

Offshore Transmission Coordination Project Conclusions Report

1 March 2012

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Forewords



Our wind, wave and tidal resources are spectacularly abundant and make us a natural leader for offshore renewable energy. We already have more offshore wind energy generation than any other country, and we are committed to being a global leader in this sector to maintain a secure energy supply, tackle climate change and meet our renewable energy targets for 2020 and beyond.

DECC has worked closely with Ofgem to put in place an effective regime for offshore transmission, so connections for offshore generators can be delivered in a secure, timely and cost-effective way. The regime has already attracted new sources of finance and new entrants to this sector, and the competitive licensing process has delivered savings to both generators and consumers.

We are committed to developing the electricity transmission system we need at least cost to consumers. With the development of Crown Estate Round 3 Zones that are larger and further from the coast, there is scope for further savings to be made for generators and consumers through the sharing of transmission assets, and by using some offshore assets to reduce pressure on onshore infrastructure.

This report sets out what Government and Ofgem intend to do to ensure there are no barriers to the development of coordinated and future-proofed offshore transmission infrastructure.

A handwritten signature in black ink that reads "Charles Hendry". The signature is written in a cursive style and is positioned above a long, horizontal, slightly wavy line that serves as a decorative underline.

Charles Hendry

Minister of State for Energy



The Government has set ambitious targets for the deployment of renewable energy over the next decade and for carbon emission reductions of 80% by 2050. Offshore wind power will play a major part in meeting these targets and in maintaining energy security. Ofgem has been pleased to work closely with the Government to establish a competitive regulatory regime which facilitates the growth of the offshore sector.

Since commencement of the Offshore Transmission Owners (OFTO) regulatory regime in 2009, Ofgem has delivered significant benefits through cost savings to consumers, attracting considerable investment into the sector and working closely with market players to maintain industry momentum. With four licences granted, 11 projects in active tendering and a longer-term pipeline worth in excess of £14 billion,¹ Ofgem continues to invest considerable time in the ongoing development of the regime.

There is, moreover, the potential for over 32GW of offshore wind generation² and other marine technologies to be developed in the next two decades. The conclusions outlined in this report are important to help us achieve this expansion and highlight the huge contribution that the UK is making to Europe-wide initiatives including the North Seas Countries' Offshore Grid Initiative. With much potential growth still ahead in this market, we are pleased to continue working in partnership with the Government to reinforce the foundations for this growth.

I am pleased to present this Joint Conclusions Report on Coordination. I hope you will find the report informative in its examination of the potential costs and benefits of a more coordinated approach to future offshore network connections. I encourage you to read this along with the accompanying Ofgem consultation document, which looks in more detail at particular measures we are taking forward to address the issues raised in this report.

A handwritten signature in black ink, appearing to read 'John Mogg'.

Lord Mogg

Chairman, Ofgem

¹ Work commissioned by Ofgem and undertaken by TNEI/PPA Energy for the Offshore Transmission Coordination Project estimates transmission investment costs of around £14billion for TCE Round 3 sites based on the National Grid 'Gone Green' scenario. There are also additional projects in development as part of TCE Round 2 and 2.5, and Scottish Territorial Waters Zones which mean that the pipeline could be significantly in excess of this figure.

² UK Renewable Energy Roadmap, DECC, July 2011, p42.

Executive Summary

Government and Ofgem recognise the potential benefits that the coordinated development of offshore electricity transmission infrastructure can offer. These include lower overall capital costs and potentially reduced environmental impacts and planning-related delays. Coordination was a major driver in the decision to extend National Grid's onshore System Operator responsibilities offshore. These responsibilities include the development of a coordinated system of electricity transmission and the creation of a licence obligation requiring the System Operator to develop an Offshore Development Information Statement (ODIS).

Respondents to a joint DECC and Ofgem consultation on the offshore transmission regulatory regime, in August 2010, expressed strong support for the principle of a coordinated approach to offshore network development, where this does not bring additional delays or costs. However, most were of the view that current incentives through the policy and regulatory framework may be insufficient to bring about significant levels of coordination in practice.

In early 2011 DECC and Ofgem launched the Offshore Transmission Coordination Project (the Project). The Project has considered whether any additional measures would be required to deliver coordinated networks through the competitive offshore transmission regime and, if so, how these measures might work in practice. This report presents our conclusions. We considered coordination to mean developing onshore and offshore transmission networks in a strategic manner. This means offshore and onshore development will need to be considered together when looking at network development needs, in order to deliver the most economic and efficient overarching design. This includes coordination within development zones, between development zones, between onshore and offshore transmission infrastructure, between offshore transmission infrastructure and cross-border interconnectors, or some combination of these.

The Project has been informed by expert stakeholder input as well as two specialist reports commissioned by Ofgem on the benefits, costs and risks associated with different offshore grid configurations, and on the potential regulatory and commercial measures for incentivising coordination.

The findings of the Project suggest that coordinated offshore network development does indeed have the potential to deliver significant savings. Modelling undertaken for the project by TNEI/PPA Energy and Redpoint Energy, using four different generation scenarios, found that coordination in respect of The Crown Estate (TCE) Round 3 Zones has the potential to deliver savings of around 8-15%, or £0.5-3.5billion, when compared to purely radial configurations.

The potential savings were found to increase as higher levels of generation are assumed, with the corollary that anticipatory investment and stranding risk, where assets are built but then underutilised, also increases. It is important to remember that the estimated savings only capture some aspects of the potential benefits and risks associated with coordinated grid configurations. Such configurations also have the potential to minimise environmental impacts (and necessary planning applications) if they reduce cabling and landing sites in sensitive areas, reduce congestion on the onshore network, and offer, during the later stages of build out, additional routes for export of power in the event of a transmission asset failure.

The potential benefits have to be weighed up against the potential risks and costs involved with more coordinated configurations. These include increased asset stranding risk, potentially

increased reliance on single cables (and associated single point of failure) in early stages of build out, and reliance on technology that is not yet commercially available, in particular 2GW High Voltage Direct Current (HVDC) cables and potentially HVDC multi-terminal links.

In addition, the benefits of coordination vary between different zones and in some zones radial connections will remain optimal. These findings, in combination with the high levels of uncertainty surrounding long-term offshore generation build-out, supports an incremental, evolutionary approach to network development rather than the building of a large-scale, meshed network from the outset.

The findings of the Project have been considered in the context of the regulatory framework for offshore electricity transmission. Offshore transmission assets must be owned and managed by an Offshore Transmission Owner (OFTO), selected through a competitive tender process run by Ofgem. Generators have the option to construct the assets themselves (Generator build) before transferring them to an OFTO upon completion, or to request an OFTO to do so (OFTO build).

The benefits of the regulatory framework have been demonstrated by developments to date. Initial analysis by Ofgem in relation to Transitional Tender Round 1 suggests that the competitive drivers within the regime will deliver considerable costs savings for generators and consumers alike. There were bids totalling almost £4billion in relation to £1.1billion of assets, and there have been a range of participants and new entrants in bidder consortia, which provides resilience in the investment environment. Developers continue to value the option of being able to choose to construct transmission assets themselves, and looking at other leading offshore wind nations, projects in GB have relatively short timescales to generation.

Within this framework, National Grid as the National Electricity Transmission System Operator (NETSO) has a key role in the development of the offshore network as it provides offshore developers with connection offers, setting out where new generation projects will connect to the National Electricity Transmission System (NETS). As the system operator across onshore and offshore networks, the NETSO is well placed to assess the needs across the NETS and determine the most economic and efficient way to meet these. In line with this, the NETSO has already been offering some TCE Round 3 developers connections which envisage more coordinated configurations where appropriate.

While there are some incentives on parties to seek coordinated outcomes of their own accord, the Project identified a number of potential barriers to the realisation of coordination benefits. These can be summarised under six headings:

- Planning an efficient network;
- Anticipatory investment;
- Consenting;
- Risk-reward profile for coordinated investments;
- Regulatory boundaries; and
- Technology and supply chain.

Addressing these potential barriers through changes to the existing offshore transmission regulatory regime will assist in realising the benefits that may come from coordination, while maintaining the benefits of regulated competition.

The Project considered whether improvements are needed to facilitate the **design of an efficient network**, and found that there could potentially be improvements to the system planning process to help ensure that the most efficient network develops. Ofgem is considering ways to address some of the apparent constraints and challenges the NETSO faces in developing an efficient, economic and coordinated network and have invited views on this in the consultation published alongside this report. This includes proposals to improve the ODIS, and other GB transmission planning documents, to provide information on likely short to medium-term network developments that can better inform coordinated network development. This could include a more holistic view across the overall GB transmission network and cross-border links.

A key issue identified by the Project concerns the importance of some investment ahead of need – **anticipatory investment (AI)** – to keep open the options for coordinated network development in the future. The most efficient, coordinated network configuration will in many cases require investment in transmission infrastructure that goes beyond the immediate needs of a specific offshore wind developer's project. This could be investment at both the pre-construction and construction stages. The Project found that uncertainty over the process for and funding of such anticipatory investment is the main issue to be resolved to facilitate coordinated network development.

Alongside this document, Ofgem is consulting on its analysis and a potential 'straw man' proposal for an approach to AI within the offshore transmission regime, including how it should be identified, taken forward and funded.

Throughout the Project stakeholders raised various issues related to **planning and consenting**. The key barrier to realising coordinated networks concerns the difficulty faced by developers in getting consent for transmission infrastructure of an anticipatory nature, where existing guidance on associated development appears to rule this out. Government considers that in many cases anticipatory infrastructure is something which ought to be open to consideration by the Infrastructure Planning Commission (IPC) as associated development under the Planning Act 2008. This should be made possible by amending the Department for Communities and Local Government (CLG) statutory guidance on Associated Development to make it clear that developments of an anticipatory nature can be considered to be associated development. CLG will be inviting views on this issue in March as part of its review of the Planning Act 2008 regulations and guidance, and expects redrafted guidance to be implemented by summer 2012.

When considering network connection offers provided by the NETSO for generation projects, a key factor for developers is the balance of **risk and reward** implicit in that offer. These risks and rewards are driven by the user commitment liabilities and the subsequent Transmission Network Use of System (TNUoS) charges that offshore generators would accrue when developing connections. Current user commitment arrangements may act as a disincentive to coordinated offshore developments, as a generation project connecting through a transmission link that would also benefit future users – i.e. of an anticipatory nature – may become liable for all the costs. In addition, there is a lack of clarity on how TNUoS charges will work for coordinated offshore networks.

The methodologies for transmission charging and user commitment therefore need to evolve to remain fit for purpose. A code change proposal is currently underway for user commitment arrangements and is currently with Ofgem for approval. National Grid has published a discussion paper setting out possible principles to form the basis of a revised approach for transmission charging. The accompanying Ofgem consultation also discusses key requirements for the charging and user commitment regimes in order to support the proposed approach to AI while protecting consumers' interests.

