on the network, trading off the benefits and risks from coordination to arrive at an optimal design. This coordination should occur across different regions where this yields benefits, in particular across offshore and onshore networks. Coordination should also occur over time, harmonising across current and future users of the transmission network.

A coordinated network can be contrasted with a radial or point-to-point design which connects each generation development offshore separately, without taking other developments into account. The asset delivery study has identified four different types of coordination (which are not necessarily mutually exclusive):

- coordination within wind farms (or within zones that are being developed by a single developer),
- the use of offshore transmission links to address constraints across transmission boundaries in the onshore network,
- coordination across different zones (for example, the asset delivery work stream study shows potential benefits from linking transmission across the Dogger Bank and Hornsea zones), *and*
- linking with international interconnectors.

There are a range of benefits that could be accessed through a coordinated approach to the development of offshore transmission infrastructure, including reduced overall investment costs. There are also potential challenges and risks associated with developing coordinated offshore networks. These are discussed in turn below.

This and subsequent sections would also benefit from being read in conjunction with Appendix B which considers the allocation of risks under the current arrangements in order help in evaluating the potential to optimise the balance between the benefits and risks of coordinated transmission build. There are various risks involved in the process of developing an offshore transmission link or system. The key parties in the existing regime are offshore generators, OFTOs, the onshore TOs, the NETSO and Ofgem. In Appendix B, we describe several aspects of these risks in the context of the current arrangements, including:

- the point(s) in the development process at which the risks arise and the severity of each risk
- who is likely to bear the risk, and
- which parties have the ability to manage the risks.

3.2 Potential benefits

Potential benefits from coordination can accrue as a consequence of a more efficient network design, greater efficiency in the utilisation of assets, and reduced risks for developers (of both generation and transmission). This includes the potential for:

- reduced total capital expenditure,
- reduced operating expenditure,
- reduced local environmental impacts,
- fewer planning and consenting issues,
- reduced connection timing risk for generators once a coordinated network is established,
- increased transmission system flexibility and security of supply, *and*
- greater consistency with wider European developments.

As a result, in aggregate there could be reduced barriers to delivering renewable energy targets. We consider each of these benefits in turn below.

3.2.1 Reduced total capital expenditure

The key economic benefit from a coordinated network stems from lower overall investment costs across the onshore and offshore networks brought about by a more efficient design and build of the overall network. A simple example is presented in Figure 1 below, which demonstrates benefits from coordinating the development of transmission links for two 450MW stages of generating capacity in the West of Isle of Wight offshore zone.

Benefits from coordination might accrue over time. For example, the two stages in the example in Figure 1 for West of Isle of Wight might not connect at the same time, but there are still likely to be savings in total capital expenditure over time from a coordinated approach that takes into account the likelihood of the second generator connecting. This is likely to require some degree of anticipatory investment – in the West of Isle of Wight example, an additional £117 million upfront investment is required to ensure that the full generating capacity of the zone can be exported through a single connection to the connection point (labelled DA1 in Figure 1).

There are also likely to be savings in capital investment costs from coordination across broader regions. The example presented below shows savings from linking generators that are likely to be located within the same zone, but there are also potential benefits from linking across Crown Estate leasing zones. For example, the coordinated network design from the asset delivery work stream demonstrates benefits from linking across the Hornsea and Dogger Bank zones on the East Coast.

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Figure 1 Radial (LHS) and coordinated (RHS) transmission design for the West of Isle of Wight zone, stage 2

Radial build: 900MW generation capacity

Coordinated build: 900MW generation capacity

Source: TNEI/PPA draft asset delivery work stream report

Taking into account all coordination over time and geography, based on TNEI/PPA work for the asset delivery work stream cost-benefit analysis presented in the following chapter , suggests that there could be savings of between 8.5% and 14.6% in capital and operating expenditure from a coordinated rather than a radial build.[11] This can be compared with analysis by National Grid and The Crown Estates for the Offshore Transmission Network Feasibility Study (OTNFS), which has estimated that a coordinated network could save 16% in capital costs to 2030 under an accelerated development scenario (involving 35 GW of installed offshore capacity by 2020 and 53.5 GW by 2030).[12]

These estimates are predicated on perfect foresight and assume that all expected offshore generation will arise. They also rely on assumptions about technological progress: there are likely to be few if any benefits from coordination if 2 GW high voltage DC (HVDC) links do not become available and acceptable from a project finance perspective. These capital expenditure savings need to be offset against the risks of overspend due to stranding of transmission assets where future generation projects do not emerge as expected, as discussed later in this Section.

[11] The cost-benefit analysis is based on the underlying capital cost and timelines developed by the Asset Delivery work stream, but adds additional information on the full lifetime cost of these assets. This includes the cost of capital (used to annuitise capital costs), depreciation, and operating and maintenance costs. The asset delivery work stream found that there could be aggregate capital expenditure savings from coordination of between 8% (scenario A) and 16% (scenario D).

[12] National Grid and The Crown Estate, *Offshore Transmission Network Feasibility Study* (September 2011).

3.2.2 Reduced operating expenditure

Any reduction in capital investment under a coordinated network could lead to ongoing cost savings through reduced expenditure on operations and maintenance, as a smaller total asset base requires lower operation and maintenance expenditure. There are likely to be a lower number of total assets to maintain under a coordinated design, with the OTNFS finding that there could be over 10% less total cable length, 34% less landing sites and 2% less offshore substations under a coordinated build.

If coordination results in a relatively small decrease in the number of offshore substations, the potential for operating expenditure savings could be limited. On the other hand, operating expenditure savings could be more than proportionate to capital expenditure savings as there are economies of scale in operating large compared with small electricity infrastructure assets. On balance, the OTNFS approximates savings in operating expenditure as proportional to savings in capital expenditure on each specific asset type.

3.2.3 Reduced local environmental impacts

Building fewer total transmission assets could be expected to reduce impacts on the local environment. Environmental impacts are likely to be reduced to the extent that the total number of cable corridors and landing points is reduced. This needs to be offset against any (ultimately unnecessary) increase in environmental impacts where oversized assets are built but not used. In either case, this has a clear interaction with the planning and consenting process, as this process is designed to optimise social, environmental and economic trade-offs. The process is thus likely to be simpler to navigate where there are smaller environmental impacts.

3.2.4 Fewer planning and consenting issues

A coordinated network is likely to lead to fewer planning and consenting issues given that fewer assets are built in total. Fewer assets are made possible by larger sizing of individual cables and substations. The additional planning burden to obtain consent for larger assets is likely to be minimal. On the other hand, the saving in terms of fewer overall consents and a reduced number of cable corridors and landing points could be significant. It is also likely to be simpler to demonstrate that coordinated developments meet the Electricity Act 1989 and the related licence requirements to develop and maintain an efficient, coordinated and economical system of electricity transmission.

A coordinated network is also likely to lower the burden of planning and consenting where it reduces the need for onshore reinforcement. As demonstrated by the asset delivery study, by developing more links offshore, a more coordinated approach can reduce the need for onshore reinforcement. Planning and consenting issues are more pressing onshore than offshore (in particular for overhead lines). This is because there can be visual and amenity impacts close to where people live, and there are a greater number of parties involved, in particular local planning authorities and councils. However, where onshore reinforcement of overhead lines is possible, this is often likely to be considerably cheaper.

3.2.5 Reduced connection timing risk for generators once a coordinated network is established

A coordinated network has some potential to reduce risk for generators by increasing the probability of a timely connection. As discussed further in Appendix B, timely connection is one of the most significant risks facing generators and has the potential to jeopardise significant revenues from electricity sales and renewables support. A coordinated network could improve timeliness for connection by minimising the planning and consenting burden for new transmission links. Further, the development of a network in a way that takes into account future developments is likely to involve some anticipatory investment, which may mean that some key infrastructure will be available for connecting new generators, easing the connection process. In particular, in some instances the new connection is likely to be shorter in a region where an offshore grid has already been developed. This is likely to be particularly important for generators that join later in the process of developing a coordinated network.

However, development of a coordinated network is also likely to involve greater complexity in developing transmission links. As discussed below, this could jeopardise connection timing, in particular for generators joining early in the process.

Where coordination improves timely connection, this could assist the UK in meeting renewable energy targets. In the longer term, a reduction in risk (timing in this case) which feeds through to a reduced cost of capital or to access to new sources of capital could flow through to the delivery of more renewable energy from offshore wind where this makes marginal projects economic.

3.2.6 Increased transmission system flexibility and security of supply

Beyond the direct impact on costs described above, there is potential for further ongoing benefits to the operation of the GB transmission system, by facilitating greater flexibility and security of supply.

A coordinated network has the potential to offer greater security of supply as it will mean electricity generated will be able to be (at least partially) exported to shore though different routes . A fully radial network would mean that each offshore generator is connected to the main interconnected system via a single link, so would be de-energised if that link becomes unavailable (due to a fault, for example).[13] The asset delivery work stream study suggests that in some regions an integrated network would mean that a single generator would have multiple routes to shore available to export power. For example, an offshore generator in the Irish Sea might be able to export its power via two different AC links to Wylfa, or HVDC links to Heysham or Pembroke (see Figure 2). This would offer greater flexibility in operating the system, as well as greater security of supply if one of these links were to fail. However, security of supply could be lower in the early stages of build, before multiple routes to shore have been established (discussed in Section 3.3.4 below).

As part of the OTNFS, National Grid and the Crown Estate have estimated that a coordinated network could save £1.2 billion in the costs of congestion management to 2030 under an accelerated development scenario.[14] This estimate is sensitive to assumptions about the average availability of offshore transmission assets and, as with any forecasts of the costs of congestion management so far into the future, carries considerable uncertainty.

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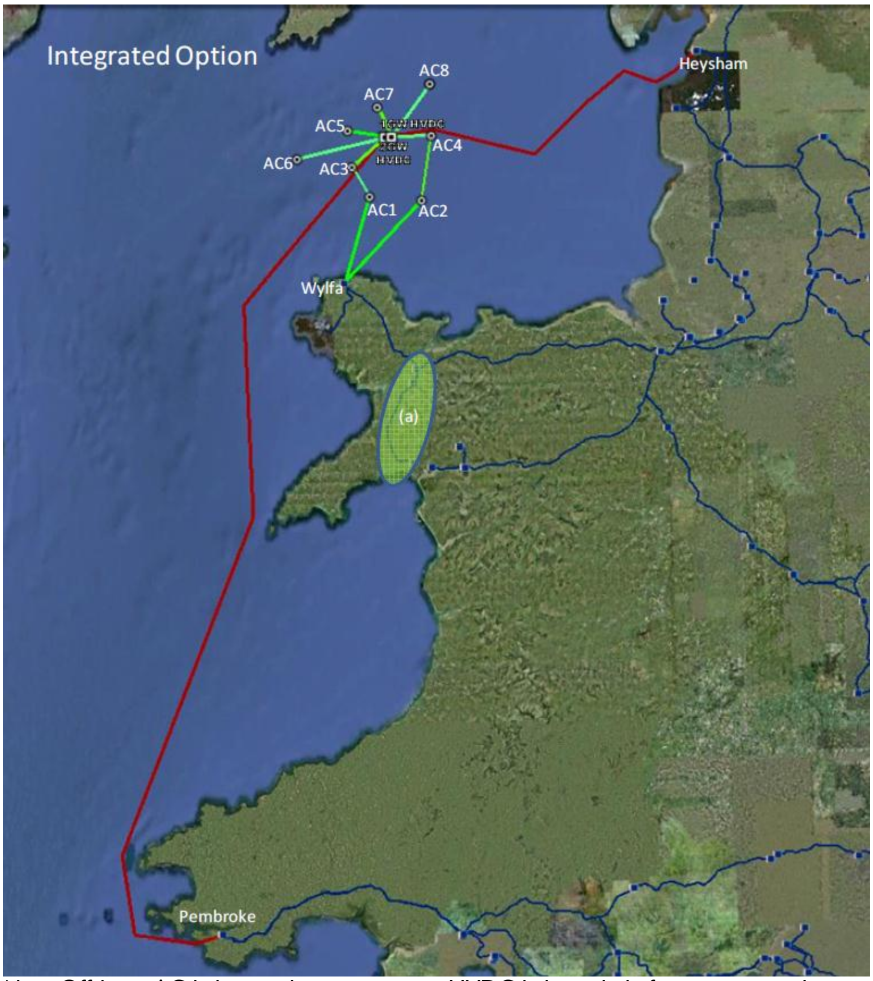
[13] However, the asset delivery work stream notes that beyond a certain size, bigger blocks of offshore generation will not use a single transmission link, so that there is likely to be some security from multiple links under a realistic design for radial build.

[14] National Grid and The Crown Estate, *Offshore Transmission Network Feasibility Study* (September 2011).

Figure 2 Coordinated development of offshore transmission in the Irish Sea



Note: Offshore AC links are shown in green. HVDC links and platforms are in red.
Source: TNEI/PPA asset delivery work stream.

3.2.7 Greater consistency with wider European developments

An increased capacity to link with networks in other countries could allow for greater consistency with European developments. In particular, a coordinated offshore network could offer opportunities to become involved in greater market coupling within the European market, and it could be an enabler of a future North Sea Grid.. The House of Commons Select Committee on Energy and Climate Change has recommended that offshore Round 3 grid connections should be capable of being linked into a future offshore 'supergrid'.[15] Work on the North Seas Countries' Offshore Grid Initiative is considering the issues associated with linking offshore networks across countries.

There are likely to be significant challenges involved in extending coordination to link with international interconnectors, and considerable uncertainty remains around the total costs and benefits of coordinated offshore grids. HVDC links that connect with an offshore wind farm need to be built using voltage source converter technology, rather than the more efficient and less costly current source converter technology that has generally been used for direct onshore to onshore interconnectors. There are also technical challenges associated with installing a greater number of converter stations and developing HVDC 'hubs'

[15] House of Commons Select Committee on Energy and Climate Change, *A European Supergrid* (September 2011).

that facilitate interconnection (discussed further below under 'potential risks and challenges' from coordination). Interconnection via offshore wind farms would need to provide advantages relative to direct interconnection, and any risks to offshore generators' access to transmission capacity would need to be taken into account in that assessment.

These challenges notwithstanding, there are potential benefits from linking offshore generators and international interconnectors under specific circumstances. In particular, this is likely to be the case where two countries are separated by relatively short spans (less than a few hundred kilometres), and the link to the offshore wind farm constitutes a large proportion of the span. For example, a study prepared for DECC last year showed that linking to Norway via Dogger Bank is unlikely to be economic when compared with direct onshore to onshore interconnection, but that there could be benefits from linking Ireland or continental Europe with the UK via offshore wind farms.[16] The asset delivery study has found that there could be, under specific circumstances, significant capital cost savings from linking between interconnectors and offshore generation[17]. The costs of interconnection via offshore generation are likely to be lower when countries on both sides of the interconnector are developing wind farms in adjacent waters since the infrastructure can be shared across a number of different users. However, the potential benefits from interconnection will depend on supply and demand fundamentals in each country and the resulting potential for arbitrage where prices in one country are higher than those in the other country. To the extent that both countries have similar generation technologies in similar locations with a similar cost profile, significant price differentials are less likely to occur be observed. Furthermore, the economic drivers for offshore wind are different to the drivers of interconnection, the former being dependant on market conditions and renewables support policy in each country.

3.3 Potential risks and challenges

The potential benefits from coordination must be offset against the potential risks and challenges. In particular, developing a coordinated network could involve:

- stranding risks associated with anticipatory investment,
- technological challenges,
- increased project complexity, *and*
- potential temporary reduction in transmission system flexibility and security of supply for early phases.

3.3.1 Stranding risk from anticipatory investment

The trade-off between coordination and asset stranding risk has been noted in OTCG meetings.[18]

As discussed earlier in this Section, development of a coordinated offshore network is likely to require some anticipatory investment (investment beyond the need of the immediate generation project) to prepare for the connection of further generators or transmission links in the future. This might include

[16] SKM, *Offshore Grid Development for a Secure Renewable Future – a UK Perspective*, Report prepared for DECC (June 2010). We have also heard evidence from developers suggesting that there are potentially opportunities for linking, in particular in the Irish Sea.

[17] Section 2.8 – Integration of an Offshore Windfarm with an Interconnector

[18] DECC and Ofgem, *Minutes of the Offshore Transmission Coordination Group (OTCG)*, 1 March 2011, http://www.ofgem.gov.uk/Networks/offtrans/pdc/pwg/OTCP/Documents1/OTCG%20meeting%20minutes%201%20Mar%2011.pdf

oversizing of cables or substations, providing additional capacity at landing points, or it could just cover undertaking anticipatory pre-construction activities (for example, cable surveys or purchase of wayleaves that cover more than one project). For example, the asset delivery work stream study showed that there could be benefits from installing a 2 GW HVDC link from offshore generators in the Irish Sea in advance of this much capacity being required (under the 'networked' design strategy), given the need to prepare for the connection of stage 3 and 4 generators later. At the completion of Stage 2, only 0.8 GW of capacity on the HVDC link is required for the export of power at peak load. Using unit costs from work stream 1 data, this suggests that more than £150 million of additional expenditure (of a total investment of £774 million) to install a 2 GW rather than a 1 GW HVDC link would be at risk of stranding.

Anticipatory investment leads to risks that oversized transmission assets will be stranded if future offshore generation projects do not go ahead as planned. Offshore generation projects might not proceed as expected for any number of reasons relating to the economics of offshore generation (including construction costs, subsidy levels and broader electricity market factors), the financial capacity of the developers, or planning and regulatory issues. The recent example of several planned projects in Scottish waters being abandoned due to planning constraints (including Solway Firth, Wigtown Bay, Bell Rock and Kintyre Array zones[19]) illustrates the uncertainty associated with future offshore projects and thus the importance of concerns with stranding risk. This uncertainty is reflected in a wide range of scenarios consistent with meeting the Government's renewables targets. For example, the four scenarios used for this study project between 15 GW and 45 GW of offshore generating capacity by 2030, and the 2011 ODIS includes a 'sustainable growth' scenario with 67 GW of capacity by this time.

The potential costs from stranding of oversized transmission assets could be a significant drawback to coordinated investment, leading to unnecessary cost where the transmission network is developed without perfect foresight. These potential costs need to be offset against longer term cost savings from a coordinated network. Even where generation projects do eventually proceed as foreseen, there are timing risks, whereby anticipatory investment might not deliver benefits until several years after transmission links are completed. The risks associated with anticipatory investment mean that it is important that they are effectively managed; this will in part be a result of whether there is an efficient allocation of these risks, and the extent to which regulatory oversight provides effective protection where consumers are at risk.

3.3.2 Technology challenges

The benefits from coordination are likely to be greater with more advanced technology, including higher capacity infrastructure. For example, the availability of higher capacity HVDC cables and converters would allow more generation capacity to be connected onto a single line to shore, which could lead to savings on overall cable costs and deliver greater benefits from coordination. The availability of multi-terminal offshore hubs would also increase the potential for linking across projects. The work stream 1 study has found that unavailability of 2 GW HVDC links and HVDC multi-terminal hubs would effectively eliminate the apparent cost advantage of integrated development.

There are likely to be challenges in delivering technologies associated with a fully coordinated solution, for example as considered in the 'integrated' design for the 2011 ODIS statement. The asset delivery work stream report suggests that 2 GW HVDC links offshore are unlikely to be available before 2018, and that financial backing for construction in 2018 is likely to be challenging (requiring a commitment in 2014 to allow for development and construction). Similarly, there are no contracted multi-terminal offshore hubs

[19] Marine Scotland, *Blue Seas – Green Energy*, A sectoral marine plan for offshore wind energy in Scottish Territorial Waters, Part A: The plan (March 2011).

at present, with the Moray Firth Hub the only such project on the horizon. These technology challenges could restrict the potential benefits from coordination in the near term, particularly before 2020.

3.3.3 Increased project complexity

Development of a coordinated network is likely to involve greater project complexity than radial links, with potential risks for offshore generators. The asset delivery work stream demonstrates that a coordinated network will require larger transmission links (involving anticipatory investment) and greater interlinking. For example, a coordinated build across the Dogger Bank and Hornsea zones is shown to involve considerable use of 2 GW HVDC technology[20] and complex linking across these two zones.

Increased project complexity could affect the risk taken by OFTOs and therefore the cost of capital to deliver offshore transmission. But the most significant impacts could be on costs for generators where project complexity threatens their connection timing. This is particularly relevant for generators connecting early in the process of developing a coordinated network, when oversized links are being delivered.[21] Changes in connection timing risk for generators have the potential to affect financing costs for the whole generation project. Transmission links are on average likely to constitute less than a quarter of total offshore wind generation costs[22] (although this will depend on specific considerations such as distance from shore) whereas financing costs for generators will affect all of the related assets required.

3.3.4 Temporary reduction in transmission system flexibility and security of supply

Network resilience and security of supply might be lower during the early stages of a coordinated build. Evidence from the TNEI/PPA work stream 1 study shows that a single point of failure risk could be heightened during the early stages of a coordinated build, before multiple routes to shore have been established. In particular, this could be a problem where 2 GW HVDC links are used, where failure of a single link could breach Security and Quality of Supply Standard (SQSS) requirements.

[20] In particular, 2GW onshore converter stations that convert output from both zones.

[21] However as discussed in section 3.2.5, there could be reduced connection timing risk for generators once a coordinated network is established.

[22] Committee on Climate Change, *The Renewable Energy Review*, May 2011.

4 Cost-benefit analysis of coordination – aggregate assessment

4.1 Introduction

A cost-benefit analysis of the incremental benefits from a coordinated build of offshore transmission networks relative to a radial one has been undertaken, drawing on capital cost data from the asset delivery study. A radial network is represented by the 'T1 – Connect and reinforce' design while a coordinated network is represented by the 'T2 – Networked' design.

The benefits from transmission build (in particular, enabling transmission of electricity generated offshore) are likely to be similar under the two scenarios, so the impacts of greater coordination are estimated through analysing the different life cycle costs of providing transmission assets under the two scenarios. A range of other potential costs and benefits are considered qualitatively. This analysis was undertaken for four scenarios for offshore generation deployment, which are described below.

Further detail on the approach to the cost-benefit analysis and sensitivity results is contained in Appendix C.

4.2 Methodology

4.2.1 Overview of methodology

The costs and benefits of a coordinated network are measured against a radial build as the counterfactual. Costs and benefits are calculated annually and converted into a net present value (NPV) for the period 2010-2030 using a real discount rate. All numbers are presented in real 2011 terms. It is important to note that the NPV analysis does not capture the costs and benefits of the options after 2030 – these are considered as part of the sensitivity analysis in Appendix C.

4.2.2 Key assumptions

The real discount rate was assumed to be 3.5% and was sourced from HM Treasury's Green Book. Additional parameters were required to annuitise capital costs according to the user cost of capital,[23] and to estimate associated operating costs. Parameters for the cost of capital and operating costs for onshore Transmission Owners (TOs) were sourced from the TPCR4 price control, as this was the most recently completed price control for onshore transmission assets. However, given that Ofgem have estimated that the OFTO tender regime has delivered significant savings from competition[24], we have included a lower cost of capital as a key sensitivity. Operating cost savings were assumed to be proportionate to capital cost savings, similar to the approach taken to estimate maintenance cost savings in the OTNFS.[25] All

[23] This is necessary to provide annual results and also to incorporate the true cost of risky investment (particularly where these are financed by international capital that must be duly compensated). By allocating the cost of capital over the life of the asset, this approach also avoids the need for any further truncation of the cost of capital assets with lifetimes that extend beyond the modelling period.

[24] Ofgem, *Three Bidders Selected to Run the First £700 Million of Transmission Links for Seven Offshore Wind Farms 2010*, Press Release (August 2010).

[25] National Grid and The Crown Estate, *Offshore Transmission Network Feasibility Study* (September 2011).

transmission assets were depreciated using a straight line method, consistent with RIIO T1 strategy decisions.[26] Key parameter values are summarised in Table 22 in Appendix C.

4.2.3 Generation scenarios

The cost–benefit analysis was undertaken across four different generation scenarios designed to assess the impact of differing UK-wide delivery of renewable targets on the likely offshore transmission requirements. These cover a broad range of deployment scenarios for offshore generation (15 GW to 45 GW installed capacity by 2030) which are summarised in Figure 28 in Annex A. These scenarios cover the full range of deployment of between 11 GW and 18 GW by 2020 under the UK Renewable Energy Roadmap[27] and involve marginally less deployment than scenarios for 2030 considered by the CCC (20 GW to just under 50 GW of capacity by 2030).[28] The scenarios are described in the asset delivery study (Chapter 4). In summary:

- *Scenario A - represents a case whereby there is an early start to offshore wind development, with more than 7 GW of capacity installed by 2015. Installation rates are then assumed to decrease, with an installed capacity of 9 GW in 2020. Capacity in 2025 is assumed to be 16 GW, with no significant additional installation thereafter, consistent with slower demand growth at this time.*
- *Scenario B - represents a case with a slower initial installation rate relative to Scenario A over the period to 2018, but a faster thereafter, with assumed capacities in 2020, 2025 and 2030 of 12 GW, 20 GW and 28 GW respectively.*
- *Scenario C - is based on the NGET ODIS 2011 scenario of the same name.*
- *Scenario D - represents a more aggressive wind capacity rollout, with capacities in 2015, 2020, 2025 and 2030 of 9 GW, 23 GW, 39 GW and 49 GW respectively.*

Each Round 3 Crown Estate zone was assumed to be built out in 'stages' in the asset delivery work stream study. The number of stages completed in each zone was calibrated to the aggregate generation scenarios. This calibration was based initially on a pro rata approach, with some subsequent scaling to ensure maximum use of transmission assets. This approach is described more fully in the TNEI/PPA asset delivery work stream report.

The approach taken in developing aggregate scenarios means that there is minimal stranding under any of the four aggregate scenarios. This would not be possible in a real-world setting where there is considerable uncertainty about future build of offshore generation, but rather is a consequence of assuming perfect foresight in building out each zone.

[26] Ofgem, *Decision on Strategy for the Next Transmission Price Control – RIIO-T1*, RIIO-T1 http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decision.pdf (March 2011).

[27] DECC, *UK Renewable Energy Roadmap* (July 2011).

[28] Committee on Climate Change, *The Renewable Energy Review* (May 2011).

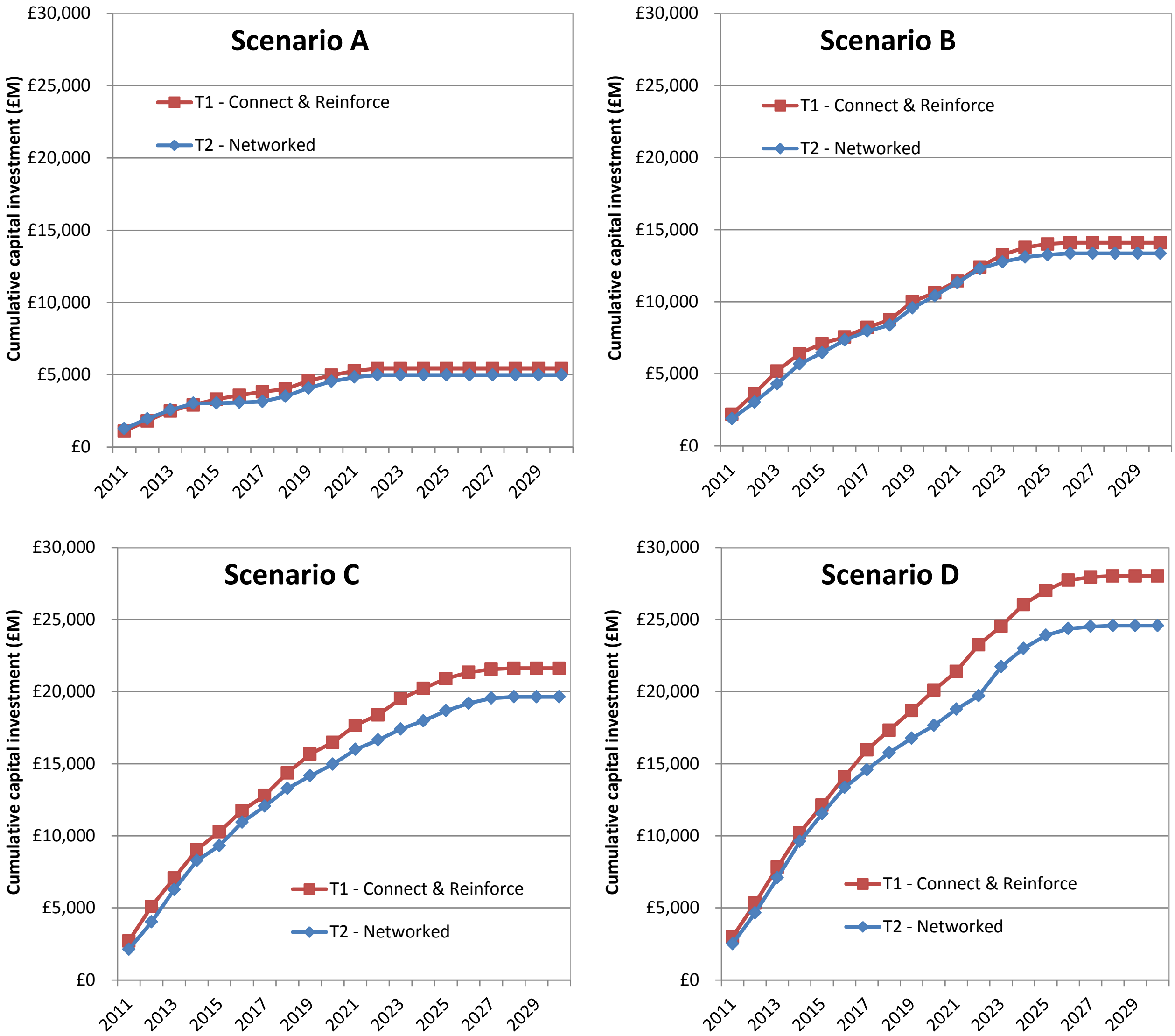
Table 6 Build-out of Round 3 zones for cost-benefit analysis

Zone	Generating capacity (MW)			
	Scenario A	Scenario B	Scenario C	Scenario D
Irish Sea	500	1,500	3,000	4,000
Dogger Bank	2,000	5,000	9,000	12,000
Hornsea	1,000	2,000	3,000	4,000
East Anglia - Norfolk Bank	1,000	3,000	6,000	7,000
Bristol Channel	0	500	1,000	1,500
West of Isle of Wight	0	0	900	900
South Coast - Hastings	0	0	600	600
Firth of Forth	1,000	2,000	3,000	4,000
Moray Firth	0	750	750	1,500
Total	**5,500**	**14,750**	**27,250**	**35,500**

4.3 Results

Cumulative capital expenditure profiles for the four scenarios are shown in Figure 3. There are savings in total capital expenditure from a coordinated build under all scenarios, which generally increase with the level of investment.

Figure 3 Cumulative capital spend profiles



Source: TNEI/PPA, asset delivery work stream.

4.3.1 Cost-benefit analysis

Results from the cost-benefit analysis shown in Table 7 demonstrate that the benefits from a coordinated build increase significantly with the total volume of generation capacity under central case assumptions. Under Scenario D, there are net present value benefits of almost £3.5 billion from a coordinated build (with perfect foresight). However, under Scenario A there are less than £500 million in net present value gains. This is due to the reduced scope for coordination where there is less offshore generation.

These results represent a saving of between 8.5% and 14.6% of the cost of a radial network. There are likely to be additional benefits from continued use of a coordinated network after 2030, which are quantified as part of the sensitivity analysis in Appendix C.

The cost-benefit analysis results are based on capital expenditure estimates from TNEI and PPA Energy's work for the asset delivery work stream. The asset delivery work stream found that there could be aggregate capital expenditure savings from coordination of between 8% (scenario A) and 16% (Scenario D). The cost-benefit analysis undertaken as part of this study uses the underlying capital cost and timelines developed by the Asset Delivery work stream, but adds additional information on the full lifetime cost of these assets, This includes the cost of capital (used to annuitise capital costs), depreciation, and operating and maintenance costs.

Table 7 Cost-benefit analysis: central case results by national generation scenario

Design	T2 - networked							
Scenario	Scenario A							
			2011-2015	**2016-2020**	**2021-2025**	**2026-2030**		**NPV (2010-2030)**
			£M (real 2011)					£M (real 2011)
Reduction in costs relative to T1 - connect and reinforce								
Cost allocation	TO capital costs		- 91.12	- 141.76	- 194.38	- 178.02		- 420.57
	TO operating costs		- 35.37	- 53.54	- 69.17	- 59.78		- 154.26
	OFTO capital costs		91.98	390.71	428.10	428.67		856.11
	OFTO operating costs		22.83	96.97	106.25	106.39		212.48
	Total		**- 11.68**	**292.38**	**270.80**	**297.26**		**493.75**

Design	T2 - networked							
Scenario	Scenario B							
			2011-2015	**2016-2020**	**2021-2025**	**2026-2030**		**NPV (2010-2030)**
			£M (real 2011)					£M (real 2011)
Reduction in costs relative to T1 - connect and reinforce								
Cost allocation	TO capital costs		- 76.43	- 238.97	- 161.16	- 94.40		- 415.00
	TO operating costs		- 31.41	- 89.44	- 52.89	- 27.78		- 150.23
	OFTO capital costs		416.89	491.39	465.90	538.43		1,311.37
	OFTO operating costs		103.47	121.96	115.63	133.63		325.47
	Total		**412.51**	**284.94**	**367.48**	**549.89**		**1,071.61**

Design	T2 - networked							
Scenario	Scenario C							
			2011-2015	**2016-2020**	**2021-2025**	**2026-2030**		**NPV (2010-2030)**
			£M (real 2011)					£M (real 2011)
Reduction in costs relative to T1 - connect and reinforce								
Cost allocation	TO capital costs		- 144.08	- 163.80	17.04	119.78		- 191.68
	TO operating costs		- 58.06	- 55.20	14.65	50.30		- 63.91
	OFTO capital costs		582.54	734.48	892.01	817.59		2,101.13
	OFTO operating costs		144.58	182.29	221.39	202.92		521.48
	Total		**524.97**	**697.77**	**1,145.09**	**1,190.58**		**2,367.02**

Design	T2 - networked							
Scenario	Scenario D							
			2011-2015	**2016-2020**	**2021-2025**	**2026-2030**		**NPV (2010-2030)**
			£M (real 2011)					£M (real 2011)
Reduction in costs relative to T1 - connect and reinforce								
Cost allocation	TO capital costs		- 153.24	- 39.49	279.81	465.21		244.88
	TO operating costs		- 60.36	- 5.92	115.75	174.25		101.50
	OFTO capital costs		532.33	894.66	1,117.21	1,080.57		2,521.29
	OFTO operating costs		132.12	222.05	277.28	268.19		625.76
	Total		**450.84**	**1,071.30**	**1,790.05**	**1,988.21**		**3,493.43**

Table 8 Cost-benefit analysis: summary of central case results

	NPV to 2030 £m (real 2011)		Reduction in cost from coordination	
	T1 (radial)	T2 (coordinated)	NPV £m (real 2011)	As a proportion of radial NPV
Scenario A	£5,784	£5,290	£494	8.5%
Scenario B	£12,468	£11,396	£1,072	8.6%
Scenario C	£19,275	£16,908	£2,367	12.3%
Scenario D	£23,976	£20,483	£3,493	14.6%

Source: Redpoint Energy analysis, based on data from the asset delivery study.

In Scenario D, cost savings occur both for assets deemed to be owned by the onshore transmission owners (TOs) and OFTOs. For the other three scenarios, additional TO assets are outweighed by savings in OFTO assets under a coordinated build. These results are based on a post-design classification of the ownership of new transmission assets, but do not necessarily reflect which party would be undertaking works that serve a dual onshore/offshore purpose. This only affects the split and not the overall cost savings under coordination.

4.3.2 Non-quantified costs and benefits

There are likely to be additional impacts of a more coordinated network that have not been included in the quantitative cost-benefit analysis. These are likely to include:

- stranding risk from anticipatory investment,
- technology risks,
- timing of generator connection,
- onshore constraint costs,
- outage risk/security of supply,
- flexibility to link with other networks,
- socio-economic and environmental impacts, *and*
- regulatory intervention costs.

Stranding risk from anticipatory investment

Stranding risks have not been quantified in the cost-benefit analysis,. Full quantification of the cost of stranding risk would require quantification of the assets subject to stranding at any point in time, and application of an appropriate risk premium based on the probability that generation demand for these assets does not materialise. Data was not available to undertake this task at an aggregate level.

Analysis from the case studies (Appendix D) shows that stranding risk can be significant for specific assets. In the West of Isle of Wight zone, a 50% increase in investment is required during the first stage of build to achieve a coordinated solution, creating significant stranding risk of more than £100 million on just over

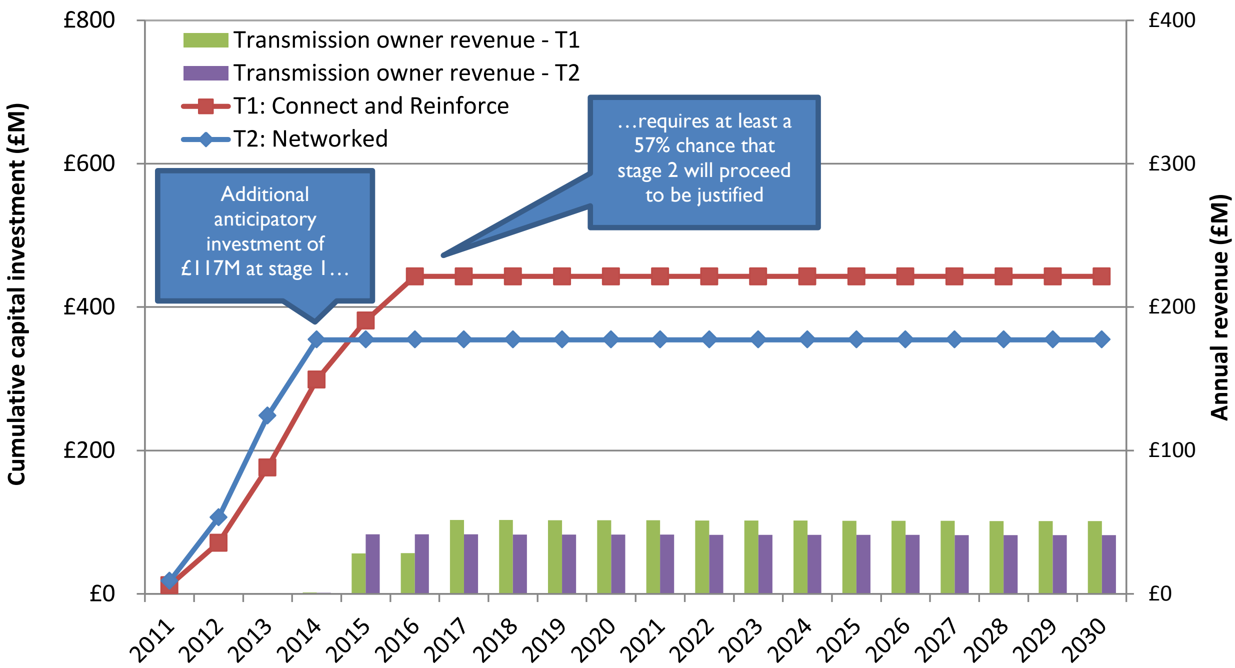
£200 million of assets. This delivers savings if the second stage of development goes ahead. To justify the additional upfront investment, a developer would need at least a 57% chance of the second stage of generation build proceeding (Figure 4). The probability would need to be greater where the developer is subject to higher financing costs due to the stranding risk, or where there is a significant time delay between the first and second stages of generation build (during which time oversized assets remain unused).

Analysis from the case studies also shows that some anticipatory investment might be needed onshore under a radial design, reducing the relative increase in stranding risk under coordinated build. For the Irish Sea zone, the coordinated design developed by work stream 1 involves development of an oversized 2 GW HVDC link at stage 2 of a 4 stage build. However, at the same development stage, the radial design involves building a 2 GW 'bootstrap' to reinforce the onshore network, which also involves some anticipatory investment to facilitate later build. Accordingly, the net increase in anticipatory investment under a coordinated build relative to radial is relatively small (£14 million) and a risk neutral decision maker would only need a 7% chance of stage 3 development proceeding to justify the additional stranding risk under a coordinated design (assuming that they take into account all costs and risks from a whole of economy perspective).

The asset delivery work stream also highlights the importance of anticipatory investment at the pre-construction stage, where the sums involved at this earlier stage of project development are less significant.

Regional and timing differences in magnitude notwithstanding, including stranding risk in the aggregate analysis would reduce the benefits from coordination and could make the achievement of any benefits less likely under low build scenarios.

Figure 4 Construction costs (LHS) and transmission owner revenue requirement (RHS) for the West of Isle of Wight zone



Note: Analysis of anticipatory investment excludes any additional financing costs from higher stranding risk.
Source: Redpoint analysis based on TNEI/PPA asset delivery work stream data

Other non-quantified risks

In contrast, many of the other impacts noted above are likely to increase benefits from coordination, as detailed in Section 3. For example, security of supply could be improved under a coordinated network by multiple transmission links to a single offshore generator, while environmental impacts would be minimised where there are less onshore landing points.

Table 9 sets out a qualitative assessment of the non-quantified costs and benefits. The materiality of these risks is also likely to depend on the degree of coordination. For example, stranding risk could be substantially higher where there is a greater degree of coordination involving anticipatory investment in oversized (for example, 2 GW HVDC) cable capacities.

Table 9 Summary of non-quantified costs and benefits from increased coordination

Non-quantified costs and benefits	Description	Increase/decrease benefits from coordination	Approximate materiality
Stranding risk from anticipatory investment	Risk associated with anticipatory investment to facilitate a coordinated network	Decrease	
Technology risks	Risk from using new technology (as available), particularly high capacity cable, offshore hubs and platforms	Decrease	
Timing of generator connection	Availability of connection critical to generator costs	Uncertain	
Onshore constraint costs	Impact on cost of managing locational transmission constraints (costs of onshore reinforcement included)	Increase	
Outage risk / security of supply	Impacts of transmission outages, which could be mitigated by greater network redundancy and security	Increase in later phases, possibly decrease in earlier phases	
Flexibility to link with other networks	Potential to link with interconnectors and into offshore grids	Increase	
Socio-economic and environmental impacts	Potential to reduce impacts through fewer cable corridors and onshore landing points	Increase	
Regulatory intervention costs	Cost of regulatory changes to facilitate coordination	Decrease	

Could have a substantial impact on overall costs and benefits   Medium impact likely   Only a moderate impact likely

4.4 Sensitivity analysis

We have undertaken a number of sensitivities on our central case assumptions. Overall, our sensitivities demonstrate that the main results are robust to changes in key parameters relating to discount rates and costs of capital. We summarise the analysis below and in Table 10 (more detailed results from the cost-benefit analysis are contained in Appendix C).

- **Discount rate**
  - A significant (1 percentage point) change in the discount rate affects the magnitude of results, but a coordinated design continues to offer benefits over the radial design in all generation scenarios modelled.
  - A higher discount rate reduces the estimated benefits from a coordinated design because the greatest benefits accrue towards the end of the modelled period and these benefits are given a lesser weight.
- **Cost of capital**
  - Changes in the cost of capital applied to transmission assets have a smaller impact on results. An increase in the cost of capital increases the benefits from a coordinated design by accentuating the higher capital costs under a radial design.
  - A sensitivity run with a lower cost of capital for OFTOs (4.05%) than for onshore TOs (5.05%) indicates that benefits from coordination are smaller. This could reflect a situation where competition for OFTO assets allows access to capital at lower costs, which is consistent with Ofgem estimates of significant savings from the OFTO tender system.[29]
  - There are net increases in TO costs with coordination in some scenarios, so reducing the OFTO costs of capital only can have a bigger impact than reducing TO and OFTO costs of capital together.
  - This result should not be interpreted as the benefits from a lower cost of capital itself, but rather as a reduction in the benefits from coordination where a lower cost of capital can be accessed for OFTO assets. Reductions of a similar magnitude are likely where OFTO operating costs are lower (as a proportion of capital costs) than those onshore.
- **Operating expenditure**
  - A reduction in operating expenditure also reduces the estimated benefits from coordination. Excluding operating expenditure from the analysis has a significant impact on the absolute magnitude of results, but coordination savings remain similar as a proportion of total modelled expenditure.

