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REGULATION OF OFFSHORE ELECTRICITY TRANSMISSION

A joint consultation by DTI/Ofgem



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We champion UK business at home and abroad. We invest heavily in world-class science and technology. We protect the rights of working people and consumers. And we stand up for fair and open markets in the UK, Europe and the world.



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Why are DTI / Ofgem conducting this consultation?

The development of an offshore electricity transmission system will be necessary to meet the requirements of new offshore electricity generation stations which are important to reducing carbon dioxide emissions and the Government's renewable energy targets. This preliminary consultation seeks views on a range of high-level options for the regulation of offshore electricity transmission. These views will be taken into account in establishing the broad regulatory approach with a further consultation on the detailed workings of any regime in early 2006.

- Issued on: 27 July 2005
- Respond by: 19 October 2005

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Executive Summary

This document consults on a range of options for the regulation of offshore electricity transmission. The development of offshore transmission will be necessary to meet the requirements of new offshore wind electricity generation stations. These wind generation projects are important to the Government's renewable energy targets and will be supported by its Renewable Obligation (RO).

The Energy Act 2004 provides powers for the Secretary of State for Trade and Industry to put in place new regulatory arrangements for offshore electricity transmission. Once these arrangements are in place it will be for the Office of Gas and Electricity Markets (Ofgem) to administer, and if necessary modify, these regulatory arrangements so that they remain fit for purpose. This is a joint consultation undertaken by the Department of Trade and Industry (DTI) and Ofgem.

At present 3.6 per cent of the UK's electricity supply comes from all renewable sources, 3.1 per cent from RO eligible renewables. In the Energy White Paper the Government set a target of increasing this to 10 per cent by 2010 and has an aspiration to achieve 20 per cent by 2020. It is envisaged by Government that wind energy will make the main contribution, with substantial increases from both onshore and offshore wind expected to provide roughly equal amounts.

The Government is therefore committed to ensuring an appropriate framework for offshore wind energy development that will ensure its energy policy objectives are met – including an appropriate approach to the regulation of offshore electricity transmission.

This consultation paper discusses what regulatory arrangements will be appropriate for offshore electricity transmission. Ofgem's present view is that unless significant information emerges during this consultation process, the same broad principles would apply to the regulation of both onshore and offshore electricity transmission. The onshore approach reflects the importance of both competition and cost reflective transmission charging.

This consultation paper is an important step in the process that the Secretary of State will go through in establishing a regulatory regime for offshore electricity transmission. Responses will be carefully taken into account in determining the broad approach to the regulation of offshore electricity transmission.

Questions for Consultation

This document discusses options for the regulation of offshore electricity transmission. Views are invited on any aspect of the issues raised in this consultation and in particular on:

 The implications for the regulation of offshore electricity transmission of the regulatory precedents described in chapter 3.

Views are also sought on the issues raised in chapter 4 (on the economics of offshore transmission and generation):

- The economics of offshore transmission assets and the scope for the provision of these assets through a competitive process;
- The estimates of capital costs of £1.1 million to £1.3 million per MW and the higher estimates of £1.5 million mentioned in paragraph 4.14 and whether respondents have evidence of either lower or higher costs;
- 4. The scope for learning efficiencies to reduce these costs and the extent and timing of any such reductions;
- The estimates of operating costs of £10/MWh to £15/MWh;
- The likely levels of revenues for offshore wind electricity and the impact of the market factors described above;

- The appropriateness of the other assumptions on project life (15 years), load factors (35 per cent) and discount factors (12 per cent) underlying the present value analysis; and
- 8. The overall conclusions that at this stage there remains some ambiguity about the economics of offshore electricity transmission and generation.

In addition views are sought on the issues raised in chapter 5 (on the regulatory options for offshore electricity transmission):

- Whether the main options for regulating offshore electricity transmission are a licensed price control approach or a licensed merchant approach;
- The advantages and disadvantages of a price control approach, cost reflective charging, some degree of charge capping and cross-subsidy for offshore wind generators and a licensed merchant approach;
- The approach that should be adopted to regulating offshore electricity transmission and the reasons that this approach should be adopted; and
- 12. What role if any should there be for a tender process in granting licences for offshore electricity transmission.

1. Introduction

Purpose of this document

- 1.1. This document consults on a range of options for the regulation of offshore electricity transmission. The development of offshore transmission will be necessary to meet the requirements of new offshore wind electricity generation stations. These wind generation projects are important to the Government's renewable energy targets and will be supported by its RO.
- 1.2. The Energy Act 2004 provides powers for the Secretary of State for Trade and Industry to put in place new regulatory arrangements for offshore electricity transmission. Once these arrangements are in place it will be for Ofgem to administer, and if necessary modify, these regulatory arrangements so that they remain fit for purpose. This is a joint consultation undertaken by DTI and Ofgem.
- 1.3. The regulatory framework for offshore electricity transmission will need to be sufficiently robust and flexible to adapt to developments in transmission or generation activities offshore. It will also need to be consistent with relevant domestic and European Union (EU) legislation.

Government policy

- 1.4. In 2001 the UK Government signed the Kyoto Protocol and has a legally binding target to reduce greenhouse gas emissions to 12.5 per cent below 1990 levels during the period 2008 to 2012. The Government's Climate Change Programme seeks to go further by reducing emissions to 20 per cent below 1990 levels by 2010.
- 1.5. The 2003 Energy White Paper set out the Government's four goals for energy policy. The Government believes that these four policy objectives are in the broad interests of current and future consumers. These goals are to:
 - put the UK on a path to cut carbon dioxide emissions – the main contributor to global warming – by 60 per cent by 2050, as recommended by the Royal Commission on Environmental Pollution, with real progress by 2020;
 - maintain the reliability of energy supplies;
 - promote competitive markets in the UK and beyond, helping to raise the rate of sustainable economic growth and to improve productivity; and
 - ensure that every home is adequately and affordably heated.
- 1.6. The Energy White Paper set a target of increasing the amount of electricity supplied from renewable sources to

10 per cent by 2010, with an aspiration to achieve 20 per cent by 2020. It was envisaged that this target would be met by contributions from renewable technologies located both onshore and offshore.