Currently, there are **regulatory boundaries** between onshore, offshore and interconnector transmission assets, reflecting the historic evolution of network regulation and the requirements of European legislation. We recognise that a number of different types of offshore development could come forward over the next decade that could cover some combination of offshore generation connection, onshore reinforcement and cross-border links. It is important that these regimes provide a clear and effective framework for network development. Ofgem and DECC will undertake work to consider whether further clarity is needed on the interface between onshore, offshore and interconnector regimes.

In terms of **technology**, the key potential barriers identified by the Project concern issues around interoperability of transmission systems, technology development, and supply chain capacity. This report highlights financial support already committed and potentially available in the future through DECC or European programmes for technology development, and draws attention to existing initiatives on interoperability. However, DECC and Ofgem will continue to monitor progress in the area of technology and will consider further action if appropriate.

This report marks the close of the joint DECC and Ofgem Project, and we would like to thank all who participated in the process. The sections below set out the Project findings in more detail, along with the key measures that are being taken forward to address the barriers identified. Ofgem is taking forward key aspects through the accompanying consultation document, to which it encourages stakeholders to respond.

1. Introduction

1. Government's aims for the development of electricity transmission infrastructure are to ensure the right policy and regulatory frameworks are in place to deliver an efficient network now and to 2050, supporting Government's objectives for low carbon, secure and affordable energy. As the independent regulator for the gas and electricity markets, Ofgem is required to protect the interests of present and future gas and electricity consumers through, amongst other things, its regulation of transmission networks. This includes its interests in the reduction of greenhouse gases and in the security of gas and electricity supplies.
2. Government and Ofgem recognise the importance of developing effective and efficient transmission infrastructure to connect offshore renewable generation to the NETS. This has been a key factor in the decision to set up a competitive offshore transmission regulatory regime, with OFTOs appointed by competitive tender, to deliver efficiency savings, encourage innovation, and attract new entrants and sources of investment. We also recognise the importance of developing both onshore and offshore transmission in a coordinated manner. This was the driver in the decision to extend the role of National Grid Electricity Transmission's (NGET) system operator responsibilities to cover offshore as well as onshore transmission, which will help ensure that new network connections are delivered in a coordinated, economic and efficient manner. It was also the driver behind the decision to create a licence obligation requiring the NETSO to develop and update the annual ODIS.³
3. To date, the most efficient means of connecting most offshore windfarms that have already been built or are currently undergoing construction to the NETS has been through radial connections to shore from each windfarm. However, as offshore generation projects become larger, more complex and further from shore and as technologies develop, this is unlikely to remain true for all of TCE Round 3 Zones, representing up to 32GW of offshore generation.⁴ This was recognised by stakeholders in responses to the joint DECC and Ofgem August 2010 consultation on certain aspects of the offshore transmission regime.⁵ Stakeholders expressed strong support for the principle of a long-term, coordinated approach to offshore transmission development, where this did not have cost or timing implications for generation project developers. However, most respondents were of the view that current incentives through the policy and regulatory framework may be insufficient to bring about significant levels of coordination in practice.
4. Therefore, DECC and Ofgem launched the joint Offshore Transmission Coordination Project in early 2011.⁶ The objective was to consider whether any additional measures would be required to deliver coordinated networks through the competitive offshore transmission regime and, if so, how these measures might work in practice.

³ <http://www.nationalgrid.com/uk/Electricity/OffshoreTransmission/ODIS/>.

⁴ <http://www.thecrownestate.co.uk/news-and-media/news/2010/the-crown-estate-announces-round-3-offshore-wind-development-partners/>.

⁵ http://www.decc.gov.uk/en/content/cms/consultations/offshore_trans/offshore_trans.aspx.

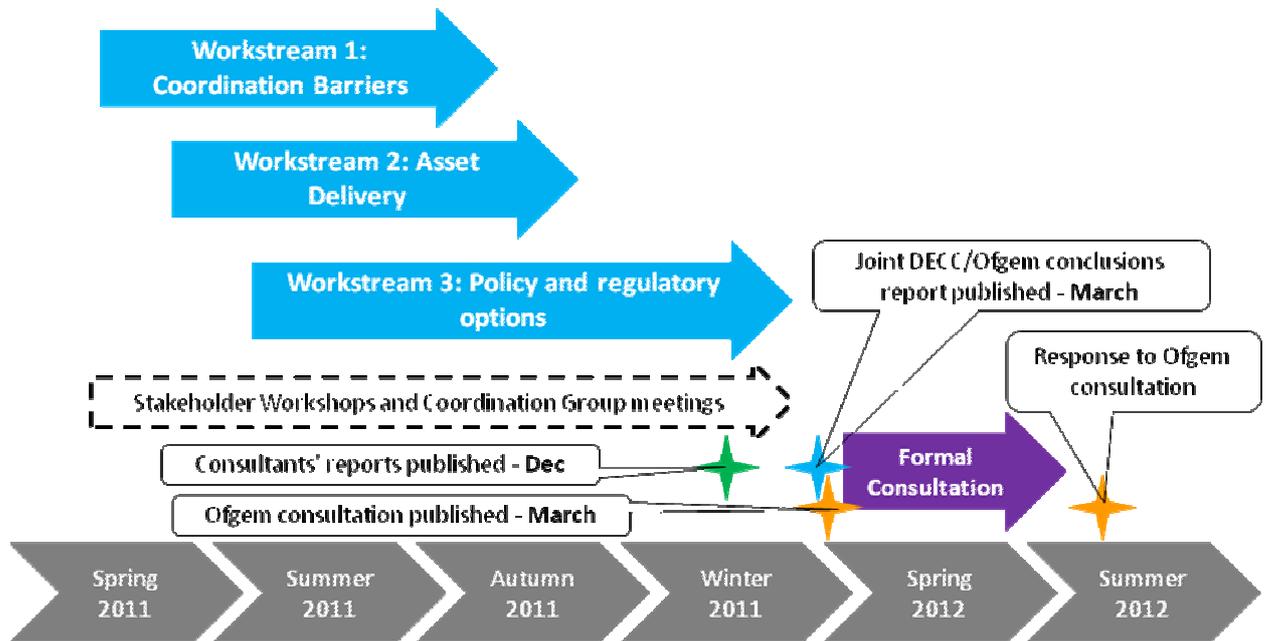
⁶ <http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=3&refer=Networks/offtrans/pdc/pwg/OTCP>.

5. To ensure that all relevant stakeholder expertise and experience was brought to bear in identifying any barriers and potential measures, DECC and Ofgem established three stakeholder fora:
- **Offshore Transmission Coordination Group (OTCG).** This high-level group, chaired by DECC and Ofgem and with representatives including generators, network companies (including existing and potential OFTOs), the supply chain and The Crown Estate, met six times during the course of the project. The OTCG provided support to DECC and Ofgem in developing and considering policy options for maximising the opportunities for coordination, and helped ensure any dependencies between the Project and other areas were considered. The terms of reference, membership and meeting minutes are available on the Project's webpage.⁷
 - **Offshore Transmission Coordination Expert Workshops.** DECC and Ofgem held five expert workshops and a stakeholder briefing event for the Project. These meetings were open for all stakeholders to attend, and considered the relevant issues in more detail, drawing on specialist industry knowledge. The minutes of the workshops are also available on the Project's webpage.
 - **Offshore Transmission Coordination Stakeholder Community.** Any interested party was invited to join a stakeholder community, to be informed of forthcoming workshops and other Project developments.
6. The approach taken by the Project is illustrated in Figure 1, showing the three analytical workstreams that formed part of the methodology. This report sets out the joint DECC and Ofgem conclusions from the Project, including our assessment of the benefits, costs and risks of more coordinated grid configurations; barriers and disincentives to coordination; and the measures we have decided to take forward to address them. The measures will be progressed by a number of different organisations. A number of these are being taken forward by Ofgem, which has published a formal consultation document in parallel with this report.⁸

⁷ <http://www.ofgem.gov.uk/Networks/offtrans/pdc/pwg/OTCP/Pages/OTCP.aspx>.

⁸ Ibid.

Figure 1: Offshore Transmission Coordination Project Plan



7. To support further the Project's analysis, Ofgem commissioned two sets of consultants to provide specialist input. Their reports were published on 15 December 2011.⁹ The consultants were:
 - **TNEI/PPA Energy**, who carried out a technical analysis of different network configuration options for connecting offshore generation projects to the NETS, considering the costs, benefits and risks of different options. TNEI/PPA's analysis supported the asset delivery workstream; and
 - **Redpoint Energy**, who undertook a review of the current offshore transmission policy, regulation and commercial incentives to understand where there may be inadequate incentives for, or barriers to, coordination. Possible measures and packages were also identified and assessed for addressing barriers. Redpoint's analysis supported the workstreams covering coordination barriers and policy and regulatory options.
8. DECC also commissioned consultants SKM and CEPA to provide a comparative analysis of other countries' offshore transmission regimes, with a particular focus on coordination issues, in order to learn lessons from these countries and from other relevant sectors. The outputs from this work are available from the DECC website.¹⁰

⁹ <http://www.ofgem.gov.uk/Networks/offtrans/pdc/pwg/OTCP/reports/Pages/reports.aspx>.

¹⁰ http://www.decc.gov.uk/en/content/cms/meeting_energy/network/offshore_dev/offshore_dev.aspx.