[29] Ofgem, *Three Bidders Selected to Run the First £700 Million of Transmission Links for Seven Offshore Wind Farms 2010*, Press Release (August 2010).

Table 10 Summary of sensitivity analysis

Parameter	Central value	Sensitivity	Impact on magnitude of cost-benefit analysis results (NPV for 2010 to 2030) versus central case			
			Scenario A	Scenario B	Scenario C	Scenario D
Discount rate	3.5%	4.5%	-13%	-10%	-10%	-11%
		2.5%	+15%	+11%	+12%	+13%
Cost of capital (Real vanilla weighted average cost of capital)	5.05% (Onshore TOs and OFTOs)	TO & OFTO: 6.05%	+4%	+5%	+7%	+7%
		TO & OFTO: 4.05%	-3%	-5%	-6%	-7%
		TO: 5.05%; OFTO: 4.05%	-14%	-10%	-7%	-6%
Operating expenditure	2.75% (Onshore TOs) 2.00% (OFTOs)	TO: 3.25% OFTO: 2.50%	+5%	+5%	+5%	+5%
		TO:2.25% OFTO: 1.50%	-5%	-5%	-5%	-5%
		TO: 2.75%; OFTO: 1.50%	-11%	-8%	-6%	-4%
		Excluding operating expenditure	-16%	-20%	-23%	-25%

Note: The coordinated design continued to offer benefits over the radial design under all sensitivity runs. The impact on results reported is the change in net benefits from the coordinated design, which varies across the different scenarios for generation build.

5 Barriers to coordination

5.1 Introduction

This section considers the key potential barriers in the current regulatory regime to achieving the benefits from coordination set out in Section 4.

The methodology used to evaluate barriers to coordination was based on gathering and evaluating evidence from a number of different sources. As set out in Section 3, we have considered the potential for a wide range of issues to act as a barrier, based on the incentives and risks imposed on relevant parties. We have also sought to validate and cross check evidence where possible. Evidence was considered from the following sources:

- submissions to Ofgem and DECC consultations on the regulation of offshore transmission
- the OTCG process, in particular through meetings and expert workshops
- OFTOs, including through the OFTO forum convened under the auspices of the Energy Networks Strategy Group, *and*
- discussion with key stakeholders, including industry groups, generators, transmission owners and the NETSO.

The list of key barriers identified through this approach is classified below into those that pertain to:

- anticipatory investment related process uncertainty,
- network optimisation (including a lack of a vision for a coordinated network),
- the risk–reward profile of coordinated investments,
- clarity of regulatory interface between onshore, offshore and interconnector regimes,
- planning and consenting, *and*
- new technology risks and asset incompatibility.

The remainder of this Section is set up to enable the evidence on barriers to coordination to be summarised into a 'problem statement'. The problem statement is presented at the end of the Section so that any potential solutions can be considered against how they help to resolve the problems identified.

5.2 Assessment of potential barriers to coordination

A number of potential barriers to the current offshore transmission regime delivering a coordinated network have been identified. These include matters that are not exclusively related to coordination, such as delivery risks to generators under the OFTO build model or the length of the tender system. These need to be considered when developing overall policy responses to deliver coordination. However, the discussion of key problems and challenges below is specifically focused on barriers that impede the capacity of the regime to deliver a coordinated solution, as developing and assessing solutions to these barriers is the core focus of this report.

5.2.1 Anticipatory investment process uncertainty

As discussed in Section 4, arrangements that facilitate efficient anticipatory investment could be a key part of an overall regime that promotes a coordinated offshore transmission network. There are multiple types of anticipatory investment, specifically:

- investment in pre-construction activities including consents, permits or preparatory works to enable a future investment to be made,
- oversizing of facilities that are being provided for a specific committed project or user need, *and*
- oversizing of assets to be built prior to a firm commitment from any projects that would utilise the assets.

It is worth noting that the amount of anticipatory investment that might be needed in different scenarios could vary significantly. In some cases, there could be relatively significant anticipatory needed in decisions regarding the oversizing of assets, whereas some anticipatory investment will involve relatively small sums. This is particularly true for anticipatory investment at the pre-construction phase of project development, which the Asset Delivery work stream has highlighted as being a key area where keeping open different development options can have significant value for only modest extra cost.

The current onshore regime is capable of allowing regulated anticipatory investment through a number of mechanisms for projects which are able to demonstrate a clear cost-benefit case[30]. For anticipatory investment related to the offshore regime the challenges are different given that the risks and rewards of anticipatory investment are distributed differently. A distinction should be drawn between anticipatory investment that directly benefits a developer and that which has wider benefits. Direct benefits occur where anticipatory investment delivers net benefits within a wind farm or zone being developed by a single consortium, in which case the developer is likely to have clear incentives to pursue anticipatory investment (where this offers net benefits). Wider coordination benefits from anticipatory investment could accrue across zones or by relieving onshore constraints, and the incentives are likely to be more widely dispersed.

Our analysis has identified several barriers to anticipatory investment, as follows:

- **Cost recovery and process certainty:** The current offshore regime is capable of allowing for anticipatory investment but the risk of that investment lies with generators. This is because any decision to undertake anticipatory investment needs to be approved by the regulator so that the generator is able to recover their costs through the transfer value (under generator build), or secured by the generator through user commitment rules (under OFTO build).
    - At the initial stages of project development, the anticipatory investment would need to be part of the project's technical specification in the tender process. This carries a degree of risk and uncertainty for any planned anticipatory investment since it would be possible for

[30] On the onshore network the established regulatory and incentives regime focuses on long term issues and investment is largely driven by 'known demand'. Specifically the network expands to meet user long-term requirements whose location is informed by administered prices (TNUoS), long-term access rights allocated when capacity is available and by short-term connect and manage by derogation. Overall, the current onshore regulatory regime funds transmission investments that are subject to user financial commitments which protects customers (and network companies) against stranded investments but means that networks are responsive to new generation and demand connection requests. Similarly for the offshore transmission investment, transmission system development by the NETSO is specifically linked to offshore generator plans. Recognising that focusing purely on short-term requirements for contracted generation may prevent major investments needed to allow the timely and firm connection of renewable generation over the medium-term the established regime may fall shore in some cases, Ofgem has put place mechanisms outside of the existing price controls such as Transmission Investment Incentives (TII) and to some extent Transmission Investment for Renewable Generation (TIRG) which allow investments of a more anticipatory nature to be made to enable the UK's decarbonisation objectives.

Ofgem to challenge the content of the project's technical specification and thus any pre-construction monies which have been spent to get to the tender stage would be at risk. Overall, to facilitate parties in undertaking economic and risk managed anticipatory investment there is a need for a clear ex-ante process for the regulatory approval of such investment such that investors have a clear indication of the costs and risks involved at each stage of the project, including at the planning and pre-construction phases.

  - More broadly, generators have no certainty on cost recovery for anticipatory investment since they will be subject to ex-post regulation by Ofgem who will consider whether the costs are economically and efficiently incurred when carrying out the cost assessment process. As part of this, Ofgem could deem anticipatory investment to be economic and efficient but in the absence of ex ante clearance or better guidance, generators might not be willing to take the risk that Ofgem will not include it in the transfer value.

- **Stranding risk:** The targeting of stranding risk onto generators through user commitment and charging arrangements (as discussed further below, as well as in the case study examples in Appendix D) is also a potential barrier to anticipatory investment under current processes.
- **Planning process uncertainty:** Generators have also pointed to a lack of clarity in whether transmission assets that are built early/oversized will be consented through the planning processes. Planning processes are discussed in more detail below.

5.2.2 Network optimisation

At the outset, it worth considering what we expect an 'optimised' and desirable network to consist of (irrespective of whether it is planned and delivered by the individual actions of generators/developers or through the NETSO and/or TOs). The starting point for this should be the objectives (set out in the relevant licence conditions) for the development of a network which allows a given volume of generation and demand to be connected efficiently and economically including a coordinated approach where this is beneficial (taking into current and future consumers). This should result in:

- fewer planning and consenting issues,
- reduced local environmental impacts,
- operational flexibility and increased security of supply, *and*
- flexibility to link with other networks including international networks and the trade which may result.

At present, to facilitate this, the role of National Grid as NETSO has been extended offshore. This means that National Grid is responsible for ensuring that electricity supply and demand stay in balance and the system remains within safe technical and operating limits. The NETSO is also responsible for providing access to the GB transmission system for offshore generators on an open, transparent and non-discriminatory basis, including provision of an initial connection offer. The connection offer is based on an application of National Grid's optioneering process, which has been developed to ensure a consistent approach is used in the identification, analysis and selection of preferred design options. An additional requirement on the NETSO (set out in Special Condition C4 of NGET's licence) is to produce an annual ODIS.

In making a connection offer, the NETSO considers requirements and makes an offer that covers the interface point with the wider network, as well as the wider and local works required to facilitate the connection. This is done within the 90 day period in which it is required to provide a connection offer so the NETSO does not get into detail such as offshore routing. Furthermore, the connection offer must consider other developments on the network but only those that are currently contracted – they do not consider future developments as they would when undertaking a high level reference design offshore (such as for ODIS)[31]. Generators have the choice of whether to accept or reject the connection offer, or to refer it to Ofgem for determination of whether it is the most efficient and economic offer possible.

The NETSO therefore could have a significant role in bringing about coordination where desirable and it has already been making so called 'integrateable' offers which include an element of anticipatory investment looking across future system demands, including where this would have benefits for the onshore system. These integrateable offers are designed to allow for coordination/integration into the future. However, no integrateable offers have been accepted to date since they involve both some level of risk associated with anticipatory investment (which they may not be willing to bear) and uncertainty on how they will have to pay for and securitise shared assets.

Thus, the current regulatory regime has a process for a central view to be taken but places constraints on the extent to which the overall transmission network can be optimised. Over time, the development of the offshore network could require additional work to re-optimise infrastructure and to deliver an optimal outcome across the offshore and onshore networks. There could also be benefits from further guidance on the future design of offshore transmission networks. The importance of both of these points is heightened by uncertainty about future offshore build – as noted previously, scenarios used for this study involve a range from 15 GW to 45 GW of offshore capacity by 2030 and other studies have considered even higher levels of deployment. There are 3 key constraints or challenges which we consider in turn below:

- **Onshore/offshore interactions** including:
  - the role of the NETSO and whether it has sufficient information on likely network development needs (taking account of all relevant demands)
  - Do the NETSO and developers have the right incentives?
  - Do the arrangements encompass broader developments such as interconnectors?
- **Lack of vision for a coordinated network**, including whether the process for short- and medium-term planning decisions could be better informed by improvements to the long-term vision
- **Re-optimisation over time**, including the roles and incentives of individual parties to re-optimise incremental capacity investments over time.

Offshore/onshore interactions

To deliver transmission infrastructure at least cost there is a need to optimise the network onshore as well as offshore. There are potential externalities available to the onshore network from the design of offshore connections, as the location of landing points can have implications for onshore reinforcement. In addition, there is potential for coordinated build of offshore networks to deliver benefits in the form of a reduced need for onshore investment. For example, the asset delivery study shows that the construction of HVDC links from the Irish Sea zone could reduce the need for reinforcement onshore, as does the 2011 ODIS.

[31] After a connection offer is made, under generator build, discussions with the generator may occur as they need to act as a transmission owner and they are responsible for the final design decisions for the offshore works and will be responsible for detailed design, offshore routing, consenting etc. Hence, the NETSO cannot direct but can influence what is built offshore. Under early OFTO build, the OFTO would also have the opportunity to change the design as part of their bid, but would need to explain the reasons for this and would generally need to adhere to the high level principles agreed between the NETSO and generator.

This issue is currently addressed through the NETSO's role in making connection offers subject to their licence obligation to deliver an 'efficient, coordinated and economical' transmission system. But there are questions around whether this produces an optimal outcome given the timescales involved in producing connection offers. The NETSO has expressed a view[32] that its current offers represent the most that is practically achievable under the current framework, and that the current framework and commercial environment may not support or encourage the scale and form of coordination envisaged, for example in the ODIS, given the much greater interaction between projects that would be involved. This view requires further investigation and whilst we believe there are some issues to be resolved around the design interactions between onshore connections and offshore build out (including the challenges with OFTO's or generators changing offshore designs without affecting the onshore connection point), the ability for the NETSO to control connection points places it at the centre, with its existing powers, of achieving a critical step towards coordination.

Lack of vision for a coordinated network

A vision for a coordinated network would provide an indication of what might be involved in its development. Information provision could assist in the development of a coordinated approach by making market participants aware of the wider trade-offs in pursuing a coordinated solution for their particular project. An overall vision for a coordinated network could provide market participants with guidance on:

- what steps need to be taken to deliver a coordinated network,
- how the offshore network is likely to evolve over time, *and*
- opportunities available from a more coordinated approach to offshore network development.

The current regime delivers some information through the ODIS, but the approach taken in the ODIS means that there are limitations to the information provided. For example, network designs for transmission assets are based on four scenarios for generation build, but each design is based on a deterministic representation of the amount of transmission infrastructure that will be required (assuming perfect foresight). One of the scenarios – sustainable growth – includes highly optimistic assumptions about future offshore generation. Whilst challenging to undertake, a process and methodology to capture deployment uncertainty in generation explicitly within the approach would deliver greater insight into the challenges and risks inherent in developing a coordinated network. In addition, the ODIS could be enhanced by continuing to take a long term view on transmission planning and coordination and then constructing a vision of how the system needs to develop in the short- to medium-term to improve the likelihood of achieving the most economic and efficient outcome (coordinated where beneficial) in the face of the long-term uncertainty. This would provide information on how decisions should be phased. This could then help generators inform their project planning, including identifying where combining with other generators could be beneficial.

Some stakeholders have expressed the view that a key challenge is that there is currently no link between the production of a vision (ODIS or others) and the responsibility for investment. Whilst it is clearly the case that there is not a direct link between the production of a vision and responsibility for investment, it is not clear to us that there needs to be such a direct link. There are a number of specific considerations:

- Could the NETSO be better incentivised to plan the network in line with any vision produced?

[32] Bilateral meeting between Redpoint Energy and National Grid, October 4 2011.

- How would the NETSO's (or other parties') risk/reward profile change in line with this, for example would they take on risk of underutilisation of assets?
- Are there any potential conflicts of interest if the same body sets the vision and builds the assets?

In addition, there are a number of further issues:

- The scenarios used are skewed towards the ambitious end of potential projects in offshore wind growth – for example, the 'sustainable growth' scenario is based on 67 GW of offshore build by 2030, requiring extensions to Round 3 Crown Estates zones and development in Scottish Territorial Waters. In comparison, the CCC has considered scenarios with between 20 GW and just under 50 GW of capacity by 2030.[33]
- The assumptions made about the availability of new technologies, particularly large 2 GW HVDC cables, are considered by some stakeholders to be overly ambitious.
- The ODIS also stops short of providing more detailed, region-specific guidance as to the steps required or the costs and benefits of a coordinated approach for particular projects or regions, although more detail is available from joint National Grid and The Crown Estates work on the Offshore Transmission Network Feasibility Study.[34]
- Neither ODIS nor the OTNFS have a significant focus on how uncertainty should be managed and stranding risks mitigated.
- The ODIS does not give detailed consideration to interconnection.

Re-optimisation of the network over time

Changes to the network might be required in response to incremental development as new offshore generators connect. At present, no specific OFTO or generator is responsible for delivering this type of broad-based work to optimise the network in a particular region, although the NETSO is able to issue modifications to connection points under Section 6.9 of the CUSC. Minor additional work on the network could be delivered under the 20% rule for additional OFTO capital spend[35], but this would require a request from a single generator for additional spend by a single OFTO. Broader-scale works might be more difficult to achieve under the existing regime where they require substantial changes to the investment to be undertaken in response to generator need.

The available evidence suggests that the requirement for re-optimisation works will be limited in some zones, but could have more applicability in larger zones. Evidence from the asset delivery work stream does not indicate a need for any major re-optimisation works in general, but this is driven by the assumption of perfect foresight of zonal build. What is clear from this analysis, however, is that in specific zones, such as those on the south coast of England, there is unlikely to be significant re-optimisation work required, as there is limited potential for interaction between zones or with the onshore network. In zones with larger resource potential, there is some opportunity for re-optimisation where the final quantity of build is uncertain and the build of the network develops in a more incremental manner. However, this is

[33] Committee on Climate Change, *The Renewable Energy Review* (May 2011).

[34] National Grid and The Crown Estate joint work for: National Grid and The Crown Estate, *Offshore Transmission Network Feasibility Study* (September 2011).

[35] OFTOs are allowed to pass on charges for incremental investment as requested by the generator. The additional investment is at Ofgem's discretion and capped at 20% of the initial capital expenditure.

critically dependant on the number of options that are feasible after taking account of all of the constraints relating to landing points, environmental issues, technology limitations and consenting. Furthermore, due to technical, security, safety and economic issues, once assets have been built and sited, it can be much more costly to add additional capacity.

Furthermore, it is not clear that the current regime either enables or supports a party that wishes to optimise network build (or build incremental capacity) over time through a process of decision making, reassessment and additional investment. This is because there is no clear process by which it can happen and thus the stranding, development and construction risk would be borne by that party alone (unless it receives regulatory approval).

5.2.3 Risk–reward profile of coordinated investments

Even if there is an adequate anticipatory investment structure and the network planning framework functions well, the risk–reward profile for generators resulting from coordinated offers they receive from the NETSO may mean that they are unwilling to take forward these connections. The key factors that could lead generators to choose not to pursue connection offers which involve coordination relate to:

- user commitment rules,
- transmission charging for anticipatory investment and shared assets,
- lack of incentive for coordination where there are impacts on other developers,
- potential cashflow constraints, *and*
- onshore/offshore interactions.

User commitment rules

At the point of signing a connection agreement, an offshore generator is responsible for securing the costs of transmission assets built by other parties for their connection. This is the means through which the NETSO protects consumers, TOs and OFTOs against the risk of unnecessary transmission investment in the event that a generator terminates its connection agreement or reduces its Connection Entry Capacity or Transmission Entry Capacity during construction. User commitment rules can potentially work against coordinated solutions by creating uncertainty about how much security will be required by generators for shared assets. As discussed in Section 4, it is also likely that a coordinated solution will require some anticipatory investment to prepare for future connections. We consider both issues below.

First, user commitment offshore is calculated according to the Final Sums methodology, which means that offshore generators must secure the full cost of construction of any offshore local works. Where coordinated infrastructure is shared between multiple parties, user commitment for each party is calculated according to clustering and sharing principles, so that securing shared offshore works should not in itself dissuade generators from taking forward a coordinated connection offer. However, offshore generators could still be responsible for securing the cost of reinforcing the onshore network via offshore links, as these works could potentially be classified as local.

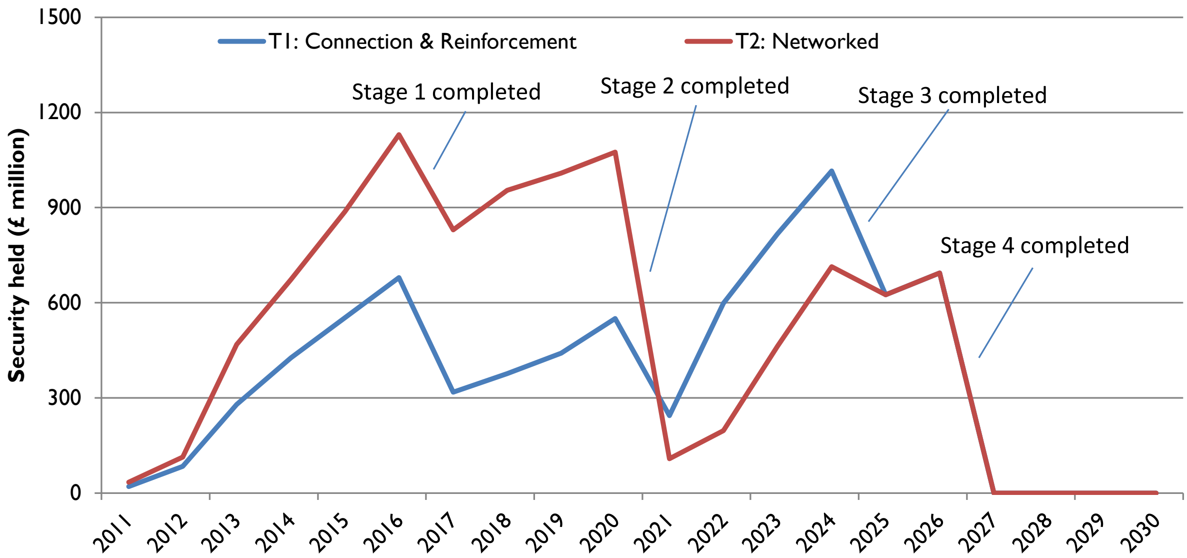
Second, with regard to anticipatory investment, current arrangements can require the initial offshore generator to secure the costs of anticipatory investment, even though they will not be the only party to benefit from lower transmission costs in the long run.[36] Irrespective of whether future connections occur

[36] Under generator build, anticipatory investment would be paid for directly rather than secured by the offshore generator, but the result is the same – offshore generators are responsible for the costs of anticipatory investment to achieve a coordinated solution.

or not, this could dissuade the first generator in a region from pursuing a coordinated solution. Under coordination, user commitment could be higher for initial generators in a zone but lower for generators that connect later (Figure 5). Generators that connect early could be required to hold an additional liability for the anticipatory investment – potentially for several years – until they have connected to the network and their user commitment liability falls away. These user commitment rules have been identified as a barrier to coordination under the existing arrangements[37].

However, these arrangements are currently being reviewed under CMP 192. Proposed changes under CMP 192 would remove generator exposure to anticipatory investment through reducing the liability according to a 'strategic investment factor'.[38] Further, it is proposed that offshore liabilities would be limited to the pro rata share of connection to the nearest reasonable point on the main interconnected system, so that offshore generators would not be responsible for securing the cost of reinforcing the onshore network via offshore links.[39] As of February 2011, proposals under CMP 192 had been consulted upon as part of the modification process and in November 2011a Final CUSC Modification Report has been published. However, approval from Ofgem will be required before any changes can be implemented.

Figure 5 Example: User commitment under interim arrangements - Irish Sea zone[40]



Source: Redpoint Energy analysis, based on data from the asset delivery work stream.

There are linkages between charging and user commitment, but there is no harmonisation of these in the current regime. Charging is the means through which transmission owners earn a return on their investment once they are in use, while user commitment ensures that they still recoup their investment costs for assets that do not get used. At present, there is no link between user commitment for anticipatory investment (local works are entirely secured by the initial generator) and charging for these

[37] For example, in OTCG, *Third Expert Workshop* (June 2011).

[38] The strategic investment factor is a discount that applies in the event that greater capability is built than is required for the forecast generation connecting to that asset. The application of this discount would mean that generators would only be responsible for capacity that they have requested.

[39] National Grid, *CMP192: Arrangements for Enduring Generation User Commitment*, Stage 03: Workgroup Report Volume 1 (September 2011).

[40] See Appendix C for details of build and assumptions used to estimate user commitment. Actual user commitment will depend on the distinction between wider and local works, as well as outcomes from CMP 192.

assets (as discussed below, the initial generator is only charged for anticipatory investment that increases the security of cable connections).

Transmission charging for anticipatory investment and shared assets

Two key issues have been identified with respect to charging for coordinated assets:

- There is uncertainty about how charging will apply to coordinated offshore assets (in particular, meshed HVDC links) where these are shared across multiple users, and
- The first generator to connect under a coordinated build could potentially pay more in transmission charges for anticipatory investment to accommodate other generators.

Charging for shared assets

Uncertainty about charging for coordinated assets is an issue because, under current arrangements, charging for shared assets will depend crucially on the distinction between local and wider assets. The current offshore charging methodology was developed to accommodate radial connections and will not necessarily transfer easily to coordinated designs. As demonstrated in the Irish Sea case study (Appendix D), the share of costs recovered from generators will depend on the treatment of coordinated HVDC links. Charging arrangements for coordinated HVDC links offshore are still being developed, creating some uncertainty about the implications of coordination for generators.

Charging for anticipatory investment

The first generator to connect could be charged more for additional cable and reactive capacity in local tariffs through an increase in the 'security factor' where there is excess capacity and circuit redundancy. The existence of circuit redundancy will depend on whether there is more than one circuit connecting the generator, so that the loss of any one of the local circuits will not prevent the export of power. Charging arrangements offshore have the same structure as those onshore and split transmission charging between specific generators, and all generators and suppliers (which pass on charges to consumers) through wider, local and residual components. The charging treatment of offshore transmission assets varies by asset type (Table 11).

Should they occur, higher charges can give the first generator a first mover disadvantage from a coordinated network, as they have to pay for oversized assets that might not be fully used for many years. In turn this can lead to excessive discounting of benefits in the choice of configuration and investment decisions. There are potentially positive externalities implicit in these arrangements where subsequent projects are developed by different parties, as future generation projects will reap some of the coordination benefits of costs incurred by the first generator. On the other hand, generators are not charged for oversizing of other components. In particular, they are not charged for additional substation capacity: any headroom in the offshore substation design is recovered from consumers through residual charges, as are all onshore substation costs. Also, the first generator will get benefits in terms of a more secure connection where there is excess capacity and circuit redundancy.

Table 11 Current TNUoS charging for offshore generators

TNUoS charging component	Asset types	Charged to
Wider locational	Marginal cost of incremental capacity on main interconnected transmission system	Generator and suppliers within each charging zone
Local circuit	AC and HVDC offshore cable, including additional charges through a security factor where there is circuit redundancy (and up to a maximum security factor of 1.8) HVDC converter station	Specific generator(s)
Local substation	Offshore substation	Specific generator(s)
Wider residual	Ensures correct revenue recovered, including from: • Onshore substation • Excess capacity in offshore substation • Onshore reinforcement • Excess capacity in local circuit (above security factor of 1.8 for multiple circuits and 1.0 for single circuits)	All generators (27%) and suppliers (73%)

To demonstrate how charging arrangements could impose costs on the first generator to connect, an example of transmission charging in the Round 3 West of Isle of Wight zone is presented below. This example is presented to demonstrate how charging might be applied in a relatively simple example with little impact on onshore networks. More detailed results from this case study, as well as a case study from the Irish Sea that demonstrates the materiality of uncertainty relating to charging for HVDC, are contained in Appendix D.

The asset delivery work stream has modelled the development of this zone in two stages, with each stage delivering an equal quantity (450MW) of generation capacity.

- A coordinated build in the West of Isle of Wight zone is shown to require anticipatory investment in oversized transmission assets.
- A radial build involves two separate cable routes to two different offshore substations, delivered sequentially to match the build of generation in the zone.
- Under a coordinated build, a single offshore platform is connected with three 300MVA rated AC cables in stage 1, sized so as to be able to accommodate the additional generation capacity if and when stage 2 is completed.
- Circuit redundancy delivers additional circuit security for the stage 1 generator before the stage 2 generator has connected.

Development of this zone is likely to have little impact on the onshore network, with new transmission build concentrated offshore. Accordingly, we assume that wider residual charges remain fixed at current levels. Where there is no change to wider charges, costs of transmission investment are recovered either through local charges to specific generators, or through residual charges to all generators and suppliers.

Figure 6 Transmission development for the West of Isle of Wight zone, stage 2

Radial build: 900MW generation capacity **Coordinated build: 900MW generation capacity**

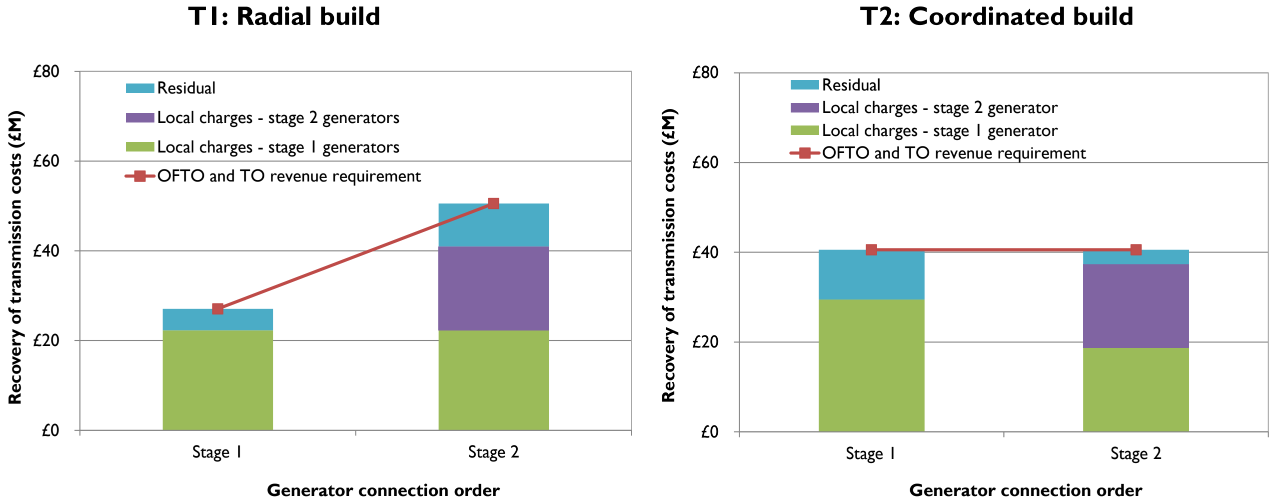
Source: TNEI/PPA analysis for asset delivery work stream

Under the current arrangements for offshore transmission charging, some of the costs of anticipatory investment will be recovered through local charges to the stage 1 generator (Figure 7). At the point of stage 1 generator connection, there will have been higher costs incurred under a coordinated build compared with a radial build, which translates into higher revenue requirements for the transmission owners. Comparing stage 1 radial build with stage 1 coordinated build, both generators (through local charges) and transmission system users as a whole (through residual charges) are responsible for greater annual costs under a coordinated design. This will continue until stage 2 is connected, at which time the stage 2 generator will pay for the cost of the additional transmission infrastructure through their local TNUoS charges. In such circumstances there will be benefits from coordination for both local generators and transmission system users more broadly.

The costs of anticipatory oversizing in this example are shared almost equally between the stage 1 generator and users of the transmission network (Table 12). These costs are calculated relative to a radial solution at stage 1, which does not involve any oversizing to accommodate later generation. The stage 1 generator is responsible for paying £8.5 million annually for additional cable capacity up to the maximum security factor of 1.8 (which, as noted, will also deliver some direct benefits through additional security of supply) and saves £1.8 million annually by paying for only its share of a larger offshore substation. Anticipatory costs from cables, oversizing of the offshore substation and onshore assets of just under £6 million per year are recovered through residual tariffs.

The benefits from coordination accrue to first and second stage generators and transmission users more broadly through lower charges once the second stage of generation is connected. In addition, the first generator receives benefits from increased security of connection before the second generator connects. The benefits available to the first generator indicate that there is a case for it to be charged for at least some of the cost of anticipatory transmission investment.

Figure 7 Recovery of transmission costs for the West of Isle of Wight zone[41]



Source: Redpoint analysis, based on TNEI/PPA data for the asset delivery work stream

Table 12 Recovery of costs of oversizing through charging (£M/year) for various asset types: West of Isle of Wight (stage 1generation build only)[42]

Asset type	Radial design		Coordinated design		Difference = share of oversizing	
	Generator	Residual	Generator	Residual	Generator	Residual
Offshore circuit	£14.3M	-	£22.9M	£2.5M	£8.5M	£2.5M
Offshore substation	£6.6M	£2.7M	£4.8M	£5.5M	-£1.8M	£2.8M
Onshore assets	-	£1.9M	-	£2.4M	-	£0.5M
Total	£20.9M	£4.6M	£27.7M	£10.5M	**£6.7M**	**£5.9M**

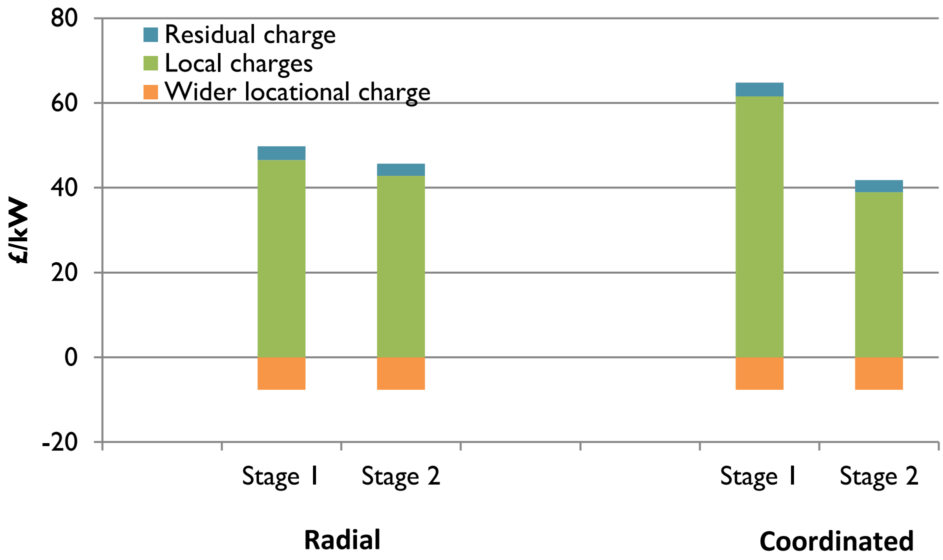
Source: Redpoint analysis, based on TNEI/PPA data for the asset delivery work stream

The charging implications of anticipatory investment in the West of Isle of Wight zone can also be considered with respect to the TNUoS tariffs payable for generators in the zone (Figure 8). This chart shows the charges payable by a generator in the zone, so the residual component is based on projections for the GB-wide generation residual to 2016 and is not comparable with the residual charge component of the recovery of transmission costs, which will be spread across all transmission system users. Wider locational charges are negative in the relevant (Wessex) TNUoS charging zone. Charges to generators in the West of Isle of Wight zone predominantly consist of local charges. Again, a comparison of local charges under radial and coordinated designs shows the potential costs and benefits of coordination from a generator's perspective.

[41] Assumes no change in wider charges.

[42] Wider locational charging assumed to remain constant for this example. Totals may not add exactly due to rounding.

Figure 8 **Transmission charging in the West of Isle of Wight zone**[43]



Source: Redpoint analysis, based on TNEI/PPA data for the asset delivery work stream

Charging arrangements that can allocate part of the cost of anticipatory investment to generators where there is circuit redundancy could dissuade generators from accepting coordinated connection offers, as could uncertainty on charging for shared assets offshore. On the other hand, the West of Isle of Wight example demonstrates that generators could access benefits from coordination through lower charging once generation build has been completed. Issues relating to charging arrangements are more likely to be a problem where the first generator does not receive all the benefits from coordination, as discussed below.

Lack of incentive for coordination where there are impacts on other developers

The issues with charging and user commitment are likely to be a more significant problem where there are multiple generators involved. Under these circumstances, the incentives for a developer to pursue a coordinated solution are likely to be substantially reduced by the number of different parties involved. Where there is only one developer, it will have an incentive to achieve the most cost-effective solution in order to minimise its construction costs and transmission charges for the life of the generation assets. As demonstrated in the 2011 ODIS, in many cases this will be a coordinated connection. For example, two separate but nearby wind farms in the Wash from Round 1 of The Crown Estate leases (Lynn and Inner Dowsing) were connected in a coordinated manner to a nearby landing point just off Skegness using a distribution connection at 33kV. These two wind farms were acquired by Centrica in 2003 and developed as a single project, so that linking to the onshore network was achieved in a single coordinated connection, including a single onshore substation. The benefits of this accrued to a single party. Similar coordination could be expected within Round 3 Crown Estate zones, where entire zones are being developed by single consortia and the interests of generators and consumers in minimising overall transmission costs are aligned. 5 GW of transmission capacity (of the 8 GW expected from Rounds 1 and 2) has already entered

[43] Transmission charges are averaged across all generators in the zone, assuming no change in wider or residual charges.

the OFTO tender process, so much of the capacity to be tendered under the enduring regime will be from Round 3.

However, where there are more parties involved it is likely to be more difficult to achieve a coordinated network as the incentives will be split across multiple parties. The benefits from coordination are unlikely to accrue to a single developer and developers are less likely to take these externalities into account when choosing their transmission links than if they impact the developer directly. This might be the case for coordination between separate zones (for example, Dogger Bank and Hornsea) or between Round 3 zones and adjacent developments in Scottish Territorial Waters. In these cases, NETSO is likely to have an important role in facilitating coordination through connection offers, but this can lead to difficulties where generators have been to date reluctant to sign integrateable offers (as discussed below in onshore/offshore interactions).

Developer cashflow constraints impinge on willingness to undertake anticipatory investment

Connection decisions need to be taken early in the development process, at a time when cashflow for the developer is likely to be at a premium. The connection decision – in particular, whether to pursue a coordinated solution – is likely to affect the initial connection offer from the NETSO. The planning and consenting process will also need to account for detailed design issues including routing and landing points, which are likely to differ depending on whether a radial or coordinated solution is pursued. As such, this decision will need to be made at the start of a process that generally takes around seven years,[44] so that the revenue stream for the investment will still be a long way off. The decision to undertake additional anticipatory investment will need to be made at a stage of the process where project outcomes are uncertain, capital outlay is consequently risky and payoffs are a long way off.

Onshore/offshore interaction

The commercial incentives for generators could compromise the extent to which the overall offshore/onshore network is optimised. Generators, in particular, have an incentive to minimise offshore infrastructure costs only, as they currently secure the full cost of offshore assets and are charged for these directly through offshore local tariffs. This could potentially come at the cost of higher costs to reinforce the onshore network[45]. User commitment arrangements also currently provide an incentive to minimise offshore in preference to onshore costs, as the latter can be secured through the Interim Generic User Commitment Method (IGUCM), or shared with other generators.[46]

This conflict between the NETSO's licence conditions and the commercial interests of generators has led to instances where generators have been unwilling to agree to connection offers from the NETSO. This was reported as evidence of failures in the current arrangements at the fourth OTCG expert workshop.[47]

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[44] Ofgem and DECC, *Government Response to Consultations on Offshore Electricity Transmission* (December 2010).

[45] For example, the Irish Sea case study (Appendix D) shows how offshore generators, under the current charging arrangements, could pay less in local TNUoS charges for a design based on radial connections, even though overall system-wide costs are lower under a coordinated build.

[46] In fact, under temporary arrangements, wider works onshore do not currently require any user commitment at all. See National Grid, *Re: Review of Sharing Arrangements for Final Sums Liabilities*, Letter (July 2010).

[47] Ofgem and DECC, *Fourth Expert Workshop: Commercial, Regulatory and Incentive Issues*, http://www.ofgem.gov.uk/Networks/offtrans/pdc/pwg/OTCP/Documents1/Offshore%20Transmission%20Coordination%20Group%20(OTCG)%20-%20Fourth%20Expert%20Workshop%20Meeting%20note.pdf (July 2011).

5.2.4 Interconnector-OFTO regulatory interface

In addition to links between the onshore and offshore networks, there might be benefits from linking to Ireland or continental Europe via offshore wind farms.[48] The asset delivery study has found that there could be significant capital cost savings (with caveats) from linking interconnectors and offshore generation[49]. Some of the benefits may include:

- Higher utilisation of new infrastructure investment,
- Efficient use of existing and new assets (onshore and offshore),
- Enhanced security of supply through greater redundancy, *and*
- Enhanced security through system balancing to meet demands created by intermittency.

To date, there have been a limited number of comprehensive studies on the economic benefits of linking between offshore generation and interconnectors. The asset delivery study notes that accessing benefits from linking would require sufficient network integration within the wind farm and could constrain technology selection for HVDC links. In particular, linking would be challenging if the interconnector does not use Voltage Source Converter technology rather than conventional Current Source Converter technology. There would also be challenges associated with multi-terminal HVDC hubs and large (2 GW) HVDC links. Work on the North Seas Countries' Offshore Grid Initiative is considering the issues associated with linking offshore networks across countries. In addition, the utilisation of offshore generation linked interconnectors has not been analysed from an economic perspective i.e. to what extent flows are complementary or competing given energy market fundamentals, potentially leading to periods where the export of the offshore generation needs to be curtailed and/or the interconnector is not available as much as desired.

To the extent that there are potential benefits from linking with interconnectors, these can only be harnessed if potential investors are able to access them, which in turn requires that the interface between the regulatory regimes for offshore transmission and interconnectors is clear and compatible. For example, at present, it is unclear how the cost of shared transmission assets could be divided between offshore generators and users of the interconnector. A particular challenge would be to maintain generator access to transmission to export power, while optimising interconnector use of transmission capacity. A broader, though not exhaustive, list of issues includes (although we recognise that some of the issues are not within the remit of the regulatory regime for offshore transmission):

- Permitting and licensing issues
  - How would leasing and permitting work for combined applications from an interconnector and offshore transmission?
  - How can the timelines and application processes be aligned given the multiple jurisdictions that would be involved?
- System operation – who would operate the combined interconnector and offshore transmission assets and how?
- Regulatory issues

[48] SKM, *Offshore Grid Development for a Secure Renewable Future – a UK Perspective*, Report prepared for DECC (June 2010).

[49] Section 2.8 – Integration of an Offshore Windfarm with an Interconnector

- For what licence would the interconnector or offshore transmission licence apply? One or both or a new licence?
  - How would the boundary between onshore, offshore and interconnector assets be defined?
  - How would third party access issues work for an interconnector with offshore transmission?
  - How would the combined assets be regulated from a revenue, charging and tariff perspective?
  - How would the unbundling issues be handled?
- Commercial issues
  - How would the parties calculate the share of revenues and costs?
  - Would the same mechanisms as currently available be used to deal with payment, cashflow and credit issues?

5.2.5 Consenting

The planning and consenting process can act as a barrier to anticipatory investment. As discussed in Appendix A, the IPC process[50] allows for a 'one stop shop' to consenting nationally significant assets through 'associated development', but might not allow any anticipatory investment as part of this associated development. For smaller projects (<100MW), the Marine Management Organisation (MMO) is responsible and there is likely to be more than one consent process required, as onshore transmission requires separate consent under either the Town and Country Planning Act (TCPA) (for example, onshore substations) or the Electricity Act 1989 Section 37 (for example, overhead transmission lines). These processes are the means to achieve compulsory acquisition or wayleaves, as the MMO's planning remit does not extend to onshore works.

In Scotland, where the IPC process does not apply, it is not possible to obtain planning permission via a single application without requiring re-consent when transmission assets are transferred to an OFTO. As for the MMO process, compulsory powers for onshore development must be obtained through alternate processes. However, there are also advantages in the Scottish planning system. In particular, there is agreement upon future infrastructure requirements (based on work by the ENSG[51]), providing a plan and a needs case for transmission development consistent with this plan.[52]

Addressing these issues would address potential regulatory failures in the way that planning and consenting arrangements operate. The consenting process has a crucial role in ensuring that local social and environmental impacts (which typically impose negative externalities) are given due consideration when developing new infrastructure. However, doing so need not create a barrier to anticipatory investment.

[50] There are plans for the IPC to become a Major Infrastructure Unit within a revised departmental structure that includes the Planning Inspectorate. These changes have been passed by Parliament as part of the Localism Bill.

[51] The Electricity Networks Strategy Group (ENSG) is chaired by DECC and Ofgem and brings together network companies, generators, Trade Associations and Devolved Administrations in a forum that aims to identify and coordinate work to help address key strategic issues that affect the electricity networks in the transition to a low-carbon future. Key work by the ENSG has included *Our Electricity Transmission Network: A Vision for 2020*, which set out the GB Transmission Owners' view of potential transmission network requirements to help the UK meet the 2020 renewable energy targets.