- 1.7. The Government's primary mechanism for supporting and promoting renewable energy is the RO. The RO was established by the Renewables Obligation Order 2002 and the Renewables Obligation (Scotland) Order 2002, both of which came into effect on 1 April 2002. It is now governed by the Renewables Obligation Order 2005 and the Renewables Obligation (Scotland) Order. The RO is a market-based mechanism that will be in place until 2027 and which aims to ensure that electricity supply companies source a percentage of their electricity sales (increasing each year until 2015 when it will be set at 15.4%) from eligible renewable sources. The RO provides significant financial support to renewable electricity generation, including offshore wind generation.
- 1.8. In November 2002 the DTI published a consultation paper, 'Future Offshore: A Strategic Framework for the Offshore Wind Industry'. This consultation paper highlighted the very large potential of offshore wind resources around GB and proposed a strategic planning framework to assist in the development of these wind resources. Given the scale of the potential resources and the size of the wind generating schemes that have been proposed for these new strategic sites, it will be necessary to construct high voltage transmission links to bring the electricity onshore where it can be used by final consumers.

Energy Act 2004

- 1.9. Following the DTI's November 2002 consultation and the Energy White Paper, the Energy Act 2004 introduced a legislative framework to permit the development of a new regulatory regime for offshore electricity transmission. The Energy Act also provides for the licensing of offshore distribution, however, given that the focus of this document is on the high level regulatory framework, this issue will be addressed at a later stage. It provides the Secretary of State with broad enabling powers, including the power to modify the conditions of transmission licences and any associated codes and agreements where he considers it appropriate to do so for purposes connected with offshore transmission¹. In doing so the Secretary of State must have regard to the same statutory objectives and general duties that guide Ofgem in regulating the electricity industry onshore.
- 1.10. This consultation paper is an important step in the process that the Secretary of State will go through in establishing a regulatory regime for offshore electricity transmission. Responses will be carefully taken into account in determining the broad approach to the regulation of offshore electricity transmission.

Ofgem policy

1.11. In discharging its principal objective and general statutory duties Ofgem has developed a broad approach that involves encouraging competition and only regulating where this is not

¹Section 90 of the Energy Act 2004

practicable. Regulation is necessary where there is natural monopoly, and in such cases Ofgem has put in place price controls to protect the interests of consumers and encourage the efficient operation of onshore distribution and transmission networks. These arrangements include obligations on the transmission System Operator (SO) to ensure charges to its customers reflect costs.

- 1.12. This consultation paper discusses what regulatory arrangements will be appropriate for offshore electricity transmission. Ofgem's present view is that unless significant information emerges during this consultation process, the same broad principles would apply to the regulation of both onshore and offshore electricity transmission. The onshore approach reflects the importance of both competition and cost reflective transmission charging.
- 1.13. In exploring any alternative approaches to offshore transmission charging it would be necessary to take into account relevant European law, in particular the requirements of the Internal Market in Electricity Directive and the Renewables Directive.

Outline of chapters

- 1.14. Chapter 2 of this document outlines the legal background to the consultation. It sets out the statutory duties of the Secretary of State and Ofgem; outlines the pertinent sections of the Energy Act 2004; and provides an overview of relevant European law.
- 1.15. Chapter 3 sets out the policy and regulatory context for offshore electricity transmission. It explains the

Government's policy objectives with regard to renewable energy generally and for offshore wind generation specifically. It provides an overview of Ofgem's approach to regulation and outlines a number of regulatory precedents illustrating how Ofgem has interpreted and discharged its statutory obligations in a range of circumstances.

- 1.16. Chapter 4 provides an overview of the economics of offshore wind, referencing a range of available studies and considers the costs and revenues likely to be faced by developers of transmission and wind generation assets offshore. It also seeks views on these estimates.
- 1.17. Chapter 5 sets out various options for the regulation of offshore electricity transmission. It discusses the advantages and disadvantages of both a licensed price control approach and a licensed merchant approach. It also discusses issues relating to charging arrangements and price controls and seeks views on all these matters.
- 1.18. Chapter 6 summarises the key issues on which the views of respondents are sought.
- 1.19. Annex 1 reproduces a letter published by Ofgem on 30 December 2004. This letter is designed to explain to the developers of offshore wind projects Ofgem's initial thinking on the regulation of offshore electricity transmission and provide comfort on the operation of any future price control regime.
- 1.20. Annex 2 reproduces a paper outlining Illustrative Transmission Charges for Offshore Networks.
- 1.21. Annex 3 contains details of the DTI Consultation Code of Practice Criteria.

Consultation timescales

Timetable

- 1.20. An outline timetable for the decisions on the regulation of offshore electricity transmission is set out below:
 - (a) October 19 2005 deadline for responses to this document;
 - (b) December 2005 decision published on the broad approach to the regulation of offshore electricity transmission;
 - (c) End 2006 standard licence conditions finalised; and
 - (d) End 2007 any remaining issues such as establishing possible price control arrangements and changing industry codes and other arrangements finalised.
- 1.21. DTI / Ofgem will look to take forward a number of the more detailed work streams (for instance relating to the development of licence conditions and industry codes) in parallel with this consultation exercise. An open letter explaining the approach to these matters will be published shortly.