2. Context – the offshore transmission regulatory framework

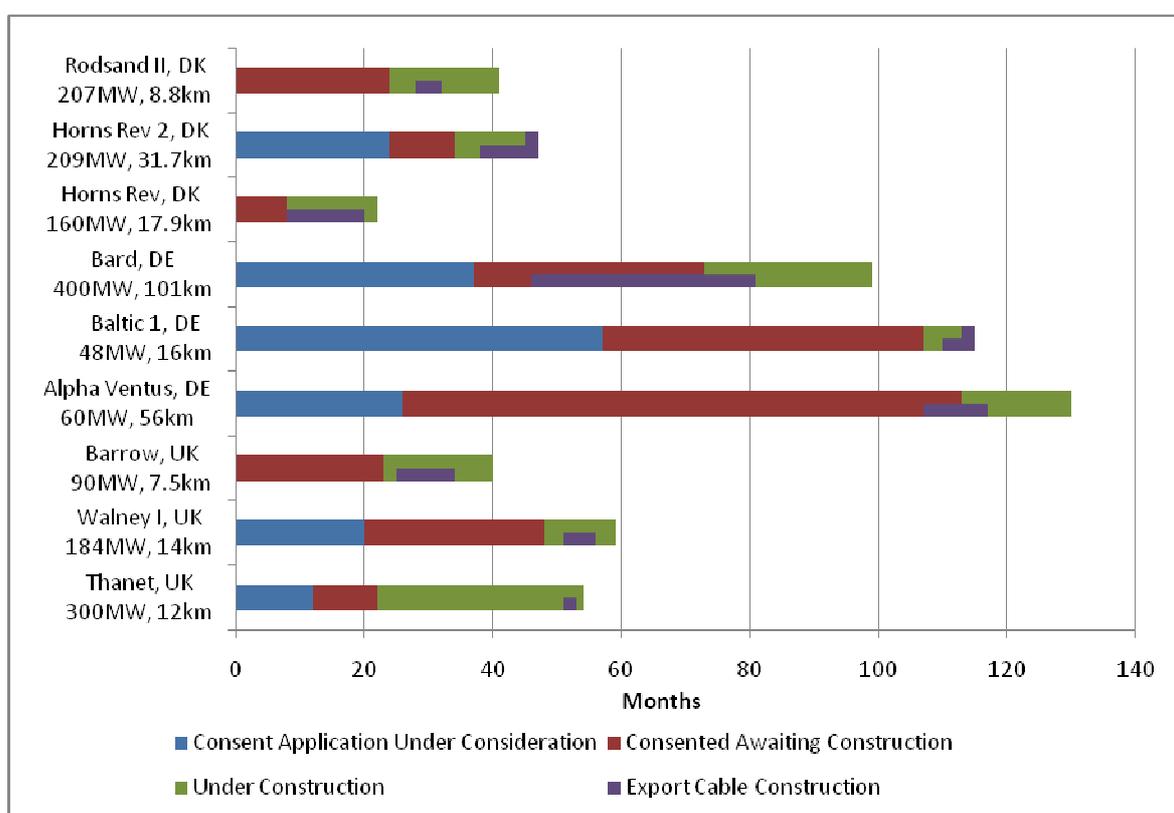
9. This section provides relevant background on the offshore transmission regulatory framework, as context for the consideration of the barriers to coordination and the measures to address them (Section 4).
10. Government and Ofgem have worked together since 2005 to design and implement the regulatory regime for offshore electricity transmission. In March 2007, following a number of prior consultations on different options, Government decided¹¹ on the overall framework for offshore transmission – a competitive, asset-based regulatory regime. This was further developed by Government and Ofgem to become an approach whereby multiple parties compete through a tender process to secure licences to build (where appropriate), own and operate offshore transmission assets. This provides the overarching legal and regulatory framework within which investment decisions are taken, and within which policy and regulatory developments occur.
11. Under these arrangements, Ofgem is responsible for running a competitive tender to select an OFTO to own and manage offshore transmission assets. Generators have the option to construct the assets themselves ('Generator build) before transferring them to an OFTO upon completion, or to request an OFTO to do so ('OFTO build'). Participants in the competitive tender bid against each other in terms of the 20-year revenue stream they would require to buy or construct the assets, and to operate and manage them. This means that the revenue stream for OFTOs does not have to be periodically reviewed every few years (as happens with onshore transmission companies through price control reviews), as efficient prices are set up front through the competitive tender process.
12. The key reasons for the decision behind the competitive framework, as set out in the March 2007 document and reiterated in joint DECC and Ofgem publications since then,¹² were that compared to an exclusive approach to asset ownership it would:
 - Deliver cheaper and more timely offshore grid connections;
 - Encourage innovation through competition and enable new entrants to compete in the market;
 - Be more focussed on generators' requirements than the onshore system or the exclusive approach; and
 - Enable generators to construct their own transmission assets if they wish, thereby creating more certainty for generators.

¹¹ <http://webarchive.nationalarchives.gov.uk/+http://www.berr.gov.uk/files/file38705.pdf>.

¹² See for example joint DECC and Ofgem consultations from December 2009 and August 2010, available at <http://www.ofgem.gov.uk/Networks/offtrans/pdc/cdr/Pages/cdr.aspx>.

13. The SKM and CEPA comparative assessment of offshore transmission regimes for key countries with significant amounts of, or plans for, offshore wind highlights the existence of a wide range of approaches to the regulation of offshore electricity transmission.¹³
14. We consider that the benefits of the GB approach have been demonstrated since the commencement of the offshore transmission regime, and have generated strong industry confidence. Initial analysis by Ofgem suggests that the competitive regime will deliver considerable savings for generators and consumers in respect of the first £1.1billion offshore transmission assets tendered, as a result of the regime's competitive drivers. The timelines for GB offshore grid connections and indeed for the offshore windfarms themselves, also compare favourably with those of other leading offshore wind nations (see Figure 2).

Figure 2: Timelines for selected projects in Denmark (DK), Germany (DE) and the UK



Source: SKM/CEPA Comparative Assessment Report for DECC

15. The offshore transmission regime has also been successful in attracting investor appetite, with new entrants and new sources of finance demonstrating interest in the sector. Funding of up almost £4billion was offered in relation to the £1.1billion of assets in the first transitional tender round, and there have been a range of participants in bidder

¹³ Tables 13, 14 and 15 in the Deliverable 1 report, available at <http://www.decc.gov.uk/assets/decc/11/meeting-energy-demand/future-elec-network/4443-skmcepa-report-1-comparative-assessment-with-key.pdf> set out the key characteristics of the offshore electricity transmission regimes for Great Britain, Germany, Denmark, the Netherlands, Ireland, USA, France, Belgium, Sweden and China.

consortia. Given the level of investment needed in the energy generation and transmission sector over the next two decades, tapping into new sources and structures of finance will be important.

16. Diversity of investors also supports resilience in the investment environment. In Germany, the transmission system operator TenneT has a monopoly on construction and ownership of offshore transmission assets in the North Sea. In January 2012, TenneT wrote to the German Government to inform it that it could not build any further connections because of financial constraints, as well as other resource constraints within the company itself and its suppliers.¹⁴
17. While the implementation of the European Union's (EU) Third Energy Package means that generators will not be able to own and operate both generation and transmission systems, under the GB regulatory regime they still have the option of constructing the transmission assets that will provide their connection to the NETS. Developers continue to value the flexibility of being able to choose to construct transmission assets themselves or to opt for an OFTO to do so. Ofgem recently launched a further consultation on tender exercises under the enduring offshore transmission regime and the proposed approach to OFTO build and Generator build options.¹⁵
18. In this framework, National Grid as the NETSO has a key role in the development of the offshore network as it provides offshore developers with connection offers, setting out where new generation projects will connect to the NETS. As the System Operator across onshore and offshore networks, the NETSO is well placed to assess the needs of the NETS and determine the most economic and efficient way to meet these.
19. In line with this, the NETSO has already been offering some TCE Round 3 developers connections which envisage more coordinated configurations where appropriate. However, this Project has identified a number of potential barriers that are important when considering the most economic and efficient network configuration.
20. The rest of this report looks at the potential benefits, costs and risks of certain coordinated offshore network configurations. It sets out the potential barriers to the development of coordinated configurations and measures for overcoming them. In assessing the potential barriers and the range of possible solutions to address them, DECC and Ofgem considered proposals involving the wholesale reform of the regulatory framework, but ruled them out due to their potential to impact on the benefits associated with the competitive approach and create uncertainty for generators and investors.

¹⁴ <http://www.tennet.org/english/tennet/news/tennet-asks-for-a-broad-discussion-on-the-connection-of-offshore-wind-farms-in-germany.aspx>.

¹⁵ <http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=42&refer=Networks/offtrans/pdc/cdr/Cons2011>.

3. Coordinated development – benefits, cost and risks

21. This section summarises the potential benefits of using more coordinated grid configurations where appropriate for TCE Round 3 projects which, together, could represent up to 32GW of generation capacity. It also summarises the potential costs and risks associated with such configurations. Further detail on the benefits, costs and risks can be found in the reports prepared by TNEI/PPA Energy and Redpoint Energy for this Project.¹⁶ The findings of the TNEI/PPA Energy report are also summarised in Annex 1.
22. For the purpose of this Project, we considered coordination to mean developing onshore and offshore transmission networks in a strategic manner. This means offshore and onshore development will need to be considered together when looking at network development needs, in order to deliver the most economic and efficient overarching design. We consider that there are four broad types of network coordination. These are illustrated in Figure 3 and described below:
 - **Between offshore generators** – of which there are two types:
 - **Intra-zonal** – coordination between different offshore generation projects within one TCE Zone;
 - **Inter-zonal** – coordination between different offshore generation projects across TCE Zones;
 - **Onshore/offshore** – coordination between the development of onshore and offshore transmission infrastructure; and
 - **International** – coordination between the development of offshore transmission infrastructure and interconnectors between countries.
23. These different forms of coordination will not necessarily be mutually exclusive. For example, onshore/offshore coordination may occur where there is also intra- and/or inter-zonal coordination.

¹⁶ <http://www.ofgem.gov.uk/Networks/offtrans/pdc/pwg/OTCP/reports/Pages/reports.aspx>.

Table 1: Summary of potential benefits and risks of offshore transmission coordination

Potential benefits	Potential risks
<ul style="list-style-type: none"> • 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 (e.g. flexibility to link with other networks including international networks and the trade which may result). 	<ul style="list-style-type: none"> • Stranding risks associated with AI; • Technological challenges; • Increased project complexity; and • Potential temporary reduction in transmission system flexibility and security of supply for early phases.

Source: Redpoint Energy

25. The TNEI/PPA Energy report suggests that for certain TCE Round 3 Zones - particularly the largest ones where there are also onshore network constraints in the areas to which they might connect - more coordinated configurations could reduce the overall costs of the Zone development, because overall less infrastructure may be needed. Coordinated grid configurations also have the potential to:

- Minimise environmental impacts (and necessary planning applications) if they reduce cabling and landing sites in sensitive areas;
- Reduce congestion on the onshore network (in the absence of other reinforcement projects over the same timeframe); and
- Offer developers additional routes for exporting their power (in the later stages of Zone build-out) in the event of a transmission asset failure.