[52] DECC and Ofgem, *Third Expert Workshop: Asset Delivery*, Meeting note – 17 June 2011, http://www.ofgem.gov.uk/Networks/offtrans/pdc/pwg/OTCP/Documents1/Offshore%20Transmission%20Coordination%20Group%20(OTCG)%20-%20Third%20Expert%20Workshop%20Meeting%20note.pdf

This is particularly the case when a more coordinated network design could have smaller environmental impacts in the long run, through fewer cables, less onshore reinforcement and fewer onshore landing points. Indeed, under these circumstances, the planning process should create positive incentives for industry participants to coordinate effectively.[53] There might also be a need to clarify the level of justification required to gain consent for anticipatory investment for future needs, as noted through the OTCG.[54]

5.2.6 New technology risks and asset incompatibility

Barriers to coordination relating to technology can be delineated into two main problems. First, there are potential issues associated with the deployment of new technologies in the transmission network. Second, transmission assets will need to be compatible to allow increased interlinkages between areas/countries as these become necessary and it is not certain that this will happen under the current regime without regulatory intervention.

Developers are likely to be reluctant to take a risk on emerging new technologies. In particular, they are unlikely to choose to be the first to use an emerging technology that has yet to be proven in other commercial applications, even where it would appear to offer net benefits and/or cost savings. Even where another party is building the transmission links, offshore generators are unlikely to be keen to take significant risks on new technology, as generators face the greatest risks associated with outages (as discussed in Appendix B). Also, as discussed in Appendix A, many of the technologies anticipated for use as part of a coordinated offshore network push the boundaries of what is technically feasible. In particular, the asset delivery study concludes that there will be challenges in delivering 2 GW HVDC links offshore and multi-terminal offshore hubs in the near term, particularly before 2020. The study also shows that the cost savings from a coordinated network are dependent on the availability of these technologies.

In many cases, avoiding risks associated with untested technologies is likely to be prudent. There are likely to be very real risks from using a 'first of a kind' technology and savings through a better transmission link need to be offset against (potentially much larger) costs if the technology fails and the generator cannot be energised. In any case, the developer is likely to be the best placed to determine if the benefits they gain from a better transmission network outweigh the costs.

However, there are also potentially wider benefits from the proven application of emerging technologies and many of these benefits are likely to accrue within the UK. Such 'spillover' benefits can form an economic argument for government intervention, as the full benefits from technological development are not captured by the party that pays for them, resulting in under provision of research, development and deployment. Benefits from deployment of new technology are likely to accrue as positive externalities to future developers that also choose to use that technology, as it will now have been commercially tested, making the business case far clearer. There could also be benefits through facilitating coordination throughout the network because, as noted above, the benefits from coordination are predicated on the emergence of new technologies.

With respect to asset incompatibility, a lack of standardisation to date has meant that assets installed by different parties might not be interoperable. Three of the largest suppliers of offshore transmission infrastructure produce transmission systems at different voltages, with control systems that cannot interact

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[53] DECC and Ofgem, *First Expert Workshop: Review of the Existing Framework*, 5th April 2011 – Meeting note, http://www.ofgem.gov.uk/Networks/offtrans/pdc/pwg/OTCP/Documents1/Meeting%20Summary%20-%20First%20Expert%20Workshop%20(5%20Apr%202011).pdf

[54] DECC and Ofgem, *Minutes of the Offshore Transmission Coordination Group (OTCG),* Meeting 2: 18 April 2011, http://www.ofgem.gov.uk/Networks/offtrans/pdc/pwg/OTCP/Documents1/OTCG%20meeting%20minutes%2018%20Apr%2011.pdf

with each other. This situation is likely to compromise interoperability and make coordination more difficult and slower to be developed, as noted during OTCG workshops.[55] Some form of standardisation could have merit as a 'public good', where benefits are conferred to all users. These benefits need to be weighed against the potential to constrain technology choices that developers can make and thereby reduce innovation.

5.3 Summary of barriers to coordination – the 'problem statement'

The key barriers to developing a coordinated transmission network under the current regime have been described in this Section, and are summarised in Table 13. Based on this we have produce a summary 'problem statement' that we believe forms the basis for considering changes to the regulatory regime in the following sections.

There are differences in the priority that key stakeholders attach to various problems, with anticipatory investment identified as the key problem at the OTCG fourth expert workshop. This priority extended to problems related to facilitating anticipatory investment, in particular process uncertainty and the risk–reward profile of coordinated investment. With respect to the risk–reward profile of coordinated investment, the OTCG has suggested a greater priority to user commitment than to transmission charging.[56]

[55] DECC and Ofgem, *First Expert Workshop: Review of the Existing Framework*, 5th April 2011 – Meeting note, http://www.ofgem.gov.uk/Networks/offtrans/pdc/pwg/OTCP/Documents1/Meeting%20Summary%20-%20First%20Expert%20Workshop%20(5%20Apr%202011).pdf

[56] DECC and Ofgem, *Minutes of the Offshore Transmission Coordination Group (OTCG),* Meeting 2: 18 April 2011, http://www.ofgem.gov.uk/Networks/offtrans/pdc/pwg/OTCP/Documents1/OTCG%20meeting%20minutes%2018%20Apr%2011.pdf

Table 13 Summary of barriers: the problem statement

Problem	Commentary
Anticipatory investment process uncertainty	Lack of clarity on process and adequacy of existing tools to give certainty on funding for anticipatory investment to keep open desirable coordinated outcomes.
Network optimisation	An optimised network would allow a given volume of generation and demand to be connected efficiently and economically including a coordinated approach where this is beneficial (taking into current and future consumers). The NETSO has a key role in ensuring coordinated network developments, but there are 3 key constraints or challenges to the development of an optimised network, including a) Onshore/offshore interactions including whether the NETSO's role could be improved b) Lack of vision for a coordinated network, including whether the process for short- and medium-term planning decisions could be better informed by improvements to the long-term vision and c) The ability to add sufficient incremental capacity to the offshore network over time, as further needs evolve.
Risk–reward profile of coordinated investments	Even if there is an adequate anticipatory investment structure, it is not clear whether the risk–reward profile (given TNUoS charging and user commitment rules) for coordinated investments will be acceptable for generators.
Interconnector-OFTO regulatory interface	Uncertain/possibly inadequate regulatory framework for interconnector-OFTO connections
Planning and consenting barriers to anticipatory investment	Planning/wider consenting process for anticipatory investment needed to facilitate coordination can be unclear (IPC guidance could prevent consenting beyond firm need) or can involve multiple applications
Technology risks and asset incompatibility	There could be a need for some standardisation to help ensure interoperability and extendibility, particularly if many players and manufacturers are involved. Some of the technology that is key to unlocking cost savings (and means coordination becomes beneficial) is not yet available and the supply chain is relatively small.

5.4 Coordination outcomes under current arrangements

Assessing the extent to which current arrangements will deliver a coordinated network is challenging since there is a limited amount of experience with the OFTO tender system, with only transitional tender rounds undertaken to date. Furthermore, there is no evidence available from OFTO build projects, or from construction of transmission links to Round 3 Crown Estates zones.

The extent to which coordination would be achieved is likely to differ across the four types of coordination[57]:

- coordination within wind farms (or within zones that are being developed by a single developer),
- the use of offshore transmission links to address constraints across transmission boundaries in the onshore network,
- coordination across different offshore zones, *and*
- linking with international interconnectors.

Taking each in turn, based on the evidence we have gathered to date, a possible set of outcomes under the current arrangements are detailed below.

- **Coordination within wind farms (or within zones that are being developed by a single developer)**
  - Within a wind farm, the developer will have incentives to pursue a coordinated transmission solution where the economic costs and stranding risks do not outweigh the economic and other benefits from coordination (in particular, those passed on to the developer through lower TNUoS charges), and has a role in determining the extent to which it coordinates within phases through how it applies to the NETSO for connection.
  - The NETSO is also likely to encourage coordination through connection offers, as evidenced by its ‘integrateable’ offers to date.
  - There are, however, some barriers to generators accepting integrateable offers, in particular relating to uncertainty on the anticipatory investment process and developer uncertainty about recovery of anticipatory investment costs through the assessed transfer value, user commitment for anticipatory investment, and potential planning barriers.
  - On balance, the current regime is likely to deliver some coordination within wind farms, but the barriers noted above mean this is likely to be less than would be optimal taking into account all of the costs and benefits associated with coordination.
- **The use of offshore coordination to increase onshore transmission (boundary) capacity**
  - The current arrangements may not provide a complete and clear framework nor incentives to allow the full trade-offs between the onshore and offshore networks to be explored.

[57] As defined by Work stream 1.

- The NETSO has a critical role in optimising offshore/onshore trade-offs and will attempt to do so through appropriate connection offers.
- However, the capacity of the NETSO to deliver onshore boundary increases through offshore coordination will depend on whether offshore generators are willing to sign 'integrateable' offers. Generators are unlikely to sign connection offers that shift costs for onshore reinforcement offshore, where they are liable for additional costs through user commitment and (possibly) charging, or if they do not have clarity on what user commitment/charging they will face.
- Under generator-build, generators will also want certainty that Ofgem will allow the costs in their asset transfer value if they are building assets for wider use.
- Current arrangements, whereby offshore generators could face additional liabilities where additional infrastructure is built offshore, will act as a disincentive to signing integrated connection offers and could significantly limit the extent to which offshore coordination will be used to increase onshore boundary capacity (pending any changes under CMP 192).

- **Coordination across different offshore zones**
  - There are a limited number of cases where linking across different offshore zones may be justified (based on the evidence from work stream 1).
  - Only specific zones (e.g. Dogger Bank and Hornsea) will be suitable for linking, and even then a detailed needs assessment will need to be undertaken in each case.
  - Coordination through the independent actions of generators may be difficult to achieve as this would require co-operation between different (albeit a limited number) of consortia, though NETSO can require this in connection offers.
  - Overall, some coordination across different zones could be expected as it is possible under current arrangements. However, the requirement for cooperation between consortia means it is less likely than coordination within wind farms and would face the same anticipatory investment process and planning uncertainties.
- **Linking with international interconnectors and networks**
  - While technically such links can work, it is not clear how this would be facilitated under the current arrangements given there is a need for clarification of how the two regimes would interface including licensing and regulatory arrangements.
  - Unlikely to occur without changes to offshore transmission and related regulatory arrangements to provide clarity on how offshore-interconnector interface would work (which might emerge in response to projects at an advanced stage of development coming forth).

6 Intervention measures and options

6.1 Introduction

We have developed a suite of possible intervention measures across the regulatory, commercial and incentive arrangements that could address issues with coordination in offshore transmission investment and build identified above. The intervention measures have been developed from our own analysis, as well as input from OTCG meetings and workshops and stakeholder responses to previous Ofgem and DECC consultation.

The intervention measures represent a mix of incremental changes that could be implemented while still maintaining the existing OFTO tender process, and more substantive changes to the regime that could potentially deliver greater coordination, but would require wholesale changes to the existing arrangements and could entail substantial risks as well as erosion of benefits from competition.

6.2 Regulatory, commercial and incentive measures to deliver coordination

In this Section, each intervention measure is categorised according to the main problem (identified in Section 5) that it seeks to address, namely:

- Anticipatory investment process uncertainty,
- Network optimisation,
- Risk–reward profile of coordinated investments,
- Interconnector-OFTO regulatory interface,
- Planning and consenting barriers to anticipatory investment, *and*
- Technology risks and asset incompatibility.

The key changes required as part of each potential solution are listed upfront. The potential advantages and drawbacks of the solution are then discussed, and advantages and drawbacks for all the potential solutions are summarised in at the end of this Section.

6.2.1 Anticipatory investment process uncertainty

As discussed in Section 5, there are a number of different types of possible anticipatory investments and there are currently barriers to economic and risk managed anticipatory investment being undertaken by generators or OFTOs. Hence, there is a case to either revise or enhance the current regulatory, commercial and incentive arrangements governing anticipatory investment.

For offshore assets within a zone that is being developed by a single consortium, generators will have an incentive to trigger anticipatory investment where this reduces the overall cost of transmission assets that they pay for through TNUoS charges. However, they potentially have less incentive to link to other zones since the linking to other zones has a wider benefit across the network.

There are several considerations for revising or enhancing the process for anticipatory investment. Where the parties that trigger anticipatory investment secure or are charged for a significant proportion of the costs involved, they will have an incentive to undertake anticipatory investment only where the benefits outweigh the costs. As such, the approval process could be relatively light-handed. On the other hand, where anticipatory investment is driven by a party that does not incur the costs involved – such as transmission owners or the NETSO – there is likely to be a need for more regulatory oversight by Ofgem.

There are also likely to be links between the process for anticipatory investment and other policy changes, which are brought out in more detail below and in the policy packages in the following Section. For example, there are likely to be links between the anticipatory investment process and user commitment and charging for anticipatory investment, discussed under the risk-reward profile of coordinated investments section below.[58]

We would expect that any new regulatory arrangements could tie in with some vision or blueprint for future build (potentially on a regional basis where this captures the main scope of coordination) in order to provide a consistent framework for evaluating investments in advance of a specific user need and commitment evident today. We recognise however, that the existing connections framework is capable of allowing a range of considerations to be taken into account. In addition, arrangements should also build on those for anticipatory investment onshore through the TII and price control processes. A revised or enhanced process for anticipatory investment in offshore links will need to provide appropriate incentives and an appropriate allocation of risks to decision makers. It would need to provide answers to several key policy questions, including:

- **Who might benefit from the investment?** In undertaking the investment, does the generator receive a direct economic benefit or is the anticipatory investment for wider system use and benefit?
- **Who can trigger anticipatory investment?**
- **What kind or size of projects can trigger anticipatory investment?** Would only investments with wider system benefits be covered by a new process? Would a new process only be applicable to minor build to facilitate future connection, or for more significant oversizing (e.g. of cable capacity)? What anticipatory investment across the project lifecycle (eg pre-construction costs) might be allowed and how?
- **What is the process for approval? How is it regulated?** Is the approval of anticipatory investment decentralised to the generator and via an automatic process or through a contracted (ie prior approval) process?
- **What security is provided to underwrite anticipatory investment and who provides it?**
- **How are any stranded costs recovered?**

Any anticipatory investment process could either be based on the existing arrangements (clarifying them where necessary), or via an enhancement to the current the arrangements through the introduction of additional or alternative processes which facilitate anticipatory investment subject to effective regulatory

[58] Anticipatory investment processes under each of the policy packages are summarised in Section 7 and the answers to the policy questions on this page are set out in detail in Appendix E.

oversight. Based on consideration of these issues, we have developed a small number of possible approaches shown in Table 14. We detail each of these approaches further below.

Table 14 Summary of possible approaches to anticipatory investment

Approach	Ex ante or ex post approval of anticipatory investment costs?	Automatic approval of specific costs?	Generator benefit or wider benefit
Clarify existing regulatory arrangements for anticipatory investment offshore	Ex post	No	Generator
Enhanced anticipatory investment process – pre-approved	Ex ante for specific costs, otherwise ex post	Yes	Generator or Wider
Enhanced process – 'contracted' ie approval through regulatory review	Ex ante	No - approval determined through regulatory review	Generator or Wider

Clarify regulatory arrangements for anticipatory investment offshore

As noted in Section 5, there exists significant process uncertainty about arrangements for allowing anticipatory investment in offshore transmission. In particular, there is uncertainty for generators undertaking anticipatory investment, as they are unsure on how much (if any) of the cost of anticipatory investment will be approved for recovery through the transfer value determined by Ofgem. Within the current arrangements, this process uncertainty could be reduced by the publication of clear guidance through the existing regulatory arrangements including the Tender Regulations. The guidance (which might be adapted for generator build versus OFTO build) would need to cover a number of areas including:

- Setting out clearly what types of anticipatory investments will be allowed by Ofgem (and therefore considered to be indicative of efficient expenditure) for the purposes of reimbursing generators for their investment costs.
- The process to be used to approve anticipatory investments, which may include the use of some projection for future build in order to inform the likelihood that assets built in anticipation of future need will be used at a later date.
- Specifying a threshold for building assets for a potential future need, which would help to determine what is allowed in terms of anticipatory investment and would thus aid regulatory clarity. For example, a threshold based on the development stage of potential future users could require that they have gone beyond signing a Crown Estates lease and have embarked on the early stages of work to develop a site.

This proposal could offer benefits in accessing economic forms of anticipatory investment, without significant costs or risks. Whilst no guarantees on cost recovery would be provided, the increased confidence that could be generated through a clearer statement of the regulatory process and decision making criteria may be sufficient in some cases to encourage anticipatory investment (where the economic case for the generator is strong).

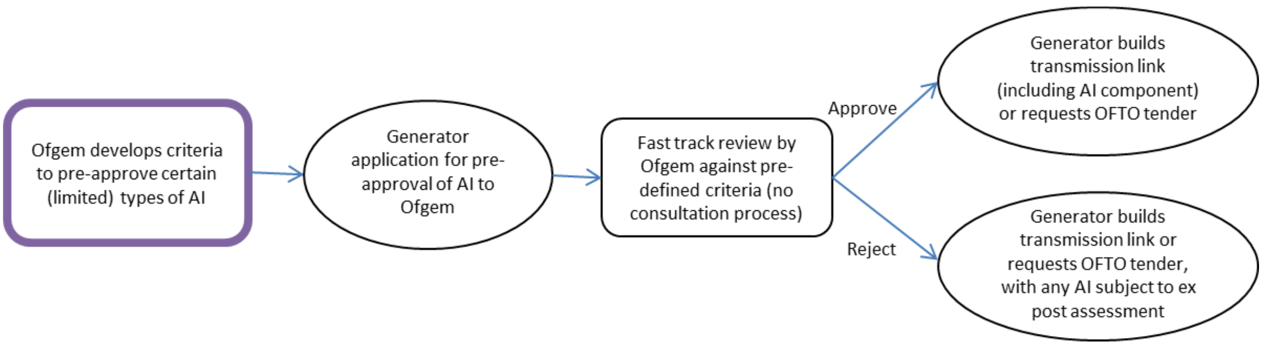
Enhanced anticipatory investment process – pre-approved

Alternatively, more targeted and enhanced measures may be required to appropriately encourage and manage anticipatory investment where it is economic and the risks can be managed appropriately. Under this approach, anticipatory investment expenditure would be automatically approved without a detailed ex-ante regulatory review based on a clear process and criteria developed to expedite straightforward cases with well-developed generator plans.

- Pre-approved anticipatory investment 'schemes' would be subject to clear criteria being met. These criteria could be based on:
  - **size** – for example, that the overall expenditure is less than a given monetary limit,
  - **commitment** – that further generators are fully consented/have passed gating criteria (and potentially provided user commitment based on a connection offer, *and*
  - **low risk** – stranding risk is less than a threshold % of the total cost of the project, or alternatively the required future build is supported by future projections.
- Generators (or the NETSO for plans proposed by it) would need to provide appropriate evidence (business plans and other evidence) that their scheme met the criteria established and in return would avoid a detailed investigation process akin to that run for onshore anticipatory investment (such as TII).
- Returns to the OFTO for the anticipatory element of investment would be underwritten by consumers.
- High-level process steps for this proposal are set out in Figure 9.

Such an enhanced anticipatory investment process could offer benefits through accessing 'low regrets' forms of anticipatory investment. Generators would gain regulatory certainty that they would be reimbursed for relatively small costs associated with anticipatory investment where these are efficiently incurred. In turn this could make the business case more attractive. Such small costs could be associated with development of landing points that allow for additional cable capacity later, or capacity for offshore substations to be expanded where necessary. This would be facilitated through a structured and clear process. However, such a fast-track approach would only be applicable to clear cases where specific criteria are met, so this is likely to exclude high-cost anticipatory investments (such as oversizing of cables) that could impose undue risks on consumers.

Figure 9 Process steps for a pre-approved approach to anticipatory investment (AI)



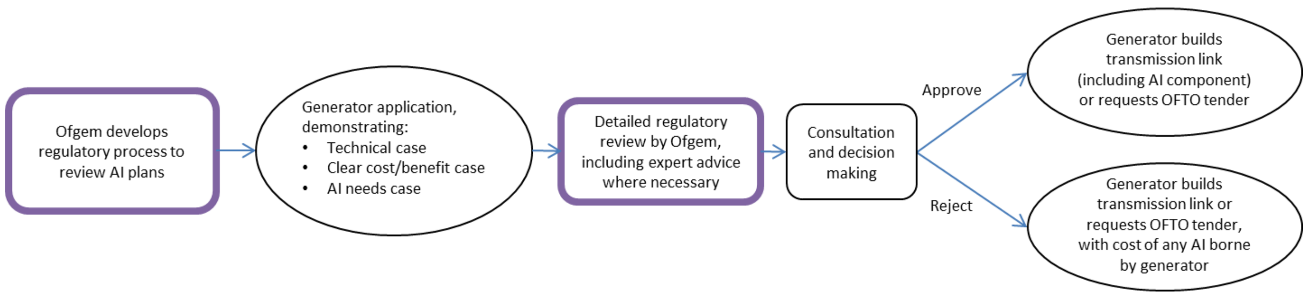
__Enhanced anticipatory investment process – 'contracted'__

Under this approach, anticipatory investment expenditure would be approved ex ante based on a clear regulatory process developed to review and approve generator plans. In this sense, all anticipatory investment would be 'contracted' in terms of regulatory approval for cost recovery and would mirror the process for onshore anticipatory investment.

- 'Contracted' approach: fully approved expenditure through a defined regulatory approval process akin to TII, TIRG etc.
- Generators would put forward detailed business plans with detailed analysis and investigation where they plan to undertake anticipatory investment offshore as part of a connection offer that has been negotiated with the NETSO.
- Once approved, the generator (under generator build) would have certainty on recovery of efficient costs to deliver the agreed anticipatory build. This does not mean they would have certainty on full recovery of costs – construction and supply chain risks would still fall on the party building the new transmission links.
- Once the case for anticipatory investment had been approved, consumers could underwrite a substantial share (or all) of the anticipatory investment and in return retain a share of the future benefits (this will depend on arrangements for user commitment and charging, as discussed in Section 6.2.3 below). The share of anticipatory investment risk taken by consumers might also depend on the type of coordination. For example, consumers might be better placed to take on anticipatory investment risk where there are wider benefits (for example, from onshore reinforcement) than where the benefits accrue to specific offshore generators.
- No overall size limit on anticipatory investment.
- High-level process steps for this proposal are set out in Figure 10.

This approach would have the benefit of delivering certainty on the treatment of anticipatory investment ex ante, but is likely to carry significant regulatory costs. The process required is likely to be time and resource intensive[59]. There are also drawbacks in allocating potentially significant anticipatory investment risks to consumers, even where there is significant regulatory oversight.

Figure 10 Process steps for a contracted approach to anticipatory investment (AI)



[59] The regulatory process to approve the Western HVDC link is a good example (although there were additional issues here with licensing transmission outside GB territorial waters).

REDPOINT

6.2.2 Network optimisation

As discussed in Section 5.2.2, network optimisation problems include planning onshore/offshore interactions, the lack of a vision for coordination and the capacity to re-optimise networks as they develop over time (including interactions with the onshore network). The potential solutions discussed below seek to address one or more of these issues and can be categorised as follows:

- **Extending the existing information available to allow the industry to take effective decisions**
  - Extended ODIS: stakeholder buy-in and pathways to long term coordination
  - Extended ODIS: cost-benefit analysis with Ofgem sign-off
- **Extending the information and coordinated decision making framework to direct coordinated outcomes**
  - Formalised and expanded role for the NETSO in high-level design
  - Central authority blueprint
  - The Crown Estate role in facilitating strategic planning and cooperation
- **Implement alternative delivery, investment and incentive arrangements**
  - TO delivery of active onshore-offshore investment
  - Regional monopoly offshore transmission owner
  - Relax 20% cap on additional OFTO build
  - Provide certainty that offshore transmission builder can recover costs from network re-optimisation
  - Deep connection charges for offshore generators

Extended ODIS: stakeholder buy-in and pathways to long term coordination

An extended ODIS which relates more directly a vision for the long term development of the system to the actions that might be taken in the short to medium term to promote coordinated investments, could create a clearer vision for the industry to consider. This could be achieved through:

- More regional detail, including:
  - more information on what a coordinated build would look like in particular regions.
  - going beyond the current desktop analysis to consider physical and planning constraints in more detail[60] and thus determining a more rigorous 'optimal' coordinated network structure.
  - one approach to deliver more regional detail without excessive expansion of the workload involved would be to concentrate on a single 'central' scenario, with network design that explicitly incorporates uncertainty about overall generation and is robust to different outcomes for generation through a staged build.

[60] These have been considered in some detail outside the ODIS, in National Grid and The Crown Estate joint work for: National Grid and The Crown Estate, *Offshore Transmission Network Feasibility Study* (September 2011).

- Information on possible incremental build and key timing/decision-making points in the face of uncertainty.
- Buy-in from more stakeholders, including:
  - by creation of a cross-industry group (similar to the ENSG – as described in the previous Section) that would cover offshore in a supervisory/ coordination planning role, building on the ODIS work
  - providing a means to access more definitive guidance on the likelihood that future offshore projects will proceed, and
  - facilitating detail on international developments through the North Seas Countries Offshore Grid Initiative.

Moving to a single central scenario for the ODIS would require uncertainty about offshore generation deployment to be incorporated explicitly in build decisions for this scenario, which would be challenging. For buy-in to be effective, this would need to achieve active input and access more definitive guidance on the likelihood of future offshore projects from developers. There is some risk here that developers would give misleading indications to tip the chance of a more favourable transmission connection, so concrete evidence (for example, signed connection agreements) should still be preferred where available.

Extended ODIS: cost-benefit analysis with Ofgem sign-off

Further extensions to the ODIS could allow it to become a benchmark for achieving regulatory and planning approval for new transmission build, perhaps on a case by case (eg zonal) basis. This could be achieved through:

- Robust cost–benefit analysis of different levels of coordination in the ODIS.
- Ofgem consultation or sign-off on coordinated network solutions to provide further comfort and direction to developers.
- Providing a strategic plan to justify anticipatory investment through the planning system[61] but with the ODIS remaining an information statement rather than a plan for how transmission build must proceed.

This would be a useful signal for whether anticipatory investment would receive regulatory approval for OFTO or generator-build recovery of costs. However, this approach would require a significant amount of detailed work including a very high regulatory burden associated with sign-off on an evolving document. Like any centralised plan, it would be subject to the risk of continuous revision as user and network needs evolve.

[61] As suggested at the OTCG, *Third Expert Workshop,* Workshop hosted by Ofgem and DECC (June 2011).

Expanded role for the NETSO in high-level design

Whilst the NETSO has the potential to play a significant role in optimising network design, as discussed in Section 5.2.2, there are some challenges in how it can perform that role, including the willingness of developers to accept connection offers that the NETSO makes.

At a minimum, an expanded role for the NETSO in high-level design would build on the NETSO's current role in developing the onshore and offshore networks (through connection agreements) by incorporating an increased role for the NETSO in providing high level reference designs for the entire offshore network. This might include high level technical and operating parameters, but it would not extend to a final design specification or consenting.

NETSO provision of high level reference designs could address potential problems with asset incompatibility and provide a clearer vision on grid design, but would place some constraints on transmission builders' decision making. However, these constraints would be limited, as the NETSO would not be responsible for the routing or detailed design of the offshore elements. In addition, the reference design could also include interconnection and European integration aspects of network optimisation. As part of this, the NETSO role could be better incentivised/structured such that, for example, it takes on some risk associated with good and bad designs.

A further expansion in the role of the NETSO (which may require licence changes) could involve the NETSO stipulating that OFTOs build certain 'least regrets' coordinated assets. This might include development of landing points that allow for additional cable capacity later, or capacity for offshore substations to be expanded where necessary. However, a role of the NETSO in mandating investment would be likely to require changes in roles, responsibilities and incentives, so has not been included in the more limited proposal above.

Central authority blueprint

The development of a full blueprint encompassing both design and development details produced by an independent central authority body would go beyond an extended ODIS. It would involve:

- An independent central authority responsible for overall system design of the offshore network.
- The NETSO would need to be involved in developing the central blueprint (building on work for the ODIS), but might not be best placed to act as the central body responsible for finalising the blueprint. For example, through the OTCG, potential conflicts of interest have been noted if the NETSO was given the central design authority role (given NGET's onshore transmission interests)[62]
- Design based on rigorous analysis that goes beyond desktop research to include physical and planning constraints. The design would need to consider explicitly the costs and benefits of different designs through an optioneering process to identify, appraise and select a technical design option to address a transmission system change requirement (similar to the process applied onshore).
- Regulatory consultation or approval (in a form to be determined) for the blueprint.

[62] DECC and Ofgem, *First Expert Workshop: Review of the Existing Framework*, 5th April 2011 – Meeting note, http://www.ofgem.gov.uk/Networks/offtrans/pdc/pwg/OTCP/Documents1/Meeting%20Summary%20-%20First%20Expert%20Workshop%20(5%20Apr%202011).pdf

The information in a blueprint would address the problem of a lack of vision for an offshore network and interactions with the onshore network. A design blueprint could also address the problem of the risk–reward profile for coordinated infrastructure if extended to a mandated coordinated build according to the blueprint and if the additional regulatory oversight allows consumers to take on a greater share of risks through charging and user commitment. By stipulating exactly what assets should be built and where, a central blueprint would provide significantly more direction on system design than an extended ODIS.

A number of stakeholders have argued that a centralised plan is necessary, including, WWF, Statkraft UK (through a role for the NETSO to develop connection agreements ahead of contractual commitment by the generator), and Renewable UK and Scottish Renewables (through a central authority responsible for the design of an offshore network). Scottish Power Renewables has argued through the OTCG forum that there is a role for more formal central planning to minimise the number of parties and interfaces involved.

On the other hand, there would be substantial risk of bad decisions if the blueprint is based on incorrect assumptions about future generation deployment, which is likely given uncertainty about future build (as detailed in Appendix A). The OTCG has also noted that continued technology development would present a challenge when developing a design blueprint.

The Crown Estate role in facilitating strategic planning and cooperation

The Crown Estate is a co-investor in all Round 3 tender zones, up until consenting stage. This could enable it to take an active role in promoting coordination during the planning stages, it could identify opportunities for linking across different projects with which it is involved. In particular, identifying potential benefits from linking across zones that are being developed by different consortia, as all will have Crown Estates involvement in the early stages of development.

Active pursuit of coordination by The Crown Estates would be consistent with their statutory objective to maintain and enhance the land and property rights under The Crown Estate management, where there are environmental and commercial benefits from coordination. This is likely to be particularly relevant for pre-construction elements such as consenting, as The Crown Estates has a commercial stake in the projects at this point. However, The Crown Estates' immediate commercial incentive is to get wind farms operating as quickly as possible, which could constrain its incentives to promote coordination if this leads to increased complexity and timing delays in the near-term.

TO delivery of active onshore-offshore investment

This solution has been proposed by National Grid and would involve two key changes to existing arrangements:

- An increased role for the NETSO in providing high level reference designs for the entire offshore network, as described in the option above
    - the reference design, in conjunction with a set of allocation principles, being used to determine whether a particular asset is tendered by Ofgem (as currently, through either OFTO build or generator build options) or built by the relevant onshore TO.

- A role for onshore TOs in constructing all 'active' elements of the onshore and offshore transmission networks.[63]
    - active elements are defined as those parts of the network that accommodate through flows and are thus used by multiple parties:
        - would include links from onshore to onshore via and between offshore wind farms that can be used to address onshore constraints, but would not include direct links (even HVDC links) from a single offshore zone to an onshore connection point (i.e. those not required for through flow)
        - National Grid have estimated that active links are likely to form about 40% of total offshore connection cost under an accelerated growth scenario for offshore generation (35 GW of installed offshore capacity by 2020 and 53.5 GW by 2030).
    - incentivisation for onshore TOs would be set on a regulated basis (based on the RIIO framework used onshore) rather than through a tender system.

As above, NETSO provision of a high level reference designs could address the potential problem with asset incompatibility identified in the previous Section and would also provide a clearer vision on grid design. This would need to outweigh the potential downside associated with the constraints placed on technical and operating parameters for transmission builders, owners and operators.

Delivery of all active links in a region by a single party would allow for re-optimisation of these links as generation and demand positions alter, as well as coordination of offshore and onshore consents for the active network. Involvement of one party across significant parts of the offshore network could also allow onshore TOs to support the development of HVDC technologies. This could address potential technology risks, and facilitate development of supply chains for new technologies. Where significant anticipatory investment is required to deliver a coordinated network and this is not backed by user commitment, however, there would still need to be a regulatory process for approval of anticipatory investment, as for similar investment onshore (such as the Western HVDC link).

On the other hand, having a single party or parties design active elements of the network carries the risk of suppressing competitive benefits and innovation for these parts of the network and could reduce the financial pool. Under current arrangements, different generators or OFTOs can design different parts of the network, allowing competition to drive innovation in the way networks are designed and managed. The competitive aspects of the current regime have generated benefits by attracting new and low cost sources of capital, but also through innovative approaches to minimising operating and maintenance costs.

Regional monopoly offshore transmission owner

This proposal would involve:

- A single regional monopoly OFTOs responsible for delivering the entire offshore transmission infrastructure needs within a defined region.

[63] National Grid's proposal only extends to England and Wales, matching the boundary of their onshore TO responsibility. However, here we have assumed that if this solution were implemented it would be applied consistently across the whole GB network, so that Scottish Power Transmission Limited and Scottish Hydro-Electric Transmission Limited would have a similar extended role in Scottish offshore waters.

- The regional OFTO would be expected to take into account their knowledge of likely future build within the region and deliver transmission links accordingly, backed by user commitment as per onshore arrangements.
- Definition of a 'region' for the purposes of appointing regional OFTOs could vary by location
    - the largest size required to optimise offshore connections would incorporate all offshore development zones that might economically be linked under a coordinated network – for example, combining the Dogger Bank and Hornsea zones on the East Coast.
    - a practical approach could be to define regions based on Round 3 Crown Estates zones and any adjacent areas being developed as part of Round 1, 2 or Scottish territorial waters.
- Regional OFTOs would be chosen through a tender proposal that specifies costs to deliver, own and operate any immediate transmission needs, but only a required rate of return for future assets, which would be regulated under regular price controls.

Allowing just one party to deliver all transmission assets would allow the regional OFTO to take responsibility for delivering a coordinated network within that region, and to re-optimise the network as new generators connect and additional transmission links are provided. The regional OFTO's knowledge of likely future build should reduce the risk that impacts on future transmission links would be ignored. For example, a regional OFTO would be unlikely to take actions that sterilise access to important landing points if they believe they are likely to need to use these landing points in the future, and if the OFTO is subject to an efficient outputs-based framework which penalises poor decisions. Conversely, the regional OFTO may not be able to optimise onshore-offshore investment and would still require regulatory approval to recoup the costs of significant anticipatory investment that is not backed by user commitment.

However, having a single party or parties design a fully coordinated network carries the risk of reducing the benefits of on-going competition both in terms of pricing and innovation in network design (as discussed above relating to the proposal for TO delivery of active onshore-offshore investment). There could be impacts on existing projects in some areas, complicating the change where these could not easily be transferred to the regional OFTO.

In addition, the generator build option might not be compatible with a regional monopoly as proposed, which would reduce the capacity for generators to control risks, in particular relating to timely connection. Further, it is unclear that a regional monopoly transmission owner would have access to significant additional knowledge on future build since this will depend on generator decisions.

Choosing a regional OFTO would also be a significant challenge. Choosing a regional OFTO would be considerably more difficult than a tender to build a single link, as the eventual quantity of transmission links that will be required is unknown at the time of the tender. It would be difficult for bidders to set bid costs under this uncertainty. Evaluation of tenders would be complicated by the trade-off between current cost (to meet immediate needs) and future costs (based on required rates of return). This approach would require regular price controls (as for onshore transmission owners) to set returns to each regional OFTO, creating additional regulatory burdens that do not exist under the existing tender-based regime. There is also a lack of data available to a regulator (for example, historic costs offshore) with which to assess company claims and/or benchmark them appropriately.

Another approach to choosing a regional OFTO would be to extend the responsibility of the onshore transmission owners, but this would have drawbacks through conferring responsibility to a single provider without considering if other parties are better placed to deliver offshore transmission.[64]

Relax 20% cap on additional OFTO build

Current arrangements cap any incremental investment by an OFTO (at the request of the generator) at 20% of the initial capital costs or transfer value of the assets. This proposal would involve:

- Relaxing the cap on additional OFTO build to allow for more significant extensions to existing OFTO assets where a future expansion is required to meet increased transmission demand from the same generator.
- As currently, incremental investment could only be undertaken at the request of the generator, with a request to the OFTO via the NETSO. This would be necessary to remove the risk of OFTOs undertaking excessive capital works, the costs of which are then passed on to generators.

This change has the potential to save on future tender costs, as at present a generator must go through another OFTO tender process if they want to increase capital expenditure by more than 20%. The cost of running an OFTO tender process has been estimated at approximately £560,000 for each project.[65,66] However, there is a risk that OFTOs would be able to increase the cost charged for additional capital expenditure up to the cost of running another tender process, as there would be no other constraint on the price they could charge. To mitigate this, Ofgem could have a continued role in approval of incremental spend.

Provide certainty that offshore transmission builder can recover costs from network re-optimisation

As discussed in Section 5, generators involved in building offshore transmission infrastructure have some uncertainty as to whether they will be exposed to costs where NETSO re-optimisation means that the onshore landing point is changed as a consequence of a Modification to the generator's connection offer. Addressing this issue would involve:

- Issuing guidance that indicates that additional costs incurred as a consequence of NETSO re-optimisation will be recoverable through transfer payments to generators where:
  - the costs are incurred as a consequence of changes in the landing point, *and*
  - the Modification was proposed by NETSO as a consequence of external changes, rather than a consequence of the actions of relevant offshore generator.

[64] Another alternative would be for tenderers to nominate their price cap for building all future transmission assets in the zone, based on key cost drivers that are unknown at the time of the tender. For example, tenderers could nominate a price cap in pounds per GW kilometre that needs to be connected (with distances measured from generators' connection point to the nearest MITs point). This could provide a strong incentive for the regional OFTO to deliver a coordinated network, but would impose considerable cost and technology risks onto the regional OFTO. This uncertainty is likely to render this approach unworkable – experience with private finance initiatives (on which the OFTO tender regime has been based) shows that these do not perform well under circumstances of significant uncertainty.

[65] Phillips, J., "Offshore transmission issues: the new regime explained", *The In-house Lawyer*, Burges Salmon (July 2009).

[66] Another approach to reduce the time and cost of tender rounds could be to use an 'empanelled vendor' approach, whereby a panel of preferred vendors are established from the first tender round in a region, potentially avoiding the Pre-Qualification stage of future tender rounds, saving approximately 4 months from a 13 month process.

The key advantage of this change would be to give generators the confidence to proceed with planning and build of offshore transmission according to their connection offer. It would also have more direct benefits for coordination by facilitating the NETSO's role in network re-optimisation. Recovery of these costs by the transmission builder would reflect the wider system benefits of network re-optimisation as demand for use of the transmission network evolves over time.

Deep connection charges for offshore generators

This proposal would involve 'deep' connection charges to offshore generators, which allocate onshore constraint costs to new generators that trigger these costs.

Deep connection charging for offshore generators would seek to address the issue of interactions and externalities between the onshore and offshore transmission networks. This would provide an incentive for generators to optimise the overall offshore/onshore design and would encourage coordination where this minimises capital investment costs (paid for by the generator). However, it would be inconsistent with arrangements onshore, and would create the same problems with allocating lumpy costs of investment to meet incremental changes. As such, this option is not developed in any further detail here.

6.2.3 Risk–reward profile of coordinated investments

Risks from coordinated investment will arise through generators' exposure to the costs of coordinated assets through charging and user commitment. There are also risks associated with anticipatory investment, as some party will have to bear the cost if future generation investment does not proceed as expected. There are also potential rewards from coordination, in particular through lower capital costs from a coordinated network. The risks and rewards of anticipatory investment can be shared between generators and consumers through user commitment and charging arrangements. These arrangements could also place some anticipatory investment risk on OFTOs. Finally, open seasons are a means to empower transmission builders to take risks on future demand for transmission assets and access rewards from coordination using a 'user pay' principle.

Clarify arrangements for sharing of coordinated assets through user commitment and charging

As identified in Section 5, there is currently a lack of clarity on user commitment and charging for shared, coordinated assets, both of which will depend crucially on the distinction between local and wider assets. Clarifications would encompass:

- User commitment arrangements to ensure that offshore generators are not responsible for securing the cost of works to reinforce the onshore network via offshore links
- Charging arrangements for coordinated offshore networks, in particular for coordinated HVDC links that reinforce the onshore network

These changes would have the benefit of addressing barriers to generators accepting coordinated offers from the NETSO. At present, offshore generators could be reticent to take up coordinated offers where works that are undertaken in part to reduce onshore constraints could be classified as local and thus secured by and charged to offshore generators. For user commitment, addressing this problem would involve explicitly specifying that offshore generators would not be responsible for securing the cost of reinforcing the onshore network via offshore links, as proposed under CMP 192. For charging, the local/wider classification of complex systems such as coordinated HVDC links is important, as demonstrated in the Irish Sea case study in Appendix D.

There are minimal risks associated with this proposal. Any reduction in user commitment for offshore generators will increase risks for other users of the transmission system, but it is not clear that offshore generators are best placed to manage risks associated with reinforcement of the onshore network. Clarification of charging arrangements will need to occur in line with the development of charging rules for coordinated offshore HVDC links.

Consumers underwrite anticipatory investment through user commitment

Currently, generators are required to underwrite any anticipatory investment in offshore transmission as they are responsible for securing the full cost of transmission investment through final sums. Shifting some or all of the responsibility for securing anticipatory investment to other users of the transmission system would involve:

- Where there is anticipatory investment, reducing the amount of capital that offshore generators are required to set aside.
- Generators would still be required to secure works that are needed immediately for their current project, but only a share (or none) of the cost of works above and beyond current needs. Where these assets are required for another generator with a current connection offer they would be secured by the other generator. Where assets are required for future projects that have not yet signed a connection offer, they would not be secured by generators[67].
- The NETSO would underwrite the remaining share of anticipatory investment and would then be allowed to pass these costs through to other users of the transmission system.

There are likely to be a couple of key benefits from reducing the role of generators in securing anticipatory investment. A reduction in the risk imposed on generators from a coordinated approach will increase their incentives to pursue a coordinated connection, offering access to the benefits discussed in Section 3. There are likely to be benefits from harmonising the extent to which consumers underwrite anticipatory investment with their charging for these assets; as discussed in Section 5, consumers are already responsible for a significant share of charging for anticipatory investment, so there is little need for securitisation of assets that are certain to be recovered through charges to consumers. The main downside is the additional risks taken by other users of the system, but there are also some potential benefits for consumers where this enables lower cost or more timely network reinforcement.

As discussed in Section 5, changes to user commitment currently under consideration through CMP 192 could achieve these changes by moving risks associated with anticipatory investment away from generators, through reducing the liability according to a 'strategic investment factor'. The application of this factor would mean that generators would only be responsible for capacity that they have requested.

[67] Provision of assets required for future projects that have not yet signed a connection offer is likely to require additional changes to the regulatory framework, as current arrangements require that the NETSO only take into account connections that are currently contracted when making a connection offer.