How to respond

1.22. This document seeks the views of interested parties on any aspect of the issues discussed in this paper and in particular on the issues summarised in chapter 6. This consultation started on 27 July 2005 and responses should be sent to the address below and be received no later than

19 October 2005.

Mr Richard Daniels Department of Trade and Industry Room 2111 1 Victoria Street, London SW1H 0ET

Tel: 020 7215 0404 Email: offshore.transmission@dti.gsi.gov.uk

- 1.23. If you would like to discuss the issues raised in this document, please contact John Overton (020 7215 6481) or Richard Mellish (020 7215 2600) at DTI or Giles Stevens (020 7901 7082) or Graham Knowles (020 7901 7103) at Ofgem.
- 1.24. DTI / Ofgem will be holding a consultation workshop in London during the consultation period.
- 1.25. Please state if you are responding as an individual or are representing the views of a company or other organisation. If responding on behalf of an organisation, please make it clear who the organisation represents and where applicable, how the views of the members were assembled.

1.26. You may make copies of this document without seeking permission. Further printed copies can be obtained from:

> DTI Publications Orderline ADMAIL 528 London, SW1W 8YT

Tel: 0845 015 0010 Fax: 0845 015 0020 Minicom: 0870 1502 100 Email: publications@dti.gsi.gov.uk Web: www.dti.gov.uk/publications

- 1.27. An electronic version can be found at: http://www.dti.gov.uk/renewables
- 1.28. A DTI Regulatory Impact Assessment (RIA) is available at http://www.dti.gov.uk/renewables
- 1.29. Your response may be made public by the DTI. If you do not want all or part of your response or name made public, please state this clearly in the response. Any confidentiality disclaimer that may be generated by your organisation's IT system or included as a general statement in your fax cover sheet will be taken to apply only to information in your response for which confidentiality has been requested. Information provided in response to this consultation, including personal information, may be subject to publication or disclosure in accordance with the access to information regimes (these are primarily the Freedom of Information Act 2000 (FOIA), the Data Protection Act 1998 (DPA) and the Environmental Information Regulations 2004).
- 1.30. If you want other information that you provide to be treated as confidential. please be aware that, under the FOIA, there is a statutory Code of Practice with which public authorities must comply and which deals, amongst other things, with obligations of confidence. In view of this it would be helpful if you could explain to us why you regard the information you have provided as confidential. If we receive a request for disclosure of the information we will take full account of your explanation, but we cannot give an assurance that confidentiality can be maintained in all circumstances. An automatic confidentiality disclaimer generated by your IT system will not, of itself, be regarded as binding on the Department.
- 1.31. The Department will process your personal data in accordance with the DPA and in the majority of circumstances this will mean that your personal data will not be disclosed to third parties
- 1.32. If you have comments or complaints about the way this consultation has been conducted, these should be sent to:

Nick Van Benschoten Consultation Co-ordinator DTI 1 Victoria Street London, SW1H 0ET

Tel: 020 7215 6206 Fax: 020 7215 0534 Email: nick.vanbenschoten@dti.gsi.gov.uk

1.33. A copy of the DTI Code of Consultation Practice is at Annex 3.

2. The legal framework

2.1. This chapter provides a summary of the domestic legislation and European Directives applicable to offshore electricity transmission. The regulatory framework for offshore electricity transmission will need to be consistent with both these parts of the legal framework.

Domestic legislation

2.2. Ofgem is the office which supports the Gas and Electricity Markets Authority (the Authority). The Secretary of State and the Authority exercise certain powers and functions in relation to the regulation of the electricity industry which are set out in the Electricity Act 1989, the Utilities Act 2000 and the Energy Act 2004. These powers and functions are generally governed by the principal objective and general duties set out in section 3A of the Electricity Act. The Authority also has powers under the Competition Act 1998.

Electricity Act – principal objective and general duties

2.3. The Secretary of State and the Authoritys' principal objective in carrying out their respective functions under Part 1 of the Electricity Act and certain functions under the Energy Act is 'to protect the interests of consumers [including future consumers] ... wherever appropriate by promoting effective competition.'

- 2.4. The Secretary of State and the Authority are required to carry out their functions in a manner best calculated to further the principal objective, having regard to the following:
 - the need to secure that all reasonable demands for electricity are met; and
 - the need to secure that licence holders are able to finance their licensable activities².

The Secretary of State and the Authority must also have regard to the interests of individuals who are disabled or chronically sick, those of pensionable age, those with low incomes and those residing in rural areas.

- 2.5. Subject to the above, the Secretary of State and the Authority are also required to carry out their functions in a manner which they consider is best calculated to:
 - Promote efficiency and economy on the part of persons authorised by licences or exemptions to distribute, supply or participate in the transmission of electricity;
 - Protect the public from dangers arising from licensable activities;
 - Secure a diverse and viable long-term energy supply; and
 - Contribute to the achievement of sustainable development³.

²Section 3A(2) of the Electricity Act 1989

³Section 3A(5) of the Electricity Act 1989

- 2.6. They must also have regard to the effect on the environment of licensable activities. The Authority must also have regard to guidance issued by the Secretary of State on social and environmental matters. The Secretary of State's most recent guidance, issued in February 2004 states that:
 - The Government expects the Authority to facilitate the achievement of the social and environmental targets set out in the White Paper.
 - The Government expects the Authority to consider how it can help achieve the carbon dioxide emissions target whilst continuing to protect the interests of consumers. In doing so the Authority will also need to take into account the Government's belief that investment in renewables, although they may be more costly in the short term, is needed now in order to meet our longer term carbon targets.
 - The Government believes that the achievement of its objectives may be dependent on a radical transformation of the energy system to one that is more diverse with a greater mix of energy, especially electricity sources and technologies, and greater diversity both in supply and the control and management of demand. This is likely to require new electricity generation in widely dispersed parts of the country, including offshore. The Government does not seek to be prescriptive in the way these changes are achieved, believing that within the broad context of policy set by the

White Paper the market is best placed to deliver cost effectively the outcomes that are sought.