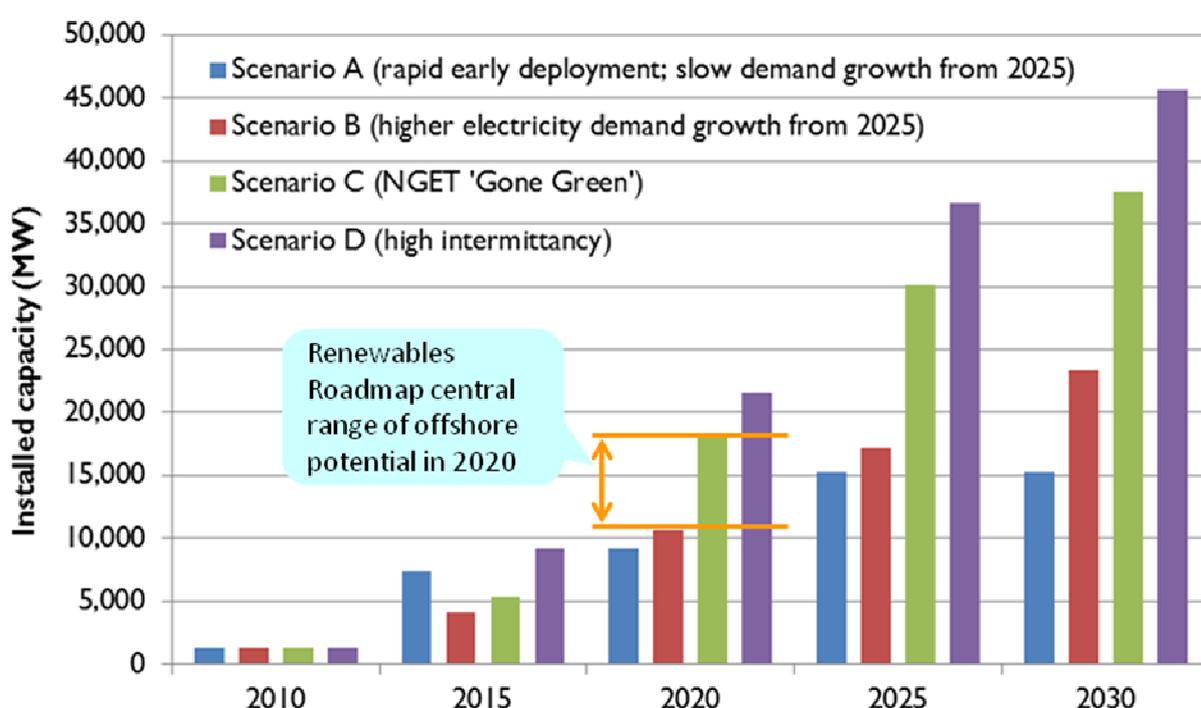
26. However, the findings of the TNEI/PPA Energy report also suggest that these potential benefits have to be weighed up against the potential risks and costs involved with more coordinated configurations. These include:

- Increased asset stranding risk where assets are built but then underutilised (as such configurations are more likely to involve the construction of some assets ahead of need), leading to unnecessary costs;
- Reliance on technology that is not yet available and proven, in particular 2GW cables and potentially HVDC multi-terminal links;
- Greater interdependency and risk of a single circuit failure during build-out. For example, the developer of one Zone dependent on the build-out of a different developer's Zone for its power export would see increased reliance on single cables in the early phases of build-out. Further, in a Zone with generation phases of 500MW and using 2GW cables, the Zones could remain within NETS Security and

Quality of Supply Standard (SQSS) limits until 60% of the capacity of the fourth phase is commissioned, but have no other means of power export in the event of a cable failure.

27. In order to estimate the potential benefits available from coordinated transmission development in respect of relevant TCE Round 3 Zones, DECC provided TNEI/PPA Energy and Redpoint Energy with four scenarios for total GB offshore generation development to 2030. These scenarios are illustrated in Figure 4, and described in more detail in the TNEI/PPA Energy report as well as summarised in Annex 1.

Figure 4: The four offshore generation scenarios used for the Coordination Project



Sources: DECC, ODIS, Redpoint

28. The modelling by TNEI/PPA Energy and Redpoint Energy for the Coordination Project using the four generation scenarios found that coordination in respect of relevant TCE Round 3 Zones has the potential to deliver savings of around 8-15% or £0.5-3.5billion.¹⁷ These savings would be additional to those already being made (and to be made in the future) as a result of regulated competition.
29. The TNEI/PPA Energy report identified that one of the key issues, in order to keep options open for realising these potential benefits of coordination, is the need for AI, i.e. capital expenditure that supports anticipated future network requirements, rather than the immediate needs of a single offshore generation phase. In the short term, the key

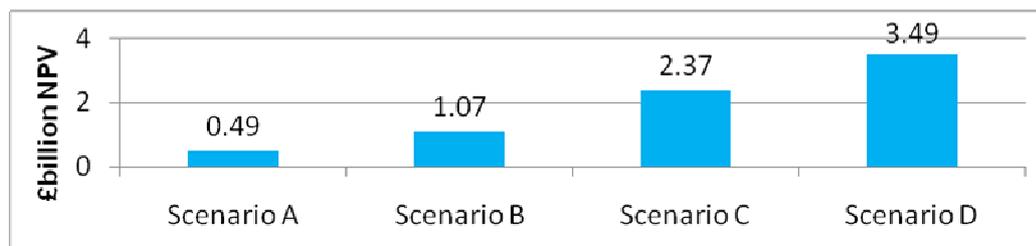
¹⁷ The savings include both capital and operating expenditure (capex and opex) and are calculated on a Net Present Value basis.

priority is to allow for some anticipatory pre-construction activities, such as cable surveys or acquiring additional wayleaves for onshore cable routes. It could also include oversizing of equipment at the construction phases, such as adding additional J tubes and circuit breakers to offshore platforms or building assets for wider network reinforcement purposes.¹⁸ The issues around the funding process and consenting for such investment are set out in Section 4.

30. The potential cost savings from coordinated configurations for relevant TCE Round 3 Zones compared to a purely radial approach are illustrated in Figure 5. The potential cost savings rise as generation is assumed to increase across scenarios A-D, with the corollary that that the amount of AI required and potential stranding risk may also increase.

Figure 5: Potential cost savings from coordination in respect of relevant TCE R3 Zones

Maximum potential CAPEX and OPEX savings (NPV) from coordination for Round 3 (£billion)



Cost saving figures expressed as a % of total CAPEX and OPEX expenditure



Source: Redpoint Energy. NPVs are for the period 2010-2030.

31. The benefits could potentially increase further if in future it becomes clear that further cross-border interconnector efficiencies could be achieved through combinations with offshore transmission assets. The integration capex saving would come from the avoided cost of an onshore converter substation and the cable from the offshore windfarm to the shore.
32. However, the benefits need to be set against the potentially significant constraints on energy exports, given that the combined capacity for interconnection trades and windfarm generation exports is likely to be lower than if the assets were developed

¹⁸ Examples of infrastructure of an anticipatory nature include the installation of additional onshore ducts for cables for further projects, additional circuit breaker and/or circuit breaker bays on an offshore platform, facilities for additional cables to offshore platforms, additional power transfer capacity for the onshore connection cable, and additional transformer capacity or additional circuit bays at the onshore substation.

separately. This means that there is an increased risk that either the windfarm exports or the interconnector trades will be constrained by the capacity of the combined link. Effectively, there will be a trade-off between potential capex savings and constraint risk. The key element in judging this trade-off will be whether the interconnector trades and windfarm generation are likely to be coincident. For cases where they are, then a high degree of constraint is likely. If the general direction of flow is the reverse, then it is possible that the windfarm and interconnector could operate with very low levels of constraint.¹⁹

33. Analysis previously undertaken for DECC on the potential for combining windfarm transmission assets with cross-border interconnectors shows that any net benefits from doing so are case specific.²⁰ It will depend on a large range of factors, including: the length of interconnector; distance from shore and position of the windfarm with respect to the interconnector; size of the windfarm and interconnector; the timing of the windfarm and interconnector projects; and the likely level of constraint due from the sharing of the assets.
34. It is important to also consider the other benefits, risks and potential costs illustrated in Table 1 in addition to the cost-benefits in Figure 5, as the latter do not necessarily represent the full range of potential benefit and risks of integration since it was limited to capex and opex cost savings only, calculated on the basis of perfect foresight, and does not address the risk of stranding. One of the key dependencies for the realisation of potential cost savings from coordinated configurations is the development of new technology.
35. The TNEI/PPA Energy report for this Project found that if HVDC links with a transfer capacity of 2GW and HVDC multi terminal links do not become available in time for TCE Round 3 development, then coordinated configuration costs could increase. This was demonstrated through testing a scenario which assumed that 2GW VSC (Voltage Source Converter) HVDC technology was unavailable and 1GW links were used instead. The results of this sensitivity suggest that if 2GW technologies are unavailable, a coordinated solution may be more expensive than the pure radial configuration across generation Scenarios A-C, and may erode most of the benefits of the coordinated configuration for generation Scenario D.

¹⁹ See Section 2.8 of the TNEI/PPA Energy report for further detail.

²⁰ <http://www.decc.gov.uk/assets/decc/What%20we%20do/UK%20energy%20supply/futureelectricitynetworks/800-offshore-grid-development-secure-renewable.pdf>.

4. Conclusions on barriers to coordinated development and measures to address them

36. This section of the report sets out the DECC and Ofgem Project conclusions on potential barriers to the coordinated development of the offshore transmission network, which could potentially outweigh the incentives that exist for parties to seek coordinated outcomes of their own accord. It also sets out measures that are being taken forward or proposed to address the potential barriers. The conclusions are the result of internal analysis and are informed by our stakeholders – including through the fora established for the Project – as well as by Redpoint Energy’s report.²¹ Table 2 summarises these potential barriers and solutions, which are explained in more detail below. Further details on the implementation of an approach to AI and designing an efficient network can be found in the Ofgem consultation published alongside this report.

Table 2: Summary of potential barriers and proposed solutions

Barrier	Description	Proposed solution
Planning an efficient and economic network	Potential modifications needed to allow NETSO to better identify coordination opportunities through the connection offer process and to help ensure that transmission planning documents effectively inform short-to medium-term developments	Ofgem is consulting on potential enhancements to the NETSO’s role in specifying coordinated offshore transmission needs and improvements to network documents
Anticipatory Investment (AI)	Currently no explicit process or guidance on how AI for offshore transmission infrastructure will be treated by Ofgem, creating uncertainty	Ofgem is consulting on analysis and ‘straw-man’ for an approach to AI within the offshore transmission regime, including how it should be identified, taken forward and funded
Consenting	Current Government guidance appears to rule out consenting of anticipatory assets	Revised guidance on associated development to enable these types of assets to be considered
Risk-reward profile	Uncertainty around how security and charging requirements for generators will work for coordinated offshore networks	Industry-led changes, subject to Ofgem approval, to provide clarified, fair and efficient charging and user commitment methodologies for coordinated offshore developments
Regulatory boundaries	Lack of clarity on regulatory treatment of assets that involve combinations of onshore reinforcement, offshore generation connection and interconnectors	Ofgem and DECC to provide improved clarity on regulatory boundaries as appropriate. For the offshore-interconnector boundary, North Seas Countries’ Offshore Grid Initiative (NSCOGI) and DECC work on renewable trading mechanisms will also be relevant
Technology	Some technologies necessary for coordination are not yet commercial; questions around interoperability	The report sets out current standardisation and innovation funding, and further work to build on this

²¹ <http://www.ofgem.gov.uk/Networks/offtrans/pdc/pwg/OTCP/reports/Pages/reports.aspx>.