Consumers responsible for a greater share of charges for anticipatory investment

Whereas changes to user commitment would affect the treatment of assets before connection, this change would affect charging for anticipatory investment post-connection as follows:

- A smaller share of the cost of anticipatory investment would be allocated to generators through the TNUoS charging methodology
  - currently, generators are charged the full cost of oversized cable capacity (where there is circuit redundancy) through the security factor, up to a maximum of 1.8 times
  - as detailed in Section 5, consumers are responsible for any further cable capacity and oversized offshore and onshore substations, which means in many cases that that there will be limited scope for reducing the consumer share of charging for anticipatory investment
  - reducing the generator share of anticipatory investment would thus involve reductions in the extent to which greater cable security is reflected in charges to offshore generators
  - in particular, this option would involve ensuring that generators do not pay excessively for assets that are primarily for onshore network reinforcement (even if they provide increased security for the generator).
- Remaining costs of anticipatory investment – now a greater share if anticipatory investment delivers additional security benefits – would be allocated to consumers through residual tariffs.
- Charging to consumers would only continue for as long as the additional investment remains 'anticipatory': once other generators connect and the assets are fully in use, the cost of the assets would be fully recovered by charges to the generators.

In principle, the share of anticipatory investment that consumers bear through residual charges should reflect their share of the benefits from anticipatory investment. Other benefits from anticipatory investment are likely to accrue to consumers where this allows lower cost or more timely network reinforcement, particularly for reinforcements to the onshore network. Charging to consumers that is commensurate with these other benefits (i.e. the benefits that do not accrue to the first or subsequent generators) would allow generators to make more appropriate anticipatory investment decisions. The generators' share of the costs of anticipatory investment would be equal to their share of the benefits, so that in trading off the costs and benefits from their own perspective, an appropriate outcome for overall societal welfare can be reached. For example, if a developer receives half of the benefits from coordination through lower TNUoS charges, and takes on half the risks, they will have an incentive to undertake coordination where the total benefits outweigh the costs, as overall trade-offs will be the same (albeit double the magnitude) as those for the generator. If a generator receives half of the benefits but takes on all the risks, they might not have an incentive to request a coordinated connection even where the full benefits outweigh total risks.

However, estimating the precise share of consumer benefits from anticipatory investment is likely to be very difficult and it is not clear that this would *a priori* justify an *increase* in consumers' share of charging for anticipatory investment. Generators are currently only charged for anticipatory investment where this delivers additional security in their connection, and this delivers immediate benefits to the generator (even where the anticipatory investment is undertaken for the purposes of onshore reinforcement). Allocating too great a share of charging for anticipatory investment to consumers could impose undue risks onto consumers and – assuming that other barriers to anticipatory investment are removed – mean that generators have an incentive to undertake excessive anticipatory investment in the knowledge that the relevant charges will be transferred to consumers. For example, current arrangements would see about half of the costs of offshore anticipatory investment to connect the West of Isle of Wight zone in a coordinated manner recovered through residual charges, and thus ultimately falling on consumers (see case study example, Appendix D, and discussion in Section 5). Delivering any higher share of charges for anticipatory investment to consumers would see them taking the majority share of charges for oversized assets. We believe that any increase in the share of anticipatory investment charged to consumers is likely to require compensating increases in regulatory oversight to avoid transferring excessive risks to consumers. This in turn could carry costs in terms of an additional regulatory burden and the risk of more conservative system planning decisions.

Allocate risk from anticipatory investment to OFTOs

OFTOs are a third party that could potentially take on some of the risk associated with anticipatory investment under a coordinated build. This proposal would require:

- A single OFTO responsible for delivering a defined block of coordinated build – for example, under a regional OFTO[68].
- Tie OFTO rewards to achievement of specific metrics indicating delivery of a coordinated network.

The difficulty with allocating anticipatory investment risk to OFTOs is designing a mechanism whereby they are also able to access the rewards from coordination. Delivering market incentives for coordination would require that the OFTO is able to access the benefits from coordination by having the prices they charge locked in before they decide on routing and network design. This would be very difficult to achieve in a regulated setting. Linking rewards precisely to an administrative estimate of benefits from coordination would require comparison with a 'hypothetical radial' baseline, which is likely to be complex, controversial and expensive to administer. The approach noted above could encourage some degree of coordination, but would not align broader benefits of coordination (for example, cost savings and environmental benefits, as set out in chapter 3) with benefits to the OFTO (tied to specific metrics).

For these and other reasons, risks from anticipatory investment have not been fully allocated to transmission owners onshore. Currently, TOs receive an annual return on any anticipatory investment that is approved by Ofgem through TII arrangements. The arrangements for anticipatory investment under the new RIIO framework for price setting will basically follow from this, with a return on the capital costs of any anticipatory wider reinforcement that receives funding approval from Ofgem. In both cases, this means that the risks from anticipatory investment are largely placed onto consumers. A similar approach is taken in other regulated infrastructure industries, for example in water, where Ofwat has approved returns on some anticipatory investment.[69]

The difficulties in developing appropriate incentives for infrastructure owners to take on risks and rewards from anticipatory investment onshore and in other industries means that significant caution should be taken

[68] Where there are multiple OFTOs involved in delivering multiple connections, it would be unclear which party had been responsible for achieving a coordinated network and thus challenging to allocate rewards from coordination to the correct party. Discussion at the OTCG third meeting noted that, under current arrangements, OFTOs are unlikely to spend more than the minimum required on, for example, increasing cable capacity, as this will disadvantage the OFTO in the bidding process.

[69] For example, in Ofwat's 2009 price determination, sewage treatment capacity expansion was approved to meet demands of an additional 1.8 million customers against expected population growth of 1.5 million, partly because "some companies are investing strategically to anticipate growth in future planning periods" – Ofwat, *Future Water and Sewerage Charges 2010–15: Final Determinations* (November 2009).

in shifting anticipatory risk to OFTOs, unless there is a clear manner for achieving an appropriate risk/reward balance that would provide incentives to deliver a coordinated network.

Open season with generator commitment

An 'open season' would require the builder of a new shared infrastructure asset to consult with potential users to gauge interest and undertake initial contracting for use of the asset (and which could ultimately be extended to a 'user pays' principle). This would require a process as follows (in line with good practice for open seasons[70]):

- Ofgem develops guidelines for conduct of open seasons, and requirements for transmission owners to obtain a licence following an open season.
- Transmission builder identifies an opportunity for developing a coordinated transmission link that would serve several offshore generators or other users.
- An informal, non-binding first stage of open season is held to gauge interest from potential users.
- A binding, second stage of open season to sign up users through precedent agreements.
- Ofgem grants a licence to transmission builder if they have met requirements set out as part of the open season regime.
- Transmission builder constructs and then operates assets, earning revenue in accordance with precedent agreements with users.
- Third party access arrangements to apply to any transmission capacity not subject to precedent agreements.

Open seasons have been used successfully to regulate build of new gas pipelines in some European countries, as well as by the US Federal Energy Regulatory Commission (FERC). In this context, the open season is used to evaluate demand for a new gas pipeline and size the build appropriately. Open seasons have also been used as a means to provide new electricity transmission assets in the US.[71] Open seasons provide incentives for provision of natural monopoly transmission assets, as the benefits from a single transmission owner serving multiple users can be accessed by the transmission owner. For offshore transmission, open season arrangements could operate alongside existing OFTO tender arrangements, in particular by offering a means by which transmission assets could be built that link multiple offshore zones.

However, signing generators for long-term use of transmission assets might be difficult, particularly where there is uncertainty about future build under a sequential build out of a region. For example, the interconnector regime in the UK has been based on signing up users to long-term contracts (although not through open seasons), and combined with other factors this has seen relatively little new interconnector investment.[72] That said, the lack of interconnector investment might be partly a function of specific regulatory arrangements – in particular, the actual and perceived difficulties of obtaining an exemption from third party access arrangements – rather than a necessary consequence of long-term user contracts.

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[70] For example, as set out by the European Regulators Group for Electricity and Gas, ERGEG Guidelines for Good Practice on Open Season Procedures (GGPOS), Ref: C06-GWG-29-05c (May 2007).

[71] For example, by the Bonneville Power Administration: see Schumacher, Fink and Porter, *Moving Beyond Paralysis: How States and Regions are Creating Innovative Transmission Projects*, National Renewable Energy Laboratory Subcontract Report (October 2009).

[72] Electricity Networks Association, *OFTO forum*, 15 August 2011; Gence-Creux, C. *Is There a Role for Merchant Lines in the Development of Interconnections?*, EU Law and Policy Workshop, November 12 2010.

Application of Connect and Manage to offshore transmission

There could be some clarification of the applicability of Connect and Manage to onshore components of transmission reinforcement needed to connect offshore generators, for example in National Grid guidance on Connect and Manage. As discussed in Appendix A, Connect and Manage is applicable to any wider onshore works required to connect offshore generators, as set out in the Government conclusions document.[73] The application of Interim Connect and Manage arrangements to several offshore generation projects indicates that developers are aware of the applicability of these arrangements, although National Grid guidance on the subject does not explicitly note the applicability to offshore generators.[74]

There is unlikely to be merit in extending Connect and Manage arrangements to offshore links in the short term, due to different security requirements offshore.[75] In the longer term, Connect and Manage could be applicable to offshore links once a coordinated offshore network has been established. This would require networks to be established that have redundancy available so that offshore connection could be made before all wider offshore works have been completed – for example if the Main Interconnected Transmission System (and attendant SQSS security requirements) was extended offshore.

6.2.4 Interconnector–OFTO regulatory interface

Allow regulatory compatibility with international interconnectors

Compatibility with interconnectors would allow developers to access potential cost savings from linking, as discussed in previous sections. This could be achieved through:

- Maintaining two separate regulatory regimes for offshore transmission and interconnectors.[76]
- The OFTO regime would continue to apply to the link from the onshore network in GB to the generator, with the link from the generator to the other country treated as an interconnector
    - the legal boundary between OFTO and interconnector would need to be clear.
- Compatibility of two separate regulatory regimes would require consideration of third party access and pricing for joint access to transmission infrastructure
    - in particular, regulatory arrangements would need to be developed for recharging of interconnector access to transmission infrastructure, so that net charges to generators are reduced proportionately with additional use of their transmission assets.
- Arrangements for renewable subsidies and credits need to be clarified
    - these arrangements go beyond the scope of this study, but would include whether the offshore generator is eligible for Renewable Obligation Credits (ROCs) (or Contracts

[73] DECC, Government Response to the technical consultation on the model for improving grid access, http://www.decc.gov.uk/assets/decc/consultations/improving%20grid%20access/251-govt-response-grid-access.pdf (July 2010).

[74] National Grid, *Connect and Manage Guidance*, version 5.0 (January 2011).

[75] For offshore transmission, the SQSS only requires a security factor of 1; that is, connections only need to have the capacity to deliver the full load of generation output, without any redundancy. Any derogation from this under Connect and Manage would mean that not all generation could be delivered to the onshore network, which is unlikely to be optimal even in the short run. This means that offshore links are likely to remain essential for connecting offshore generators, similar to 'enabling works' onshore.

[76] It is likely to be difficult to have a single regulatory regime for both because (unlike for offshore generators) TNUoS charges are not applicable to interconnectors, and interconnectors cannot be owned and operated by the same legal entity that owns a transmission network.

for Difference under Electricity Market Reform) if the power they generate flows directly to the other country, and whether credit could be gained for renewable generation in the other country that is imported to GB via the interconnector.

- The North Seas Countries' Offshore Grid Initiative is an agreement between countries bordering the North Sea to cooperate in facilitating a strategic, coordinated development of offshore grids, and will have a significant role in addressing issues related to linking countries via offshore grids.

A key step in developing regulatory compatibility between offshore transmission and interconnectors is the method for recharging of access to transmission infrastructure and the revenue regulation (including charges for the use of the interconnector). This charging methodology would need to ensure that the benefits from joint use of transmission infrastructure are passed on to users. Regulatory compatibility will need to be capable of handling the build of offshore transmission occurs in tandem with interconnection build, or where an OFTO link is later extended to achieve interconnection. Regulatory compatibility with international interconnectors would also tie in with other initiatives to allow anticipatory investment, as some oversizing might be required to incorporate interconnector linking at a later date.

However, it would be more difficult to facilitate connection of an offshore generator to a pre-existing interconnector under the approach proposed above, as this would require reclassification of part of the interconnector after it is already in use. At any rate, this outcome is less likely as it would probably require pre-investment when building the interconnector, most likely involving construction of an offshore HVDC hub on the interconnector, which is unlikely without a pre-defined use for the offshore hub.

6.2.5 Planning and consenting barriers to anticipatory investment

Facilitate anticipatory investment in the planning process

Changes to planning and consenting processes could address an existing barrier to coordination. These changes would involve allowing anticipatory investment in a single application for generation and transmission planning

- In England and Wales, clarify or change guidance on associated development under the IPC to allow anticipatory investment in transmission links to be consented through a single joint generation/transmission application.
- In Scotland, permit onshore transmission works as part of deemed planning in order to effect a single application for an offshore generation project, and allow the transfer of ownership of transmission assets in Scotland without the requirement to issue a new consent (which might require changes to Primary Legislation in the Marine (Scotland) Act 2010 or the Electricity Act 1989).

Clarification of, or changes to, guidance on associated development under the IPC would allow anticipatory investment in transmission links to be consented through a single joint generation/transmission application. This would allow the IPC to make a judgement on whether a particular transmission asset is required without the stipulation that it has to be 'necessary' for the generation project in question in order to be included as part of associated development. This could be done by making evidence requirements consistent with those required to convince Ofgem of the need for anticipatory investment, or consistent with requirements under the onshore regime. In Scotland, these changes to the consenting process are likely to be necessary to allow single application for offshore generation and transmission assets.

Changes to improve the planning process offer potential coordination benefits and should be considered not just as a worthwhile internal goal, but also as a contribution to the North Seas Grid Initiative once consent is required for assets that could form a part of a future offshore grid.

Planning requirements (for early developers) to avoid route sterilisation

The risk of route sterilisation – where a route or landing point becomes unavailable for future transmission lines with installation of a first transmission line – has been raised as an issue by various stakeholders. One approach to dealing with this issue would be through planning requirements:

- Planning requirements would require developers to demonstrate that they have considered impacts on future developers and have taken appropriate steps to minimise any negative external effects.

However, incentives through well-defined property rights to landing sites and routes are already likely to internalise some or all of the cost imposed on future generators, without the additional burden of more stringent planning requirements. For The Crown Estate Round 3 zones, these incentives are particularly clear, as a single consortium is responsible for developing the entire zone. Accordingly, this proposal is not developed further here.

Sterilisation periods in coastline development

Alternatively, some stakeholders have suggested that regulatory changes should be made so that:

- Nearby developers are obliged to build at the same time through enforcing 'sterilisation periods' in coastline development for landing points.
- This would be the responsibility of The Crown Estate or local authorities, depending on ownership of local shoreline.

This might facilitate coordination as local offshore developers would have to develop their transmission needs at the same time, but could impose significant costs. In particular, it would trigger costs through an additional constraint to development timetables, and might be unworkable for large projects that are being developed in sequence.

6.2.6 Technology risks and asset incompatibility

Standardisation of voltage and control systems

A standard describes an agreed, repeatable way of doing something and can range from a broad and general guide to a specification of detailed requirements. In the context of offshore transmission, this proposal would involve:

- Setting consistent parameters for the development of offshore transmission networks. This could range from setting operating parameters for voltage or control, to more stringent requirements for standardisation of assets.

- Standards would be developed under a transparent and consensus-based process involving key industry participants. Standards should be developed initially at a UK level, with industry consensus used to determine whether standards should be mandatory.
- Regulatory approval should be required for any mandatory standards.

A strong view has emerged from OTCG workshops that common technical standards should be developed; it has also been noted that there are a range of different bodies working separately on standardisation. Similarly, analysis from the asset delivery work stream study has found that there could be benefits from spares holding and reduced support costs, although this study also noted that common-failure aspects might also need to be considered. There is also a risk that standardisation could constrain innovation.

Standardisation across the UK would cover a sufficient scope to facilitate benefits from coordination within wind farms, across zones and through easing of onshore constraints, and might be easier to achieve compared with standardisation on a European basis.[77] Standardisation across the EU could assist with accessing benefits from coordination between offshore generators and interconnectors and should be a longer term goal, to be advanced through the North Seas Countries' Grid Initiative and other relevant forums. The development of appropriate UK level standards first could also be advantageous to influence the development of EU-wide standards.

Sharing of new technology risks

Sharing of technology risks would involve allocating some funds from consumers to encourage investment in new technologies. As discussed in Section 5, there are potentially broader benefits from the adoption of new technology that accrue beyond the direct user. Currently, developers generally underwrite technology risks (although they may be able to pass some of these risks through to their suppliers). This risk could be shifted entirely to consumers, but this would require significant oversight as developers might be incentivised to pursue risky speculative technologies with little probability of success. A more workable solution would involve sharing of the risks. One option would involve:

- Sharing of technology risks between early adopters and consumers through a mechanism similar to the Low Carbon Networks Fund (LCNF)
    - formation of an oversight/determination committee with clear terms of reference for funding deployment of new technologies
    - criteria for funding would need to be tightly defined and could cover cabling or platform technologies as well as coordinated consenting and planning costs.
- Some degree of competition for schemes could be established, although this would not be the primary focus.

This proposal could address potential under investment in new technologies where market failures associated with spillover benefits occur and coordination benefits reliant are reliant on 2 GW HVDC links. However, it entails risks to consumers, who are not as well placed as developers to understand and manage technology risks. There are also alternative options to encourage innovation, such as directly

[77] Addressing these issues through action at a UK rather than EU level would also be consistent with the principal of subsidiarity, whereby issues should be tackled by the lowest level of government able to deal with the problem.

undertaking development work earlier in the innovation chain (for example, the Carbon Trust has undertaken some development work on new inter-array cabling technologies).

6.2.7 Summary of advantages and drawbacks for options

We have assessed the advantages and drawbacks of each of the options described above based on our consideration and evidence gathered through the stakeholder engagement process. Table 15 below summarises the main advantages and drawbacks of the options described above.

Table 15 Summary of advantages and drawbacks for each policy option

Potential solutions	Advantages	Drawbacks
Anticipatory investment process uncertainty		
Clarify regulatory arrangements for anticipatory investment offshore	• Could deliver a more coordinated network by removing regulatory risk associated with anticipatory investment	• No significant drawbacks providing the revised arrangements are not in themselves distortionary • Ex-post approval arrangements may not provide sufficient certainty or protect consumers
Enhanced anticipatory investment process – pre-approved	• Could enable more coordination by providing a structured and clear process through which clear cases could be pre-approved	• Fast-track approach only applicable to clear cases where specific criteria are met – might not extend to significant anticipatory investment
Enhanced anticipatory investment process – contracted	• Ex ante certainty on the treatment of anticipatory investment	• Significant regulatory complexity and risk of attendant delays • Potential increase in stranding risk for consumers
Network optimisation		
Extended ODIS: stakeholder buy-in	• More regional detail to assist developers • Greater buy-in could assist with planning approval for coordinated infrastructure • Phasing provides a clearer picture of how the network is likely to evolve in the short-term, informing developer planning	• Greater cost from broadening participation • Greater cost from going beyond current desktop only study
Extended ODIS: cost-benefit analysis with Ofgem sign-off	• Reduces regulatory risk to developer by indicating whether anticipatory investment would, in principle, receive regulatory approval • Could assist with planning	• Significant regulatory burden of more detailed analysis • Link between cost-benefits and investments to be made remains unclear • Sign-off still likely to be needed on individual projects
Central authority blueprint	• Centralised blueprint to ensure that transmission build is coordinated • Could still retain existing tender system	• Uncertainty over future build and technological development a significant challenge for blueprint • Significant stranding risk if assets built according to blueprint are not required • Centralised decision-making might reduce potential for innovation in routing high level design

Potential solutions	Advantages	Drawbacks
The Crown Estate role in facilitating strategic planning and cooperation	• Single body with interest in all Round 3 sites likely to be well placed to pursue coordination • Consistent with statutory objective to maintain and enhance land and property rights.	• Need to ensure this does not conflict with other Crown Estate objectives, such as obtaining the best return on leases • The Crown Estate could be more concerned with timely development than coordination
Expanded role for the NETSO in high-level design	• High level reference design could address asset incompatibility and provide a clearer vision for coordination	• Some constraints on transmission builders' decision making regarding technical and operating parameters
TO delivery of active onshore-offshore investment	• As above, high level reference design could address asset incompatibility • Single party delivering through (or 'active') links better placed to deliver re-optimisation of the network and develop new technologies	• Reduction in competition for construction and ownership of active components of the network, with potential to jeopardise innovation and lead to higher costs for consumers
Regional monopoly offshore transmission owner	• Single regional OFTO might be better placed to deliver coordinated build of all infrastructure across a region	• Significant challenge in choosing a regional OFTO • Confers regional monopoly, with attendant risk of abuse of market power and loss of competitive pressures, unless well designed incentive and charging framework is in place
Relax 20% cap on additional OFTO build	• Allows for harnessing economies of scale where a single generator is best served by a single OFTO • Saves additional tendering cost	• Risk of OFTO undertaking excessive capital works, but only where the generator making the request does not pay for the works through transmission charging • Role of Ofgem in approving to be determined • Potentially reduced cost pressure as existing OFTO not subject to tender competition
Provide certainty that offshore transmission builder can recover costs from network re-optimisation	• Facilitate NETSO role in network re-optimisation • Give generators confidence to proceed with planning and build offshore according to their connection offer	• Increase in risks borne by consumers
Deep connection charges for offshore generators	• Sharpens incentives to optimise offshore/onshore interactions	• Inconsistent with arrangements onshore • Allocation of lumpy capital costs dissuades incremental investment when this triggers significant new transmission build • Significant potential impact on generator cost of capital
Risk–reward profile of coordinated investments		
Clarify arrangements for sharing of coordinated assets through user commitment and charging	• Reduction in barriers to generators accepting coordinated offers from the NETSO	• Additional risks for consumers where reinforcement of onshore network is not secured by generators
Consumers underwrite anticipatory investment through user commitment	• Would encourage generators to pursue anticipatory investment as part of a coordinated network	• Additional, potentially significant risk to consumers of stranded costs • Removal of incentives for generators to

Potential solutions	Advantages	Drawbacks
	• Harmonising user commitment and charging would mean that the same party would pay for assets whether or not the connection went ahead	minimise stranding
Consumers responsible for a greater share of charges for anticipatory investment	• Encourages developers to pursue a coordinated solution where this delivers cost savings • Linking consumer share of charges for anticipatory investment with their share of benefits would promote a fairer and more efficient division of risks	• Potential for additional costs to consumers from stranded costs • Unclear that existing consumer share of charging for anticipatory investment is too small • Removal of incentives for generators to minimise stranding, likely to require additional regulatory oversight
Allocate risk from anticipatory investment to OFTOs	• Could incentivise a regional OFTO to deliver coordination	• Where there are many OFTOs in a region, difficult for any one of these to deliver coordination • Difficult to direct rewards from coordination to OFTOs • Inconsistent with arrangements onshore • Significant potential impact on OFTO cost of capital/willingness to participate
Open season with generator commitment	• Market-based system with potential to achieve coordinated designs, including across zones	• Would require generators to sign contracts at time of open season • Potential for confusion and duplication where transmission owner rather than generators take the lead in proposing/requesting a connection • Untested approach in a GB context (and may not be suitable given the potential staging of build out/investments)
Application of Connect and Manage to offshore transmission	• Could speed connection of offshore generation in the longer term	• Unlikely to be any benefit in the short term, before offshore networks with redundancy are established
Interconnector-OFTO regulatory interface		
Allow regulatory compatibility with international interconnectors	• Allows access to potential benefits from international integration • Interaction with North Seas Countries Offshore Grid Initiative	• Barriers to implementing as a single regulatory regime • Could add complexity to the regulatory regime
Planning and consenting barriers to anticipatory investment		
Facilitate anticipatory investment in the planning process	• Facilitate coordinated build by removing a regulatory and process barrier to coordination and anticipatory investment (in particular, in a single planning application)	• Additional upfront costs that could be stranded
Planning incentives (for early developers) to avoid route sterilisation	• Reduction in negative externalities on future developers	• Could add further difficulty to planning requirements
Sterilisation periods in	• Could facilitate some additional coordination	• Imposes costs through an additional constraint on generators

Potential solutions	Advantages	Drawbacks
coastline development		• Disallowing local access after a certain date would compromise delivery of offshore generation
Technology risks and asset incompatibility.		
Standardisation of voltage and control systems	• Assists development of a coordinated network through interoperability • Provides developers with greater certainty on quality and operation of transmission systems	• Could impede innovation and development of new technologies if standards too specific • Need to consider interaction with other EU member state standards and developments
Sharing of technology risks	• Addresses potential under investment in new technologies where market failures associated with spillover benefits occur	• Cost/risk to consumers or other funders, who are not as well placed as developers to understand and manage technology risks

6.3 Summary of policy measures as potential solutions to identified problems

Changes to the regulatory regime for offshore transmission should be predicated on addressing one of the potential problems identified in Section 5. The matching between problems and solutions relating to coordination in offshore transmission is complicated in that more than one solution can address any one problem and some solutions can address multiple problems. Potential for changes to go beyond the energy system are not considered here as this would go beyond DECC and Ofgem jurisdiction. For example, shifting risks to taxpayers more broadly rather than to electricity consumers would go beyond the remit of this study.

In Figure 11 we attempt to present how the intervention measures identified above can be mapped to the potential problems identified in Section 5. Policy measures that have been evaluated as having significant disadvantages that outweigh the potential coordination benefits are discarded and do not feature in the figure. These include:

- **A hybrid extension of the onshore regime**: maintaining generator build option could compromise the achievement of coordination, while reducing the role of competition in the OFTO build process. The benefits can largely be achieved through other means.
- **Deep connection charges for offshore generators**: this would be inconsistent with arrangements onshore, where deep connection charges have not been used because the allocation of lumpy capital costs could dissuade incremental investment when this triggers significant new transmission build.
- **Allocate risk from anticipatory investment to OFTOs**: Likely to be unworkable where there are many OFTOs in a region, as this makes it difficult for any one of these to deliver coordination. Even where only one OFTO responsible for designing an offshore network, this is inconsistent with arrangements onshore.
- **Application of Connect and Manage to offshore transmission**: there is unlikely to be any benefit in the short term of extending connect and manage beyond current arrangements (where Connect and Manage applies to onshore works to connect an offshore generator), before offshore networks with redundancy are established.
- **Planning incentives to avoid route sterilisation**: could further complicate planning processes, creating risks for generators.

- **Sterilisation periods in coastline development**: would impose costs through an additional constraint on generators and could compromise delivery of offshore generation.

The linking between problems and solutions is also useful for considering the risk/reward trade-offs in different solutions to addressing coordination problems. Broadly speaking, solutions on the left hand side of Figure 11 involve generators taking on risks, while those on the right hand side involve significant risk reallocation, in particular to consumers.[78] Many of the options in the middle of the figure involve sharing of risks between parties.

These policy solutions are taken forward in the next Section to develop policy packages that have the potential to address problems of coordination by harmonising various solutions that would work sensibly together as a package of intervention measures.

Figure 11 Linking of problems and potential solutions

Potential problem	Potential solutions
Anticipatory investment process uncertainty	Clarify regulatory arrangements Enhanced AI process – pre-approved Enhanced AI process – contracted
Network optimisation	Relax 20% cap Extended ODIS Expanded NETSO role TO delivery of active network Regional OFTO Central authority blueprint
Risk-reward profile of coordinated investments	Clarify regulatory arrangements Sharing of risk with consumers and/or OFTOs Open season arrangements Consumers underwrite
Interconnector-OFTO regulatory interface	Regulatory compatibility
Planning and consenting barriers to anticipatory investment	Facilitate anticipatory investment in planning process
Technology risks and asset incompatibility	Standardisation of operating parameters Standardisation of assets Sharing of new technology risks

[78] The allocation of risks and rewards between generators and consumers is driven primarily by charging and user commitment arrangements. However, solutions to the right of the diagram are able to facilitate allocation of a greater share of risk to consumers. For example, an enhanced anticipatory investment process or centralised blueprint would provide additional regulatory oversight that could allow consumers to take responsibility for a greater share of risk.

7 Policy packages to promote coordination

7.1 Introduction

We have developed policy packages through consideration and analysis of the various intervention measures described in the previous Section and their capacity to address the identified problems in the current regime. They are presented for illustrative purposes and to facilitate qualitative analysis, but are just four of many different combinations of the solutions presented in Section 6 and do not necessarily represent our view of the 'optimal' or best response. They also do not represent Ofgem or DECC's positions, and the policies that are taken forward by them could draw from different components across the policy packages or from measures that have not been included in any of the packages.

In all we have developed four policy packages by combining intervention measures and assessed them qualitatively. Comparison of how each package would work is facilitated by the following questions:

- Who decides whether coordination is possible and beneficial?
- Does there need to be a stronger role for a centralised body to provide a vision for coordination?
- Who will take on risks associated with anticipatory investment?
- What degree of competition is maintained?
- How can technology innovation and investment be encouraged?
- Will the package be consistent with other developments, including Electricity Market Reform, RIIO, Project TransmiT and broader European developments?

7.2 Overview of illustrative policy packages

7.2.1 Summary of illustrative policy packages

The four illustrative policy packages represent different approaches to the offshore regulatory and commercial regime and the treatment of risk and reward. Each package combines a number of different policy measures identified in Section 6 (Table 16) and has been constructed such that they reflect consistent approaches to risk allocation, regulatory burdens and risk management. They have been developed by giving consideration to the following principles:

- A consistent risk/reward balance across generators, OFTOs and consumers.
- Risks (in particular relating to anticipatory investment, which is likely to be necessary to access benefits from coordination) being allocated to the party or parties best incentivised and able to manage them. Where risks are allocated to consumers, there will need to be appropriate regulatory oversight to ensure these risks are minimised.
- Maintaining competitive pressure on costs and financing through a tender process.
- Ensuring that as a group, each of the key players (generators, OFTO, NETSO, consumers) are in principle no worse off under a coordinated approach.
- Not introducing undue delay into the decision making process for investors in offshore generation nor deterring the new sources of finance and construction that have been forthcoming in the OFTO process.

- Consistency with the feasible asset delivery scenarios identified in work stream 1.

We describe each option below:

- **Package 1– 'Inform and enable':** The first package involves only incremental changes to the existing regime, with the emphasis on clarifying arrangements for coordinated investment. This entails a clearer role for generators to take the lead in developing a coordinated network and thus represents an enabling framework for coordination.

  Information provision will clarify what aspects of anticipatory investment will be given regulatory approval so that the developer is reimbursed for the additional costs. This approach is likely to be particularly applicable to Round 3 Crown Estates tender zones, as each of these is being developed by a single entity or consortium and each developer will thus have incentives to minimise transmission costs across each zone. Its success will depend on the willingness and capability of generators to bear risk and collaborate, albeit within an enhanced coordination and investment incentive framework.

- **Package 2 – 'Market led evolution':** The second package builds on the first by proposing an additional role for a central body (which could be an enhanced NETSO role or a new central design authority), overseen by Ofgem, to direct developers to undertake anticipatory work up to a small proportion of total capital costs and where the benefits of this work are evidenced in an enhanced ODIS.

  Consumers would share in some of the risks from anticipatory investment. This would be achieved through changes to user commitment that clarify arrangements for shared assets and move risks associated with anticipatory investment for such assets away from the first generator (or generators as a whole where the asset is primarily to reinforce the onshore network), providing additional incentives for market-led delivery of coordinated assets. There are also provisions, if required, for 'open season' arrangements that could be used to access benefits from coordination across zones and potentially across countries.

- **Package 3 – 'Regional monopoly':** The third package facilitates coordination through a regional (or zonal) OFTO. Optimisation of zonal networks over time would be the responsibility of regional OFTOs. Competition is encouraged in finance and asset build through the tendering of initial asset requirements in each zone to choose a regional OFTO. Anticipatory investment risk is shared between generators and consumers in a manner to be agreed based on the magnitude of the risk and who is best placed to manage it. The generator receives upside (through reduced charges) in exchange for bearing some risk. Regional OFTOs would be incentivised to deliver a coordinated solution through specification of key metrics that indicate the degree of efficient coordination. The generator build option would be discontinued to facilitate optimisation of each zone by a single OFTO. In a version of the package, it would be possible for the generators to 'self-refer' themselves into this model providing some minimum criteria had been met. This would be akin to the OFTO build approach currently in place but would need careful consideration and design.

- **Package 4 – 'Blueprint and build':** The fourth and final package establishes a common vision of a coordinated offshore transmission network through an independent central body empowered to establish a blueprint. This would include a fixed (but periodically updated) high-level design for offshore transmission, based not only on currently contracted demand but also future expected offshore developments in line with generator investment plans. The central body would then plan and manage transmission investment in accordance with the blueprint. Investment would be driven by generator connection requests, or centralised direction in the case of anticipatory investment. The existing OFTO tender process would be maintained. Consumers would bear a greater portion of the risks from anticipatory investment but would be protected from excessive costs through oversight by the central body.

Table 16 Combination of policy measures in each package

Policy measure	Package 1 – Inform and enable	Package 2 – Market led evolution	Package 3 – Regional monopoly	Package 4 – Blueprint and build
Clarification of AI process	X			
New AI process		X	X	X
Extended ODIS		X		
Design blueprint				X
Regional OFTO			X	
Sharing of AI risk with consumers		X	X	X
Open seasons		X		
Regulatory compatibility with interconnectors	X	X	X	X
Remove planning barriers to AI	X	X	X	X
Sharing of technology risks		X		
Asset standardisation	X	X	X	X

7.2.2 Key policy development issues

Table 17 below summarises the four options with respect to their overall theme and the key policy development questions set out above.

Table 17 Summary of straw man packages

Policy lever	Package 1 – Inform and enable	Package 2 – Market led evolution	Package 3 – Regional monopoly	Package 4 – Blueprint and build
Theme	Incremental reforms to the current regime	As for Package 1, but with sharing of technology and stranding risks between consumers and generators	Facilitated regional monopolies designed for coordinated build out with risk sharing between investors and consumers	Central direction and blueprinting for coordinated build out with consumers bearing the risk (and subsequent reward)

Role of centralised body in coordination planning	Provision of information to facilitate coordination	Light touch – vision for build, design only for 'no regrets' investments	Light touch design with a regional focus	Complete blueprint by a central body with oversight
Who decides whether coordination is beneficial	Generators and/or NETSO through connection offer	Generators and/or NETSO through connection offer	Regional OFTO, informed by generators	Central body
Anticipatory investment process	Guidance to clarify what forms of anticipatory investment will be given regulatory approval	Clarification as well as pre-approval of specific low cost anticipatory investments; risks shared between consumers and generators through changes to user commitment	Regulatory approval of regional OFTO plans as per the onshore regime; risks shared between consumers and generators through changes to user commitment and regular price controls	Anticipatory investment allowed as set out in blueprint; risk largely borne by consumers through user commitment and charging
Degree of competition (initial and subsequent)	Tender-based competition for build	Tender-based competition for build	Competition for regional monopolies	Tender-based competition for build out of each component
Technology innovation and investment	Generator/OFTO responsibility	Sharing of new technology risks through support mechanism	Sharing of new technology risks through support mechanism	Sharing of new technology risks through support mechanism
Consistency with broader developments	Retain flexibility to adapt to broader changes, such as shift to CfD support under EMR and potential changes to TNUoS and user commitment under TransmiT	As for package 1	Regional OFTO mirrors onshore, price regulated regime, making RIIO framework applicable in the medium term	Blueprint to incorporate international developments such as North Sea Grid and linking of offshore transmission with interconnectors

7.2.3 Process flow for policy packages

For each of the illustrative policy packages we have developed a series of high level process flows for build of new transmission assets (including anticipatory investment) and these are shown in Figure 12, Figure 13 and Figure 14. The process flow for packages 1 and 2 are the same as they both envisage a continuation of the existing OFTO tender arrangements (with amendments), albeit with some difference in the sharing of risks between parties. Packages 3 and 4 require different processes to accommodate a regional OFTO and centralised blueprint respectively.

Key implementation features are compared across the four straw man policy packages in Appendix E.

Figure 12 Process flow for Packages 1 and 2

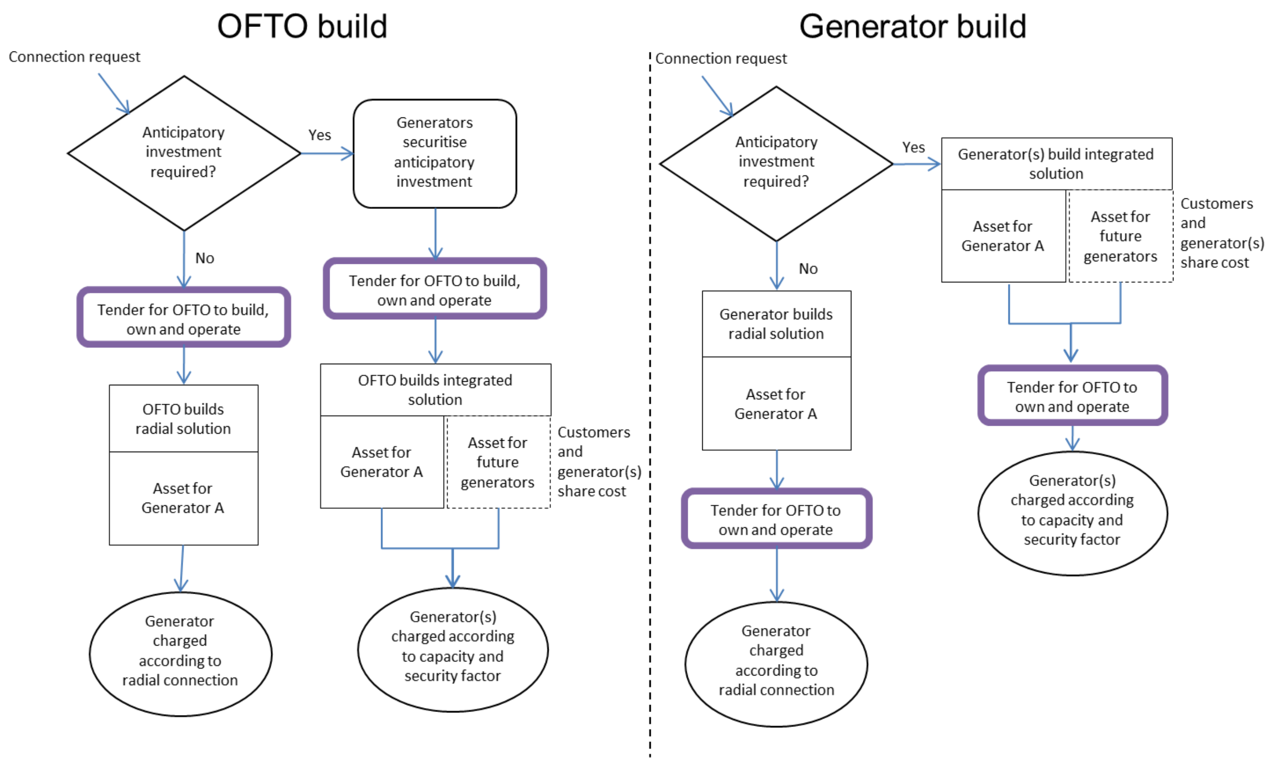


Figure 13 Process flow for Package 3

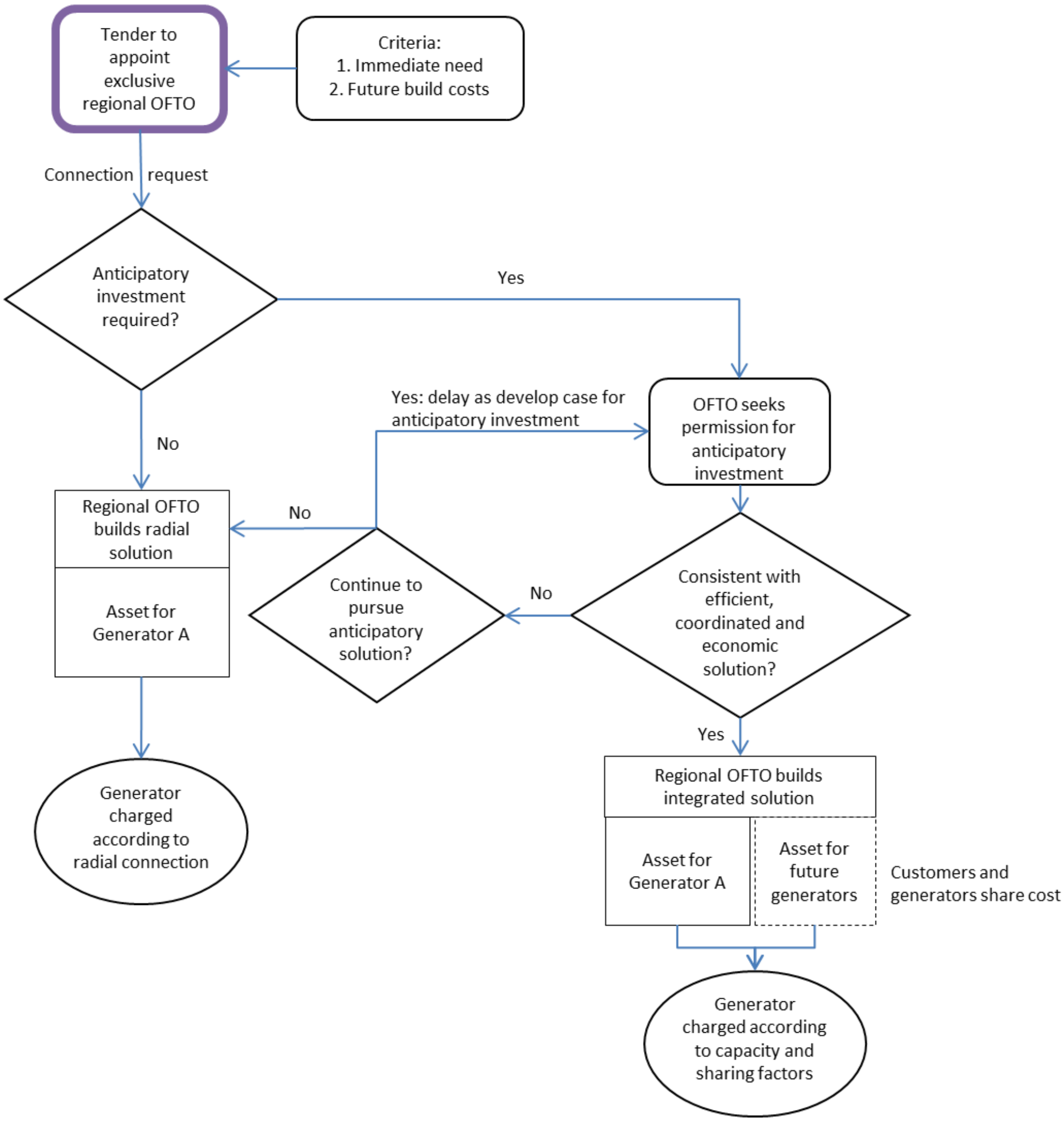
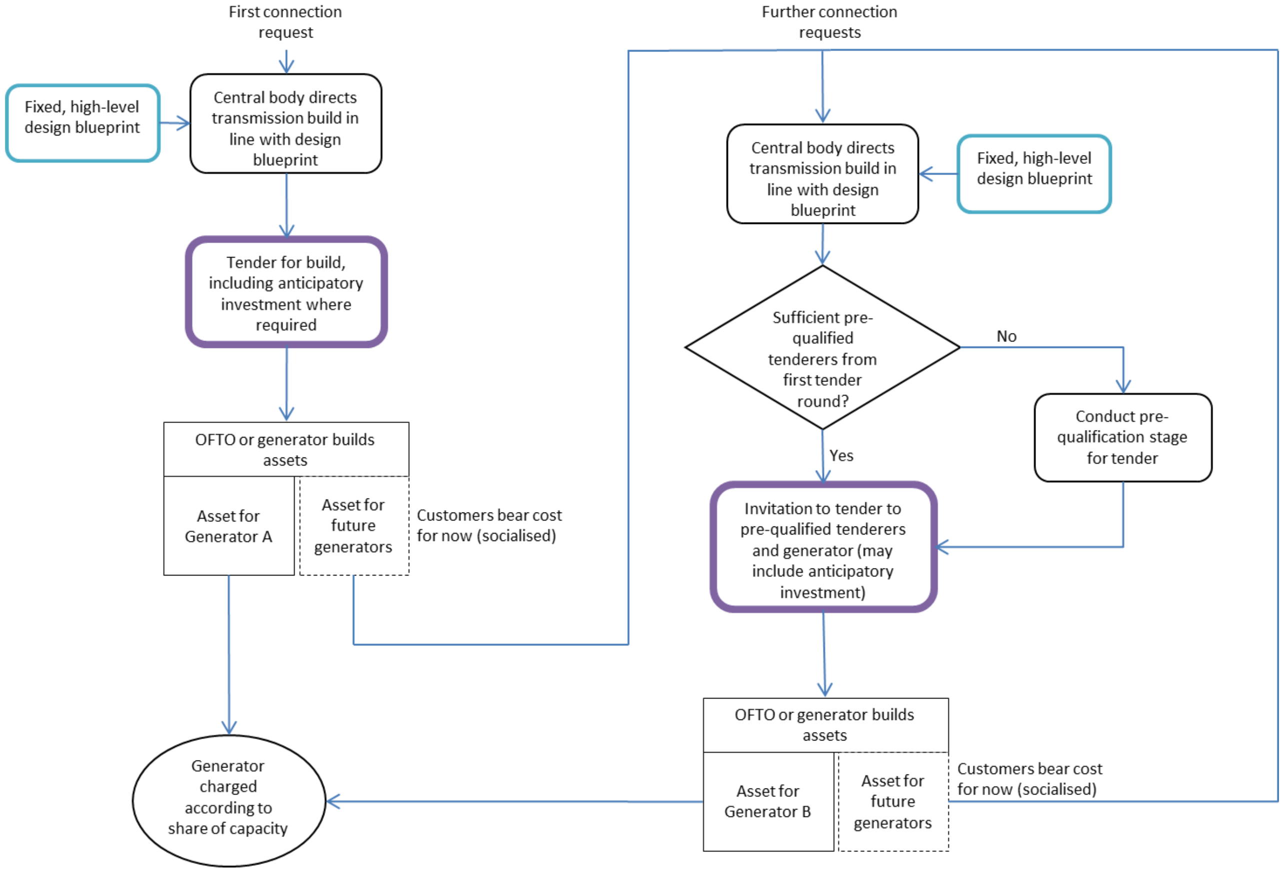


Figure 14 Process flow for Package 4



7.3 Implementation considerations

Practical implementation issues are a key consideration in the workability of each policy package. As emphasised earlier, each of the packages have been constructed such that under the right conditions each should be capable of achieving a coordinated outcome.