- If at any point, the Authority foresees any actual or potential difficulties in reconciling the energy policy goals and targets set out in this Guidance with their own regulatory responsibilities or policies then the Government encourages the Authority to seek early dialogue and discussion on these issues.
- Where the Government wishes to implement specific social or environmental measures which would have significant financial implications for consumers or for the regulated companies, these will be implemented by Ministers, rather than the Authority by means of specific primary legislation or secondary legislation. The Government does not seek to do this through this guidance.
- 2.7. Under section 3A(5A) of the Electricity Act (as introduced by the Energy Act) the Secretary of State and the Authority are required to have regard to the principles of best regulatory practice in carrying out their functions under the Electricity Act. This duty requires the Secretary of State and the Authority to have regard to the principles under which regulatory activities should be transparent, accountable, proportionate, consistent, targeted only at cases in which action is needed, and any other principles which appear to the Secretary of State or the Authority to represent best regulatory practice.

Electricity Act - licensing

- 2.8. The Electricity Act provides the statutory framework for transmission licensing. Licences provide the primary means by which Ofgem regulates electricity transmission.
- 2.9. The Electricity Act prohibits a person from participating in the transmission of electricity without a licence or a specific exemption granted by the Secretary of State⁴. This prohibition currently applies in Great Britain and the territorial sea adjacent to Great Britain (the prohibition extends to 12 miles offshore).
- 2.10. Any exemption will be granted by the Secretary of State by way of an Order and may apply to either a specific person or a class of persons. The Secretary of State may grant any exemption subject to conditions.
- 2.11. A person participates in the transmission of electricity if they:
 - (a) co-ordinate and direct the flow of electricity onto and over a transmission system; or
 - (b) make available for use for the purposes of transmission anything which forms part of the transmission system⁵.
- 2.12. The activities described in paragraph (a) above are commonly referred to as SO activities and the activities described in paragraph (b) above are commonly referred to as Transmission Owner (TO) activities.

- 2.13. Electricity transmission licences are granted under the Electricity Act⁶ by the Authority and are subject to both standard licence conditions and conditions particular to an individual licence, known as special conditions.
- 2.14. A transmission licence containing the same standard conditions will be granted regardless of whether the person is carrying out SO activities or TO activities. However, the SO standard licence conditions or the TO standard licence conditions will be switched on or off in the particular licence to reflect the activities which the licence holder is undertaking.
- 2.15. The standard conditions of a transmission licence include a requirement for all transmission licence holders to be a party to the System Operator – Transmission Operator Code (STC), an obligation on the SO to have in place a Balancing and Settlement Code (BSC), a Connection and Use of System Code (CUSC), a Grid Code and certain other codes and agreements.
- 2.16. The special conditions of a TO licence typically include a price control licence condition.

Energy Act 2004

2.17. The relevant sections of the Energy Act (90, 91, 92 and 180) will provide enabling powers for the Secretary of State to establish a regulatory framework for offshore electricity transmission. They do not prescribe the form of this regulatory framework.

⁴Section 4 of the Electricity Act 1989

- 2.18. The relevant sections of the Energy Act have not yet been commenced. It is the DTI's intention to commence them at the appropriate time after the detailed consultation on the proposed licence conditions and codes, and arrangements for issue of licences has been completed.
- 2.19. These sections provide for a prohibition on persons participating in transmission activities without a licence (or exemption) in Great Britain, the territorial sea adjacent to Great Britain and any designated Renewable Energy Zone (REZ). They will also provide the Secretary of State with the power to modify the conditions of transmission licences for purposes connected with offshore transmission, subject to the principal objective and general duties set out in the Electricity Act.

Defining transmission

2.20. For the purposes of the Electricity Act⁷, a transmission system is one which consists wholly or mainly of high voltage lines. The Energy Act will amend the definition of a high voltage line so as to also include an electrical line connecting an offshore generating station to an onshore network. Such electrical lines will be high voltage lines for the purposes of the Electricity Act at a nominal voltage of 132kV or more.

Modifications of licence conditions and industry codes

2.21. The Energy Act⁸ will provide the Secretary of State with the power to modify the standard conditions of transmission licences and any associated codes and agreements, where he considers it appropriate to do so for purposes connected with offshore transmission. The Secretary of State has also been provided with the power to make consequential and incidental changes to the special conditions of a transmission licence.

Extending the remit of the Great Britain System Operator (GBSO) to offshore areas

2.22. The Secretary of State will have the power to modify the terms of the GBSO transmission licence so as to extend it to offshore waters⁹.

Granting of offshore transmission operator licences

2.23. The Energy Act¹⁰ will enable (rather than require) the granting of offshore TO licences by way of a tender process. Such licences may also be granted by way of an application process.

Competition Act 1998

- 2.24. The Competition Act will apply within Great Britain, the territorial sea adjacent to Great Britain and any designated REZ. The Authority has concurrent powers with the Office of Fair Trading (OFT) under the Competition Act to investigate and take enforcement action in relation to suspected infringements of UK and European Community (EC) competition law.
- 2.25. Under the Competition Act, the Authority and OFT can apply and enforce Chapter I and Chapter II prohibitions.