Planning an efficient network

37. We expect that technology will drive increased interaction between onshore, offshore and cross-border drivers for transmission investment. As a result, there will be an increased need for taking a coordinated view of transmission development across the whole of the GB network.
38. National Grid's position as the NETSO has been extended to cover the offshore network, and it has a key role in ensuring efficient coordination of network developments given its singular position in having oversight across the NETS. The NETSO is also required through its licence to prepare the ODIS to facilitate the development of an efficient, co-ordinated and economical system of electricity transmission.
39. The Project considered whether improvements are needed to facilitate efficient network development. One of the key areas where the NETSO plays a role is through the connection offer process, where developers request a connection to the NETS for their prospective offshore generation project and the NETSO responds with an offer for where and when that connection can be provided. Recently, NGET has looked to identify where coordination could be beneficial through the connection offer process.
40. However, analysis and stakeholder feedback through the Project suggested there could potentially be improvements to the system planning process, to help ensure that the most efficient network develops. Ofgem is considering ways to address some of the apparent constraints and challenges the NETSO faces in developing an efficient, economic and coordinated network and have invited views on this in the consultation published alongside this report.
41. The Project findings also suggest that improvements could be made to the ODIS and other GB transmission planning documents, to provide information on likely short- to medium-term network developments that can better inform coordinated network development. This could include a more holistic view across the NETS and cross-border links.
42. NGET has already proposed that the existing ODIS document and the onshore Seven Year Statement (SYS) be combined into a single transmission planning document covering onshore and offshore networks, which could also be used to inform the European Ten-Year Network Development Plan.²² The accompanying Ofgem consultation sets out and invites views on suggested key requirements of a reformed network planning document and proposed next steps in this area.

Anticipatory investment

43. As set out in Section 3, the most efficient, coordinated network configuration will in some cases require AI offshore, i.e. investment in transmission infrastructure that goes beyond the immediate needs of a specific offshore wind developer's project. This could be investment at both the pre-construction and construction stages that allows for greater

²² The Third Energy Package mandates the European Network of Transmission System Operators for Electricity (ENTSO-E) to publish a biannual, non-binding, Ten-Year Network Development Plan (TYNDP), to increase information and transparency regarding the electricity transmission network in the Community and to support decision making processes at regional and European levels. More information is available at <https://www.entsoe.eu/system-development/tyndp/>.

transmission capacity in anticipation of future offshore generators, or for the primary purpose of providing reinforcement of the onshore network given anticipated network constraints.

44. Stakeholder feedback, together with our analysis, has shown that uncertainty over the process for and funding of such AI is the main issue to be resolved to facilitate coordinated network development. Given project timings, providing certainty for pre-construction funding is the key short-term priority.
45. Under the current offshore transmission regulatory framework there is not an equivalent process to the onshore Transmission Investment Incentive (TII) framework and the RIIO-T1 successor to this.²³ While AI is potentially available under the current offshore regime, stakeholders have suggested that it is unclear how it will be dealt with in relation to the cost assessment process which takes place as part of the tender process. This includes a lack of certainty for developers incurring the initial costs of AI on whether they will be able to recover those costs when transferring the transmission assets to the successful OFTO bidder for that project. Developers are therefore reluctant in some cases to take forward projects that involve AI as they do not have confidence that they will be able to recover their investment.
46. Alongside this report, Ofgem is consulting on its analysis and ‘straw-man’ for an approach to AI for offshore transmission assets within the offshore regulatory framework. This includes the approach taken in relation to:
 - Different parties’ roles in identifying and undertaking AI, including for the NETSO and TOs, as well as generators where this could enable beneficial coordinated network configurations; and
 - The funding of AI, including remuneration for the party undertaking the works and the role of user commitment and Transmission Network use of System (TNUoS) charges in ensuring benefits, costs and risks are allocated efficiently.
47. Stakeholders are invited to read the consultation for more detail and feed their views back to Ofgem.

Consenting

48. Throughout the Project, stakeholders raised various planning and consenting issues that may act as a barrier to offshore wind deployment. Four key potential barriers emerged, though some of these are general concerns rather than coordination specific barriers:
 - Consenting for AI;

²³ The Transmission Investment Incentives (TII) framework has provided project-specific, interim funding for critical, large-scale onshore investments the electricity which Transmission Owners (TOs) identify are required to support achievement of the Government’s 2020 renewable energy targets. For all transmission investment projects covered by the TII framework, funding from 1 April 2013 will be addressed under RIIO-T1 through the arrangements for electricity transmission wider works. Funding requests will be subject to the same level of scrutiny but will take place within particular price control periods, allowing essential investment to take place. More information can be found at http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/CriticalInvestments/InvestmentIncentives/Documents1/Nov11_Extension_Decision_Letter.pdf.

- Compulsory purchase and wayleave powers;
- Transferability of consents; and
- Flexibility of consents.

Consenting for anticipatory investment

49. A coordination-specific barrier identified by the Project is the difficulty faced by developers in getting planning consent for transmission infrastructure of an anticipatory nature, examples of which were set out in Section 3.
50. In order to secure consent for associated transmission assets of an anticipatory nature, developers would be likely to need to show that the relevant infrastructure stands a good chance of being used by a future generation project, and that constructing or partly constructing it in advance could either reduce or not add to the overall adverse impacts associated with constructing the assets separately.
51. The procedural routes available to developers seeking consent for anticipatory infrastructure vary depending on the size, nature and location of the development. For English offshore generation projects above 100MW, the Planning Act 2008 allows for a 'one stop shop' approach to consenting, enabling a single application for generation and transmission infrastructure, by including transmission as an associated development to generation. However, the Infrastructure Planning Commission (IPC), which examines applications for nationally significant infrastructure projects, must have regard to guidance issued by the CLG in deciding what constitutes associated development.
52. The existing guidance on associated development states that “[a]ssociated development should not be the aim in itself but should be subordinate to and **necessary for the development and effective operation to its design capacity of the Nationally Significant Infrastructure Project (NSIP) that is the subject of the application**”.²⁴ This drafting has been interpreted by the IPC as ruling out the consenting of transmission infrastructure of an anticipatory nature, as such infrastructure is not strictly necessary for the project which is the subject of the application, but is intended to facilitate future developments. In addition, while the illustrative Annex A to the guidance contains examples of the types of development that may qualify as associated development, it does not currently provide any examples specifically related to offshore electricity transmission infrastructure. Therefore, the guidance as it currently stands does not give the IPC sufficient comfort to give consent to such offshore infrastructure.
53. Government considers that in many cases anticipatory transmission infrastructure is something which ought to be open to consideration by the IPC as associated development under the Planning Act 2008. This should be made possible by amending CLG’s statutory guidance on associated development to make it clear that such developments can be considered to be associated development. CLG will be holding a public discussion on revised guidance in March 2012 as part of its review of the Planning Act 2008 regulations and guidance. CLG expects redrafted guidance to be

²⁴ Paragraph 10 of the guidance, available at <http://www.communities.gov.uk/documents/planningandbuilding/pdf/guidanceassocdevelopment.pdf>.

implemented by summer 2012, and DECC will continue to liaise with CLG on this matter.

54. In relation to Scotland, the Scottish Government is also considering clarifying the issue of anticipatory consenting of transmission assets through guidance.

Compulsory purchase and necessary wayleave powers

55. As well as obtaining the necessary development consents, developers undertaking pre-construction and construction of transmission infrastructure need sufficient private law rights over the land where they install that infrastructure. Where such rights cannot be agreed as part of a commercial negotiation with the relevant owner, developers may wish to apply for the compulsory acquisition of them using the available statutory powers.
56. The Electricity Act 1989 provides, amongst other powers, for the Secretary of State to (i) authorise the compulsory purchase of land required by a licence holder for any purpose connected with its licensed activities (Schedule 3), and (ii) grant a licence holder the necessary wayleaves to install an electric line on, under or over any land (or keep such a line installed), where it is necessary or expedient to do so for any purpose connected with its licensed activities (Schedule 4). These powers are available to transmission licence holders. They are also available to licensed generators to the extent that their licence provides.
57. The standard generation licence conditions state that the Schedule 3 and 4 powers shall have effect to enable the licensee to carry on its authorised activities, including in relation to the installation, maintenance, removal or replacement of electric lines or associated electrical plant connecting a generating station with the GB transmission system. While generators are not required to obtain a generation licence before they are generating, they can do so should they need to access the compulsory purchase and wayleave powers through this mechanism.
58. During the course of the Project some stakeholders raised concerns that the standard generation licence conditions have been amended to limit the scope of the Schedule 3 and 4 powers to connecting lines up to the offshore connection point only, by replacing references to the 'GB transmission system' with the 'NETS' and thereby possibly limiting the powers to the offshore parts of the system only.
59. However, Ofgem has confirmed that the relevant conditions have not been amended in this way, and DECC and Ofgem do not consider that the conditions prevent licensed offshore generator developers, or OFTOs, accessing the compulsory purchase and wayleave powers set out in the Electricity Act 1989 for the offshore or onshore elements of their transmission developments.
60. In addition, where an offshore wind project is the subject of an application for development consent under the Planning Act 2008, the offshore developer can also be granted compulsory purchase or wayleave powers for the offshore or onshore elements of their transmission developments as part of any resulting development consent order, provided the transmission assets concerned are "associated development" for the purposes of that Act.

Transferability of consents

61. Some stakeholders have expressed uncertainty over whether development consents or parts thereof can be transferred from a generator as part of a sale of an offshore generation project. We do not consider this to be a problem. Whether the relevant transmission infrastructure has been consented through the Electricity Act 1989, the marine licensing regime, the town and country planning regime (for onshore elements) or the Planning Act 2008, the default position is that the benefit of the relevant consent runs with the land.
62. Transfer of consents under the Planning Act 2008 is covered by CLG's Model Planning Condition 5²⁵, which provides for the benefit of the Development Consent Order (DCO) to be transferred with the consent of the Secretary of State. There should be no barrier to the transferability of development consents under that Act, provided that the DCO is drafted effectively, and the developer makes clear in submissions to the IPC / Secretary of State the range of possible future transfer scenarios so that these can be properly considered during the examination process and provided for in the final DCO.

Flexibility of consents

63. Some stakeholders have suggested that the development of a coordinated network could be facilitated by allowing more flexibility within the consents, to accommodate later changes. Developers are aware that the 'Rochdale Envelope' approach, in which an application is submitted before all details of a project have been resolved, already allows some flexibility within consents. However, it was felt by some that there is a lack of clarity from the IPC on the degree of flexibility this approach allows (i.e. how much uncertainty is considered acceptable).
64. Our current understanding is that within the constraints imposed by relevant EU environmental legislation, the 'Rochdale Envelope' approach should be sufficient for coordinated network development. We would encourage developers to refer to the guidance issued by the IPC on 'Using the Rochdale Envelope'²⁶, as well as continuing their discussions with the IPC and others on this issue. The Scottish Government intends to issue guidance on the Rochdale envelope in Scotland, as well as transferability of consents, in summer 2012 following consultation.