Package 1 would be relatively simple to implement, as represents an evolution of the existing regime. There would only need to be minor changes to the statement of charging under the CUSC to place the risk of anticipatory investment with generators. The greatest challenge will be providing information in a clear and informative manner to stakeholders.

Package 2 would involve some implementation complexity in sharing of risk between consumers and generators. This would include detailed design of a financing mechanism for supporting technology deployment in offshore transmission. There would also be a challenge involved in choosing the share of anticipatory and technology risk to allocate to consumers. Finally, regulatory arrangements would need to be developed to allow open seasons to proceed and to allow for the granting of a licence for offshore transmission. Further changes may also be required to the NETSO licence.

The key challenge in implementing package 3 would be the process of choosing a regional OFTO. Again, it would also be necessary to choose a share of risk to be allocated to consumers, and there would be an additional challenge in designing an appropriate incentive mechanism for regional OFTOs to deliver coordinated build. Discontinuation of the generator build option would remove the opportunity for generators to manage connection timing risks themselves.

There would be considerable complexity involved in designing the blueprint for package 4. The central body responsible for developing the blueprint would need to conduct a thorough optimisation exercise that goes well beyond the desktop analysis in the ODIS. Regulatory approval for the blueprint would need to give due weight to economic, environmental and social considerations before tendering for build of a coordinated network. Such a detailed process would preclude frequent updating of the blueprint, with periodic updates likely to be less regular than the ODIS (e.g. every two years). However, the existing tender regime would continue, which would smooth implementation.

Implementation considerations are considered as part of the key objective that the regulatory regime be deliverable and flexible, in the qualitative assessment below.

7.4 Qualitative assessment

Table 18 illustrates the key advantages and drawbacks of each of the policy packages.

Table 18 Summary of advantages and drawbacks of Package 4 – Blueprint and build

Illustrative policy package	Advantages	Drawbacks
Package 1 – Inform and enable	• minor changes to regulatory regime means less uncertainty and less interruption of existing developments • improvements in clarity of processes for anticipatory investment • no increase in socialisation of anticipatory investment	• fully coordinated outcome could remain unlikely as reliant on developers and NETSO – developers might continue to be reluctant to accept coordinated offers due to charging and user commitment risks, in particular where offshore coordination used to increase onshore boundary capacity – NETSO would need sufficient incentives as system planner • generators remain responsible for all development risks, even when benefits accrue more widely
Package 2 – Market led evolution	• minor changes to regulatory regime means less uncertainty and less interruption of existing developments • scope to share some of the cost of technology development and 'no regrets' anticipatory investment	• fully coordinated outcome could remain unlikely as reliant on developers and NETSO – developers might continue to be reluctant to accept coordinated offers, though changes to user commitment would help here – NETSO would need sufficient incentives as system planner • open season might be difficult to implement
Package 3 – Regional monopoly	• single regional provider to aid coordination • potential to benchmark regional TOs for price setting • less need for standardisation of voltage and control except at link with onshore network	• creates a monopoly, with no potential for competition after the initial tender • capital cost of regional OFTO likely to be higher than OFTOs under current regime • bidding and evaluation of tender difficult

		under uncertain future build • significant disruption to the existing regime to institute regional monopolies
Package 4 – Blueprint and build	• gives a central body the authority to design an offshore network that maximises the benefits from coordination • method of accessing 'least regrets' anticipatory investment if used conservatively • save on time and expense of later tender rounds	• central planning might reduce potential for innovation and lead to poor decisions given inability to flex against changing outlook • costs from actual build outcomes diverging from assumptions used for central planning accrue to the consumer: minimal risk taken by OFTOs/generators despite generators being the main source of uncertainty • fast tracking of later tender rounds could reduce competition

In addition, we have undertaken a qualitative assessment of the illustrative policy packages against criteria agreed with Ofgem and DECC and which have been tested with stakeholders through the OTCG process. While qualitative, the method has enabled an assessment of different packages and identification of key risks, strengths and weaknesses in each package. More detail, including an explanation of the criteria and a summary of the reason for each score, is contained in Appendix F. A summary of our qualitative assessment is shown in Figure 15.

- Packages 1 and 2 perform well by delivering potential benefits associated with a more coordinated build of offshore transmission infrastructure through potentially bringing forward 'low regrets' anticipatory investment without involving significant risk compared with current arrangements.
- Package 1 ('inform and enable') involves incremental changes to the current regime and offers potential benefits with few risks.
- Package 2 ('market led') also involves largely incremental changes to the current regime but could deliver greater benefits from coordination, although this needs to be set against greater risks. The main risks associated with the market led package relate to greater stranding risk (in particular, where some of this falls on consumers) and additional complexity from an expanded central agency role and provision for open seasons.
- Packages 3 and 4 offer greater certainty in realising the potential benefits from increased coordination, but there are also greater risks for consumers (in particular, increased stranding risk) and potential disruptions to the existing regime.
- Package 3 would involve significant changes from the existing regime to institute regional monopolies and considerable complexity in the tender system to appoint regional OFTOs. This could disrupt existing developments and even compromise timely build of offshore generation in the near term, as well as compromise benefits from competition.
- Package 4 is assessed as offering the greatest certainty for supply chains, generators (with flow-on benefits to timely build of offshore generation) and economic benefits from coordination, but these benefits come at the risk of substantial costs for developers and consumers given that, in the absence of perfect foresight, there could be significant asset stranding if building to a relatively inflexible blueprint. There will also be considerable complexity for the central body in developing the blueprint, with attendant losses of flexibility to respond to changes in build if projections on which the blueprint is based turn out to be incorrect.

Overall, the four illustrative policy packages represent different approaches to the offshore transmission regulatory and commercial regime and the treatment of risk and reward. Each package combines a number of different policy measures and has been constructed such that they reflect consistent approaches to risk allocation, regulatory burdens and risk management. Looking across the assessment of the illustrative policy packages, where modest assumptions are made on the development of offshore generation and/or the outlook is highly uncertain the incremental changes in packages 1 and 2 offer benefits versus the current arrangements with relatively low implementation and stranding risk. Furthermore, they represent an evolution from the current arrangements. Where significantly more ambitious development of offshore generation is expected with some certainty, then packages 3 and 4 can offer significant benefits but at significantly increased regulatory, implementation and stranding risk and with major changes required to the current arrangements with the commensurate disruption and potential risk to current investment plans that this would entail.

Figure 15 Qualitative assessment results (all impacts relative to current regime)

Criteria	Package 1 Clarify and inform	Package 2 Market led	Package 3 Regional monopoly	Package 4 Blueprint and build
Support timely build of offshore generation to 2020 (inc. costs to generators)				
Support timely build of offshore generation to 2030 (inc. costs to generators)				
Local environmental impacts				
Reliability of GB transmission network				
Flexibility in system operation				
Deliver economic benefits of coordination				
Promote economic efficiency through charging and role of markets				
Impact on innovation/dynamic efficiency				
Risk of stranded transmission assets				
Impact on supply chains				
Financeability of offshore generation				
Financeability of offshore transmission				
Breadth of potential investors				
Optimise onshore reinforcement costs				
Risk for consumers				
Risk of excessive rents				
Efficient allocation of risk				
Flexibility to deal with range of future possibilities				
Compatibility with current arrangements/risk of disruption				
Level of complexity and administration cost				

Strongly positive impact	
Neutral impact	
Strongly negative impact	

A Background: existing regulatory arrangements

A.1 Renewable policy

The UK is a signatory to the EU Renewable Energy Directive, which includes a UK target of 15% of overall energy use to be met from renewables by 2020. The Government's strategy to meet this target requires that about 30% of UK electricity come from renewables by 2020.

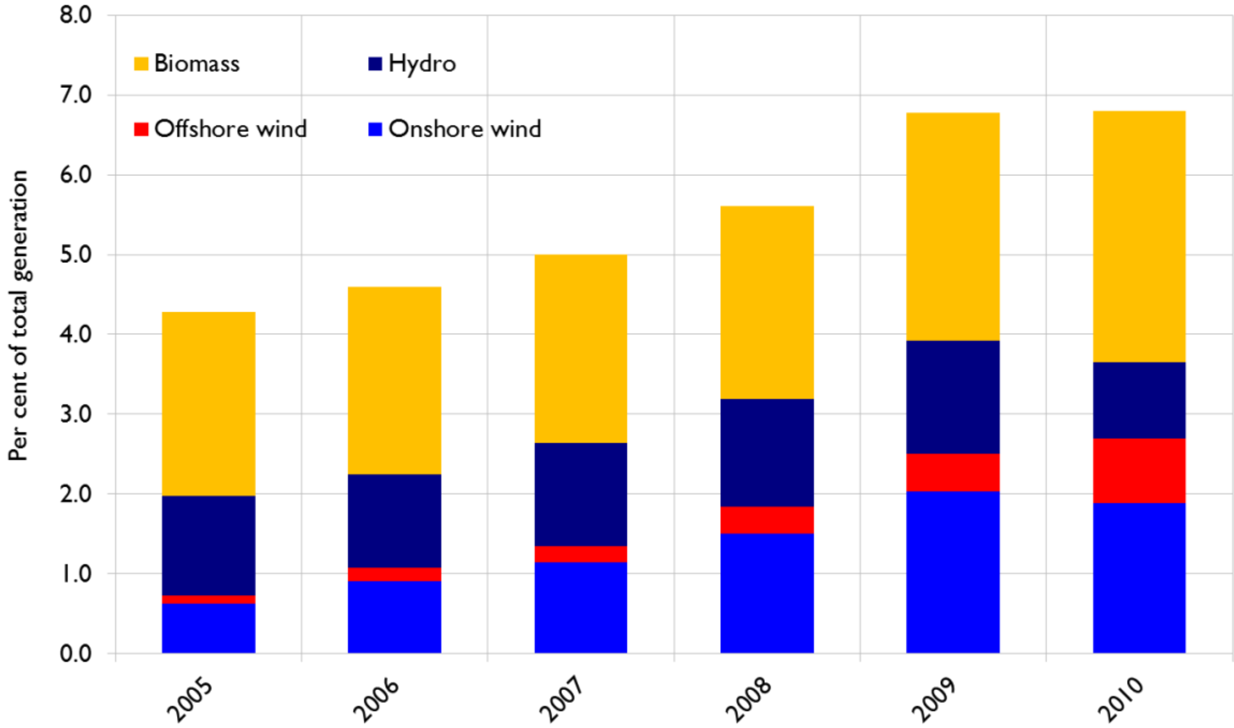
Policy measures to meet this target have focused on providing developers of renewable resources with subsidies reflecting the above market component of the current costs of these technologies. Eligible renewable generation facilities receive ROCs for each MWh of generation. Electricity suppliers are obliged to buy ROCs corresponding to their share of total electricity sales. This obligation was set at 3% of sales in 2002/03, increasing to 15.4% by 2015/16. A supplier that does not obtain sufficient ROCs has to make 'buy-out' payments (£30/MWh in 2002/3, rising annually in line with inflation).

Offshore generation receives considerable support through the RO scheme. The original RO provided the same support level irrespective of technology (1 ROC for 1 MWh), leading to strong investment in the lower cost technologies such as landfill gas, onshore wind and biomass co-firing in thermal power stations. In May 2007, the Government published a consultation document on the introduction of 'banding', which would lead to the issue of different numbers of ROCs per MWh for different types of renewable generation. The Energy Act 2008 provided the necessary powers to introduce banding and the changes to the RO were implemented from April 2009.

A.2 Generation mix and offshore wind development

The RO has been successful in increasing the renewable share of generation in the UK, although it is still well short of the 2020 target. As shown in Figure 16, between 2005 and 2010, the renewable share of generation increased by more than 50% to just less than 7% of total electricity generation (although there was little increase between 2009 and 2010 owing to low load factors for wind and hydro in 2010). Onshore wind generation tripled between 2005 and 2010, while offshore wind increased by a factor of seven – albeit from a low base. Current offshore wind generating capacity in the UK is 1.3 GW across 15 wind farms.

Figure 16 Renewable share of UK generation

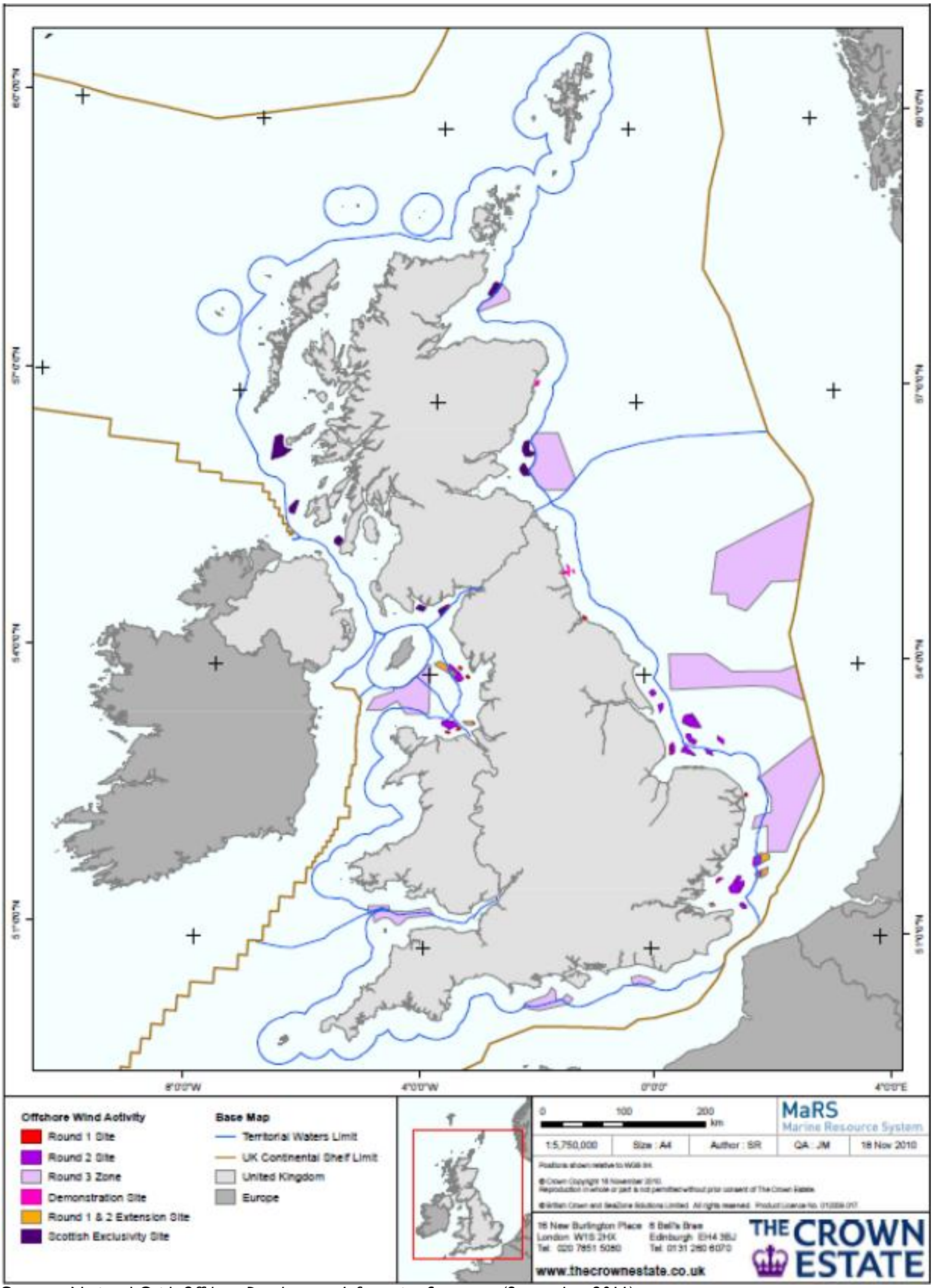


Source: DECC, *Digest of United Kingdom Energy Statistics 2011* (July 2011).

The scope for continued increases in offshore wind generation will depend on sites being made available by The Crown Estate. To date there have been five wind development leasing rounds, offering access to increasingly distant and challenging offshore conditions, and one marine round (tidal range and tidal stream). The five wind development leasing rounds have been (see Figure 17 for locations):

- Round 1,
- Round 2,
- Scottish territorial waters,
- Round 3, *and*
- Round 1&2 extensions.

Figure 17 Location of offshore development zones



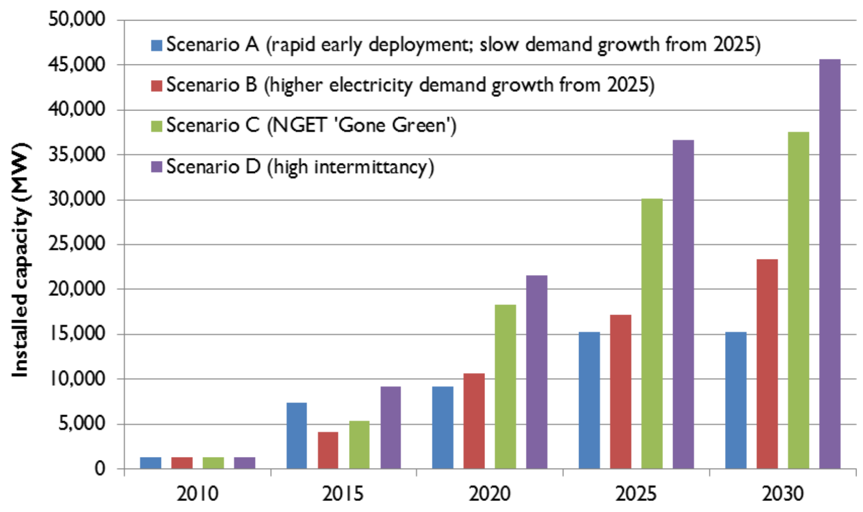
Source: National Grid, *Offshore Development Information Statement* (September 2011).

There remains considerable uncertainty about the total volume of generation that will be delivered from the leased sites, as development is a commercial decision to be made by the lease holders. The decision to develop an offshore generation site depends on profitability and financeability considerations, which in turn are dependent on the level of subsidy available for offshore technologies. Offshore generation represents relatively high cost technologies among those expected to deliver 2020 renewables targets, so are likely to require subsidies to remain economic. Further into the future, support for offshore wind will be affected by the intention signalled in the Electricity Market Reform White Paper to replace RO support with Feed-in Tariffs with Contracts for Difference from 31 March 2017 and the nature of renewables targets after 2020. Development might also be constrained by technological or supply chain considerations.

The maximum capacity that could be delivered from existing leases is estimated to be 55 GW[79]. However, scenarios have been developed for the 2011 ODIS that consider up to 67 GW of capacity by 2030. The Crown Estate's aim to install 25 GW of capacity in Round 3 would see 40 GW of total offshore capacity when added to the 8 GW due to be commissioned under Rounds 1 and 2 and the 6.4 GW announced in Scottish territorial waters.[80] There is also uncertainty over the timing of when offshore regions might be developed.

A range of scenarios for future build of offshore generation have been constructed by various parties to consider offshore development under this volume and timing uncertainty. Figure 18 presents four scenarios for build that have been compiled for the purposes of the current research and which have been used in considering asset delivery. Each scenario reflects different outcomes for the key constraints and uncertainties in offshore deployment identified above. Scenario A is based on rapid early deployment, but a slowing in deployment to reflect slower demand growth after 2025. Scenario B has a more gradual start, but higher deployment later to meet higher demand growth from 2025. Scenario C is the 'Gone Green' scenario, one of four scenarios from the ODIS (discussed further below). Scenario D reflects a scenario with high build of intermittent generation sources, including offshore wind, but does not reach the same level of offshore deployment as the ODIS 2011 'sustainable growth' scenario.

Figure 18 Scenarios for future build of offshore wind generation



Sources: National Grid, *Briefing Note: 2011 Offshore Development Information Statement* (June 2011); DECC.

[79] National Grid, *Offshore Development Information Statement* (September 2010).

[80] The Crown Estates, "Marine: Offshore Wind Energy", *Our Portfolio*, http://www.thecrownestate.co.uk/our_portfolio/marine/offshore_wind_energy.htm

A.3 Regulatory arrangements for offshore transmission

A.3.1 Offshore transmission connection process

The regulatory arrangements for offshore transmission in the UK are based on an extension of the onshore regime, but with the addition of a tender process to choose an OFTO for each transmission link (Table 19). Connection of a generator onshore is overseen by the NETSO and delivered by the onshore TO responsible for that area (NGET for England and Wales, Scottish Power Transmission Limited for southern Scotland, and Scottish Hydro-Electric Transmission Limited for northern Scotland). For offshore areas, there is no responsible TO, so a tender system is used to select an owner and operator for the transmission assets. The tender process is discussed below, after an explanation of how the onshore statutory, regulatory and licensing arrangements have been extended offshore.

Table 19 Comparison of onshore and offshore connections process

High level onshore process	High level offshore process (under OFTO-build model)
• Customer applies • 3 months for NETSO to provide offer • Offer • 3 months for generator to accept/reject/refer offer • Construction Agreement • Construction phase • Operational	• Customer applies • 3 months for NETSO to provide offer • Initial Offer • 3 months for generator to accept/reject/refer offer • Tender process is undertaken • OFTO is selected • Offer is finalised including offshore element • Construction Agreement • Construction phase • Operational

A.3.2 Extension of the onshore regime

The role of National Grid as NETSO has been extended offshore. This means that National Grid is responsible for ensuring that electricity supply and demand stay in balance and the system remains within safe technical and operating limits. The NETSO is also responsible for providing access to the GB transmission system for offshore generators on an open, transparent, non-discriminatory basis, including providing an initial connection offer to generators offshore, based on an application of National Grid's optioneering process, which has been developed to ensure a consistent approach is used in the identification, analysis and selection of preferred design options. An additional requirement on the NETSO (set out in Special Condition C4 of NGET's licence) is to produce an annual ODIS.

The ODIS details the various ways in which the onshore and offshore transmission networks can be developed to support the connection of offshore generation sources. The statement is based on a high-level desktop analysis, rather than a full network optimisation that takes into account all physical and planning constraints. A key part of the analysis involves a comparison of point-to-point radial connections and a coordinated network. The uncertainty about future generation build – as discussed above – means that a range of scenarios are considered.

As under the onshore regime, generators are required to make a connection request to NETSO. Generators can make an application to NETSO at any time, which has obligations to provide an initial connection offer within 3 months. There can be significant issues with regards to the interaction with the onshore network around the point of connection to the transmission or distribution network and the need for onshore reinforcements.

Changes to transmission access arrangements brought in by Government under 'Connect and Manage' are also applicable for offshore connections with respect to wider onshore works to reinforce the network. Connect and Manage allows generators to connect to the grid immediately after local 'enabling' works have been completed, rather than waiting for the transmission companies to carry out the deep reinforcements of the wider network necessary to support the additional generation on the system. For offshore generators, any reinforcement assets needed to connect the project from the generating station to the onshore Main Interconnected Transmission System substation will always be required to be completed before connection,[81] so that only associated onshore works can be delivered later. Under Interim Connect and Manage, eight offshore wind projects (with capacity of 3.8 GW) advanced their connection dates by an average of 3.6 years[82] through the allowance for the onshore TOs to acquire a temporary derogation from the SQSS.

There is a requirement for the generator to have undertaken specific pre-application work to constitute a competent application. In addition, in order to trigger an OFTO tender process, the generator must provide payment and security to Ofgem – calculated in accordance with its cost recovery methodology – as stipulated in The Electricity (Competitive Tenders for Offshore Transmission Licences) Regulations 2010.

After the tender process and selection of an OFTO, a Connection Agreement between NETSO and the generator is signed, requiring the generator to secure financially the required assets until connection. Securitisation occurs through a combination of approaches developed for the onshore regime (as discussed in more detail in Section A.3.5 below).

The OFTO is responsible for owning and operating transmission assets between the point of connection with the generator and the point of connection with the onshore TO. This is likely to include some onshore infrastructure, including onshore substation assets. Onshore works from the point of connection to the onshore system are the responsibility of the relevant onshore TO (as for onshore generators).

Offshore transmission above 132kV is a licensable activity. As for onshore transmission owners, OFTOs must hold a transmission licence. The licence is granted by Ofgem to the successful tenderer and requires that the OFTO has a decommissioning plan, as well as bestowing a duty under Section 9(2) of the Electricity Act 1989:

- to develop and maintain an efficient, coordinated and economical system of electricity transmission, *and*
- to facilitate competition in the supply and generation of electricity.

OFTOs also need to comply with onshore transmission standards: the System Operator – Transmission Owner Code, Grid Code and the SQSS. SQSS standards for offshore transmission do not require the

[81] DECC, *Definition of 'enabling works' in the proposed connect and manage grid access reforms*, Information note (March 2010).

[82] DECC, *Government Response to the technical consultation on the model for improving grid access*, http://www.decc.gov.uk/assets/decc/Consultations/Improving%20Grid%20Access/251-govt-response-grid-access.pdf (July 2010).

same redundancy as for onshore links, primarily because offshore transmission is not required to connect demand.

A.3.3 OFTO tender process

The tender process is the key differentiating feature between the onshore and offshore transmission regimes. This approach reflects a compromise between the following alternative approaches:

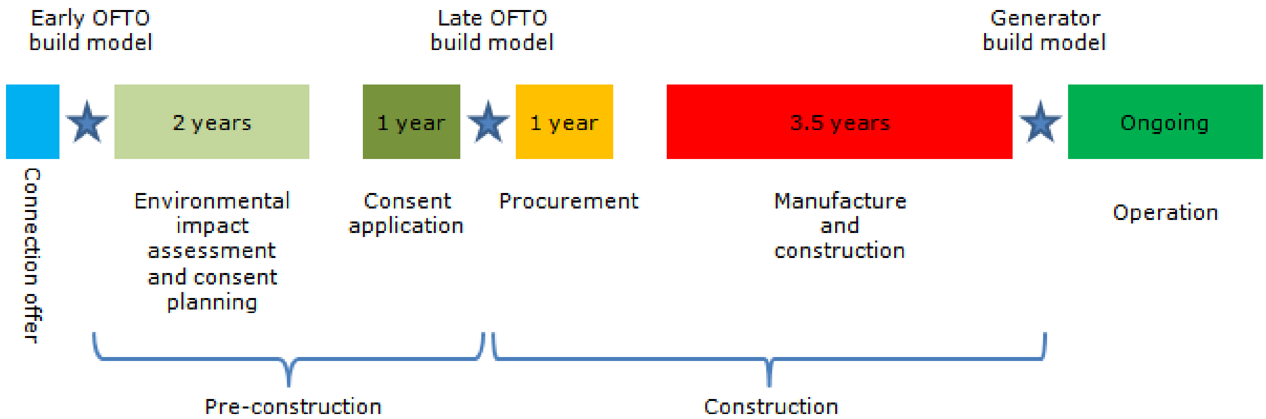
- a regulated model whereby the extension of the existing transmission licences to encompass offshore transmission would be coupled with the economic regulation of the offshore infrastructure on broadly the same basis as onshore transmission, *and*
- a merchant model whereby the developers of offshore generation would be left to make their own arrangements for offshore transmission connection in a model akin to that used by the offshore oil and gas industry.

Under the OFTO tender approach there is no monopoly transmission licence holder for a particular region as under a regulated model, so a tender process is undertaken by Ofgem to select an OFTO. The OFTO is selected by Ofgem on the basis of a detailed set of objective criteria in respect of each applicant's approach to financing and their operational and managerial proposal. An important aspect of evaluating the bids is each applicant's statement of the 20 year revenue stream that they require if they are the successful OFTO.

The tender process can occur at various stages of the construction process, at the discretion of the generator (Figure 19), as follows:

- **Early OFTO build**: the OFTO is responsible for planning and consenting, construction, operation and ownership of offshore transmission assets,
- **Late OFTO build**: the OFTO is responsible for construction, operation and ownership of offshore transmission assets, *and*
- **Generator build**: the OFTO is responsible for operation and ownership of offshore transmission assets.

Figure 19 Indicative timing of early OFTO, late OFTO and generator build models



Source: Ofgem and DECC, *Government Response to Consultations on Offshore Electricity Transmission* (December 2010).

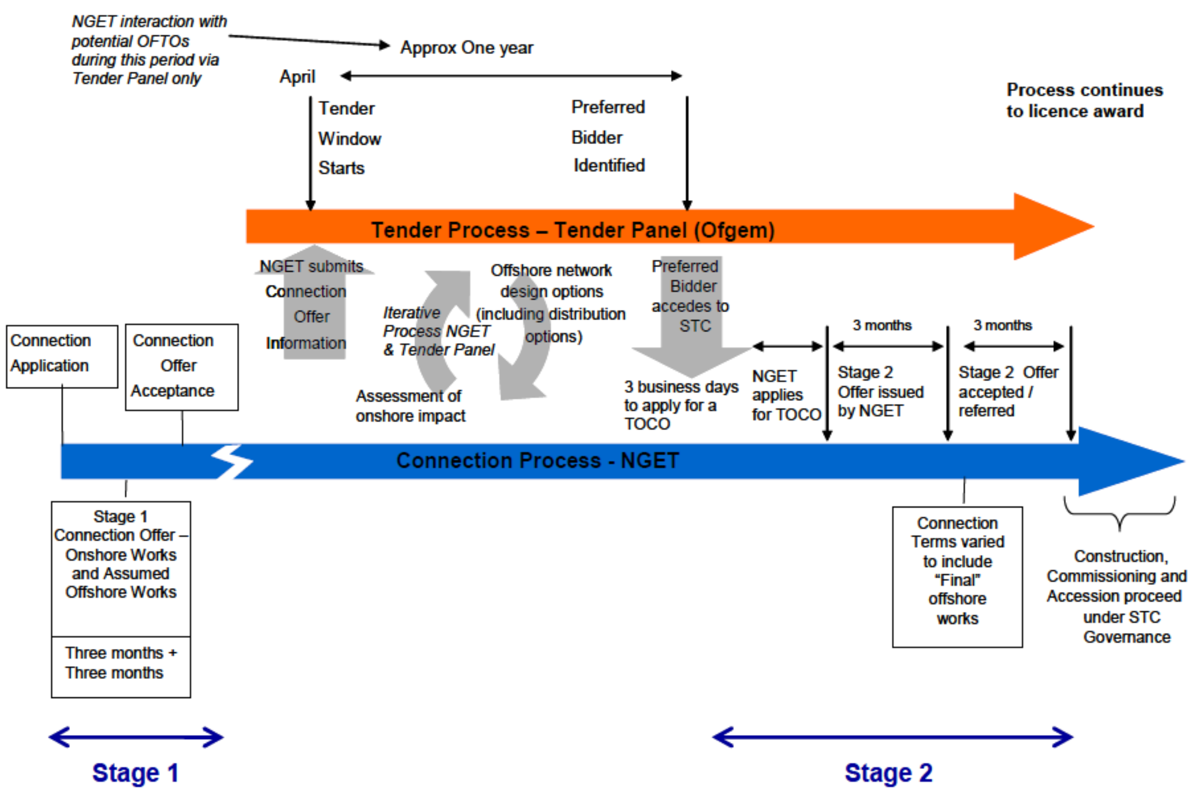
OFTO Early and Late Build

This section sets out how the OFTO build model could work at a high level according to Ofgem consultation. No decision has been reached to date on the detailed design of the OFTO build model.

Under the OFTO build model, applicants to the tender process would bid to own, construct and maintain the required offshore transmission assets. The successful bidder would also be responsible for planning and consenting under the OFTO early build model. The revenue stream detailed in the successful bid would compensate the OFTO for their construction and operating costs. The tender process would require iteration between NETSO and the tender panel to optimise onshore/offshore interactions (Figure 20) as there are typically multiple technical design solutions that could be used to address a system change or connection requirement.

If the tender process does not provide a successful bidder, there is scope to repeat the tender, or the generator could choose to build the assets themselves under the generator build option – there is no 'OFTO of last resort' under the OFTO build model.

Figure 20 Detailed process for OFTO build models



Source: National Grid, *Offshore Development Information Statement* (September 2010).

Generator build

Generators are also able to choose to build offshore transmission assets themselves. This approach was the basis of the 'transitional regime' under which OFTOs have been appointed to date and was extended to the enduring regime in 2010. The generator is required to ring fence the transmission assets during construction. On completion, transmission assets are transferred to an OFTO chosen through a competitive tender run by Ofgem.

As under the OFTO build model, an important input to the tender process is each bidder's nominated 20-year revenue stream. This represents the compensation that the OFTO requires to purchase the transmission assets from the generator and to continue to finance, own and operate these assets. The purchase price of the assets is determined by Ofgem, based on an assessment of 'efficiently incurred ex post cost' in consenting, building and financing construction. Generators are allowed to recover 100% of costs deemed to be efficiently incurred. If there is no OFTO appointed through the tender system, an 'OFTO of last resort' can be appointed to accept assets if necessary. The OFTO of last resort would be either a previously successful OFTO or one of the onshore TOs.

As discussed, the generator build model has been the basis for the transitional regime, under which various OFTOs have been appointed to date. The first transitional OFTO tender round commenced in June 2009, with a total of £1.1 billion in transmission links put to tender. Outcomes of seven of the nine tenders were announced in August 2010. The other two tenders had both been completed by May 2011. The second transitional tender round commenced in November 2010 and was still underway as of 1 July 2011.

The first transitional tender round involved ownership transfer of transmission assets with just over 2 GW capacity, while assets included in the second tender round have a capacity of just under 3 GW.

A.3.4 Planning and consenting

Planning and consenting arrangements are broadly the same in England and Wales: the MMO or the IPC[83] is responsible for consenting of offshore generation projects. In Scotland, on the other hand, Marine Scotland is the responsible body for developments over 1MW in Scottish inshore and offshore waters (Table 20).

Table 20 Summary of arrangements for planning and consenting

	England and Wales	Scotland
Body responsible	<1MW: Local planning authorities 1-100MW: MMO 100MW+: IPC Marine licensing in Welsh inshore waters: Welsh Assembly Government	<1MW: Local planning authorities 1MW+: Marine Scotland
Relevant Acts	Planning Act 2008 Electricity Act 1989 Transport and Works Act 1992 Town and Country Planning Act (TCPA) 1990	Marine (Scotland) Act 2010 Electricity Act 1989 Town and Country Planning (Scotland) Act 1997 Marine and Coastal Access Act 2009

[83] There are plans for the IPC to become a Major Infrastructure Unit within a revised departmental structure that includes the Planning Inspectorate. These changes are have been passed by Parliament as part of the Localism Bill.

	Marine and Coastal Access Act 2009 Food and Environment Protection Act 1985 Coastal Protections Act 1949	Food and Environment Protection Act 1985 Coastal Protections Act 1949
Single generation/ transmission application possible?	<100MW: Need to make separate applications for generation (Electricity Act 1989 Section 36) and marine licences, but both are evaluated in a single MMO process. Offshore cables can also be included in this process, but onshore infrastructure requires separate consent through the TCPA. >100MW: Yes, through IPC process (although a marine licence is still required for Welsh inshore waters)	Undersea cables can be consented along with generation assets, but this requires re-consent when ownership is transferred. Arrangements for onshore infrastructure are still under development

England and Wales

Requirements under the Electricity Act 1989 (Section 36), Food and Environment Protection Act 1985 (FEPA) and Coastal Protections Act 1949 (CPA) are met if consent for an offshore wind project in England or Wales is given by the MMO or IPC. Projects in Welsh inshore waters also require a marine licence issued by the Welsh Assembly Government.

The IPC process is applicable to developments of more than 100MW and offers the advantage of enabling a single application for generation and transmission infrastructure, by including the latter as 'associated development'. Ownership of transmission assets can be transferred later without further consenting, as the transfer of property, rights, liabilities or functions can be consented in the IPC process as part of ancillary matters set out in the 'Guidance on Associated Development' document (issued by the Department for Communities and Local Government on behalf of the Secretary of State). The IPC process also allows for wayleaves and compulsory powers for developers: 'An order granting development consent may include provision authorising the compulsory acquisition of land' (Planning Act 2008, Section 122).

However, consenting of anticipatory investment is constrained through the IPC route, as the Guidance on Associated Development (p. 5) sets out that any associated development should be necessary for the Nationally Significant Infrastructure Project (NSIP) under consent:

"Associated development … should be subordinate to and necessary for the development and effective operation to its design capacity of the NSIP that is the subject of the application."[84]

The MMO is responsible for consenting of offshore projects of less than 100MW. A single application for generation and offshore transmission is possible through the MMO process, but onshore transmission requires separate consent under either the TCPA (for example, onshore substations) or the Electricity Act 1989 Section 37 (overhead transmission lines). Accordingly, compulsory purchase and necessary wayleaves for onshore works must be sought through the TCPA or the Electricity Act 1989 rather than through the MMO process. As under the IPC process, ownership of offshore transmission infrastructure can be

[84] Department for Communities and Local Government, *Guidance on Associated Development* (September 2009), p. 5.

transferred to the OFTO without the need for any further consent under the Marine and Coastal Access Act 2009.

Scotland

Marine Scotland (on behalf of the Scottish Government) is the single point of application for Electricity Act Section 36, FEPA and CPA applications relevant to offshore generation in Scottish Waters with a capacity greater than 1MW. The National Marine Plan is currently in development and will guide the planning process. For offshore generation, a separate application is required for Electricity Act Section 36 and marine licensing, but both are submitted to Marine Scotland and are considered together.

Undersea cables can be considered as part of a single Marine Scotland application, but a further application would be required in order to issue a new consent if ownership is transferred from a generator to an OFTO. Arrangements for consenting of associated onshore transmission works are still under development, but at present a separate application is recommended. Marine Scotland does not have jurisdiction to grant compulsory purchase powers or wayleaves for onshore works, so these must be sought through separate applications through the TCPA or the Electricity Act 1989.

A.3.5 User commitment

Onshore, there is a choice between the IGUCM method and the Final Sums Methodology for securing connection and reinforcement works triggered by the connection of a new generator. Final Sums is based on the expenditure associated with relevant transmission reinforcement works as set out in the Construction Agreement and updated on a 6 monthly basis, while IGUCM is a generic methodology that does not relate to specific transmission reinforcement works needed for connection of the generator and does not involve any 'sharing' of financial liabilities with other users. Instead, generators are responsible for paying 10 years of TNUoS charges if they terminate the project under IGUCM.

For offshore generation, the onshore component can be secured using either the IGUCM or Final Sums Methodology, while the offshore component must be secured using the Final Sums Methodology.[85] The application of Final Sums offshore means that the offshore generator must secure the full cost of construction of any offshore local works.

For onshore works, the IGUCM method can offer some advantages through a generic methodology that caps commitment at ten times applicable wider zonal TNUoS charges, but will not be as favourable as Final Sums for wider works. Under a continuation of an interim decision made in July 2010,[86] wider works do not currently need to be secured under the Final Sums Methodology.

User commitment arrangements are currently being reviewed under CMP 192. Proposed changes under CMP 192 would remove generator exposure to anticipatory investment through reducing the liability according to a 'strategic investment factor'. Further, it is proposed that offshore liabilities would be limited to the pro rata share of connection to the nearest reasonable point on the main interconnected system, so that offshore generators would not be responsible for securing the cost of reinforcing the onshore network via offshore links. As of November 2011, proposals under CMP 192 have been consulted upon as part of the modification process and a Final CUSC Modification Report has been written. However, approval from Ofgem will be required before any changes can be implemented. Ofgem has indicated that it is not satisfied with the existing arrangement for user securitisation of transmission assets and is likely to

[85] National Grid, *Re: Interim Generic User Commitment Methodology in Relation to Offshore Projects*, Letter (July 2010).

[86] National Grid, *Re: Review of Sharing Arrangements for Final Sums Liabilities*, Letter (July 2010).

consult on initiating a Significant Code Review on user commitment if it is not satisfied with proposed changes at the end of the CMP process[87].

A.3.6 Charging

Each OFTO recovers its revenue from the NETSO in accordance with the 20 year revenue stream agreed through the tender process. Unlike for the onshore TOs, there is no periodic review of the revenue stream. However, there is scope for charges to vary to allow pass-through of some predictable but uncertain costs, including changes to decommissioning costs, code changes, lease costs, licence fees and Ofgem tender costs. Sourcing the OFTO revenue from NETSO minimises credit risk for the OFTO, but the majority of OFTO revenues are recovered from the relevant generator by the NETSO.

The NETSO is responsible for setting charges to recover the total allowed revenue of all onshore and offshore transmission owners according to the TNUoS charging methodology. For each offshore generation project, charges are allocated to:[88]

- Local tariffs to recover (most of) the allowed revenue of the OFTO, which includes
  - a local circuit component (adjusted for offshore security factor: 1.0 for single cable and, as for the onshore network, capped at 1.8)
  - a local substation component (composed of platform, switchgear and transformers)
- Wider tariffs to recover onshore costs
  - wider locational TNUoS
  - wider residual.

This charging methodology means that the majority of OFTO costs are passed through to the relevant generator, but there is still some socialisation of costs. Costs for onshore substation assets owned by the OFTO and any over-specification of offshore substation assets are socialised by spreading them across all generators and users through the residual tariff. For example, under the worked example prepared by National Grid[89] – updated for changes to the charging regime in July 2010[90] – 78% of OFTO charges would be passed on to the generator using the offshore transmission assets and the remainder would be socialised and recovered through wider residual charges. Current charging arrangements have been developed with a focus on radial links, as these have been used to connect offshore projects to date. Charging arrangements for coordinated transmission assets offshore (in particular, meshed HVDC links) have not yet been fully developed.