⁷Section 180 of the Energy Act 2004

⁸ Section 90 of the Energy Act 2004

⁹Section 91 of the Energy Act 2004 ¹⁰Section 92 of the Energy Act 2004

Chapter I prohibits agreements between undertakings, decisions by associations of undertakings and concerted practices which may affect trade within the United Kingdom that have as their object or effect the restriction, distortion or prevention of competition. Chapter II prohibits conduct by one or more undertakings which amounts to abuse of a dominant position in a relevant market if it may affect trade within the United Kingdom.

European law

2.26. The regulatory regime for offshore electricity transmission will also need to be consistent with European law. Of particular relevance will be the requirements of the EU Directive 2003/54/EC Concerning Common Rules for the Internal Market in Electricity (IMED) and the EU Directive 2001/77/EC on the promotion of electricity produced from renewable energy sources in the internal electricity market (Renewables Directive).

IMED

2.27. The IMED includes requirements relating to transmission third party access, balancing services, dispute resolution, system operation and technical rules.

Third party access

2.28. Third party access to a transmission system has to be offered where spare capacity is available¹¹. That third party access must be based upon published tariffs for connection and access to the transmission system, with the tariffs (or the methodologies underlying their calculation) requiring prior approval by a regulatory authority. These tariffs (or tariff methodologies) must be objective and non-discriminatory.

Balancing services

2.29. Transmission SOs are required to have rules for balancing services that are objective, transparent and nondiscriminatory¹². The IMED also requires balancing services to be based upon published terms and conditions, with the terms and conditions (or the methodologies underlying their calculation) requiring prior approval by a regulatory authority. The terms and conditions must be non-discriminatory and cost-reflective.

Dispute resolution

2.30. The regulatory authority is required to act as a dispute resolution body in relation to complaints by any party against a transmission operator with respect to the terms and conditions for connection, access and balancing services¹³.

Transmission system operation

2.31. The IMED requires the designation of one or more transmission SOs¹⁴. The transmission SO will be responsible for operating and developing the transmission system. The transmission SO is also responsible for ensuring the long-term ability of the transmission system to meet reasonable demands for the transmission of electricity.

¹² Article 11(7) of the IMED

¹¹ Article 20 of the IMED

2.32. Where a transmission SO is part of an undertaking which is performing transmission and generation activities, the transmission SO must be independent in its legal form, organisation and decision making from the generation activities.

Technical rules

2.33. The IMED requires the development of technical safety criteria and technical rules establishing minimum technical design and operational requirements for connecting generating stations to the transmission system¹⁵. The technical rules must be objective, nondiscriminatory and made public.

Renewables Directive

2.34. The Renewables Directive contains provisions relating to transmission network access and charging.

Access to the transmission network

2.35. Member States are required to ensure that transmission SOs guarantee the transmission of electricity produced from renewable energy sources (subject to maintaining the reliability and safety of the system)¹⁶.

Connection charges

- 2.36. The Renewables Directive requires transmission SOs to:
 - Set up and publish their standard rules relating to the bearing of costs of technical adaptations (such as grid connections and grid reinforcements) which are necessary in order to allow new renewable generators to connect to the transmission system¹⁷. These rules must be based on objective, transparent and nondiscriminatory criteria, taking particular account of all the costs and benefits associated with the connection of these renewable generators. Where appropriate, Member States may require transmission SOs to bear some or all of such costs;¹⁸ and
 - Provide new renewable generators wishing to be connected to the transmission system with a comprehensive and detailed estimate of connection costs¹⁹.

Transmission charging

2.37. Member States are required to ensure that transmission charges do not discriminate against electricity from renewable energy sources²⁰.

 $^{\scriptscriptstyle 15}\mbox{Article}$ 5 of the IMED

- ¹⁶ Article 7(1) of the Renewables Directive
- ¹⁷ Article 7(2) of the Renewables Directive

- ¹⁸ Article 7(3) of the Renewables Directive
- ¹⁹Article 7(4) of the Renewables Directive
- ²⁰ Article 7(6) of the Renewables Directive

3. Government policy and regulatory precedents

3.1. The first part of this chapter outlines the four key goals for energy policy set out in the Government's Energy White Paper 2003. It goes on to explain the importance of renewable energy and offshore wind electricity generation to this policy. The second part of the chapter explains the approach that Ofgem (and its predecessor organisations Ofgas and OFFER) has taken to the regulation of the gas and electricity industries since the privatisation programmes of 1986 and 1989. It also looks forward to the approach to regulation that Ofgem is likely to adopt in the forthcoming review of the transmission price controls for onshore transmission operators.

Government's energy policy and the development of offshore wind

- 3.2. It is for the Government to establish UK energy policy and the legislative framework for utility regulation and for the Government to discharge its powers under the legislative framework. The Government has set a framework for regulation which sets clear objectives for regulation of essential energy services consistent with its wider policy objectives.
- 3.3. This framework seeks to strike the appropriate balance between the interests of consumers and investors, support social cohesion, and balance

short-term consumption with the long-term conservation of resources.

- 3.4. In 2001 the UK Government signed the Kyoto Protocol and has a legally binding target to reduce greenhouse gas emissions to 12.5 per cent below 1990 levels during the period 2008 to 2012. The Government's Climate Change Programme of 2000 seeks to go further by reducing emissions to 20 per cent below 1990 levels by 2010.
- 3.5. In the 2003 Energy White Paper the Government set out its four goals for energy policy. The Government believes that these four policy objectives are in the broad interests of current and future consumers. These goals are to:
 - Put the UK on a path to cut carbon dioxide emissions – the main contributor to global warming – by some 60 per cent by 2050, as recommended by the Royal Commission on Environmental Pollution, with real progress by 2020;
 - Maintain the reliability of energy supplies;
 - Promote competitive markets in the UK and beyond, helping to raise the rate of sustainable economic growth and to improve our productivity; and
 - Ensure that every home is adequately and affordably heated.