Risk-reward profile for coordinated investments

65. When considering network connection offers provided by the NETSO for generation projects, a key factor for developers is the balance of risk and reward they would face if they agree to the offer. For developers, these risks and rewards are largely driven by the user commitment liabilities and the subsequent TNUoS charges they would accrue should the connection detailed in the agreement be developed.
66. User commitment arrangements set out generators' liabilities for costs incurred by other parties in developing the transmission assets necessary to connect them to the NETS. The current arrangements could mean that a generation project connecting through a new transmission link that will also benefit future users – i.e. it involves AI - may become

²⁵ <http://www.legislation.gov.uk/ukxi/2009/2265/schedule/1/paragraph/5/made>.

²⁶ <http://infrastructure.independent.gov.uk/wp-content/uploads/2011/02/Advice-note-9.-Rochdale-envelope-web.pdf>.

liable for all the costs even though the benefits will be shared by other users. This is likely to create a barrier to coordination as developers would be reluctant to sign up to connection agreements involving AI even though the transmission developments envisaged may be the most efficient overall outcome.

67. Further there is, at present, a lack of clarity regarding how TNUoS charges will work for coordinated offshore networks given that the current TNUoS charging methodology was set up to deal with radial offshore links. This means that offshore developers cannot reliably predict what charges they would face if they were to accept connection offers that incorporate coordinated elements. They are therefore reluctant to commit to offers that include coordinated elements, particularly where links that would be primarily for onshore network reinforcement would originate from their offshore assets.
68. The more complex, coordinated nature of some offshore transmission projects means that, as is often the case, the methodologies for transmission charging and user commitment need to evolve to ensure that they remain fit for purpose. In most cases, such evolution occurs through the industry code review process, with industry initiating code changes and Ofgem having an approval role.
69. Such a code change proposal is currently underway for user commitment arrangements, where Code Modification Proposal 192 (CMP192) has been submitted by the industry workgroup to Ofgem for approval. The changes proposed as part of CMP192 would reduce the proportion of liability that a generator would have to securitise for works undertaken for the benefit of other users, removing this potential disincentive for coordination. It would also have implications for the level of liabilities accrued for transmission connections more generally, which could have implications for which parties bear the risk of AI.
70. These changes relate to Ofgem's proposals for the approach to AI and are discussed in more detail in Ofgem's accompanying consultation. Ofgem has also published a draft Impact Assessment on the CMP192 changes for consultation.²⁷ This consultation will close in mid-March and a final decision on the CMP192 proposals is expected soon thereafter. Should Ofgem approve the modification, it is proposed that the new regime would take full effect from April 2013. If the proposals are taken forward then NGET will publish a transition plan, and as part of this has indicated that it will provide initial clarification on how the CMP192 proposals would work for coordinated offshore developments.
71. For transmission charging, Ofgem is currently undertaking a Significant Code Review through Project TransmiT, which is a review of the transmission charging regime as a whole. This review is not looking in detail at potential reforms to offshore charging as it relates to coordinated networks, as it is focused on high-level charging principles. However, while it is underway this does mean that there are limits on the ability of industry to launch related code modification proposals. Once Project TransmiT has completed, NGET has signalled that it intends to launch a code modification review focused on amending the offshore charging methodology to cater for more coordinated offshore networks. It published a discussion paper in January setting out possible

²⁷ http://www.ofgem.gov.uk/Licensing/ElecCodes/CUSC/Ias/Documents1/CMP%20192_master_9.pdf.

principles to form the basis of a revised approach.²⁸ With this in mind we expect additional industry-led discussions and a further code modification process will be required to clarify the future charging arrangements and principles for coordinated offshore networks.

72. Government and Ofgem welcome NGET's publication as a continuation of discussions on this issue and encourage the industry to engage in debate on the principles put forward. In addition, the accompanying Ofgem consultation discusses key requirements for the charging regime in order to support the proposed approach to AI while ensuring that consumers' interests are protected.

Regulatory boundaries

73. There are separate regulatory regimes for onshore, offshore and interconnector transmission assets, reflecting the clear distinction between these assets up until the present, as well as the historic evolution of network regulation and the requirements of European legislation. However, going forward, technology developments and the growth in offshore generation mean that a number of different types of development could materialise over the next decade, covering some combination of offshore generation connection, onshore reinforcement and cross-border links.
74. It is important that the different regulatory regimes continue to provide a clear and effective framework to deliver the most economic and efficient network development, including where this involves assets that blur the traditional onshore, offshore and interconnector distinctions.
75. A key part of this is ensuring that the NETSO has an effective role in determining what developments are economic and efficient, discussed above. There may also be a need to provide clarifications or amendments to how the regulatory regimes (covering both transmission and generation) apply for projects in future.
76. Ofgem and DECC will therefore undertake further work over the course of 2012 to consider whether further clarity is needed on the interface between onshore, offshore and interconnector regimes. For potential future connections between offshore generation and interconnectors, issues to be considered include how transmission charging and requirements for interconnection capacity auctioning apply.
77. For potential cross-border projects, there will also need to be clarification of how renewable support mechanisms might apply for generation projects located outside the UK, and vice versa for UK projects that could potentially export some of their generation through interconnectors. The Government is considering the potential enabling powers for renewables trading mechanisms as a contingency against cost and delivery risks of the 2020 renewables target; and work is also being undertaken in this area through the British-Irish Council and the EU-Concerted Action Network on Renewables. DECC expects to publish an update shortly on policy in this area
78. DECC and Ofgem will also continue to engage in the North Seas Countries' Offshore Grid Initiative (NSCOGI) during 2012. This initiative is considering the benefits of more

²⁸ <http://www.nationalgrid.com/NR/rdonlyres/28C89919-815F-4AD9-8ACF-4CC246EA18B6/51330/Finalcoordinatedchargingnote.pdf>.

coordinated grid configurations and regulatory options for combined offshore connections and interconnectors in the North, Irish and Baltic Seas.

Technology and supply chain

79. The TNEI/PPA Energy report undertaken for this Project identified that coordinated configurations for offshore transmission, including combination with international interconnectors, is technically achievable with currently available technology. However, the development of higher capacity cables and multi terminal HVDC links are key to enabling such configurations to be cost effective.
80. Stakeholders have raised three types of issue related to transmission asset design and construction that are relevant for coordinated offshore configurations:
 - Interoperability of HVDC equipment from different vendors;
 - Technology development, including 2GW HVDC cables and multi-ended HVDC links; and
 - Supply chain capacity.

Interoperability of equipment from different vendors

81. Interoperability of equipment will be essential for effective systems integration, particularly regarding protection and control, network management and other system interfaces. Even the simplest radial HVDC configurations must be capable of integrating with the transmission systems they are connected to and being controlled by the host system operator network management systems. More complex configurations will require increasingly complex interface solutions and could involve more than one supplier of equipment.
82. Functional specification standards are not yet adequately developed to ensure that manufacturers deliver compatible equipment. It is in this area, interfaces and communication systems, where there may be the most immediate requirement for standards to be developed. Timely development and application by manufacturers of standard interfaces would reduce the likelihood of early installations becoming obsolete or limiting competition for subsequent additions and extensions. However, this needs to be set against the risk that standardisation too early may result in a sub-optimal solution and discourage ongoing research and further development.
83. There is a high level of international interest in HVDC transmission, and the industry is responding through industry fora and standards development organisations to develop HVDC related standards. Box 1 highlights some of the current initiatives working towards standards for interoperability of equipment produced and other areas of technical development.

Box 1: Examples of ongoing work on HVDC standardisation to support development and interoperability

International Electrotechnical Commission (IEC)
IEC TC115 - Technical Committee 115

The IEC is looking at standardisation in the field of HVDC Transmission technology above 100kV. The task includes HVDC system oriented standards as design aspects, technical requirements, construction and commissioning, reliability and availability, and operation and maintenance. Standards of HVDC equipment so far related to the system aspects will be prepared in close collaboration with the relevant Technical Committees and Subcommittees.

British Standards Institution (BSI);

Electrotechnical Committee PEL/022 HVDC Transmission for voltages above 100kV
eCommittee PEL/022-/22 has the brief under the direction of BSI Technical Committee PEL/22, to develop standards in the field of HVDC transmission for DC voltages above 100 kV. PEL/22-/2 mirrors the work of IEC TC 115

CIGRE: Study Committee B4 Group

- B4-55 Studying the interoperability of equipment provided by different parties. Study period 2010-2013;
- B4-56 Guidelines for the preparation of “connection agreements” or “Grid Codes” for HVDC grids;
- B4-57 Guidelines for the development of models for HVDC converters in an HVDC grid;
- B4-58 Devices for load flow control and methodologies for direct voltage control in a meshed HVDC Grid;
- B4-59 Devices for load flow control and methodologies for direct voltage control in a meshed HVDC Grid;
- B4-60 Designing HVDC Grids for Optimal Reliability and Availability Performance.

84. There is opportunity for sufficient stakeholder engagement through these channels for a balanced approach to timely standardisation to be taken without inhibiting development and commercial opportunity. We expect that the work in progress on development of standards for HVDC systems alongside ongoing orders from developers and international transmission owners will deliver appropriate standards for the medium- to long-term. However, DECC and Ofgem will continue to monitor the industry-led work that is already being progressed in this area, with a view to maintaining confidence that standards will be developed. Should a lack of progress present an ongoing barrier to coordination, DECC and Ofgem will consider promoting the development of a functional specification if there are indications from stakeholders that this is needed.
85. There is also industry discussion related to standardisation in terms of module sizes for converters and transformer capacity with a view to reducing the costs of production, spares holding, maintenance and staff training requirements. The Crown Estate is actively promoting the adoption of standard specifications in terms of component type and rating, to drive down capital costs and lead times as well as reducing ongoing spares holding and skills requirement.

86. Further, as part of the UK Renewable Energy Roadmap, a cost-cutting task force was announced by DECC in July 2011,²⁹ consisting of manufacturers, developers and other stakeholders. It aims to cut the cost of offshore wind energy to £100/MWh by 2020 to enable the planned roll out of offshore wind generation as a viable part of the energy portfolio. Although the Final Report will not be submitted to Ministers until later in spring 2012, it is expected that standardisation to an appropriate level to enable production costs to be reduced, which will also support interoperability of equipment from different suppliers, will be considered as part of its work.