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[87] Ofgem, *Scope of Project TransmiT and Summary of Responses to Our Call for Evidence*, http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/110125_TransmiT_Scope_Letter_Final.pdf

[88] A worked example of the application of TNUoS charges to offshore generators is available from: National Grid, *Guidance Note: TNUoS charges for Offshore Generators*, http://www.nationalgrid.com/NR/rdonlyres/869AF29F-0CBE-4189-97D5-562CBD01AD86/44194/GuidetooffshoreTNUoStariffs.pdf (November 2010).

[89] Ibid.

[90] The most material of these changes involved changing the rating of the offshore platform to reflect the lower (instead of the higher) of the transformer and switchgear ratings. As any oversizing of the offshore platform is socialised, this change had the effect of increasing the amount of OFTO revenue recovered from the generator. National Grid's worked example was drafted prior to confirmation of Ofgem's decision on these changes and accordingly showed that only 68% of the OFTO charges would have been passed through to the generator.

Charging for offshore transmission is also currently under review by Ofgem as part of broader changes being considered under Project TransmiT. Project TransmiT is Ofgem's independent review of the charging arrangements for gas and electricity transmission networks and certain connection arrangements[91]. As part of this, a Significant Code Review has been launched of TNUoS charging arrangements, referred to as the 'TNUoS charging SCR'. Various charging arrangements are under consideration, based either on a 'socialised' or 'postage stamp' approach in which part or all of the costs relating to shared transmission assets are recovered through a uniform tariff that would apply to all generation users irrespective of where they are located, or a continuation of 'Incremental Cost Related Pricing' (upon which the current TNUoS charges are based) where users are subject to locational signals reflecting their impact on efficient transmission investment. The outcomes of Project TransmiT could have significant implications for charging for offshore transmission.

The offshore regime also incorporates an 'availability incentive' to ensure prompt fixing of outages. As set out in the OFTO licence, 10% of annual OFTO revenue is at risk under the availability incentive – six times higher than the maximum onshore penalty. No compensation is payable if the OFTO meets its availability target, which has a default of 98% (meaning that planned and unplanned outages should occur no more the 2% of the time). Compensation for outages is paid to the generator via NETSO through a reduction in TNUoS charges, as set out in the CUSC.

The OFTO is allowed to pass on charges for incremental investment as requested by the generator. The additional investment is at Ofgem's discretion and capped at 20% of the initial capital expenditure.

[91] Ofgem, *Project TransmiT,* http://www.ofgem.gov.uk/Networks/Trans/PT/Pages/ProjectTransmiT.aspx

B Risk allocation under the current arrangements

B.1 Introduction

In order to evaluate the potential to optimise the balance between the benefits and risks of coordinated transmission build, we consider the allocation of risks under the current arrangements. There are various risks involved in the process of developing an offshore transmission link or system. In this Appendix, several aspects of these risks are described in the context of the current arrangements:

- the point(s) in the development process at which the risks arise and the severity of each risk
- who is likely to bear the risk, and
- which parties have the ability to manage the risks.

For further context this Appendix should be read in conjunction with Appendix A, which sets out in detail the current offshore regulatory, commercial and incentive arrangements. The key parties in the existing regime are offshore generators, OFTOs, the onshore TOs, the NETSO and Ofgem. Table 21 illustrates the roles, objectives and incentives of each of these parties.

Table 21 Key parties in offshore transmission – illustrative roles, objectives and incentives

Party	Role	Example objectives	Illustrative incentives under current regime
Offshore generators	Commit to construction of generator and apply for connection Consenting and planning (OFTO late build or generator build) Construction (generator build)	Minimise cost of transmission paid through TNUoS Achieve timely build Minimise outages	Minimise cost of charging for offshore network Minimise cost of any onshore connections charge Obtain connection to service generator commissioning Meet Ofgem assessment of efficient build in order to transfer full asset value under generator build
OFTOs	Consenting and planning (OFTO early build) Construction and procurement (OFTO late or early build) Financing and operation of transmission assets	Maximise returns to investors, through either - Maximising value of tenders won, or - Maximising annual return Minimise risk to investors	Win tender with highest bid possible Maximise efficiency of build under OFTO build Optimise performance against asset availability incentive Meet licensing condition to deliver an efficient, coordinated and economic system of electricity transmission
Onshore TOs	Onshore reinforcement	Maximise returns to investors, through either	Reinforce network to comply with SQSS Meet licensing condition to deliver an

		- Maximising value of assets built, or - Maximising annual return Minimise risk to investors	efficient, coordinated and economic system of electricity transmission Maximise regulated return to reinforcement assets
NGET (as NETSO)	Provide preliminary connection offer within 3 months, including onshore connection point, consistent with licence obligation to provide an efficient, coordinated and economical system of electricity transmission. Modify onshore connection point as part of system re-optimisation where required Recover cost of network through charging Maintain STC, CUSC, Grid Code	Ensure that electricity supply and demand stay in balance and the system remains within safe technical and operating limits Provide timely and optimal connection offer to offshore generators	Maximise returns under System Operator incentives
Ofgem	Set regulatory regime Legal requirement to undertake tender process	Regulate licensed companies Protect the interests of consumers, by promoting effective competition where appropriate	Achieve minimum price through tender system Ensure successful tenderers have adequate financial, operational, technical and supply chain capacity to deliver
The Crown Estate	Lease of The Crown Estate seabed to generator and OFTO Co-investor in Round 3 developments (until the point of consenting)	Consistent the with The Crown Estate statutory requirements: Obtain the best possible return on leases (excluding any element of monopoly value) Maintain and enhance the land and property rights under The Crown Estate management	Optimise The Crown Estate fees Ensure regulatory settings and asset development are consistent with ongoing use of The Crown Estates seabed resources Facilitate coordination and cooperation across multiple projects where this enhances land and property rights

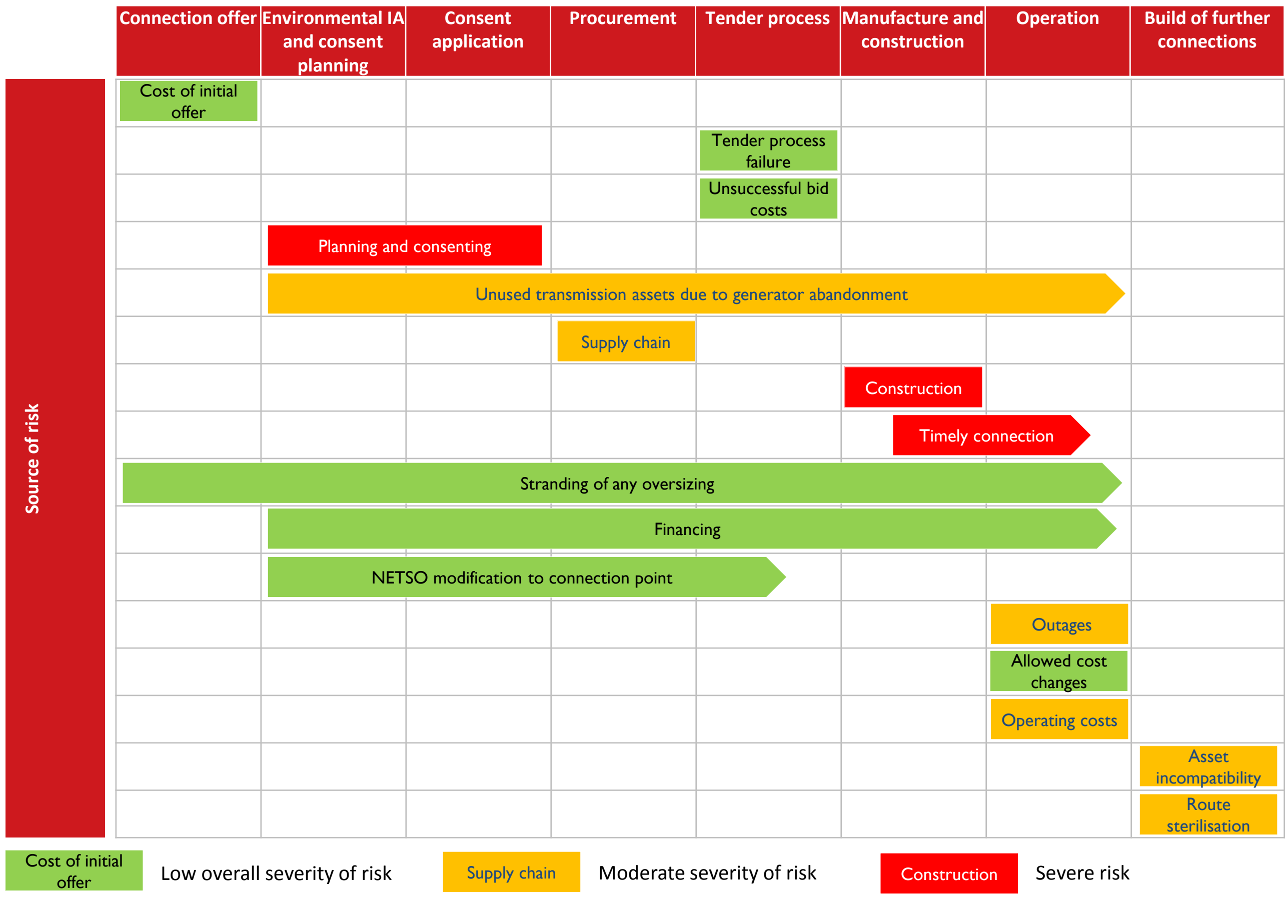
Source: Redpoint Energy assessment

B.2 Severity and timing of risk

The severity of the various sources of risk across the development process can be compared on the basis of their expected value, expressed as the product of the potential loss and the probability of a negative outcome. Such a comparison is presented in Figure 21, expressed through green, amber and red colouring representing increasing severity of a risk.

For example, the failure of the tender process could impose significant costs on the generator through a delay in their connection under OFTO-build. However a 100% success rate on round 1 OFTO tenders suggests that the tender process is unlikely to fail, so the overall severity of risk is considered to be low (this is not to say of course that this risk could not change). On the other hand, there are significant risks in the planning and consenting process, as the probability of planning difficulties (either onshore or offshore) is considerably higher.

Figure 21 Severity and timing of risk under the current regime[92]

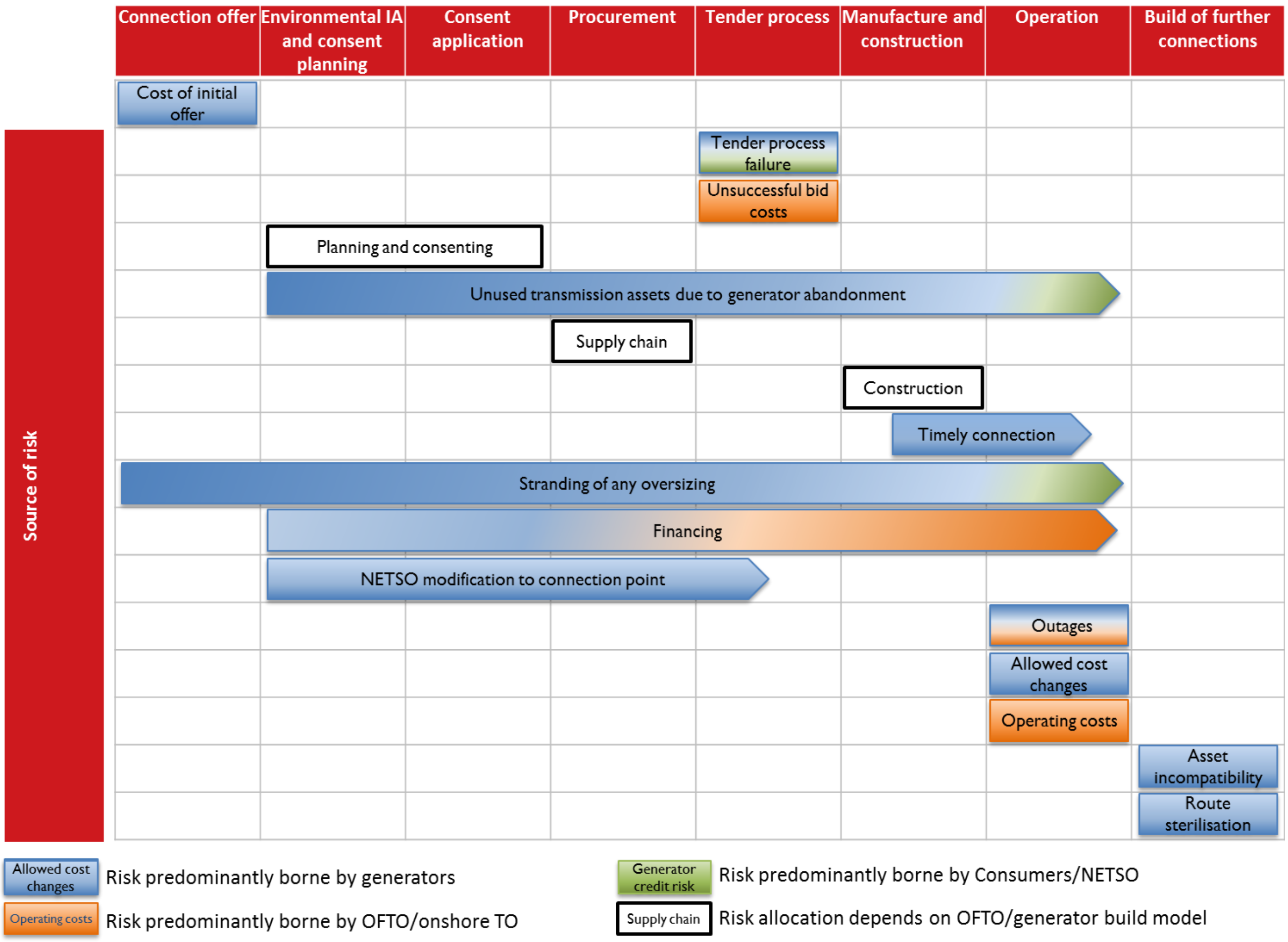


B.3 Who is likely to bear risks?

A high level assessment of the allocation of potential risks under the existing regime is described in Figure 22, with indicative shading in the figure used to indicate where a particular risk is shared between different parties, or where the party taking on a risk changes throughout the development process.

[92] All parties are also exposed to sovereign risk (Government, regulatory and legislative changes) throughout the development process. Timing of the tender process will depend on the OFTO/generator build model; this diagram is based on a late OFTO build model, but the risk types and severities would be maintained under an early OFTO or generator build.

Figure 22 Allocation of risk under the current regime



While illustrative only, our views on the potential risks and who bears them have been informed by the experience with tender rounds to date. For example:

- The **cost of initial offer** for connection from the NETSO relates to the risk that transmission works will turn out to be more expensive than anticipated, and will affect the generator through the cost of securitising works and ongoing Transmission Network Use of System (TNUoS) charges. There have been a number of connection offers to offshore generators to date that have not been signed due to concerns about the connection offered and uncertainty about the process for investment in a coordinated approach.
- **Tender process failure** has not occurred to date (as discussed above) but if it did occur in future it could impose costs on the generator through a delay in transmission connection.
- **Unsuccessful bid costs** are a risk for specific OFTOs and fall on unsuccessful bidders. For example, Green Energy Transmission (a consortium of Equitix Ltd and AMP Capital Investors Ltd) and National Grid Offshore Limited were involved in OFTO tender round 1 (including invitation to tender for the Greater Gabbard project) but were not successful in winning any of the round 1 tenders, so had to absorb the costs of their involvement in the tender process. Successful bidders, on the other hand, are able to pass on bid costs for the successful project.
- **Unused transmission assets due to generator abandonment** will arise when the generation project is abandoned after asset construction/cost incurred (for example, due to

generator insolvency). Prior to operation, the generator will be responsible for the costs of transmission construction according to the final sums methodology. There are examples where final sums have been payable for onshore connections, but the payments involved have been small as they have typically occurred at the pre-consenting stage. Post-commissioning, much of this risk will fall to consumers as the NETSO sits as counterparty to the OFTO, and the generator liability is limited to one year of TNUoS charges.

- **Timely connection** is critical for the generator as they will not be able to export power to market without transmission. SSE has estimated that a one year delay to connection for a completed generation project would cost a generator £200 million per GW of capacity and reduce a project's internal rate of return by 1%.[93] There are many examples where onshore wind projects in Scotland have been delayed (albeit without necessarily undertaking generation investment first) due to inability to access the transmission network[94]. In 2008, the queue for connection included over 16 GW of renewables.[95] The generator build option gives generators some opportunity to manage this risk themselves.
- **Stranding of any over sizing** is a risk that falls primarily to generators under the current regime, as they are responsible for securing construction of transmission assets until the point at which they are in use. Where generators build transmission assets themselves, there is a risk that the full cost of oversized assets will not be allowed to be recovered under the OFTO tender process. Once construction is completed, much of the risk of stranding is transferred to consumers, as the cost of oversizing is recovered mainly through residual TNUoS charges.[96]
- **Financing risks** for the transmission link initially fall on the offshore generator. The Gunfleet Sands development is an example where the generator has been affected by financing risk, as Ofgem deemed some of the interest costs incurred inefficient and thus did not allow full recovery by the generator. Financing risks are transferred to the OFTO along with the control of transmission assets, with the exact timing of this transfer dependant on whether an OFTO early/late build or generator build model is pursued. OFTOs can be expected to take action to minimise financing risks. For example, Transmission Capital Partners (a consortium that was successful in three first round OFTO tenders) have debt in place for the entire 20 year life of transmission assets for the Robin Rigg project, removing any mandatory refinancing risk.[97]
- **NETSO modification to the connection point** can occur under Section 6.9 of the Connection and Use of System Code (CUSC) and can potentially impose costs on the generator where they have already invested in planning and consenting or procurement based on the initial connection offer. Costs are likely to accrue to the generator whether or not these costs are recognised in the transfer value approved by Ofgem, as even where they are included in the transfer value they are likely to pay more through higher TNUoS charges.
- **Outages** are primarily a risk for the generator, as they prevent the transmission of generation to market, imposing costs for which – under a typical offshore connection, with no redundancy – the CUSC only allows for compensation to the extent of their TNUoS payments. However there is

[93] SSE, *Re Offshore Electricity Transmission: Further Consultation on the Enduring Regime*, submission to Ofgem/DECC consultation, http://www.ofgem.gov.uk/Networks/offtrans/pdc/cdr/Cons2010/Documents1/SSE%20response%20to%20further%20consultation%20on%20the%20Enduring%20Regulatory%20Regime.pdf (September 2010).

[94] For example, see Econnect, *BWEA – Npower Juice 'Path to Power', Stage 3 Discussion Document – GB Electricity Network Access*, Econnect Project No: 1548 prepared for the British Wind Energy Association (March 2006).

[95] Kay, A., *Connecting Renewables to the National Grid*, National Grid Presentation to Scotland's Energy Future Conference (September 2008).

[96] Generators are only responsible for the cost of any oversized cable connections where there is circuit redundancy.

[97] International Public Partnerships, *Robin Rigg Offshore Transmission Project Reaches Financial Close*, http://www.amberinfrastructure.com/pdf/020311%20Robin%20Rigg%20-%20Financial%20Close%20Announcement.pdf (March 2011).

also risk taken by the OFTO, as charging arrangements in the System Operator-Transmission Owner Code (STC) allow for a performance incentive as set out in the OFTO licence. Under current arrangements, this puts 10% of OFTO revenue at risk, which could compromise their capacity to repay equity finance.

- **Allowed cost changes** can be fully passed through from the OFTO, passing all associated risk to the generator. For example, the offshore transmission licence issued by Ofgem to Transmission Capital Partners in respect of the Robin Rigg offshore wind project states that certain costs can be passed through. These relate to adjustments in network rates, Crown Estate Lease costs, decommissioning costs, tender fee costs, temporary physical disconnection payments, 'force majeure' under the STC or changes to the STC, and costs relating to the introduction of the Marine and Coastal Access Act 2009.
- **Operating costs** – with the exception of allowed cost changes – are incurred by the OFTO. Operating costs such as maintenance of transmission assets are the responsibility of the OFTO and they bear the associated risks. Operating costs for an OFTO operating just one or several offshore links are likely to be more variable relative to those for onshore TOs, as onshore TOs can benefit from a larger portfolio of transmission assets.[98]
- **Asset incompatibility** and **route sterilisation** are risks that could impact generators seeking further connections after the immediate project has been completed. Asset incompatibility means that a future connection needs to use technologies that are unavailable or uneconomic in order to link with the first transmission project (and could arise in the absence of technology standardisation). Route sterilisation would occur where an initial transmission investment constrains future delivery, and could arise due to cable corridors and be exacerbated by constraints on onshore landing points.
- Some other risks – **planning and consenting**, **supply chain** and **construction** – could fall on the generator or the OFTO depending on the generator/OFTO build model chosen. These risks relate to the possibility that costs for consenting and building new transmission links will be higher than expected due to planning and consenting, supply chain or construction issues respectively. Under the transitional regime, these risks have fallen on the generator. To date, Ofgem has typically allowed generators to recover all construction costs through the OFTO tender process, however construction risk was a factor in transmission assets for the Walney 1development, where £3.7M in costs (of a total of about £90M capital expenditure) were considered not to be economic and efficient[99]. These risks will remain for generators under generator build in the enduring regime, as Ofgem might find that construction costs have not been efficiently incurred. OFTOs will be subject to risks under OFTO build as they have bid for a fixed revenue stream.

B.4 Which parties have the ability to manage the risks?

This section judges which parties are likely have the greatest capacity to manage risks associated with the development of offshore transmission networks. This judgement is based on a consideration of:

- the incentives to minimise the likelihood of the risk occurring,
- incentives to reduce the impact of a risk if it does eventuate, and
- capability to deal with the risk.

[98] For example, annual operating costs for the onshore TOs have stayed within a band of plus or minus 15% during the last decade. See: Ofgem 2011, *Transmission Annual Report for 2009-10*, Annual Report (April 2011).

[99] Ofgem, *Offshore Transmission: Cost Assessment for the Walney 1 transmission assets,* Draft, (August 2011).

Risks through the development process can create a well-known economic problem - the 'Principal–Agent problem' - whereby the party with the incentive to minimise the impact of risks (the principal, typically generator in this context) does not control the risk and does not have full information about the actions of the agent to control risks. In this case, contracts need to be designed so as to align incentives and enable risks to be distributed to those parties best able to manage them.

The capability or capacity to deal with risk will also be important. For example, dealing with construction risk requires specific skills and the capacity to manage the construction process, while supply chain risks require skills in managing the procurement process and third party relationships. These will not be core competencies for all parties in the process.

Using this approach, below we indicate the key parties likely to be best placed to manage specific risks. The NETSO (on behalf of consumers) could have a role in taking on those risks that generators and transmission owners are not well placed to manage, and where consumers stand to benefit from these risks being taken.

- **Generators**:
  - unused transmission assets due to generator abandonment
  - planning and consenting (in particular, where generation and transmission assets are consented in a single application)
  - supply chain
  - construction
  - timely connection

    under generator build & where have access to technical skills

- **OFTOs:**
  - unsuccessful bid costs
  - supply chain
  - construction

    under OFTO build & where have access to technical skills
  - financing
  - outages (but limited incentive beyond cap of10% revenue loss,
  - operating costs.

- **Onshore TO**:
  - financing of onshore network
  - outages due to onshore network
  - operating costs for onshore network.

    where price regulation provides incentives to minimise the impact of these risks

C Cost-benefit analysis approach and sensitivities

In this appendix, we describe the cost-benefit analysis approach used and present additional results for the sensitivities undertaken.

C.1 Cost-benefit analysis: approach

The costs and benefits of a coordinated network are measured against a radial build as the counterfactual.

- The 'T1 – connect and reinforce' design as developed by TNEI/PPA for the asset delivery work stream is used for the radial counterfactual, *and*
- The coordinated network is represented by the 'T2 – networked' design.

Cost and benefits are calculated annually and converted into a net present value (NPV) for the period 2010-2030 using the Green Book real discount rate of 3.5% and presented in real 2011 terms. It is important to note that the NPV analysis does not capture the costs and benefits of the options after 2030, except as part of the sensitivity analysis presented below.

Each component of the cost-benefit analysis is described below.

- **TO capital costs:** The annualised change in capital costs for onshore transmission owners. This includes the cost of capital applied to the regulatory asset value, as well as depreciation of new assets.[100] Onshore transmission owners are responsible for all transmission infrastructure on the onshore side of onshore substations, including undersea HVDC 'bootstraps' that connect two onshore transmission points.
- **TO operating costs:** The change in annual operating costs to maintain additional capital assets, estimated as a proportion of TO capital assets.
- **OFTO capital costs:** The annualised change in capital costs for onshore transmission owners. Capital costs are calculated as a constant annual rate, sufficient to cover OFTO cost of capital and depreciation over the 20 year life of the assets.
- **OFTO operating costs:** The change in annual operating costs to maintain additional capital assets, estimated as a proportion of OFTO capital assets.
- **Overall impacts:** The decrease in capital and operating costs to build and maintain the transmission network to service offshore generation (net benefits of coordination). A negative number represents an increase in the overall cost of transmission assets versus the counterfactual.

[100] TO capital costs include the cost of onshore reinforcements to key boundaries, but exclude any other constraint costs as these data were not available from work stream 1.

C.2 Cost-benefit analysis: key parameters

The capital costs described above were sourced from the asset delivery work stream of the Offshore Transmission Coordination Project. However, additional parameters were required to annuitise capital costs according to the user cost of capital,[101] and to estimate associated operating costs. Parameters for the cost of capital and operating costs for onshore TOs were source from the TPCR4 price control as this was the most recently completed price control for onshore transmission assets. All transmission assets are depreciated using a straight line method, consistent with RIIO T1 strategy decisions.[102] Key parameter values are summarised in Table 22.

Table 22 Parameter values for the central cost-benefit analysis

Parameter	Value	Source
Discount rate	3.5%	The Green Book[103]
Economic life of transmission assets Onshore TO assets OFTOs	 45 years 20 years	 RIIO T1 Strategy Decision OFTO regime
Real vanilla weighted average cost of capital Onshore TOs OFTOs	 5.05% 5.05%	 TPCR4 price control[104] TPCR4 price control
Operating costs as a proportion of capital cost Onshore TOs OFTOs	 2.75% 2.00%	 TPCR4 price control Maintenance of offshore platforms from Offshore Transmission Network Feasibility Study[105]

C.3 Sensitivity analysis: the discount rate

Changes in the discount rate do not impact annual (undiscounted) results, as the discount rate is only used to discount back to give a net present value. As such, changes to the discount rate do impact the overall net present value of a coordinated network relative to a radial design (Table 23). A lower discount rate increases the weight attached to future years, so increases the importance of later years in the analysis, where the benefits from a coordinated network are greatest. Thus, the estimated benefits from a coordinated network are greater when a lower discount rate is used for the analysis.

[101] This is necessary to provide annual results and also to incorporate the true cost of risky investment (particularly where these are financed by international capital that must be duly compensated). By allocating the cost of capital over the life of the asset, this approach also avoids the need for any further truncation of the cost of capital assets with lifetimes that extend beyond the modelling period.

[102] Ofgem, *Decision on Strategy for the Next Transmission Price Control – RIIO-T1*, RIIO-T1 http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decision.pdf (March 2011).

[103] HM Treasury, *The Green Book: Appraisal and Evaluation in Central Government*, http://www.hm-treasury.gov.uk/d/green_book_complete.pdf.

[104] Ofgem, *Transmission Price Control Review: Final Proposals*, Decision document, http://www.ofgem.gov.uk/Networks/Trans/Archive/TPCR4/ConsultationDecisionsResponses/Documents1/16342-20061201_TPCR%20Final%20Proposals_in_v71%206%20Final.pdf (December 2006).

[105] National Grid and The Crown Estate, *Offshore Transmission Network Feasibility Study* (September 2011).

Table 23 Sensitivity analysis (total cost only) for the discount rate

Discount rate sensitivity

		2011-2015	2016-2020	2021-2025	2026-2030		NPV (2010-2030)	Change from base case
		£M (real 2011)					£M (real 2011)	%
Reduction in costs for T2 relative to T1	Generation scenario							
Total cost - low discount rate (2.5%)	A	- 12	292	271	297		**566**	15%
	B	413	285	367	550		**1,190**	11%
	C	525	698	1,145	1,191		**2,646**	12%
	D	451	1,071	1,790	1,988		**3,931**	13%
Total cost - base case discount rate (3.5%)	A	- 12	292	271	297		**494**	
	B	413	285	367	550		**1,072**	
	C	525	698	1,145	1,191		**2,367**	
	D	451	1,071	1,790	1,988		**3,493**	
Total cost - high discount rate (4.5%)	A	- 12	292	271	297		**431**	-13%
	B	413	285	367	550		**969**	-10%
	C	525	698	1,145	1,191		**2,125**	-10%
	D	451	1,071	1,790	1,988		**3,116**	-11%

C.4 Sensitivity analysis: cost of capital

Changes in the cost of capital used for the cost-benefit analysis have the opposite impact to the discount rate: a higher cost of capital increases estimated benefits from a coordinated network (Table 24). An increase in the cost of capital increases the benefits from a coordinated design because it gives greater weight to the higher capital costs modelled under a radial design.

A sensitivity run was also undertaken with a lower cost of capital for onshore TOs (4.05%) than for OFTOs (5.05%) This change could reflect a situation where competition for OFTO assets allows access to capital at lower costs, as reflected in Ofgem estimates of significant savings from the OFTO tender system.[106]

Results demonstrate that benefits from coordination are smaller where OFTO costs of capital are lower, in particular for scenarios with less overall build (scenarios A and B). Benefits from coordination are smaller where OFTO costs of capital are lower because this reduces the weight given to OFTO capital savings under coordination. The reduction in estimated benefits from coordination is particularly large in scenarios A and B because:

- There are net increases in TO costs with coordination under these scenarios
  - these cost increases are given a relatively high weight, as TO capital costs are still weighted by the base case TO cost of capital (5.05%)
- There are offsetting decreases in OFTO costs under coordination
  - these cost decreases are given a relatively low weight, as OFTO capital costs are weighted by a lower (4.05%) cost of capital
- These two effects mean that overall benefits from coordination are substantially lower where there is a lower OFTO cost of capital; in fact, reducing the OFTO cost of capital only has a bigger impact on these scenarios than reducing the TO and OFTO costs of capital together.

[106] Ofgem, *Three Bidders Selected to Run the First £700 Million of Transmission Links for Seven Offshore Wind Farms 2010*, Press Release (August 2010).

This result should not be interpreted as the benefits from a lower cost of capital itself, but rather as a reduction in the benefits from coordination where a lower cost of capital can be accessed for OFTO assets.

Table 24 Sensitivity analysis (total cost only) for the cost of capital

Cost of capital sensitivity								
		2011-2015	2016-2020	2021-2025	2026-2030		NPV (2010-2030)	Change from base case
		£M (real 2011)					£M (real 2011)	%
Reduction in costs for T2 relative to T1	Generation scenario							
Total cost - low capital costs (4.05%)	A	- 6	279	260	283		**479**	-3%
	B	389	277	348	515		**1,018**	-5%
	C	498	657	1,066	1,105		**2,216**	-6%
	D	429	999	1,655	1,835		**3,248**	-7%
Total cost - base case capital costs (5.05%)	A	- 12	292	271	297		**494**	
	B	413	285	367	550		**1,072**	
	C	525	698	1,145	1,191		**2,367**	
	D	451	1,071	1,790	1,988		**3,493**	
Total cost - high capital costs (6.05%)	A	- 17	307	283	313		**512**	4%
	B	437	295	388	586		**1,130**	5%
	C	554	741	1,227	1,279		**2,525**	7%
	D	475	1,146	1,929	2,145		**3,748**	7%
Total cost - low OFTO capital costs (TO = 5.05% and OFTO = 4.05%)	A	- 19	260	235	262		**423**	-14%
	B	378	244	329	505		**963**	-10%
	C	477	637	1,071	1,123		**2,193**	-7%
	D	407	997	1,698	1,899		**3,285**	-6%

C.5 Sensitivity analysis: operating expenditure

Higher operating costs onshore and offshore would increase the estimated benefits from a coordinated network (Table 25). An increase in operating expenditure increases the benefits from a coordinated design because it gives greater weight to higher operating costs under a radial design, similar to changes in the cost of capital described above.

A sensitivity scenario with lower operating costs for OFTO assets compared with TO assets was also tested. As for capital costs, this could reflect benefits from competition through the OFTO tender system, and would tend to reduce the benefits from coordination. Combining both a lower cost of capital and a lower rate of operating expenditure for OFTO assets would see the benefits of coordination under Scenario A reduced to £370 million (a 25% reduction from the base case), or 7.2% of the net present value cost of a radial network.

Table 25 Sensitivity analysis (total cost only) for operating expenditure

Operating expenditure sensitivity			2011-2015	2016-2020	2021-2025	2026-2030		NPV (2010-2030)	Change from base case
			£M (real 2011)					£M (real 2011)	%
Reduction in costs for T2 relative to T1	Generation scenario								
Total cost - low operating expenditure (TO: 2.25%; OFTO: 1.5%)	A		- 11	278	257	282		**469**	-5%
	B		392	271	348	522		**1,018**	-5%
	C		499	662	1,087	1,131		**2,248**	-5%
	D		429	1,017	1,700	1,889		**3,319**	-5%
Total cost - base case operating expenditure (TO: 2.75%; OFTO: 2.0%)	A		- 12	292	271	297		**494**	
	B		413	285	367	550		**1,072**	
	C		525	698	1,145	1,191		**2,367**	
	D		451	1,071	1,790	1,988		**3,493**	
Total cost - high operating expenditure (TO: 3.25%; OFTO: 2.5%)	A		- 12	307	285	313		**519**	5%
	B		433	299	387	578		**1,126**	5%
	C		551	733	1,203	1,250		**2,486**	5%
	D		473	1,126	1,880	2,087		**3,668**	5%
Total cost - low OFTO operating expenditure (TO: 2.75%; OFTO: 1.5%)	A		- 17	268	244	271		**441**	-11%
	B		387	254	339	516		**990**	-8%
	C		489	652	1,090	1,140		**2,237**	-6%
	D		418	1,016	1,721	1,921		**3,337**	-4%
Total cost - no saving in operating expenditure	A		1	249	234	251		**436**	-16%
	B		340	252	305	444		**896**	-20%
	C		438	571	909	937		**1,909**	-23%
	D		379	855	1,397	1,546		**2,766**	-25%

C.6 Sensitivity analysis: extending the time horizon

There are likely to be benefits from a coordinated network that extend after 2030. The analysis of assets built to 2030 has been extended to 2050, to consider longer-term benefits from a coordinated network. The full cost of the offshore network would have been depreciated under its 20 year asset life by this time, but many onshore assets would still be within their economic life as these have a 45 year regulatory lifetime under RIIO.

For the scenarios with more aggregate build (C and D) this increases the absolute benefits from coordination, but the proportional savings are marginally lower.

For the scenarios with less build (A and B), extending the time horizon for the cost-benefit analysis reduces the benefits from coordination by giving greater weight to onshore assets. This is because:

- Onshore assets have longer economic lives than offshore assets
- Accordingly, from 2040, most of the asset value is made up of onshore assets
- There is more build onshore under the coordinated design in these scenarios
- So there are net costs from coordination under these scenarios after 2040 and extending the analysis to 2050 reduces the total benefits from coordination under scenarios A and B.

Table 26 Sensitivity analysis for extending the analysis to 2050

		Reduction in cost relative to T1 (radial)	
		NPV £m (real 2011)	As a proportion of radial NPV
NPV to 2030	Scenario A	£494	8.5%
	Scenario B	£1,072	8.6%
	Scenario C	£2,367	12.3%
	Scenario D	£3,493	14.6%
NPV to 2050	Scenario A	£314	4.5%
	Scenario B	£978	6.0%
	Scenario C	£2,872	11.2%
	Scenario D	£4,965	15.2%

D Case studies: Irish Sea, West of Isle of Wight and Hornsea

D.1 Introduction

The purpose of the case studies is to:

- Demonstrate sequential generation build decisions and associated transmission delivery,
- Consider the cost profile of alternative transmission designs and cashflows required to compensate transmission owners,
- Investigate how risks are allocated between key participants, in particular through user commitment for new transmission build,
- Investigate how the cost of transmission investment would be recouped through charging under current and alternative arrangements, including the distributional implications of this, *and*
- Consider the commercial and regulatory incentives facing generators, transmission owners and other participants under these arrangements.

The three case studies cover three Round 3 zones: The Irish Sea, West of Isle of Wight and Hornsea. They are presented in turn below.

- The Irish Sea zone has been chosen for investigation through a detailed case study as it offers examples of many of the key issues relating to coordinated network development. The zone has significant (approximately 4 GW) development potential, offering opportunities for integrating connections to various generators. Connections are likely to be developed using both AC and DC technologies. There are potential interactions with the onshore network, in particular in northern Wales and around Liverpool.
- The West of Isle of Wight zone has been chosen because it is an example of potential benefits from anticipatory investment offshore under a coordinated design. There are minimal interactions with the onshore network, allowing abstraction from broader issues when considering anticipatory investment risks, user commitment and charging in the zone.
- Finally, the Hornsea zone has also been chosen for investigation as it offers an example where there is potential for linking across different zones.

The methodology used in the case studies for estimating user commitment and charging impacts is set out below.

D.2 Background to User Commitment and Charging

D.2.1 User Commitment

User commitment arrangements require new generators to hold a liability and corresponding security to cover transmission construction costs until they connect to the network, protecting consumers from these costs if the generator terminates their connection agreement. As described in Appendix A, offshore generators can secure the onshore component of connection works using either the IGUCM or Final Sums Methodology, while the offshore component must be secured using the Final Sums Methodology. The application of Final Sums offshore means that the offshore generator must secure the full cost of construction of any offshore local works.

User commitment arrangements are currently under review as part of CMP 192. Under these circumstances, the following assumptions were made based on existing, time limited arrangements in calculating indicative user commitment figures for the Irish Sea:

- All offshore works are treated as local transmission works and fully secured by new generators in each 'stage' of development until connection, according to the rule that '[l]ocal schemes are secured either 100% by the associated generators or pro rated by TEC in cases where several generators share the same local reinforcements'[107]
- Single user onshore assets to connect offshore generators (including onshore DC converter stations and new onshore substations) are treated as part of offshore assets
- All other onshore works are treated as wider works for the purposes of calculating Final Sums liabilities
- Generators will choose the lower of IGUCM or Final Sums liability for onshore assets
- User commitment is based on the OFTO build option. Under generator build, developers will be responsible for similar costs, but much of this will be incurred themselves through the construction process (and recouped upon transfer to an OFTO) rather than secured through user commitment.

D.2.2 Transmission charging

As for onshore generators, offshore generators are charged for access to offshore transmission infrastructure through locational charges.[108] Locational charges are divided into wider locational (zonal) and local tariffs, the latter of which are more important in delivering price signals to offshore generators. Wider TNUoS charges range from -£7/kW to +£23/kW annually, whereas offshore local tariffs are likely to be larger than this. For example, National Grid's worked example shows a local tariff of £66/kW for an offshore generator, along with a wider tariff of £3.59/kW. Our analysis of three zone 3 case studies has estimated local tariffs that could range from just under £40/kW to more than £70/kW.

Wider locational charges to generators are not modelled here for two reasons:

- First, as discussed above, wider locational charges are less important than local charges in terms of costs to offshore generators
- Second, modelling impacts on wider locational charges would require a transport model for the full GB transmission network, as well as assumptions about the location of generation build and retirement throughout the entire system until 2030, neither of which is available as part of this project.

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[107] As defined in National Grid, *Review of Sharing Arrangements for Final Sums Liabilities*, Consultation Report (April 2010), p. 14.

[108] Although onshore and offshore generation tariffs have the same structure (consisting of wider, local substation and local circuit elements), offshore local tariffs have a different basis in that they are based on recovering project specific costs of offshore links, whereas onshore local charges are derived from average generic cost analysis for the relevant design and type of circuit and substation assets.

For similar reasons, it is assumed that offshore transmission links will not become part of the Main Interconnected Transmission System (MITS). Current guidance in the CUSC defines a MITS node as a connection with more than 4 transmission circuits connecting at the site.[109] This means that parts of the MITS could potentially extend offshore in some zones under a coordinated build. Rather than being charged as local assets, the cost of some offshore links would be then reflected in wider locational charges, likely requiring the creation of new TNUoS charging zones. The creation of new zones is determined by whether the costs within a specific area meet the generation zoning criteria set out in 14.15.26 of The Statement of the Transmission System Use of System Charging Methodology. The creation of new charging zones would mean that charges to offshore generators might not fall significantly (if at all) if offshore links become part of the MITS. Accurately capturing this would require the modelling of wider locational charges discussed above. Instead, transmission charges to generators are estimated using local circuit charges estimated through a transport model of the local offshore zone.

Charging for HVDC is modelled according to National Grid's 'required capacity' option. Flows through HVDC links are controllable and therefore assumptions are needed about how power will flow. For the purposes of this example, it was assumed that offshore HVDC links carried the remaining flows after AC links have been used to their maximum capacity. This is particularly important for the coordinated design option in the Irish Sea, as offshore HVDC links are installed and progressively used more intensively as more generators connect. Local charging for HVDC links is split pro rata between all generators connected to each HVDC link, according to their Transmission Entry Capacity (TEC). Arrangements for charging of HVDC links are still under consideration, and a 'required capacity' approach is one of the options being considered.[110]

As noted in Appendix A, current charging arrangements have been developed with a focus on radial links, and are not necessarily suited for application to coordinated offshore transmission assets (in particular, meshed HVDC links). The approach used to model transmission charges for coordinated offshore networks involves assumptions based on extending some of the rules that apply already. This approach will not necessarily work well and there remains uncertainty about actual charging for coordinated assets while charging methodologies are under development.

To reflect this uncertainty, an alternative charging approach for HVDC is also demonstrated for the coordinated network in the Irish Sea, where HVDC links parallel the onshore network. In this case, there are likely to be wider system benefits from a coordinated HVDC network, so an alternative is presented in which HVDC links are recovered through wider or residual charges.

To summarise, the key assumptions used to model transmission charging in the case studies are:

- Wider locational charges were not modelled,
- Offshore transmission networks do not become part of the MITS, and
- HVDC charges are set according to their required capacity, with the cost of HVDC links shared pro-rata according to the TEC for all offshore generators connected to each link
  - two extremes for coordinated HVDC links that parallel the onshore network are considered: either they form part of local charges, or they are recovered through wider and residual charges.

[109] Alternatively, a MITS node can be a Grid Supply Point with 2 or more transmission circuits, but this is less likely to be relevant offshore given the lack of demand.

[110] National Grid, *ENSG 'Bootstraps'*, Investigating the charging treatment of HVDC links operated in parallel with the AC network, http://www.nationalgrid.com/NR/rdonlyres/4904BFDF-19C4-4C25-9354-70F958406F2A/39941/ENSGbootstrapsLSF084ENSG_final.pdf (January 2010).

The examples developed use these assumptions to apply charging arrangements detailed in the Statement of the Use of System Methodology in Section 14 of the CUSC,[111] in conjunction with the worked example of TNUoS charges for offshore generators.[112] Various components of TNUoS charges are modelled according to Table 27.

Table 27 Charging for use of transmission assets

Component	Asset types	Charged to:
Wider locational	Not modeled	Generators within each charging zone
Local circuit	AC offshore cable HVDC offshore cable HVDC converter stations	Specific generator(s)
Local substation	Offshore substation	Specific generator(s)
Wider residual	Onshore substation Onshore reinforcement (AC and DC, including converter stations) Excess capacity in offshore substation Excess capacity in local circuit (above security factor of 1.8 for multiple circuits and 1.0 for single circuits)	All generators and suppliers

Note: Reactive equipment located onshore or offshore should be included in the local circuit component of charges, but it was not possible to isolate these assets in the data available from the asset delivery work stream.