- 3.6. The main driving force behind the Government's policy of developing offshore wind is in its potential benefits for climate change and energy security.
- 3.7. At present 3.6 per cent of the UK's electricity supply comes from all renewable sources, 3.1 per cent from RO eligible renewables. In the Energy White Paper the Government set a target of increasing this to 10 per cent by 2010 and has an aspiration to achieve 20 per cent by 2020. It is envisaged by Government that wind energy will make the main contribution, with the majority of new renewable capacity being a combination of onshore and offshore wind, which are expected to provide roughly equal amounts.
- The Energy White Paper also sets out 3.8. the importance of diversity in ensuring a resilient energy system which works well and which recovers quickly if problems occur - in particular, diversity of fuel types and of supply routes – as well as efficient international markets, back-up facilities such as storage, and a robust infrastructure. The Government believes that over-reliance on too few sources and supply routes might leave the UK less able to maintain supplies in the event of price fluctuations and interruptions to supply caused by regulatory or market failure, political instability or conflict or technical problems in the UK or overseas. Renewables and smaller-scale, distributed energy sources contribute towards ensuring diversity which in turn enhances security of supply.
- 3.9. The UK has some of the best wind resources in Europe and the world, in both onshore and offshore locations. The high average wind speeds and reliability should result in more power output and

lower costs. In the UK, offshore wind speeds tend to be higher and there is lower visual impact, making it practicable to build more and larger turbines offshore.

- 3.10. The Government is therefore committed to ensuring an appropriate framework for offshore wind energy development that will ensure its energy policy objectives are met – including an appropriate approach to the regulation of offshore electricity transmission. Statutory guidance from Ministers to Ofgem on social and environmental matters forms an important part of the regulatory framework.
- 3.11. In December 2000 The Crown Estate invited developers to apply for site leases for the development of offshore electricity wind generating stations within territorial waters. This first round of offshore wind development involved relatively small-scale projects, limited to a maximum of 30 turbines per project. Of these Round One (R1) projects, 12 of the 18 have received development consents and two are already generating (North Hoyle and Scroby Sands). Two more (Kentish Flats) and (Barrow) are currently under construction. Due to the relatively small size of these projects, they could be connected to the onshore networks by building links to local distribution systems. Neither of the projects that are generating require distribution or transmission licences.
- 3.12. This first round of offshore development demonstrated the interest of the wind energy industry in offshore development. It also emphasised the need for a strategic planning framework to optimise the exploitation of the potential resource in an appropriate way.

- 3.13. In November 2002 DTI proposed a strategic planning framework in the consultation document *Future Offshore: A Strategic Framework for the Offshore Wind Industry* as a basis for the expansion of the offshore wind electricity generation industry. The document set out the approach the Government intended to take to a range of issues necessary for offshore development in both territorial waters and beyond.
- 3.14. The document proposed that development should take place in three strategic areas: the Greater Wash, the North West and the Thames Estuary. A Strategic Environmental Assessment (SEA) was then commissioned for these three areas. A second licensing round (R2) was held by the Crown Estate which resulted in the letting of sites for 15 wind energy projects (9 projects in the Greater Wash, 3 in the North West and 3 in the Thames Estuary).
- 3.15. As previously stated, the Energy Act includes provisions which will enable the R2 electrical grid connections to be regulated and the transmission links be constructed, allowing these sites to export electricity to the onshore transmission system.
- 3.16. The Government's aim is that these connections and transmission links are regulated and funded in a manner that assists the R2 projects to be constructed in time to achieve the 2010 target. R1 wind generation projects received capital grants in addition to the support derived from the RO. No decision has been taken as to whether there will be similar grant support for R2 wind generation projects. The regulation of offshore electricity transmission should encourage efficiency and allow offshore wind generation

stations access to the onshore system on open and reasonable terms.

- 3.17. As set out in the Energy White Paper, the Government believes that the achievement of its broader objectives may be dependent on a radical transformation of the energy system to one that is more diverse, with a greater mix of energy sources and technologies and with the control and management of demand. This is likely to require new electricity generation in widely dispersed parts of the country, including offshore. The Government does not seek to be prescriptive in the way these changes are achieved, believing that within the context of policy set by the Energy White Paper the market is best placed to deliver cost effectively the outcomes that are sought.
- 3.18. Any regulatory regime put in place will need to be able to evolve to accommodate the next generation of offshore development including wave and tidal devices.
- 3.19. The Government has recognised that there may be particular issues for renewable generation, since transmission charges are relatively high in outlying areas of the North of Scotland, which offer significant potential for renewable development. The Government consulted on this issue in August 2003, noting the requirement in Article 7.6 of the Renewables Directive that 'Member States shall ensure that the charging of transmission and distribution fees does not discriminate against electricity from renewable energy sources, including in particular electricity from renewable energy sources produced in peripheral regions, such as island regions and regions of low population density.'