Technology Development

87. The availability of larger capacity links is considered by some stakeholders to be the most immediate potential technology barrier to coordination. Such links are in turn dependent on at least two parallel areas of technology development: voltage source converter (VSC) alternating current (AC) to direct current (DC) converters of higher capacity; and increased submarine cable ratings.
88. VSCs required for HVDC links at 2GW and above are not yet commercially available, and there is no known reference site even at 1GW. The largest delivered or contracted cable to date is at 800MW, with only one agreed order for a 1GW project scheduled for delivery in 2013. The VSC technology is new compared with Current Source Converter (CSC) technology already in use on established DC links. While VSC technology offers great advantages over CSC in terms of power system voltage control and interconnection, at its current stage of development it may also involve higher electrical losses and require more complex control and protection systems than CSC.
89. A capacity of 2GW is currently beyond the range of commercially available submarine power cables. Increasing the capacity of cables requires an increase in either current carrying capacity and/or operating voltage, either of which will almost certainly require the physical size of the cables to increase with further impact on minimum bending radius, maximum cable length without a joint and cable laying capability. Another disadvantage of larger sized circuits of concern is the increased loss of output from a single circuit failure.
90. Manufacturers of this type of cable, of which there are very few in Europe, are raising their cable capacities through a combination of current and voltage increases, but the target currents and voltages are considered commercially sensitive information. The incentive for the supply chain to accelerate its development work in this area may be limited by orders placed for existing ratings being at or close to production capacity. Therefore it is not certain that 2GW capacity cables will be available for commissioning in time for initial phases of TCE Round 3 developments.
91. Further development of coordinated offshore networks and integration with other European networks would be aided by the development of multi-ended HVDC links, allowing three or more points to be connected to an HVDC system, for example a new windfarm being connected into an existing offshore transmission connection or interconnector. For full flexibility this in turn could depend on the availability of HVDC circuit breakers able to rapidly interrupt current flow on the HVDC system in the case of

²⁹ http://www.decc.gov.uk/en/content/cms/news/pn11_81/pn11_81.aspx.

a system fault to disconnect the faulted section and leave the healthy section in service. There is no call for this on point to point systems as interruption can be carried out by established technology on the AC side of the system. The developments in HVDC circuit breaker have been well documented³⁰ over several years, with the technology now understood to be developed to a proof of concept level but not yet commercially available due to a lack of demand to date. At least one manufacturer is openly discussing its prototype design and declaring it will be available in the market for 2015/2016.³¹

92. The control and protection systems are often overlooked requirements but are considered by some stakeholders to be the main issue to resolve. There are discussions (see the ISLES project³²) for development of multi-ended HVDC systems in advance of the commercial availability of HVDC circuit breakers using HVDC switch disconnectors instead. NGET's published coordinated configuration designs assume HVDC circuit breakers are not available, although their availability would bring down costs further.³³ The approach included in NGET proposals and as a solution for the ISLES study is not necessarily a long-term alternative to HVDC circuit breakers on larger or more complex networks.
93. Various mechanisms have been launched by Government and the European Commission to encourage technology development either with the objective of developing offshore wind technology or to enable the Commission's objective of developing a new EU energy infrastructure policy to coordinate and optimise network development on a continental scale. DECC has previously funded transmission asset technology innovation in the past through the Environmental Transformation Fund³⁴.
94. In the UK Renewables Roadmap, published in July 2011, DECC announced funding of up to £30 million, subject to value for money assessments, for offshore wind innovation. DECC expects to fund two schemes under this programme, one of which is the Offshore Wind Component Technologies Development and Demonstration scheme. DECC has provisionally allocated £15 million to this scheme and expects to use that funding to run two calls for proposals. The first call ran in autumn 2011 for innovators to apply for support for the development and demonstration of innovative component technologies across the offshore wind system. With a call budget of around £5 million capital, the funding will help companies with novel ideas that could further improve offshore wind systems. DECC and the Technology Strategy Board are working together on this scheme. The first call is funded and managed by DECC but the Technology Strategy Board is participating in the appraisal process. DECC plans to launch the second call in spring 2012.
95. More broadly across the electricity and gas sectors, network companies will play an important role in facilitating the move to a low carbon economy. To do so will require

³⁰ Multiple references, summary at http://ieeexplore.ieee.org/xpl/freeabs_all.jsp?arnumber=5686894 and http://ieeexplore.ieee.org/xpl/freeabs_all.jsp?arnumber=4112552.

³¹ September 2011 CIGRE presentation, [http://www05.abb.com/global/scot/scot221.nsf/veritydisplay/f024bf4c6291931dc125790d00415992/\\$file/0264_BOL_OGNA_2011.pdf](http://www05.abb.com/global/scot/scot221.nsf/veritydisplay/f024bf4c6291931dc125790d00415992/$file/0264_BOL_OGNA_2011.pdf).

³² Irish-Scottish Links on Energy Study. See <http://www.scotland.gov.uk/Resource/Doc/175776/0116740.pdf>.
³³ <http://www.nationalgrid.com/NR/rdonlyres/4FBE15A0-B244-4BEF-87DC-8D0B7D792EAE/49346/Part1MainBodysection191.pdf> (para 3.24).

³⁴ http://www.decc.gov.uk/en/content/cms/funding/funding_ops/innovation/historic/wind_demo/wind_demo.aspx.

innovation to address issues such as connection of increasing volumes of intermittent generation and renewable energy sources. To encourage this level of innovation, Ofgem is introducing a package of measures called the Innovation Stimulus as part of the new RIIO framework. The Innovation Stimulus will include a Network Innovation Competition (NIC), which is an annual competition where network companies compete for funding for research, development and trialling of new technology, operating and commercial arrangements. Ofgem has recently published a consultation inviting views on whether access to the NIC could be extended to other parties, including licensed OFTOs.³⁵

96. Significant amounts of technology innovation funding are available from the European Union. For example, in December 2009, Scottish Hydro Electric Transmission Ltd (SHETL), one of two Scottish transmission owners, was selected for a 50% grant from the European Commission, under the European Energy Programme for Recovery (EPR). The grant provides up to €74.1million toward the incremental costs of an offshore hub in the Moray Firth, which was originally proposed as part of its design for the proposed link to Shetland and which now forms part of SHETL's overall strategy for reinforcing the network in North East Scotland.
97. Looking ahead, on 29 June 2011, the European Commission adopted the Communication *A Budget for Europe 2020* on the next multi-annual financial framework (2014-2020), which proposes the creation of a Connecting Europe Facility to promote the completion of priority energy, transport and digital infrastructures with a single fund of €40 billion, out of which €9.1 billion are dedicated to energy.³⁶

Supply chain capacity

98. The supply chain for key components for offshore transmission (submarine cables, HVDC converters, HVDC circuit breakers, and protection and control systems for multi-ended and inter-system links) is currently highly concentrated. Development, production and delivery lead times are between three and five years with the current level of offshore activity, and the availability of offshore contractors able to install and commission platforms and submarine cable routes may also be expected to become a constraint.
99. DECC has committed to developing the supply chain, by providing up to £60million for the development of wind manufacturing facilities at ports and working with high-value added manufacturers to exploit supply chain opportunities.

³⁵ More information about the Innovation Stimulus is available at <http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decisionbusplan.pdf>, and the consultation on the design of the Network Innovation Competition at <http://www.ofgem.gov.uk/Networks/nic/Pages/nic.aspx>.

³⁶ <http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:52011PC0658:EN:NOT>.

5. Next steps

100. This report marks the close of the joint DECC and Ofgem Offshore Transmission Coordination Project, with Ofgem taking forward the implementation of a number of the measures set out in this report through the accompanying consultation document. A number of other measures are being taken forward by different parties. Table 2 summarises the responsible parties and next steps for implementing the measures set out in Section 4.

Table 2: Summary of next steps

BARRIER	MEASURE	ORGANISATION	TIMING
Planning an efficient and economic network	Enhancing NETSO role in connection offer process	Ofgem	Accompanying consultation
	Improvements to network documents.	Ofgem	Accompanying consultation
Anticipatory investment	Consultation on potential 'straw-man' for an approach to AI within the offshore transmission regime	Ofgem	Accompanying consultation
Consenting	Anticipatory consenting	CLG	During 2012
Risk-reward profile	Development of offshore charging	NGET, industry	Discussion paper published in January 2012
	Decision on proposed user commitment rule changes	Ofgem	Consultation open; changes proposed to take effect from April 2013
Regulatory boundaries	Clarification of regulatory interfaces as necessary	Ofgem/DECC	During 2012
	Engagement with NSCOGI	DECC/Ofgem	During 2012
Technology	Monitor progress on production of standards for interoperability	DECC/Ofgem	Ongoing
	Consider proposals for funding innovation	DECC	During 2012
	Consider proposals for easing the supply chain	DECC	During 2012

Annex 1: TNEI/PPA Energy findings

Objective

For the Offshore Transmission Coordination Project, Ofgem commissioned TNEI/PPA Energy to carry out a technical analysis of a range of potential transmission configurations for connecting TCE Round 3 offshore wind generation to the NETS.³⁷ Analysis primarily considered the capex cost savings of a range of offshore transmission configurations, each representing a different level of coordination. However, consideration was also given to cost savings associated with avoided reinforcement of the NETS and the inclusion of possible interconnectors with neighbouring European countries.

The analysis of alternative transmission configurations was undertaken through three distinct models:

- Generic model – transmission network configurations were designed for two highly stylised offshore windfarm developments to help identify the key drivers of cost savings associated with different configurations;
- TCE Round 3 zonal model – different transmission network configurations were assessed, independent of national generation levels, to uncover the key drivers of cost savings in individual TCE Round 3 zones; and
- National scenarios model - different national transmission configurations were assessed against 4 different national renewable generation levels to assess aggregate cost savings associated with a coordinated transmission network.

To ensure consistency wherever possible, the analysis undertaken draws on assumptions and perspectives presented in NGET's ODIS, while reviewing their validity and robustness.

All three models, as detailed above, assume perfect foresight and the optimisation of transmission network design considers:

- The location and capacity ranges of the offshore wind resources;
- Possible onshore network connection points;
- Timing of project developments, connection requirements, network reinforcements, onshore generation;
- The characteristics and readiness of network technology; and
- The required level of system reliability and security of supply (SQSS).

³⁷ Full report available at <http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=2&refer=Networks/offtrans/pdc/pwg/OTCP/reports>.

Generic network analysis

Generic network analysis was undertaken to identify the key drivers of cost savings associated with different transmission network configurations. The optimisation of transmission network design considers:

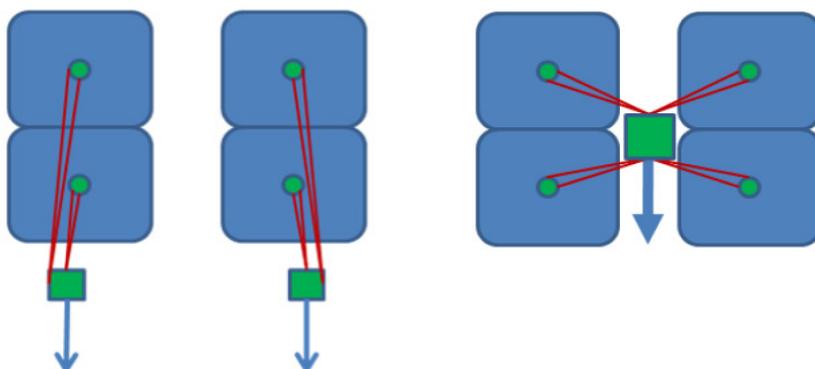
- Generator benefits from additional network resilience, i.e. the avoidance of single points of failure;
- Appropriate phasing of transmission construction alongside generation build-out;
- Benefits from an increase in onshore boundary capabilities;
- Benefits and risks of new technology developments, i.e. higher HVDC link ratings;
- The type and level of AI required;
- Benefits of combining windfarm transmission assets and interconnectors; and
- Impact of the physical layout of the windfarm on capex cost savings.