D.3 The Irish Sea

The Irish Sea is a Round 3 Crown Estates tender zone and is being developed exclusively by Centrica. For the purposes of this analysis, generation developments undertaken during each stage of development are treated as separate projects.

D.3.1 Network build design options

Two options for build design were analysed, based on the design strategies modelled by TNEI/PPA for the asset delivery work stream.

- **'Connection and reinforcement'** – a broadly radial solution network design
- **'Networked'** – a broadly coordinated solution to network design

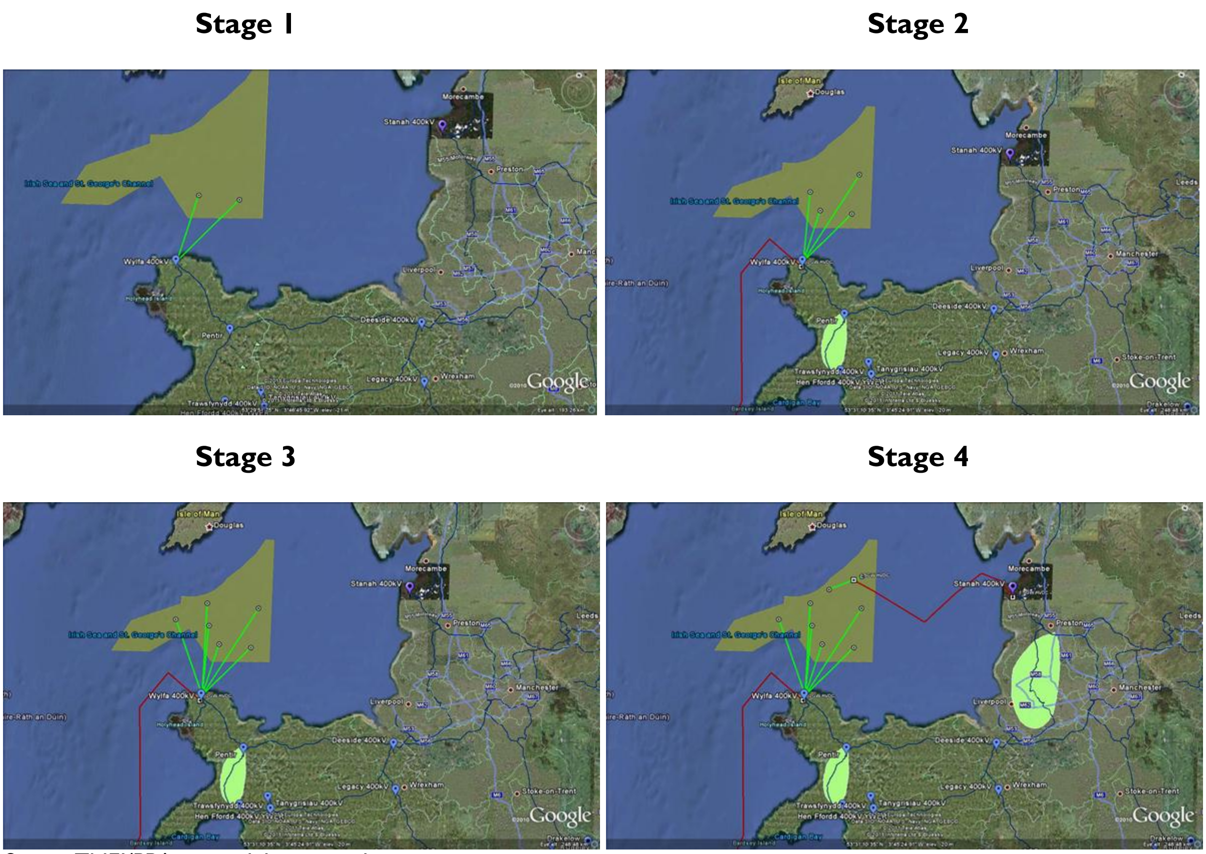
[111] National Grid, *Charging Methodologies*, CUSC Section 14, http://www.nationalgrid.com/NR/rdonlyres/8FFA9408-9DC7-44C2-AF68-93E684A176D8/47549/CUSC_Section_14combinedmasterclean5July11_FINAL.pdf (July 2011).

[112] National Grid, *Guidance Note: TNUoS charges for Offshore Generators*, http://www.nationalgrid.com/NR/rdonlyres/869AF29F-0CBE-4189-97D5-562CBD01AD86/44194/GuidetooffshoreTNUoStariffs .pdf (November 2010).

We describe each design below. Under either design, the zone is built out in 'stages', as described in the asset delivery work stream report. For the Irish Sea, each stage represents two new wind farms, or 1 GW of additional generating capacity.

'Connection and reinforcement' is based on a broadly radial build of transmission, with point-to-point connections from individual wind farms (each with capacity of 500MW) to shore (Figure 23). Reinforcements to the onshore network are required as part of stage 2 (including an undersea HVDC link from Wylfa to Pemberton) and stage 4 development.

Figure 23 Radial build under the 'connection and reinforcement' design

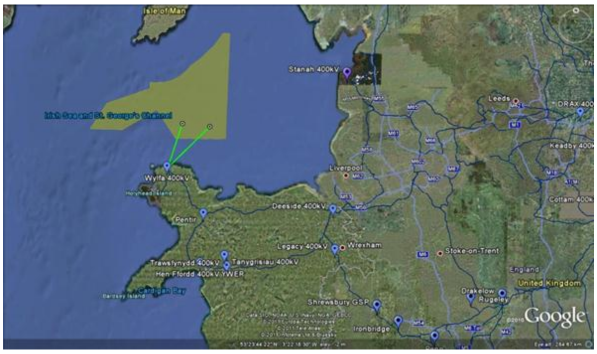


Source: TNEI/PPA, asset delivery work stream

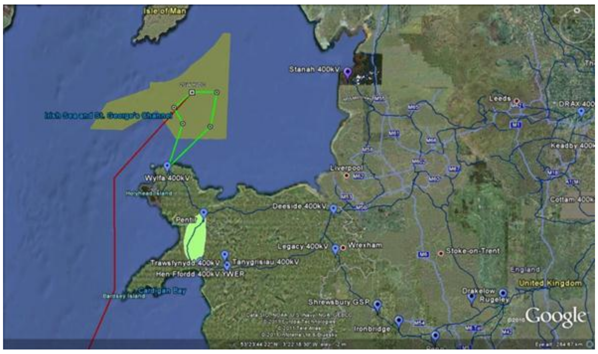
The '**networked'** design is based on a more coordinated build (Figure 24). The first stage of development is similar, but subsequent build occurs in a more coordinated fashion, so that all generators within the zone are linked by AC circuits and the majority of power generated at full load is exported using two HVDC links.

Figure 24 Coordinated build under the 'networked' design

Stage 1



Stage 2



Stage 3

Stage 4

Source: TNEI/PPA, asset delivery work stream

D.3.2 Capital investment and anticipatory investment

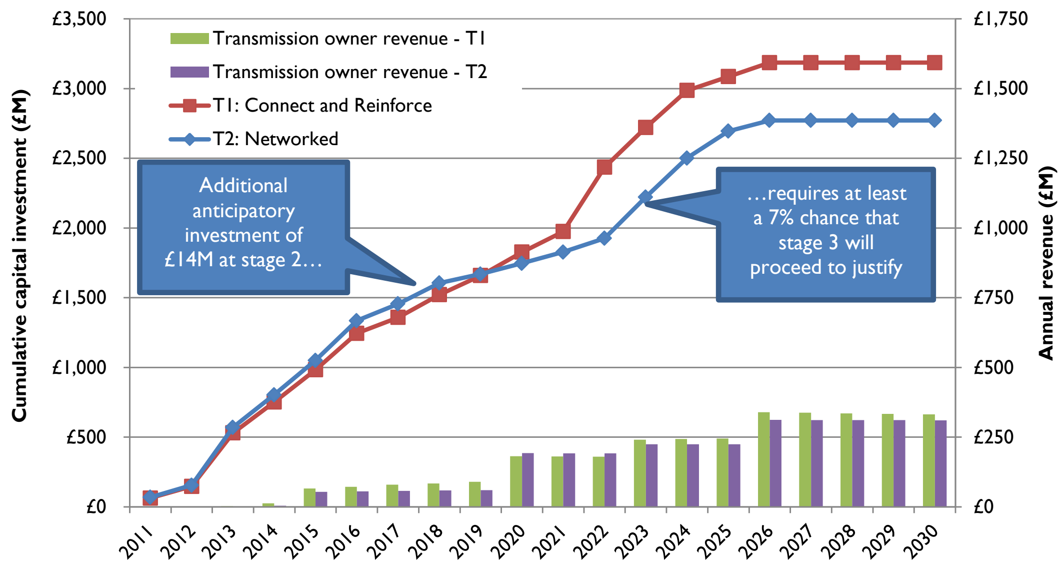
A more coordinated approach delivers savings in overall capital investment costs (see Figure 25). There are initially higher costs from developing a coordinated network through stages 1 and 2, but this delivers benefits for stage four in particular, as considerable onshore reinforcement is avoided (associated with Mersey ring reinforcement work).

- Higher costs initially under a coordinated build are associated with a small increase in anticipatory investment. There is significant anticipatory investment at stage 2 of coordinated build, relating to the oversized construction of a 2 GW HVDC link.
- However, there is also anticipatory spend under a radial design, in this case primarily relating to the HVDC link from Wylfa to Pemberton.
- As such, the incremental increase in anticipatory investment comparing coordinated and radial build is relatively small: £14 million in stage 2 of development.

Only a small chance of stage 3 development proceeding is required to justify the additional anticipatory investment under a coordinated build in stage 2. The cost savings at stage 3 under coordinated build are such that a risk neutral developer that is responsible for the full cost of transmission investment would only need a 7% chance of stage 3 proceeding in order to justify the small increase in anticipatory investment at stage 2[113]. This is a much smaller probability than that required to justify anticipatory spend in the West of Isle of Wight zone (detailed later in this chapter), primarily because the use of radial offshore links does not obviate the need for anticipatory investment onshore.

Annual cashflow requirements for transmission owners are just over 10% of cumulative capital costs (see Figure 25). Cashflow requirements cover the cost of capital, depreciation, and operating expenses for transmission owners. The requirements step up as each new stage is connected, since OFTO revenues are only payable once the assets are in use. Onshore TOs, on the other hand, receive revenue for capital works in progress according to their Regulated Asset Value. These cashflows cover the cost of constructing, financing and operating transmission assets over their regulatory life: 20 years for offshore works and 45 years for onshore works.[114]

Figure 25 Construction costs (LHS) and transmission owner revenue requirement (RHS) for alternative network designs



Note: Analysis of anticipatory investment based on a risk neutral investor
Data source: Redpoint analysis based on TNEI/PPA asset delivery work stream

Key conclusions from this analysis

- There are likely to be savings in overall capital costs and revenue requirements for transmission owners under a coordinated build in the Irish Sea
- Significant anticipatory investment occurs at stage 2 under either radial or coordinated designs, so that there is only a small increase in anticipatory spend under a coordinated versus radial build
    - only a small (around 10%) probability of stage 3 proceeding is required for subsequent cost savings to justify the additional anticipatory spend at stage 2
- There is more investment by OFTOs under the coordinated solution, but less investment by onshore TOs.

[113] A higher probability would be required if, as is likely, the risk of stranding increased finance costs.

[114] Ofgem, *Decision Strategy for the next transmission price control – RIIO-T1*, http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decision.pdf (March 2011).

D.3.3 User commitment

An example of the build-up of user commitment for generators in the Irish Sea is presented in Figure 26. The commitment required from generators for onshore works is based on temporary arrangements (due to expire in April next year) that do not require any securitisation of wider works under final sums. [115] Under these circumstances, generators will choose to secure onshore assets through final sums rather than IGUCM. IGUCM commitment builds up over the last four years of construction to reach ten times relevant wider TNUoS charges for the zone (wider zonal TNUoS of £6.43/kW for Anglesey plus £0.66/kW for the average local circuit TNUoS tariffs for National Grid). Wider assets not secured by generators are secured by the NETSO and, if generators were to terminate their agreement, they would be recovered from consumers.

In this example, consumers are responsible for securing the cost of more works than the offshore generators, but this is not the case more generally. The large cost secured by consumers in this example occurs due to the significant expense associated with wider onshore reinforcement, in particular through the HVDC link undersea from Wylfa to Pemberton.

Generators in the Irish Sea would be responsible for securing a greater share of capital costs under the coordinated design (Figure 26). In particular:

- During construction of stage 2 works, they will be responsible for securing the HVDC link from the offshore generators to Pembroke.
- At the completion of each stage, associated generators will connect to the network and begin paying TNUoS charges, and their user commitment will fall away under the Construction Agreement.
- Outstanding user commitments do not fall away altogether at the end of stages 1, 2 and 3 as construction of subsequent stages will have already begun in order to deliver the full 4 GW of generation capacity in the Irish Sea by 2030.

Whether there are higher user commitment requirements under a coordinated build depends on the distinction between wider and local works. Where offshore transmission links become part of the MITS, they will no longer need to be secured as local works. This is particularly relevant at advanced stages of build of a coordinated network, such as when the second offshore HVDC link is installed so that it parallels the onshore network.

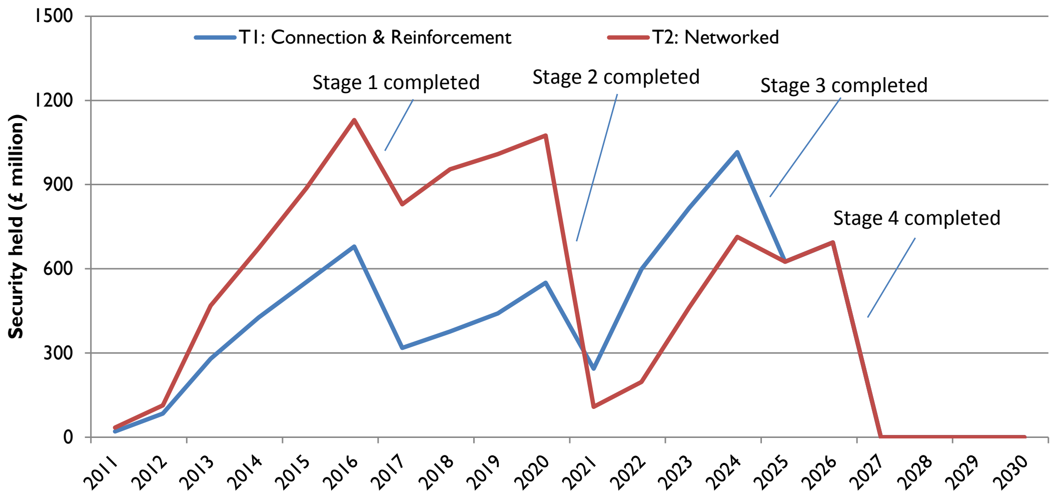
Changes to user commitment proposed under CMP 192 could also be important for user commitment for offshore works. Proposed changes under CMP 192 would remove generator exposure to anticipatory investment through reducing the liability according to a 'strategic investment factor'.[116] Furthermore, it is proposed that offshore liabilities would be limited to the pro rata share of connection to the nearest reasonable point on the main interconnected system, so that offshore generators would not be responsible for securing the cost of reinforcing the onshore network via offshore links.[117]

[115] National Grid, *Re: Review of Sharing Arrangements for Final Sums Liabilities*, Letter (July 2010).

[116] The strategic investment factor is a discount that applies in the event that greater capability is built than is required for the forecast generation connecting to that asset. The application of this discount would mean that generators would only be responsible for capacity that they have requested.

[117] National Grid, *CMP192: Arrangements for Enduring Generation User Commitment*, Stage 03: Workgroup Report Volume 1 (September 2011).

Figure 26 Total generator user commitment, Irish Sea



Note: Assumes that the full 4 GW generation capacity is delivered by 2030.
Data source: Redpoint analysis, based on TNEI/PPA asset delivery work stream

Key conclusions on generator user commitment in the Irish Sea:

- Generators are likely to be responsible for securing (or building themselves) substantial sums for offshore transmission development in the Irish Sea.
- Under current arrangements, generators could be responsible for securing a greater value of transmission assets under a coordinated build
  - This will depend on the specific definition of wider versus local works for HVDC links, as well as potential changes proposed under CMP 192.

D.3.4 Charging under current arrangements

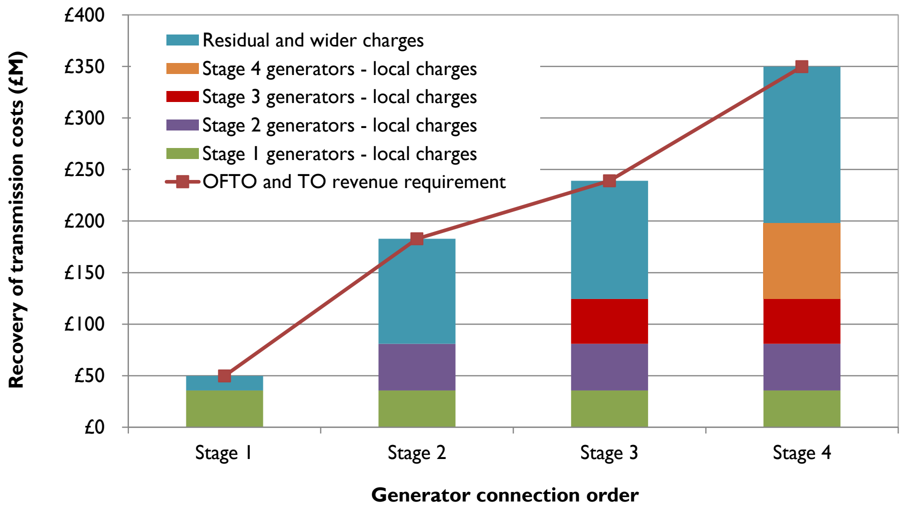
Connection and reinforcement

Under the radial 'connection and reinforcement' design, a large proportion of transmission owners' capital requirements would be sourced from wider and residual charges. Annual revenue requirements are calculated based on capital expenditure and annual depreciation, cost of capital and estimated operating costs for OFTO and TO assets. Wider and residual charges mainly recoup the cost of onshore reinforcement at stage 2 and stage 4, including the undersea HVDC 'bootstrap' between Wylfa and Pemberton as part of stage 2.

There is no anticipatory investment offshore under this design, so charges to specific generators remain constant over time. These charges include a security factor of 1.2 for cable connections, but these are point to point connections that are not used by other generators so the security factor – and associated charges – remains constant over time. Charges for the stage 4 generators are higher than those for stages 1, 2 and 3, because they cover additional costs of the HVDC cable and converter stations used to connect onshore at Stannah.

OFTOs receive the majority of charging revenue, but as much as 40% of the revenue from local and residual charges accrues to onshore transmission owners under the connection and reinforcement design. This covers the cost of onshore reinforcement and the undersea bootstrap connection.

Figure 27 Recovery of costs under the 'connection and reinforcement' design



Source: Redpoint analysis, based on TNEI/PPA asset delivery work stream

Networked design

Under a networked (coordinated) design, overall transmission costs are lower (by stages 3 and 4), requiring less total transmission charges.

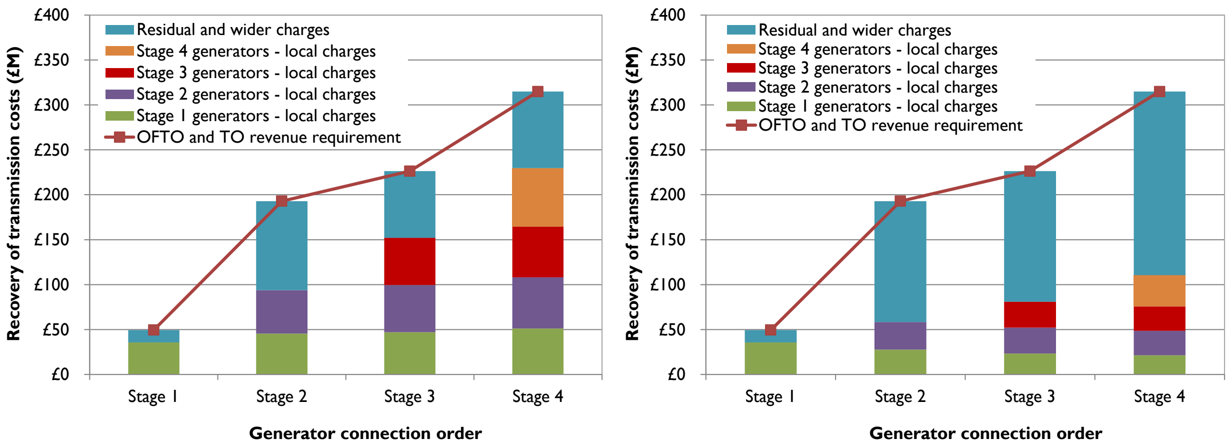
Local charges to generators will depend critically on charging arrangements for coordinated HVDC links. Where the cost of HVDC links (currently in use) are recovered through local charges according to the required capacity approach, charges to generators could potentially be higher than under a radial build, even after the entire zone has been built out. Where these are recovered through wider and residual charges, local charges to generators would be significantly lower than under a radial build (although there are likely to be significant impacts on wider tariffs for these offshore generators).

Charging revenue under the coordinated design accrues primarily to OFTOs, with only around 10% of revenue going to onshore TOs.

There is some anticipatory investment under the coordinated build, but this is paid for mainly through residual charges. Anticipatory investment is primarily in the 2 GW HVDC link installed as part of stage 2 network development. As there is no circuit redundancy in this link, generators will not pay for its anticipatory oversizing, or for enduring additional capacity (although the exact outcome will depend on arrangements for HVDC charging).

REDPOINT

Figure 28 Recovery of costs under the 'networked' design, with coordinated HVDC links recovered through local charges (LHS) or residual and wider charges (RHS)



Source: Redpoint analysis, based on TNEI/PPA asset delivery work stream.

Key conclusions on charging in the Irish Sea under current arrangements

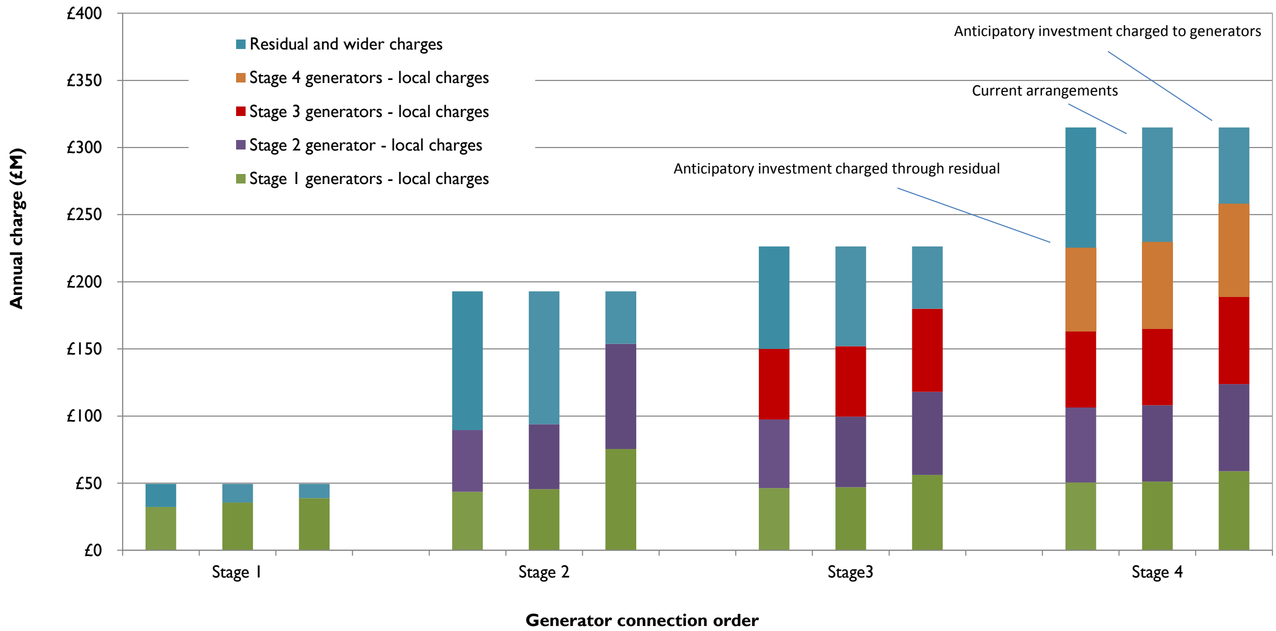
- Consumers (through residual charges) could be exposed to a considerable proportion of the cost of a radial network, due to the need for onshore reinforcement,
- Charging for access to transmission networks in the Irish Sea is likely to be split evenly between different wind farms, but with slightly higher charges to wind farms located further from onshore landing points and which justify the use of HVDC technology, *and*
- Charging to generators under a coordinated design depends critically on arrangements for charging of HVDC links that parallel the onshore network.

D.3.5 Alternative charging arrangements for coordinated build

Two extreme scenarios are shown in Figure 29, with consumers largely responsible for anticipatory investment (through residual charges) in the left hand columns, and generators responsible in the right hand columns. To maintain comparability, HVDC costs are recovered through local charges for both scenarios. Onshore substations and reinforcements continue to be recouped through residual charges under both scenarios, with the change from one scenario to the other relating to charging for oversized cables and offshore substations.

Current arrangements for this particular example (assuming that HVDC links are treated according to required capacity) are very close to the left hand columns in Figure 29, where residual charges pay for anticipatory investment. As discussed, this is because generators do not pay for the anticipatory investment in a 2 GW offshore HVDC link at stage 2. This is markedly different to the West Isle of Wight example (presented below) where offshore generators pay for anticipatory investment in multiple circuit AC cables through an increase in the local security factor (and also receive temporary benefits from increased transmission security). If offshore generators paid for a greater share of HVDC links using a different charging methodology, this would push arrangements closer to the situation on the right.

Figure 29 Alternative charging under the 'networked' design



Source: Redpoint analysis, based on TNEI/PPA asset delivery work stream.

Key conclusions on alternative charging arrangements

- Under a coordinated design, early generation projects could be charged significantly more if they pay for the full cost of anticipatory investment in HVDC links, *and*
- For this example, the charging treatment of oversized assets continues to have an impact even after all generators are connected, as there remains additional capacity in offshore substations and HVDC links even after stage 4 generators have connected.

D.3.6 Cost-benefit analysis

A cost-benefit analysis has been undertaken for the networked (coordinated) design in the Irish Sea, relative to the connection and reinforcement (radial) design. The benefits from transmission build (in particular, energisation of offshore generators) are likely to be similar under the two scenarios, so the impacts of greater coordination are estimated through analysing the different costs of providing transmission assets under the two scenarios. Additional benefits from a coordinated network might arise due to improved operational flexibility and security of supply (as discussed in Section 3), but these have not been quantified.

The costs and benefits estimated are based on applying an appropriate user cost of capital to annuitise capital costs. These are different for OFTO and TO assets, owing to different asset lives for calculating depreciation. Operating costs are also likely to be lower offshore than onshore.

The zonal cost-benefit analysis assumes that the entire capacity of the Irish Sea zone is built out before 2030, through completion of all four stages of generation build. The aggregate cost-benefit analysis presented in Section 4 considers alternative outcomes, where Round 3 zones are not entirely built out by 2030.

Key conclusions from this analysis

- A coordinated design delivers £275 million in net present value benefits between 2011 and 2030, relative to the connection and reinforcement design (Table 28),
- Benefits accrue due to savings in onshore transmission capital and operating costs,
- Benefits from a coordinated design accrue mainly after 2020, with significant onshore savings offset by the offshore expense of a 2 GW HVDC link that is not economic until stage 3 generators connect, *and*
- There would continue to be benefits from a coordinated design after 2030.

Table 28 Cost-benefit analysis for the 'networked' design in the Irish Sea zone

Design	T2 - networked							
Scenario	Scenario D							
			2011-2015	**2016-2020**	**2021-2025**	**2026-2030**		**NPV (2011-2030)**
			£M (real 2011)					£M (real 2011)
Reduction in costs relative to T1 - connect and reinforce								
Cost allocation	TO capital costs		52.43	173.33	248.37	274.55		£482.93
	TO operating costs		22.29	66.55	91.39	95.56		£179.63
	OFTO capital costs		- 19.57	- 158.73	- 108.08	- 154.95		-£288.71
	OFTO operating costs		- 6.68	- 54.17	- 36.88	- 52.88		-£98.52
	Total		**48.48**	**26.99**	**194.80**	**162.27**		**£275.33**
Proportional reduction in costs relative to T1								10.6%

Source: Redpoint analysis, based on TNEI/PPA asset delivery work stream.

D.3.7 Lessons from the Irish Sea case study

- Depending on charging and user commitment arrangements, generators might prefer a radial solution to minimise their exposure to the costs of offshore HVDC links, even though the radial solution results in greater overall system costs
  - a coordinated design could deliver net present value benefits of £275 million relative to a radial design under full build of the Irish Sea zone
- Depending on the definition of wider works and potential changes to user commitment proposed under CMP 192, generators could carry a significant liability associated with securing offshore HVDC links as part of a coordinated solution
- Anticipatory investment in HVDC links would largely be recouped through residual charges, but generators would still pay more for their share of HVDC assets in use. There could also be implications for wider locational charges, which were not modelled for this analysis.

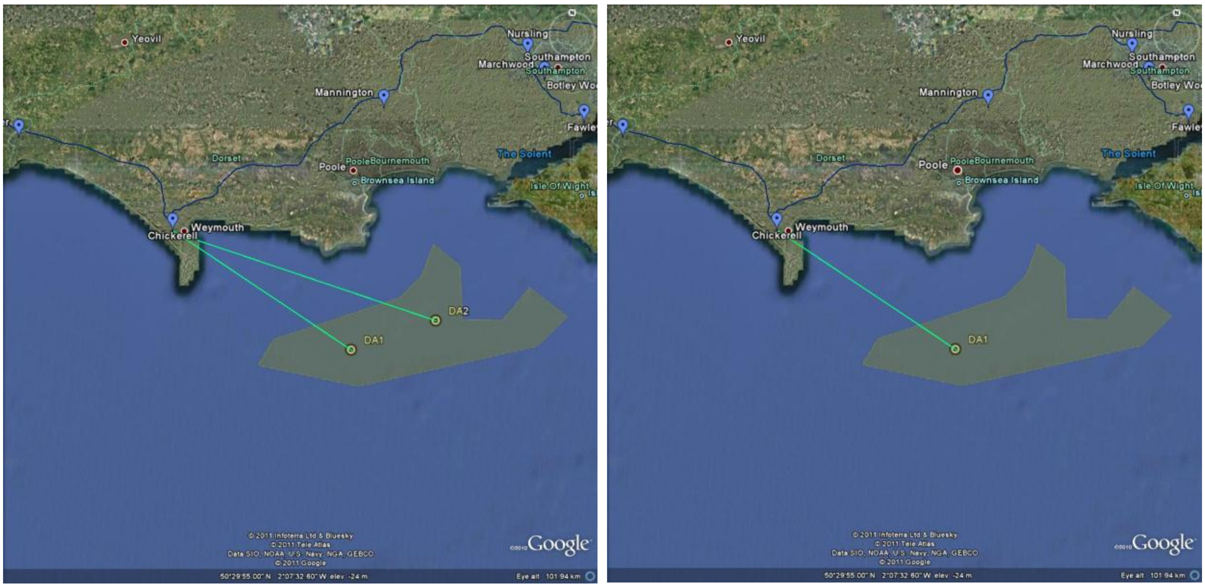
D.4 West of Isle of Wight

The West of Isle of Wight is a Round 3 Crown Estate zone. Compared with many other Round 3 zones it has limited development potential, with the Crown Estate and developers planning for 900MW of capacity. There is little scope to link with other offshore zones and development of the zone does not trigger a need for any reinforcements to the onshore network. For this example, based on the asset delivery work stream study, it is assumed that the zone is developed in two offshore wind farm blocks, each with a capacity of 450MW.

D.4.1 Network build design options

Similar to the Irish Sea, radial and coordinated designs were considered. The radial design involves two separate offshore platforms and cable routes to export power from the two wind farm blocks. Under a coordinated build, a single offshore platform and cable route will be built for stage 1. Three 300MVA cables are delivered along the same route at stage 1 of development, sized so as to be able to accommodate the additional generation capacity in stage 2.

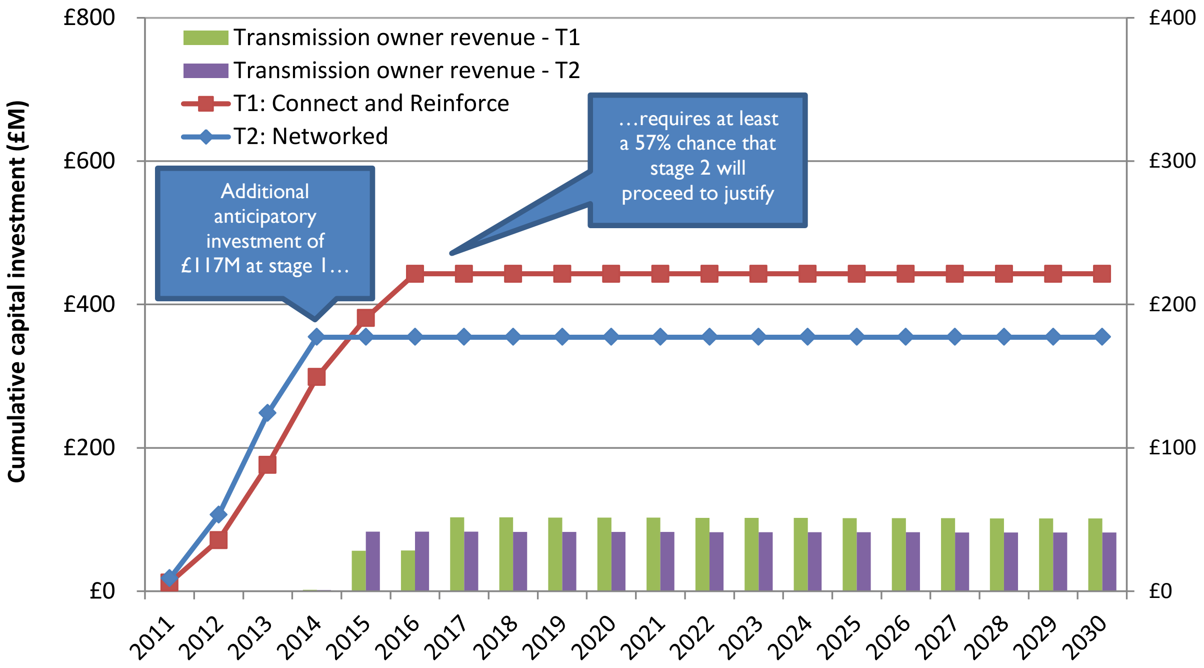
Figure 30 Radial build under the 'connection and reinforcement' design (LHS) and coordinated build under the 'networked' design (RHS)



D.4.2 Capital investment and anticipatory investment

Anticipatory investment is required to achieve the coordinated solution. Oversizing of cables and the initial offshore substation requires additional upfront spend of £117 million, which only delivers benefits in terms of overall cost savings if the second stage of generation build proceeds. To justify the additional upfront investment, a developer would need at least a 57% chance of the second stage of generation build proceeding (Figure 4). The probability would need to be greater where the developer is subject to higher financing costs due to the stranding risk, or where there is a significant time delay between the first and second stages of generation build (during which time oversized assets remain unused).

Figure 31 **Construction costs (LHS) and transmission owner revenue requirement (RHS) for alternative network designs**

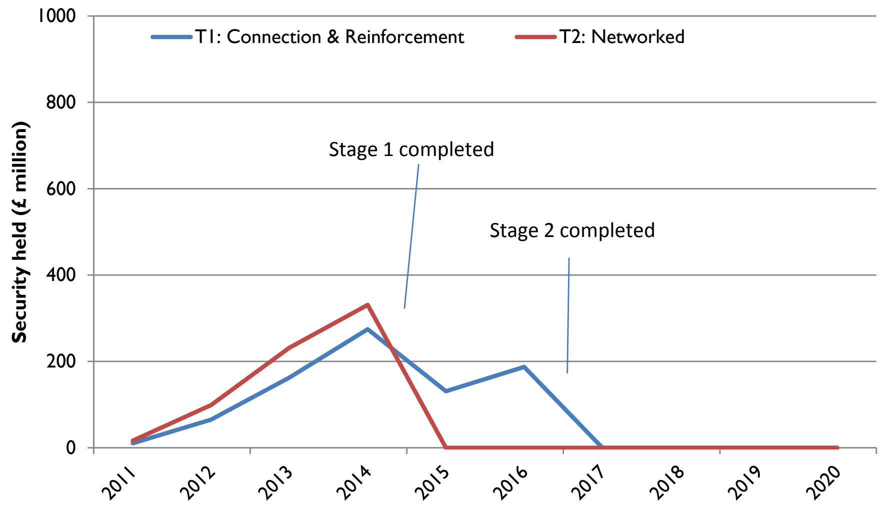


Note: Analysis of anticipatory investment based on a risk neutral investor
Data source: Redpoint analysis based on TNEI/PPA asset delivery work stream

D.4.3 User commitment

User commitment liabilities for the West of Isle of Wight example were calculated as set out in the Irish Sea case study. Additional user commitment would be required during Stage 1 of a coordinated build, as offshore investment is higher. However, user commitment drops off earlier as there is no further transmission build required to connect stage 2 generation.

Figure 32 Total generator user commitment, West of Isle of Wight



Data source: Redpoint analysis, based on TNEI/PPA asset delivery work stream

D.4.4 Charging under current arrangements

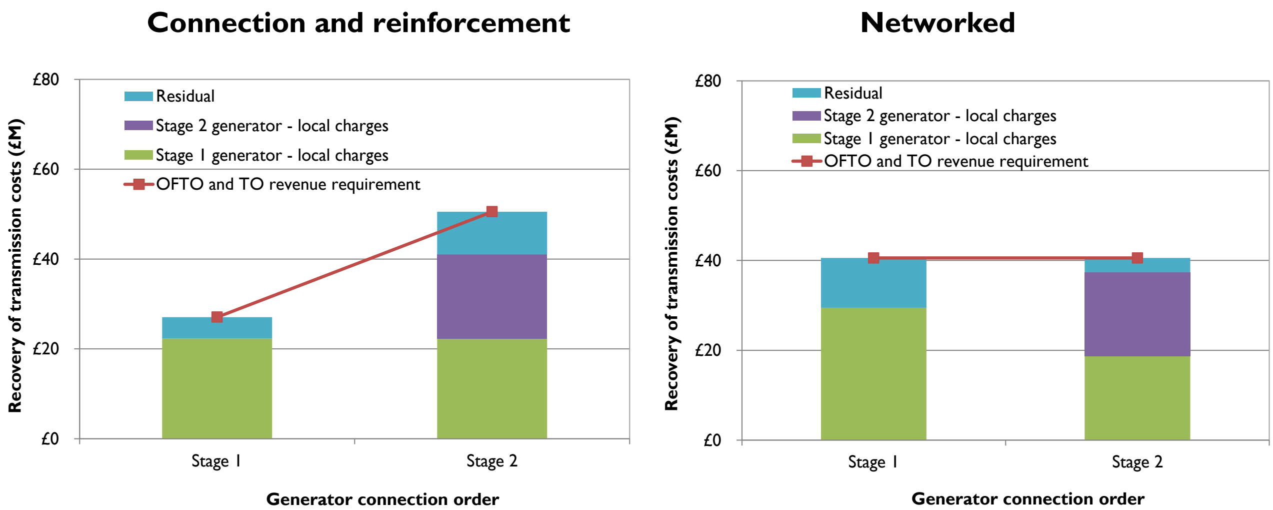
Development of the West of Isle of Wight zone does not involve any significant onshore reinforcement, so this analysis was undertaken assuming that wider charges remain unchanged. This means that any costs not recovered through local charges will be recovered through the residual, and also allows for estimation of total transmission charges faced by generators in the West of Isle of Wight zone.

Under the current arrangements for offshore transmission charging, generation built in stage 1 will be charged for some of the cost of additional capacity delivered to prepare for stage 2 generation. Additional charges to the first generator are incurred because the coordinated build involves installing three cables each rated at 300MVA, so that there is full redundancy in the circuit, which would be charged to the generator through an increase in their security factor. This will continue until stage 2 is completed and connected, at which time the stage 2 generator will pay for the cost of the transmission infrastructure through their local TNUoS charges (Figure 33).

These arrangements mean that the costs of anticipatory investment are shared relatively evenly between consumers (through residual charges) and generators (through local charges). Similarly, there are benefits for both consumers and generators from a coordinated build once stage 2 is completed.

The benefits from coordination accrue to first and second stage generators and transmission users more broadly through lower charges once the second stage of generation is connected. Residual charges are higher at stage 2 under a radial build largely because the most economic solution involves headroom in the offshore substations, where 600MW substations are installed to cater to 450MW of capacity.

Figure 33 Recovery of costs under alternative designs for the West of Isle of Wight zone

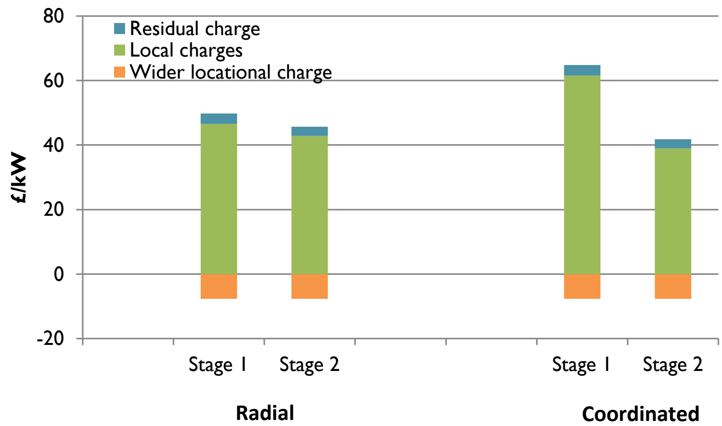


Note: Assumes no change in wider charges.
Source: Redpoint analysis, based on TNEI/PPA asset delivery work stream

The charging implications of anticipatory investment in the West of Isle of Wight zone can also be considered with respect to the TNUoS tariffs payable for generators in the zone. Charges to generators in the West of Isle of Wight zone predominantly consist of local charges (Figure 34). Under a coordinated build, generator charges would be higher after only stage 1 had proceeded, but would be lower after completion of the two stages, providing an incentive for coordinated build where the generator is sufficiently certain that the second stage will proceed. Generator charges were estimated on the basis that wider charges will not change as a consequence of development of the West of Isle of Wight zone, and that residual tariffs change as forecast in National Grid's five year forecast.[118]

[118] National Grid, *Information Paper: 5 Year Forecast of Transmission Network Use of System Tariffs* (January 2011).