- 3.20. Following this consultation, the Government included a power in the Energy Act to enable it to adjust the level of transmission charges in a specified area of GB if those charges would otherwise deter renewable development. On 8 March 2005, Ministers announced that they intended to exercise this power to adjust transmission charges for renewable generation on the Scottish Islands (The Shetlands, Orkneys and Western Isles) and to consult on whether to adjust charges in the North of mainland Scotland.
- 3.21. The power in section 185 of the Energy Act enables the Government to adjust transmission charges for renewable generators in a specified area of GB, if the level of charges that would otherwise apply would be likely to deter or hinder renewable generation in the area. The power provides that the shortfall would be recovered from suppliers across GB. In taking this power the Government recognised that renewable generators are constrained in the locations they can choose by the availability of natural resources. The North of Scotland and the Scottish Islands in particular have excellent resources for renewable development, but transmission charges in the area are relatively high. The Government has taken the view that it does not want high transmission charges to deter renewable development in these areas.

Regulatory precedents

- 3.22. As explained in chapter 2, in developing the regulatory framework for offshore electricity transmission Ofgem is guided by its principal objective and general statutory duties as set out in the Electricity Act. The Electricity Act principal objective and general statutory duties apply both to regulation onshore and to the development of a regulatory framework for offshore electricity transmission. The principal objective is to protect the interest of electricity consumers in relation to electricity conveyed by distribution systems or transmission systems. In interpreting this principal objective, Ofgem focuses on those matters that relate directly to electricity consumption - prices charged, the choices available in a competitive market, the quality of service and the security of supplies. Ofgem's general statutory duties require that it must also have regard to other factors, such as social considerations and environmental policy, but these are secondary to the principal objective. The Government also expects the Authority to take into account the Secretary of State's Social and Environmental Guidance when taking decisions.
- 3.23. In order to discharge its principal objective and its general statutory duties, Ofgem has developed a broad approach to encouraging competition and developing regulation only where competition is not practicable. This approach to competition and regulation has been consistently applied to a wide range of policy areas, including:
 - transmission charges and British Electricity Trading and Transmission Arrangements (BETTA);

- the development of wholesale energy markets;
- distribution charges;
- the removal of price controls from the supply market;
- encouraging the development of merchant interconnectors;
- the undergrounding of cables under the distribution price control; and
- transmission investment for renewable generation.
- 3.24. Looking forward, the challenge for this approach to competition and regulation is that it needs to be flexible enough to accommodate the future challenges that the energy sector is likely to face. In particular the forthcoming review of price controls for onshore transmission asset owners will need to deal with changing investment requirements to accommodate an increase in the amount of renewable generation connecting to the electricity transmission network and a change in the pattern of network usage on the National Gas Transmission System as supplies from the North Sea reduce and imports from interconnectors and LNG increase.

Ofgem's general approach to competition and regulation

3.25. The general approach to developing the regulatory framework has been to encourage competition and develop regulation only where competition is not practicable. This is consistent with Ofgem's principal statutory objective and has a number of advantages for consumers. In particular competition tends to encourage companies to seek

out and meet the needs of their customers with respect to prices and standards of service. The competitive process encourages efficient operation and investment and encourages innovation - both in terms of efficiency and developing new products and services.

- 3.26. Ofgem has actively promoted competition in wholesale energy markets and in supply to final consumers. As competition has developed Ofgem has been able to remove price controls from the supply market, and the electricity and gas markets are now the most liberalised in Europe. Consumers have been able to make savings in the region of 20 per cent by changing supplier. Liberalised wholesale markets also promote timely investment in new capacity. In electricity more than 20GW of new and relatively efficient gas-fired generating stations have been built since privatisation.
- 3.27. In those network monopoly businesses where competition is not practicable, price controls and arrangements designed to encourage efficient network operation, such as cost reflective charging, have been introduced in order to protect the interests of consumers. Price controls are designed to ensure that network companies do not exploit their monopoly position. They also provide incentives for efficiency. Cost reflective charges help ensure that network users take account of distribution/transmission costs in operating or investing in capacity. This encourages overall efficiency, cost effective investment decisions, and leads to lower prices for consumers.

Transmission charging under BETTA

- 3.28. In March 2005 Ofgem published its decision to approve the transmission use of system charging methodology proposed by National Grid Company (NGC) for the transmission network in Great Britain²¹.
- 3.29. The new charges should be consistent with the principles set out in the transmission licences granted by the Secretary of State to NGC for the operation of the GB transmission system. These principles include facilitating effective competition and ensuring (as far as reasonably practicable) that transmission charges reflect the costs incurred by transmission licensees in their transmission businesses.
- 3.30. Cost reflective charges are particularly important in transmission because they influence the operation of existing generating plant and the location of new plant and large loads. Onshore transmission charges tend to be relatively low close to the strategic areas identified by the DTI for the development of R2 offshore wind generation (although the generating stations themselves will be some distance from shore and many will require long cable connections which could give rise to higher transmission charges). Cost reflective charging should help ensure that developers make efficient choices in choosing where to locate new renewable generation, although the Government has recognised that renewable generators face particular constraints in their location, which is why it introduced the Section 185 power in

the Energy Act (as described earlier in this chapter).

Arrangements in the wholesale electricity market

- 3.31. The New Electricity Trading Arrangements (NETA) implemented in 2001 and extended GB wide under BETTA in April 2005, introduced market based trading arrangements (similar to those in other commodity markets) to the wholesale electricity market. These market based arrangements have a number of advantages over the administered arrangements for the electricity pool that they replaced, including:
 - providing greater transparency to the market in the form of increased trading mechanisms and packages;
 - more flexible arrangements and increased demand–side participation leading to efficient matching of demand and supply; and
 - plant margin that responds to prices.