Methodology

The generic model primarily focuses on 2GW windfarms but also includes analysis of a 4GW windfarm. The model assumes that offshore generation is built-out in 1GW stages, each comprising 2x500MW windfarms. The construction of transmission assets in financially independent 1GW stages reflects both technology constraints and financial limitations.

The generic model considered 5 different transmission network configurations, including a 'radial' base case design and 4 alternative 'coordinated' designs. In order to assess dependencies between the physical layout of the windfarm and the level of capex savings associated with individual transmission configurations, the generic model considers both a 'box layout' and a 'flat layout'.

Figure 1: Illustrative example of a 'radial' and 2GW 'coordinated' configuration for a 'box layout' windfarm



Key findings

Analysis suggested that:

- Some coordinated network solutions risk the construction of stranded transmission assets if the windfarm is not fully built-out;
- Coordinated network solutions can provide additional system security once the windfarm is fully built-out, but may lead to reduced system security during the phased build-out;
- 2GW HVDC technology may result in significant capex savings but is also associated with higher stranding risks, a reduced level of system security during the build-out of the offshore windfarm, and issues surrounding the readiness of 2GW technology;
- The physical layout of the windfarm will not necessarily have a significant effect on the overall transmission capex;
- The development sequence of the individual 500MW windfarm blocks should be coordinated to ensure efficient transmission investment and avoid excessive cable lengths which have a significant impact on the capex; and
- The benefits of onshore boundary reinforcement can depend on the wider works otherwise required for reinforcement and any future option value that those works may provide.

Most importantly, due to cost estimation certainty at this level of concept engineering, the generic analysis does not suggest a relevant differentiation between the different network designs on a total capex basis. (Analysis estimated that coordinated solutions provide capex savings, from the base case, of between -5% and +14% for flat layout and between -1% and +15% for the box layout.) Therefore greater importance should be given to other value drivers such as level of energy availability from the developer perspective, the type and level of AI required, and the overall deliverability of the development (particularly for the onshore elements). In summary, the optimal transmission network design depends on the overall view of risk and benefit of the relevant stakeholders.

Interconnectors

A coordinated transmission configuration could have significant potential capex saving when interconnector capacity is small relative to the windfarm, or if the windfarm avoids investing in further transmission export links. However, the extent to which these benefits can be captured may be dependent on:

- Sufficient offshore network integration within the windfarm such that the windfarm export links can be used in parallel to the interconnector;

- The implementation of trading strategies which manage and minimise anticipated power flow constraints, and therefore reduce operational risk for both interconnector and OTFO; and
- Undertaking early decisions on technology (compatibility) and AI to preserve future opportunities for interconnection.

TCE Round 3 zonal model

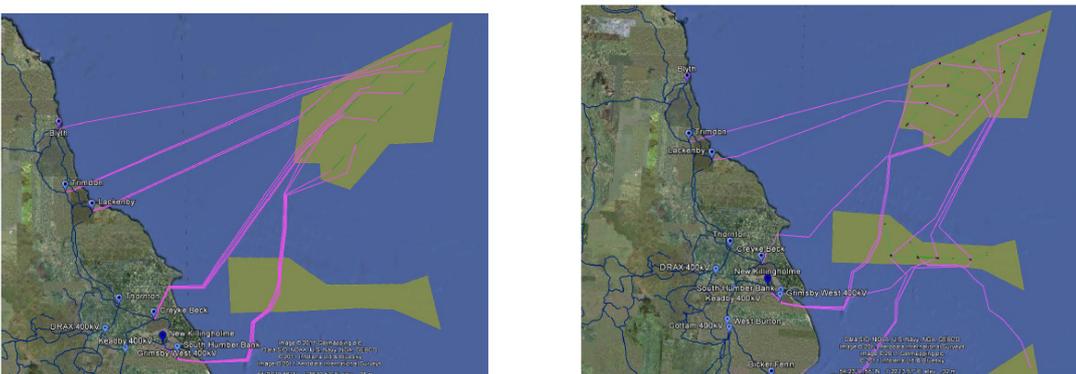
This model tests the theory developed in the generic model by analysing different transmission network configurations when developed for use in actual TCE Round 3 zones. The model assesses each TCE Round 3 zone individually, and independent of national renewable targets, to uncover the key drivers behind capex cost savings associated with different transmission configurations.

The report assesses options for the following TCE Round 3 zones: Moray Firth; Firth of Forth; Dogger Bank; Hornsea; East Anglia; Hastings; West of Isle of Wight; Bristol Channel; and the Irish Sea.

Methodology

TCE Round 3 zonal analysis assumes full zone build-out up to 2030, while maintaining the realistic assumption of phased developments. The model primarily tested two transmission configurations: ‘radial’ and ‘coordinated’. Sensitivity analysis was also conducted to identify cost savings attributable to offshore reinforcement of the onshore network and to the availability of 2GW HVDC technology.

Figure 2: Illustrative example – Dogger Bank under a ‘radial’ solution and Dogger Bank & Hornsea under a ‘coordinated’ solution



Key findings

TCE Round 3 zonal analysis suggests that the benefits and costs associated with the development of a coordinated offshore transmission network are zone-specific. For example, analysis suggested that:

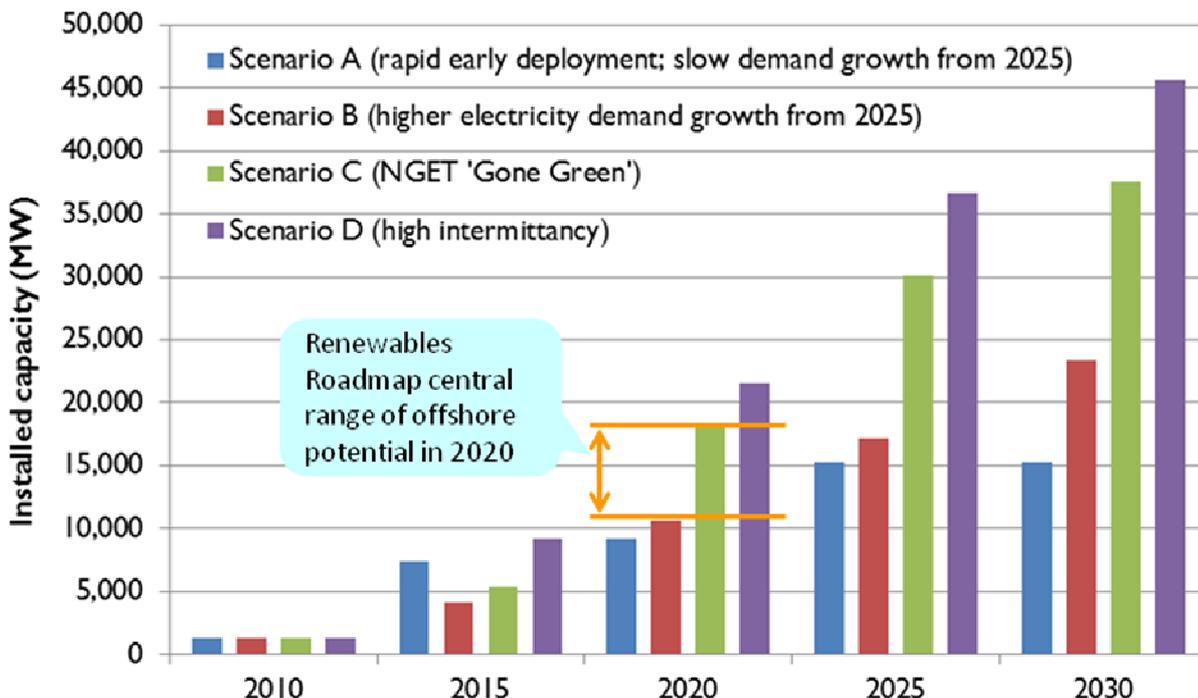
- For the Hastings zone (0.6GW), a radial approach is likely to remain optimal;

- For both the Firth of Forth and East Anglia zones there may be no practical financial benefits to differentiate the radial and coordinated configurations, however, the two options may offer different non-technical advantages; and
- A coordinated approach to network development across Dogger Bank and Hornsea Zones could result in a 16% cost saving when compared to a radial configuration, assuming 2GW HVDC technology is available. However, if 2GW technology is not available, a coordinated approach may incur greater capex costs than a radial approach.

National scenarios modelling

This model aims to assess the impact of 4 different scenarios for national renewable energy generation on the aggregate benefits of developing of a coordinated offshore transmission network. For each scenario, TNEI/PPA Energy developed an associated offshore generation build-out scenario.

Figure 3: The four offshore generation scenarios used for the Coordination Project



Sources: DECC, ODIS, Redpoint

Scenario A represents a case whereby there is an early start to offshore wind development, with more than 7GW of capacity installed by 2015. Installation rates are then assumed to decrease, with an installed capacity of 9GW in 2020. Capacity in 2025 is assumed to be 16GW, 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 rate thereafter, with assumed capacities in 2020, 2025 and 2030 of 12GW, 20GW and 28GW 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 9GW, 23GW, 39GW and 49GW respectively.

To provide context, particularly on Scenarios A and B, Government’s Renewables Roadmap has a central range of 11-18GW of offshore wind in 2020.

Data from the TCE Round 3 zonal model formed the basis for the cost build-ups in this model.

Key findings

Analysis suggests that potential savings from developing a coordinated network could be most significant under the most ambitious offshore generation build-out scenarios. However, the difference in capex cost between most of the transmission options is expected to be relatively small when compared with the overall costs of the offshore generation development.

The generation build-out scenarios, construction timelines and underlying capex capital costs developed in this model fed into a cost–benefit analysis undertaken for the regulatory and commercial policy workstream by Redpoint Energy. That analysis provides a Net Present Value analysis which incorporates both operational expenditure (opex) and capex estimates, see Figure 4.

Figure 4 – Summary of NPV analysis from Regulatory and Commercial Policy workstream

	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

The national scenarios model also highlights several additional factors which, although not quantified, may significantly affect estimated capex savings resulting from a coordinated offshore network. These include:

- Greater complexity/delays in the consenting process;
- The accessibility of suitable shoreline landing points, problems in reopening corridors and environmental impact of larger building works;
- The timing alignment of transmission and generation projects; and
- The ability to deliver the project in terms of technology and the supply chain.

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