Figure 34 Transmission charges for generators in the West of Isle of Wight zone

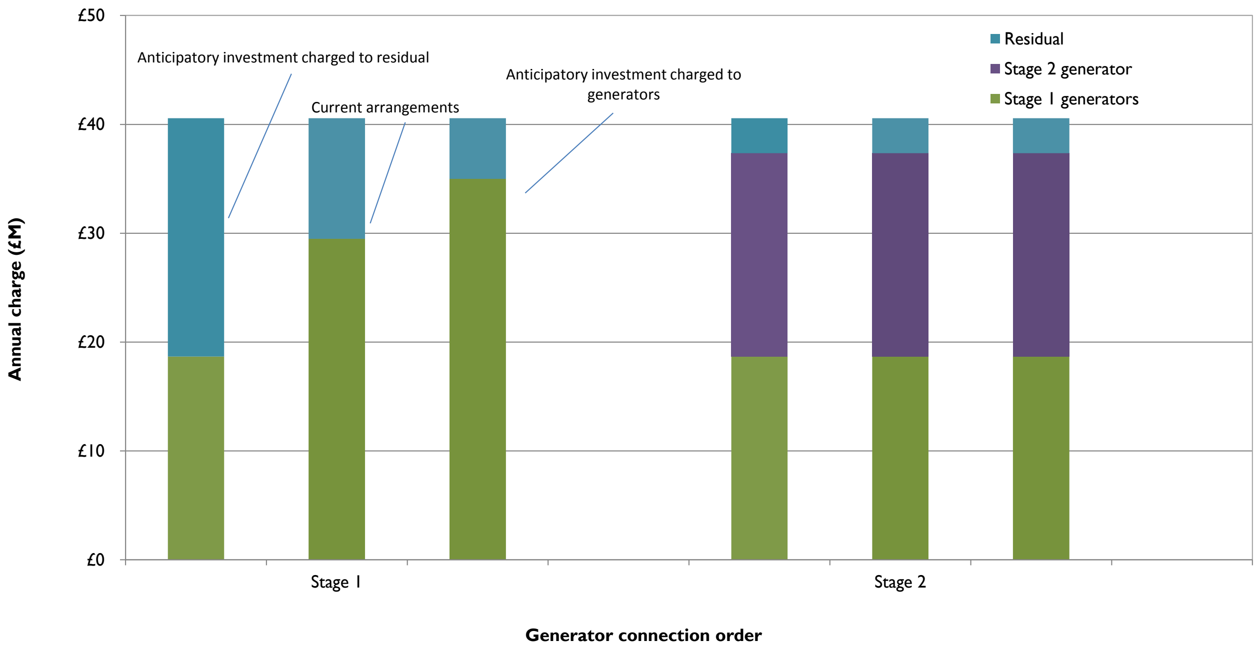


Note: Transmission charges are averaged across all generators in the zone, assuming no change in wider or residual charges.
Source: Redpoint analysis, based on TNEI/PPA asset delivery work stream

D.4.5 Alternative charging arrangements

As noted above, current arrangements see the costs of anticipatory investment in the West of Isle of Wight zone roughly evenly shared between the stage 1 generator and consumers (through residual charges). Alternatives could involve all the cost of anticipatory investment falling on consumers (left hand column, Figure 35) or all on generators (right hand column).

Figure 35 Alternative charging under the 'networked' design



Source: Redpoint analysis, based on TNEI/PPA asset delivery work stream.

D.4.6 Cost-benefit analysis

The overall long-term benefits from a coordinated build in the West of Isle of Wight zone if both generation stages proceed are demonstrated through the cost-benefit analysis (Table 29). Short-term cost increases are more than outweighed by benefits after 2015.

Table 29 Cost-benefit analysis for the 'networked' design in the West of Isle of Wight zone

Design	T2 - networked							
Scenario	Scenario D							
			2011-2015	**2016-2020**	**2021-2025**	**2026-2030**		**NPV (2011-2030)**
			£M (real 2011)					£M (real 2011)
Reduction in costs relative to T1 - connect and reinforce								
Cost allocation	TO capital costs		- 1.04	2.60	2.51	2.30		£3.89
	TO operating costs		- 0.37	1.03	0.91	0.80		£1.46
	OFTO capital costs		- 0.98	32.56	32.56	32.56		£62.51
	OFTO operating costs		- 0.33	11.11	11.11	11.11		£21.33
	Total		**- 2.72**	**47.30**	**47.10**	**46.78**		**£89.20**
Proportional reduction in costs relative to T1								16.4%

D.4.7 Lessons from the West of Isle of Wight case study

- There are potentially significant savings in the longer term from anticipatory investment to allow a coordinated build in the West of Isle of Wight zone
  - accordingly, lower charges are required to recover capital costs under a coordinated build once stage 2 is developed.
- Additional user commitment is required early in the development stage under a coordinated build, but there is less security required later once larger assets have already been built.
- Charging for anticipatory investment when only stage 1 generation has been developed is shared between local charges to generators and residual charges
  - generators are charged for additional cable capacity (up to a security factor of 1.8); which also delivers additional transmission security
  - the costs of overhead in onshore and offshore substations are recovered through residual charges.
- There are benefits to both consumers (through lower residual charges) and generators (lower local and total TNUoS charges) from a coordinated build once stage 2 of generation proceeds
  - generator benefits mean they will have an incentive to pursue a coordinated connection if this outweighs the additional stranding risk they must take on through user commitment and higher charges in the short term.
- Alternative charging arrangements could potentially allocate more or less of the cost of anticipatory investment to offshore generators through local charging.

D.5 Hornsea

The Hornsea zone is also a Round 3 Crown Estate zone, but with significantly greater development potential than the West of Isle of Wight zone. Similar to the Irish Sea zone, there is 4 GW of development potential, which the asset delivery work stream study has modelled as being developed in four 1 GW stages.

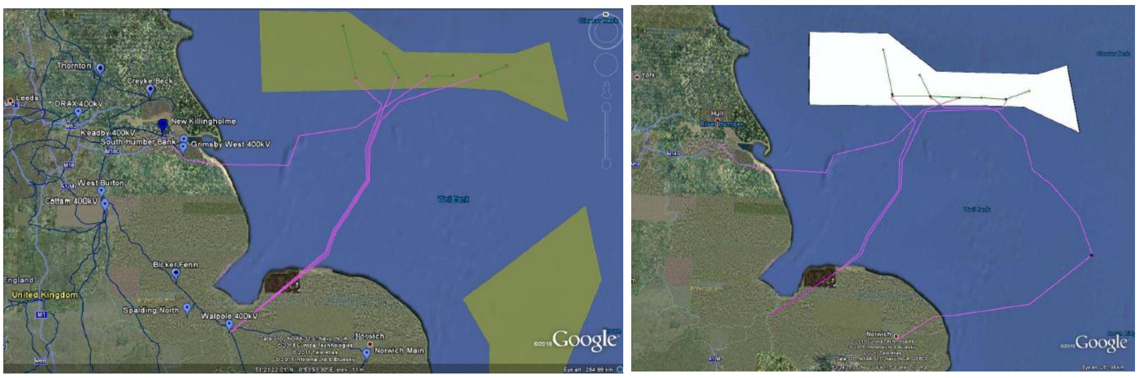
An important feature of the Hornsea zone is the potential to link with other nearby zones, namely Dogger Bank and East Anglia. For the analysis presented here, the cost of HVDC converter and cable assets that are shared with other zones has been reduced according to the Hornsea zone's pro rata use of these assets. Capital investment and cost-benefit analysis data are not presented for this case study as the costs and benefits of coordinated infrastructure accrue across the Dogger Bank and East Anglia zones, so that analysis of one zone in isolation is not meaningful.

D.5.1 Network build design options

The radial design for the Hornsea zone involves sequential use of 1 GW HVDC links (Figure 36). The significant distance from shore merits the use of HVDC links instead of AC even in the radial design.

There is little anticipatory investment as part of a coordinated build in the Hornsea zone. Rather, coordination involves linking with nearby zones (Dogger Bank and East Anglia) using 2 GW HVDC cables and onshore converter stations. There is also greater AC connection between individual wind farms under the coordinated design.

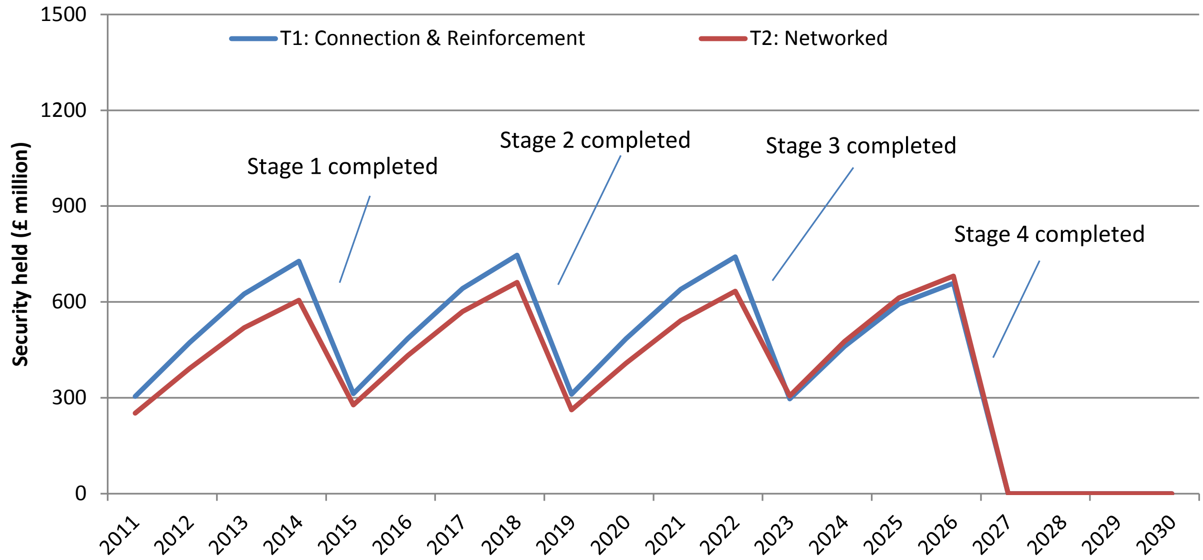
Figure 36 Radial build under the 'connection and reinforcement' design (LHS) and coordinated build under the 'networked' design (RHS)



D.5.2 User commitment

Unlike the Irish Sea and West of Isle of Wight case studies, there is little or no increase in user commitment under a coordinated build in the Hornsea zone. Securitisation of shared assets is shared between users, allowing generators in the Hornsea zone to share securitisation of larger assets with other generators, in particular at Dogger Bank. User commitment builds up through the four stages of generation development.

Figure 37 Total generator user commitment, Hornsea

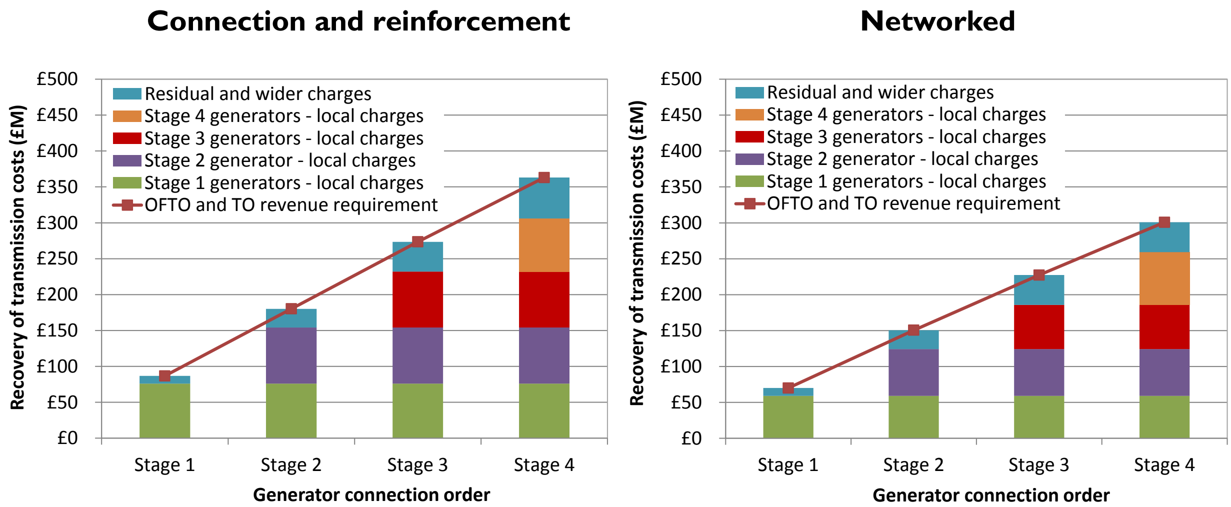


Data source: Redpoint analysis, based on TNEI/PPA asset delivery work stream

D.5.3 Charging under current arrangements

Most of the transmission costs for the Hornsea zone are likely to be recovered through local charges. This is based on assuming that all offshore links remain local assets (even under a coordinated build) and that revenue requirements for shared assets are shared pro rata between different generation zones. The lack of anticipatory investment or significant onshore development is reflected in relatively small impacts on residual and wider tariffs.

Figure 38 Recovery of costs under alternative designs for the Hornsea zone

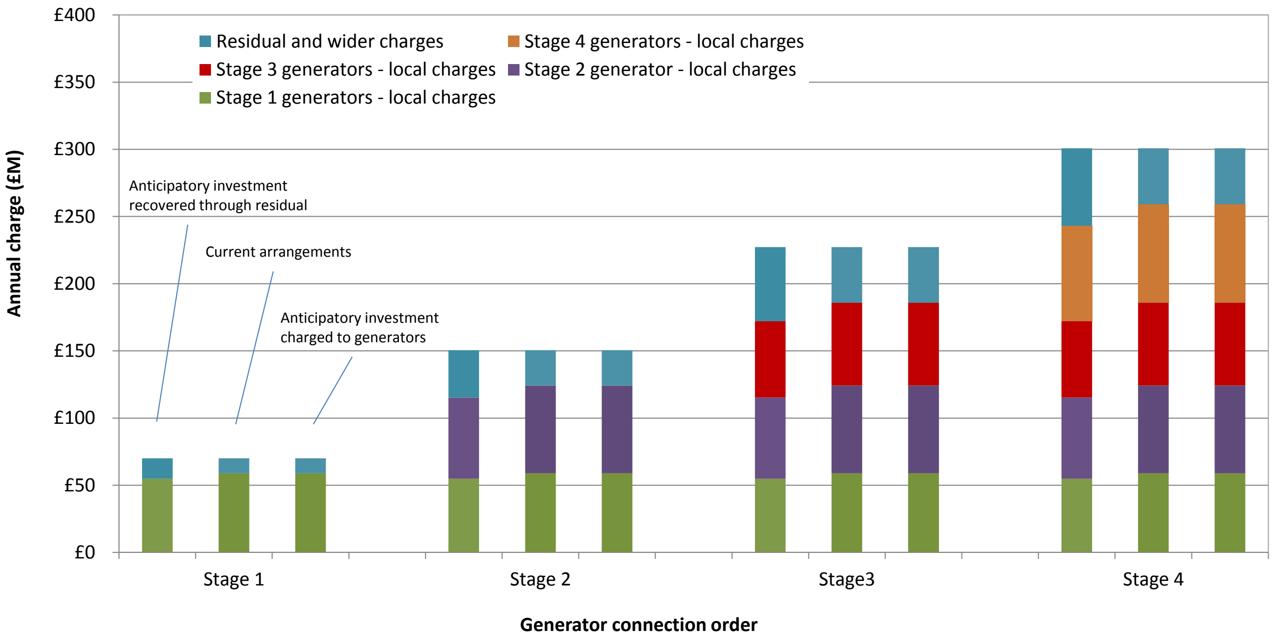


Source: Redpoint analysis, based on TNEI/PPA asset delivery work stream

D.5.4 Alternative charging arrangements

The lack of anticipatory investment in the Hornsea zone means that there is limited scope to vary charges by changing how the costs of anticipatory investment are recovered. There is only scope for a small decrease in generators' share of anticipatory investment by reducing their responsibility for charging for offshore AC links with excess capacity and circuit redundancy.

Figure 39 Alternative charging under the 'networked' design



D.5.5 Lessons from the Hornsea case study

- There is only limited anticipatory investment required to achieve a coordinated solution in the Hornsea zone
    - 2 GW HVDC links are built for sharing with nearby zones, rather than for later connection of generation within Hornsea
    - cooperation between zones is more important than anticipatory investment.
- User commitment could be lower under a coordinated build, as securitisation is shared between multiple users.
- The lack of anticipatory investment also means there is lack of scope for any increase or decrease in the generator share of charges for anticipatory investment and that changes in arrangements for charging of anticipatory investment would have little impact.
- There are also likely to be security benefits to generators from additional AC links between offshore platforms under a coordinated build.

E Key features of illustrative policy packages

Table 30 below provides a comparison of the key features of each of our illustrative policy packages.

Table 30 Comparison of key features of the illustrative policy packages

Licencing and consents, technical and design standards				
Design element	**Package 1 – Inform and enable**	**Package 2 – Market led evolution**	**Package 3 – Regional monopoly**	**Package 4 – Blueprint and build**
Degree of centralised coordination planning (who, to what level of detail, when)	ODIS Generator and NETSO driven	ODIS Generator and NETSO driven	Either NETSO, ENSG or another body established to provide the light touch plan envisaged Needs to cover onshore and offshore design and investment	Independent central body established to provide a centralised blueprint for a coordinated onshore and offshore transmission network
Development and consenting of common corridors for shared assets (who, how)	Generator and NETSO driven as and when possible and economic	Generator and NETSO driven as and when possible and economic	Regional or zonal driven by light touch plan Governance framework to be established for collaboration amongst generators/NETSO/Crown Estate and relevant third parties	Centrally guided within existing tender framework Governance framework to be established for collaboration amongst generators/NETSO/Crown Estate and relevant third parties
Technology standardisation (what, how)	Industry under Ofgem/DECC direction to develop a voluntary code for standardisation, inter-operability and commonality	Industry under Ofgem/DECC direction to develop a voluntary code for standardisation, inter-operability and commonality	Industry under Ofgem/DECC direction to develop a mandatory code for standardisation, inter-operability and commonality. Regional/zonal focus for greater standardisation	Industry under Ofgem/DECC direction to develop a mandatory code for standardisation, inter-operability and commonality. Regional/zonal focus for greater standardisation
How are any pre-construction and common corridors consenting financed (when, how)?	Generator and NETSO driven	Pre-determined amount of socialised funding available to finance pre-construction and common corridors	Pre-determined amount of socialised funding available to finance pre-construction and common corridors Further funding available for identified priority regions/zones	Socialised funding available to finance pre-construction and common corridors based on blueprint
How can technology innovation and incubation be encouraged to deliver benefits for consumers?	Generator, NETSO and supply chain driven	Pre-determined amount of socialised funding available to test new technologies overseen by a central body	Driven by regional OFTO	Generator, NETSO and supply chain driven (as long as consistent with blueprint)

REDPOINT

Design element	Package 1 – Inform and enable	Package 2 – Market led evolution	Package 3 – Regional monopoly	Package 4 – Blueprint and build
Anticipatory investment process				
Who triggers anticipatory investment?	Generator decision on oversizing of offshore links; NETSO role to optimise onshore/offshore interactions	Generator decision on oversizing of offshore links; NETSO role to optimise onshore/offshore interactions and to ensure 'no regrets' oversizing	Regional OFTO selects appropriate regional/zonal vision and submits for approval to Ofgem; regulatory incentives for regional OFTO to pursue a coordinated solution	Central authority according to centralised blueprint
What projects can trigger anticipatory investment process?	Any, but generators likely to focus on coordination within a zone	As for package 1, plus minor additions to projects can trigger NETSO stipulation of oversizing	Regional basis for anticipatory investment	Any, according to blueprint
Process for regulatory approval of anticipatory investment	Ofgem approval, with guidance issued to clarify what will receive regulatory approval	Ofgem approval based on clarified guidelines and pre-approval of specific low-cost anticipatory investments, as well as an extended ODIS	Ofgem approval of regional OFTO investment plans based on clear guidelines and light touch central plan	Ofgem approval as part of blueprint process
Who bears the risk of securing anticipatory investment?	Generators and consumers as per current arrangements	Shared between consumers and generators through changes to user commitment	Shared between consumers and generators through changes to user commitment and regular price controls	Risk largely borne by consumers through user commitment and charging
How are stranded costs recovered?	As per existing arrangements Offshore – TNUoS local charges to offshore generators and residual charges Onshore – TNUoS residual charges transfer costs to consumers	Offshore – TNUoS local charges to offshore generators and residual charges Onshore – TNUoS residual charges	Offshore – TNUoS local charges to offshore generators and residual charges Onshore – TNUoS residual charges	Recovered through TNUoS residual charge
Procurement, construction and the role of competition				
How could the OFTO tender process operate?	No change to the current regime	No change to the current regime	Tender based on an initial tender for the first asset in a region, with future build compensated through a regulated return on increases in the regional OFTO's Regulatory Asset Value	Initial tender for each region according to blueprint and current tender arrangements.

Procurement, construction and the role of competition				
Design element	**Package 1 – Inform and enable**	**Package 2 – Market led evolution**	**Package 3 – Regional monopoly**	**Package 4 – Blueprint and build**
When should transmission assets be ordered?	No change to the current regime	No change to the current regime	As per build and tender process	As per build and tender process
Who should order the transmission assets?	No change to the current regime	No change to the current regime	As per build and tender process	As per build and tender process
Who should construct onshore works and how appointed?	No change to the current regime	No change to the current regime	No change to the current regime	No change to the current regime
Who should construct offshore works and how appointed?	No change to the current regime	No change to the current regime	As per build and tender process	As per build and tender process
Can generators request additional build from OFTOs?	Yes - 20% cap on over sizing removed	Yes - 20% cap on over sizing removed	Yes - through generator request to regional OFTO	Yes - 20% cap on over sizing removed
Operation of transmission assets				
Transmission charging arrangements	No change to the current arrangements	No change to the current arrangements	'Charging statement' or equivalent required for socialising agreed stranded costs Regular price control reviews	'Charging statement' or equivalent required for socialising agreed stranded costs 'Charging statement' for generators to share costs
Control systems requirement	No change to the current arrangements	No change to the current arrangements	Consideration to be given to how the regime impacts this	Consideration to be given to how the regime impacts this
SQSS and other system operation standards	No change to the current arrangements	No change to the current arrangements	Consideration to be given to how the regime impacts this	Consideration to be given to how the regime impacts this
Coordination between regions and internationally	Regulatory changes to facilitate compatibility with international interconnectors	Regulatory changes to facilitate compatibility with international interconnectors	Central Authority driven remit to include consideration of inter-regional/zonal and international coordination (and associated investment requirements)	Central Authority driven remit to include consideration of inter-regional/zonal and international coordination (and associated investment requirements)

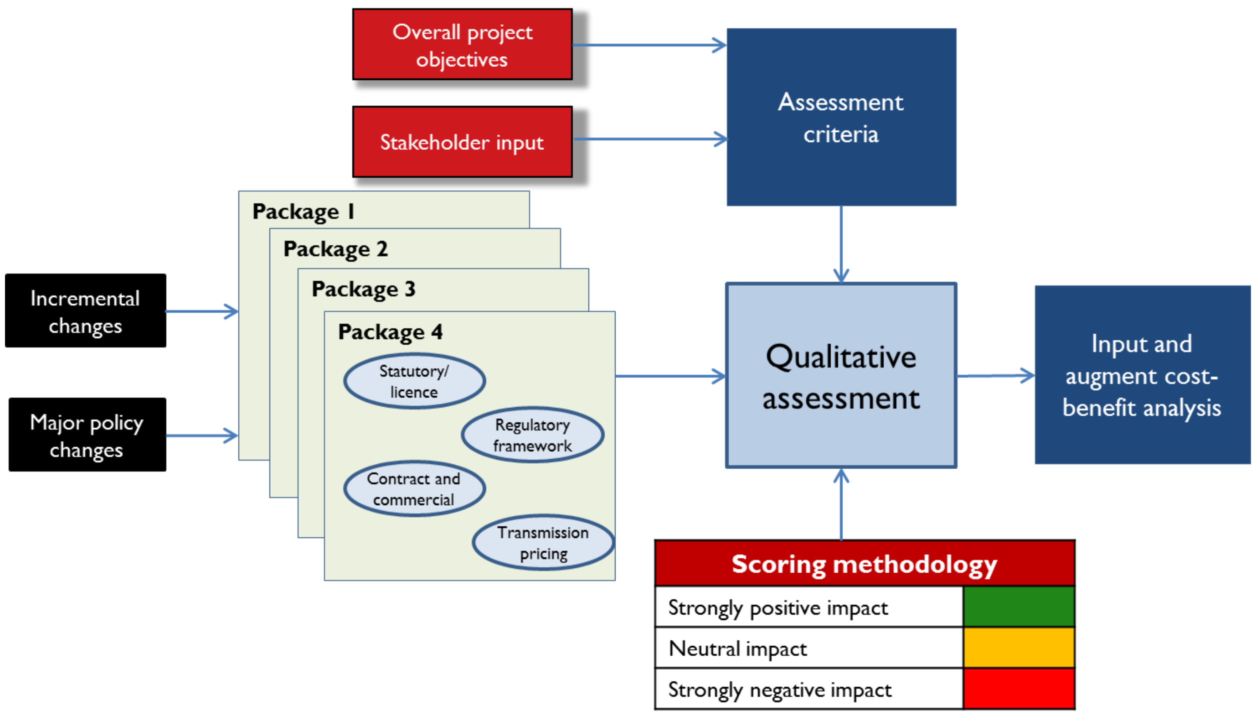
F Qualitative assessment

In this appendix, we outline the evaluation method used for the qualitative assessment, list the key criteria against which different schemes were evaluated, and then provide detailed results for the four illustrative policy packages.

F.1 Evaluation method

The first step in the policy evaluation approach involved the identification of a list of criteria based on the key objectives for the study. These criteria were developed in order to translate the broader objectives into measurable (albeit qualitative) indicators of policy success. The criteria have benefitted from stakeholder input, in particular through the OTCG.

Figure 40 Inputs to qualitative assessment



Each policy package has been scored against each criterion using a simple 'traffic light' scale from red (strongly negative) through amber (neutral) to green (strongly positive), with shades in between representing relatively less severe impacts (Figure 40). Each score is based on an assessment of the likely change relative to existing arrangements. Given the complexity of issues and the subjectivity of views about potential future impacts, no weighting has been applied to the various criteria.

F.2 Qualitative assessment criteria

As noted above, the assessment criteria were developed to measure success against the overall objectives for this study. The overall objectives follow from Government and Ofgem objectives and require that the offshore transmission regulatory regime:

- Supports the timely build of offshore generation and wider sustainability,
- Promotes reliability and security of supply,
- Delivers economic benefits beyond those that could be expected to be the case under the current regulatory arrangements,
- Ensures a fair and proportionate distribution of benefits, costs and risks, *and*
- Is deliverable and has a reasonable probability of being flexible in response to future (eg European) developments.

F.2.1 Support timely build of offshore generation and wider sustainability

Three criteria have been developed as indicators of this first objective - support timely build of offshore generation and wider sustainability.

Support timely build of offshore generation to 2020 (including costs to generators)

Timely build of offshore generation to 2020 will be an important part of meeting the UK government's target under the EU Renewable Energy Directive that 15% of overall energy use be met from renewables by 2020. This is likely to require that around 30% of electricity generation comes from renewable sources by 2020. Total capacity of around 13 GW of offshore wind by 2020 has been estimated to be consistent with meeting this target.[119]

Supporting timely build to 2020 will require that transmission links for offshore generators are available when required. The cost of transmission links should also be minimised, as far as possible.

Support timely build of offshore generation to 2030 (including costs to generators)

The UK Government has not committed to renewables targets beyond 2020 though if it chooses to do so they are likely to be higher than the existing 2020 targets. For example, the CCC has modelled renewable energy penetration of 30% (double the 2020 targets) as a central case for 2030. A coordinated transmission network will be an important element in delivering offshore generation to 2030, as economic benefits from more efficient transmission infrastructure investment flow through to generators and facilitate connection.

[119] Committee on Climate Change, *The Renewable Energy Review* (May 2011).

Local environmental impacts

Local environmental impacts are also an important part of sustainability. Local environmental impacts will depend in particular on disruption during construction and will be determined by the number of landing points and cables as well as the extent of any onshore work required.

F.2.2 Promote reliability and security of supply

Two criteria relate to the promotion of reliability and security of supply.

Reliability of GB transmission network

The reliability of the electricity network relates to the capacity to meet demand by users at any given point in time. Reliability of the transmission network specifically will depend on the probability of outages, as well as the impact of those outages on meeting demand. Where multiple circuits connect offshore generators and there is some redundancy, this will tend to improve reliability by providing additional security in transmission where one circuit fails.

Flexibility in system operation

National Grid, as NETSO is responsible for system operation including managing the security and quality of electricity supply in specific timescales and balancing generation and demand economically and efficiently. The design of the network will have implications for the flexibility of system operation and the cost of managing constraints through the balancing market, intertrip services, traded solutions and balancing services contracts.

F.2.3 Deliver economic benefits

The delivery of economic benefits is an important element of the regulatory and commercial arrangements and nine criteria have been developed relating to this objective.

Deliver economic benefits of coordination

A key measure of whether economic benefits of coordination have been delivered is the extent to which resource costs can be minimised. The costs of developing transmission networks include the costs of physical investment, financing costs and annual operating costs. The cost-benefit analysis undertaken for this study (Section 4) suggests that there could be savings of up to 14.6% to 2030 from developing a coordinated instead of a radial network.

Promote economic efficiency through charging and role of markets

Charging should promote economic efficiency through facilitating effective competition in generation and supply, allowing for recovery of transmission investments and being cost reflective as far as reasonably practicable. Markets have an important role in delivering efficiency in competitive settings, in particular the generation and retail electricity markets. Markets can also be used to deliver efficiency gains in regulated markets, such as through the existing OFTO tender system.

Impact on innovation/dynamic efficiency

Longer-term economic benefits require innovation and efficiency improvements over time. This will require incentives for transmission innovation to be brought forward, as well as pressures on cost reduction in the longer term.

Risk of stranded transmission assets

As discussed in Section 3, anticipatory investment carries with it risks of stranded transmission assets. If investment in transmission assets is predicated partly on preparing for future generation build, additional assets run a risk of becoming non-economic and accordingly 'stranded' if future generation projects do not proceed. This could happen for any number of reasons relating to the economics of offshore generation (including construction costs, subsidy levels and broader electricity market factors), the financial capacity of the developers or regulatory issues. The latter could include planning issues, such as the difficulties that offshore wind developers have recently experienced in getting environmental approval for several projects (including Solway Firth, Wigtown Bay, Bell Rock and Kintyre Array zones) in Scottish waters. Anticipatory investment is likely to be necessary to deliver a coordinated network, but the risk of stranded assets should be minimised under any regulatory regime.

Impact on supply chains

This criterion relates to the capacity for the upstream market for manufacture of offshore transmission technology to meet the demand for transmission assets. In general, visibility and commitment to future network plans will improve supply chain responses by improving certainty.

Financeability of offshore generation

Changes to the regulatory regime for offshore transmission should not jeopardise the supply of capital investment in offshore generation. This could occur if the costs imposed on generators were too high, or if excessive risks were transferred onto generators. A key risk for generators is the timing of their connection, as a one year delay has been estimated to reduce overall project internal rates of return by 1%.[120] On average, more than three quarters of the total capital cost of offshore wind generation is expected to come from generation costs[121] (in particular, foundation and turbine assets) so this can have significant implications for the overall cost of offshore generation. This criterion has important links with the first two criteria (relating to the delivery of offshore generation) as an inability to finance offshore generation will compromise the ability of the industry to deliver new generation investment.

[120] SSE, *Re Offshore Electricity Transmission: Further Consultation on the Enduring Regime*, submission to Ofgem/DECC consultation, http://www.ofgem.gov.uk/Networks/offtrans/pdc/cdr/Cons2010/Documents1/SSE%20response%20to%20further%20consultation%20on%20the%20Enduring%20Regulatory%20Regime.pdf (September 2010).

[121] Committee on Climate Change, *The Renewable Energy Review* (May 2011).

Financeability of offshore transmission

The flow of capital into offshore transmission is also important. This requires offshore transmission to continue to be an attractive source for investor funds, which would not be the case if too much risk is transferred to OFTOs. However, the type of investors attracted to the sector might change with a shift in the risk/reward balance. For example, the current OFTO regime has attracted mainly consortia of private equity investors seeking a high degree of certainty regarding investment returns. Arrangements where OFTOs take on construction risk (such as under an OFTO build model) might be more attractive to infrastructure companies with experience in managing these risks.

Breadth of potential investors

In addition to maintaining sufficient capital flows into the offshore transmission sector, it is important that a broad range of potential investors are interested in offshore transmission. This will place downward pressure on the cost of capital, with those investors best placed to take on specific project risks likely to be able to accept the most competitive rate of return. Maintaining a breadth of potential investors is particularly important for the OFTO tender system.

Optimise onshore reinforcement costs

Offshore build decisions will have implications for the need to reinforce onshore networks. The regulatory regime should include mechanisms to ensure that trade-offs between offshore and onshore reinforcement (for example, as a consequence of the choice of onshore landing point) are optimised.

F.2.4 Ensure a fair and proportionate distribution of benefits, costs and risks

The distribution of costs and risks between consumers, government, generators, OFTOs, TOs and the NETSO is evaluated using the following three criteria.

Risk for consumers

Consumers might be required to take on risks relating to anticipatory investment or new types of technology in the transmission network. All else being equal, these risks should be minimised.

Risk of excessive rents

The rents, or excess profits over and above their required rate of risk-adjusted return, captured by asset owners can vary depending on the regulatory regime adopted. Although these rents do not directly impact resource costs, they do increase the overall level of the cost borne by consumers. The distributional effect between producers and consumers is a key regulatory and political consideration.

Efficient allocation of risk

Risk should be allocated to those parties best able to manage the risk, whether by taking action to avoid or minimise risks directly, transferring or spreading the risk or accepting those risks that cannot be avoided or transferred. The efficient allocation of risk has distributional and fairness implications, but also offers potential benefits for economic efficiency by ensuring optimal management of risk.

F.2.5 Deliverability and flexibility

Three criteria measure the extent to which the proposed policy packages are deliverable and flexible.

Flexibility to deal with range of future possibilities

The regulatory regime must have flexibility to deliver under uncertainty about market development. This does not mean that the regime itself should change to deal with changing circumstances: industry participants need the certainty offered by a clear and consistent regulatory regime. Instead, it means that the regime is able to deliver efficient outcomes under a range of different possibilities. For offshore generation, key uncertainties include electricity market prices, capital and operating costs and the speed of planning and connection access. These uncertainties will drive the extent of future build of offshore generation, which is itself a key outcome that the regime must deal with. The four scenarios used for this study project between 15 GW and 45 GW of offshore generating capacity by 2030, and the 2011 Offshore Development Information Statement (ODIS) includes a 'sustainable growth' scenario with 67 GW of capacity by 2030.This variation has significant implications for the potential benefits from coordination, with the benefits from coordination increasing with build.

Compatibility with current arrangements/risk of disruptions

Any changes to the regulatory regime for offshore transmission occur in the context of an existing regime and significant changes would carry the risk of disrupting existing and future projects. There are also potential benefits from compatibility with connected markets, in particular onshore transmission and international links. Compatibility with regimes of other countries is unlikely to be a sensible primary consideration in making changes to the current offshore regime, but it will be important to monitor international developments and to consider the costs and impacts from divergence in national approaches.

Level of complexity and administration cost

Excessive complexity in the regulatory regime would be likely to lead to administrative costs for both industry participants and the government regulator. There is also a risk of unintended consequences involved with any regulation and this tends to increase with the degree of complexity.

F.3 Qualitative assessment results

Results of the qualitative assessment of each of the illustrative policy packages are shown in turn below.

F.3.1 Package 1: Inform and enable

Package	Clarify and inform

Criteria	Scoring	Explanation
Support timely build of offshore generation to 2020 (inc. costs to generators)		Little benefit from increase in coordination in near-term
Support timely build of offshore generation to 2030 (inc. costs to generators)		Broadly neutral but could deliver benefits through additional coordination
Local environmental impacts		No change from existing regime
Reliability of GB transmission network		No change to risk for consumers
Flexibility in system operation		No change from existing regime
Deliver economic benefits of coordination		Facilitates coordination through clarification of arrangements and standardisation
Promote economic efficiency through charging and role of markets		Significant role for market follows from existing regime
Impact on innovation/dynamic efficiency		No change from existing regime
Risk of stranded transmission assets		No change from existing regime
Impact on supply chains		Development of standards to improve supply chain certainty
Financeability of offshore generation		No change from existing regime
Financeability of offshore transmission		No change from existing regime
Breadth of potential investors		No change from existing regime
Optimise onshore reinforcement costs		No change from existing regime
Risk for consumers		No change from existing regime
Risk of excessive rents		No change from existing regime
Efficient allocation of risk		No change from existing regime
Flexibility to deal with range of future possibilities		No change from existing regime
Compatibility with current arrangements/risk of disruption		Little change from existing regime
Level of complexity and administration cost		Little change from existing regime

Strongly positive impact	
Neutral impact	
Strongly negative impact	

F.3.2 Package 2: Market led

Package	Market led

Criteria	Scoring	Explanation
Support timely build of offshore generation to 2020 (inc. costs to generators)		Little benefit from increase in coordination in near-term
Support timely build of offshore generation to 2030 (inc. costs to generators)		Lower transmission cost through coordinated network in longer term.
Local environmental impacts		A more coordinated network has potential to minimise environmental impact through less landing pts etc
Reliability of GB transmission network		Standardisation and coordination aids this
Flexibility in system operation		Little change to system operation
Deliver economic benefits of coordination		Facilitates coordination through improvements to planning and consenting and standardisation; encouragement of 'no regrets' coordination and open season for linking across zones
Promote economic efficiency through charging and role of markets		Little change to charging regime and central role of markets maintained
Impact on innovation/dynamic efficiency		Fund to encourage innovation; open season allows innovative transmission operators to take the lead in developing a coordinated network.
Risk of stranded transmission assets		Increases as integrated network is likely to require some degree of anticipatory investment (although likely to be minimised)
Impact on supply chains		Development of standards to improve supply chain certainty
Financeability of offshore generation		Slight reduction in transmission costs where network more coordinated; easier financing where transmission links and/or consented corridoors already exist
Financeability of offshore transmission		Builds on existing regime so broadly neutral impact
Breadth of potential investors		Open season allows innovative transmission operators to take the lead in developing a coordinated network but broadly neutral
Optimise onshore reinforcement costs		Changes to user commitment to facilitate NETSO role in optimising onshore/offshore interactions
Risk for consumers		Builds on existing regime so broadly neutral impact
Risk of excessive rents		Builds on existing regime so broadly neutral impact
Efficient allocation of risk		Builds on existing regime so broadly neutral impact
Flexibility to deal with range of future possibilities		Market approach to retain flexibility; open seasons to deliver interzonal linking if warranted
Compatibility with current arrangements/risk of disruption		Standardisation, extended central agency role and open seasons to facilitate linking with interconnectors; some risk of disruption from changes
Level of complexity and administration cost		Extended central agency role and open season to add complexity

Strongly positive impact	
Neutral impact	
Strongly negative impact	

F.3.3 Package 3: Regional monopoly

Package	Regional monopoly

Criteria	Scoring	Explanation
Support timely build of offshore generation to 2020 (inc. costs to generators)		Potential for some short-term delay from changing regulatory regime and establishing regional OFTOs
Support timely build of offshore generation to 2030 (inc. costs to generators)		Reduce cost of transmission for renewables through coordination; quicker connection through avoiding tender process for most offshore generators
Local environmental impacts		A more coordinated network has potential to minimise environmental impact through less landing pts etc
Reliability of GB transmission network		Coordinated network to contribute to reliability of transmission through multiple transmission routes
Flexibility in system operation		Regional OFTO better able to time outages and build additional kit where necessary to optimise system operation within a region
Deliver economic benefits of coordination		Facilitates coordination through improvements to planning and consenting and standardisation; regional OFTO responsible for coordinated network within each region
Promote economic efficiency through charging and role of markets		Sharing factors reduce pass-through of charges so that they become less cost-reflective; role of markets reduced through introduction of regional monopoly
Impact on innovation/dynamic efficiency		Regional OFTO well placed to support development of HVDC technologies; offset by potential lessening of innovation under a monopoly
Risk of stranded transmission assets		Increases with degree of coordination as likely to require anticipatory invesment
Impact on supply chains		Regional OFTOs better placed to manage supply chains; development of standards to improve supply chain certainty
Financeability of offshore generation		Reduction in transmission costs where network more coordinated; easier financing where transmission links and/or consented corridoors already exist; but removal of generator build could create timing risks
Financeability of offshore transmission		Regional OFTOs to take on more risk than current OFTOs (particularly given uncertainty about future build and construction costs)
Breadth of potential investors		Limited number of parties likely to take on broader, more capital intensive and risky regional OFTO role but infrastructure companies might be interested
Optimise onshore reinforcement costs		Single regional OFTO better placed to work with onshore TOs, particularly if appointed through extension of oshore TO so that a single party is responsible for both
Risk for consumers		User commitment and charging passes on anticipatory risks to consumers, at least in the short run
Risk of excessive rents		Risk of market power for regional OFTO once established
Efficient allocation of risk		Difficult to allocate risk to regional OFTO as difficult to specify reward; allocation of anticipatory risk to consumers who are unlikely to be best placed to manage the risk.
Flexibility to deal with range of future possibilities		Regional OFTO has incentives to monitor developments in the region and adapt their strategy accordingly
Compatibility with current arrangements/risk of disruption		Several OFTOs might need to be replaced by a single regional OFTO (need to minimise this risk); significant changes to tender process; end generator build
Level of complexity and administration cost		Considerable complexity involved in assessment of initial tender

Strongly positive impact	
Neutral impact	
Strongly negative impact	

F.3.4 Package 4: Blueprint and build

Package	Blueprint and build

Criteria	Scoring	Explanation
Support timely build of offshore generation to 2020 (inc. costs to generators)		Lower transmission costs to generators with greater socialisation of costs could encourage investment in the short term
Support timely build of offshore generation to 2030 (inc. costs to generators)		Blueprint delivers greater certainty for generators and potentially quicker connection through empanelled vendors; lower transmission costs to generators under a coordinated network with greater socialisation of costs
Local environmental impacts		A more coordinated network has potential to minimise environmental impact through less landing pts etc
Reliability of GB transmission network		Coordinated network to contribute to reliability of transmission through multiple transmission routes
Flexibility in system operation		Little change to system operation
Deliver economic benefits of coordination		Facilitates coordination through improvements to planning and consenting and standardisation; centralised blueprint to deliver coordination
Promote economic efficiency through charging and role of markets		Socialisation of anticipatory risk reduces pass-through of charges from OFTO to generators so that they become less cost-reflective until further generators connect; outcomes determined by blueprint rather than market
Impact on innovation/dynamic efficiency		Less potential for innovation in design and delivery under blueprint
Risk of stranded transmission assets		Increases with degree of coordination as likely to require some degree of anticipatory invesment
Impact on supply chains		Development of standards and blueprint both likely to improve supply chain certainty
Financeability of offshore generation		Reduction in transmission costs where network more coordinated; easier financing where transmission links and/or consented corridoors already exist; blueprint to give some design certainty
Financeability of offshore transmission		Little change to risk taken by OFTOs as anticipatory risk socialised; potentially greater certainty at tender stage through blueprint
Breadth of potential investors		Continuation of existing tender regime to deliver similar breadth of investors, but potentially some bigger projects
Optimise onshore reinforcement costs		Onshore/offshore tradeoffs optimised under blueprint
Risk for consumers		Consumers to take on all stranding risks, which could be significant if blueprint turns out to be wrong
Risk of excessive rents		Excessive rents to OFTOs curtailed by tender system
Efficient allocation of risk		Alocation of anticipatory risk to consumers who are unlikely to be best placed to manage the risk.
Flexibility to deal with range of future possibilities		Blueprint based on expected build and likely to impose costs if central plan incorrect
Compatibility with current arrangements/risk of disruption		Significant increase in central authority role but only incremental changes to tender system
Level of complexity and administration cost		Administrative cost from developing and operationalising blueprint; additional complexity from incorporating future demand into asset tenders

Strongly positive impact	
Neutral impact	
Strongly negative impact	

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Redpoint Energy (www.redpointenergy.com) is a specialist energy consultancy, advising clients on investments, strategy and regulation across Europe's liberalised power, gas and carbon markets. Since its formation in October 2004, Redpoint's clients have included some of Europe's largest energy companies and financial organisations, as well as governments and regulators.

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