Distribution charging

3.32. Ofgem has reviewed the methods by which the electricity Distribution Network Operators (DNOs) charge for connection to and use of the distribution system²². It is important that the charging arrangements evolve to reflect the changing nature of the industry – in particular the growth in renewable and Combined Heat and Power (CHP) generation connecting to distribution networks. The intention is that from April 2005 each DNO will have in place a

 ²¹ 'NGC's proposed GB electricity transmission use of system charging methodology - The Authority's decisions' March 2005, 80/05
 ²² See for example, Structure of electricity distribution charges: Proposed DNO charging methodology statements, October 2004

transparent, cost-reflective charging methodology which facilitates competition in generation and supply.

The removal of supply price controls

3.33. Price controls were put in place on the regional electricity companies at privatisation while competition was phased in for supply. These price controls were removed when competition made them unnecessary. While Ofgem maintains a regulatory role in respect of enforcing licence conditions, it has withdrawn altogether from price regulation in the supply market.

The regulation and development of merchant interconnectors

3.34. At present there are a number of interconnectors that link the gas and electricity markets in GB with those in Ireland and mainland Europe. In developing policy toward interconnectors Ofgem has tried to encourage competition rather than develop price controls. These merchant interconnectors take advantage of market opportunities and so increase competition and the security of supply. There are strong incentives for efficiency and so consumers are protected from the cost of stranded assets and other inefficient investment. The majority of interconnectors have been built on a merchant basis.

Undergrounding of cables under the distribution price control

3.35. Following analysis of customer research results and cost information for the distribution price control review, Ofgem concluded that it would be appropriate to allocate funds for undergrounding of cables in national parks and areas of outstanding natural beauty. Ofgem allowed the DNOs to undertake £64 million of capital expenditure for removing overhead lines and replacing them with underground cables in these areas. The cost to consumers is equivalent on average to approximately 50p per customer per year over a period of 5 years. Ofgem took the view that there was a clear environmental benefit, with investment proven to be at an acceptable cost to consumers.

Transmission investment for renewable generation

3.36. At the last main electricity transmission price control reviews (undertaken in 1999 for the Scottish transmission companies and 2000 for NGC) there was significant uncertainty regarding the likely level and pattern of renewable generation and so it was not practical to establish incentive arrangements to deal with the associated transmission investment. Since then the Government has established the RO and the generators have responded to this signal by bringing forward proposals for new onshore renewable generation capacity, particularly in Scotland.

- 3.37. The transmission licensees put forward a number of investment schemes that would allow the connection of additional renewable generation in Scotland. Each of these projects was assessed to establish whether it could be justified in terms of reducing network constraint costs and transmission losses. Incentive arrangements were designed to help ensure that investment is carried out in a timely and efficient manner, which in turn should protect consumers from the costs of stranded assets and lead to charges to generators that are no higher than is necessary.
- 3.38. The regulatory arrangements for onshore transmission have been developed on the basis of Ofgem's principal objective and general statutory duties. They reflect a broad approach to regulation based on encouraging competition and regulating only where competition is not practicable. Incentives for investment and cost reflective charging ensure the efficient operation of the transmission system and protect consumers from bearing unnecessary costs.

4. The economics of offshore transmission and generation

4.1. This chapter discusses the economics of offshore electricity transmission and generation. The basic economic characteristics of offshore electricity transmission will be an important consideration in determining the most appropriate regulatory framework for offshore electricity transmission. While not the primary focus of this consultation, it is also instructive to consider the wider economics of offshore electricity generation. This should cast light on the economic viability of offshore electricity transmission and the importance of the associated regulatory reforms.

Background

- 4.2. Across the world around 40GW²³ of onshore wind generation capacity had been installed at the end of 2003, with 1GW²⁴ currently installed in Great Britain. Over time there have also been sharp falls in the costs of onshore wind generation, from around 7p/kWh in the early 1990's to around 3.2p/kWh (+/- 0.3p kw/h) in 2004²⁵.
- 4.3. In comparison the development of wind technology offshore is at a much earlier stage and the costs of installation remain high. To date about 0.5GW²⁶

of offshore wind generation has been installed worldwide of which about 120MW²⁷ has been built around Great Britain.

- 4.4. The R1 projects are relatively small with an average capacity of 90MW from a maximum of 30 turbines within a 10 sq km site (although one project amalgamated adjoining sites) and are reasonably close to shore (between 1.5km and 8km from the coast).²⁸ To date only two projects are generating. Given their relatively small scale R1 projects are likely to connect to distribution systems.
- 4.5. The limited experience gained from R1 development makes it difficult to estimate reliably trends in costs (with some reports of cost increase stemming from higher steel prices and contractor costs). R2 projects are of a significantly bigger scale – up to 1.2GW and with sites up to 250 sq km and are situated further from shore²⁹. These sites are confined to three strategic areas off the North West of England / North Wales, in the Greater Wash, and the Thames Estuary. The greater size of these projects makes it more appropriate for them to be connected to the transmission system.
- ²³ European Wind Energy Association Wind Energy The Facts February 2004
- ²⁴ http://www.bwea.com/map/index.html
- ²⁵ Sustainable Development Commission (2005). Wind Power in the UK; http://www.sd-commission.org.uk
- ²⁶ DTI Renewables Innovation Review, 2004
- ²⁷ North Hoyle (60MW), Scroby Sands (60MW) and Blythe Offshore (4MW).
- ²⁸ http://www.crownestate.co.uk/estates/marine/34_wind_farms_04_02_07.htm See also DTI Future
- ²⁹ http://www.crownestate.co.uk/estates/marine/34_wind_farms_04_02_07.htm

The economic characteristics of offshore electricity transmission

- 4.6. Information from the companies that are looking at developing R2 wind generation sites and their advisers suggests that the most economic method of connection for R2 offshore sites will be 132kV or 245kV single core transmission cables³⁰. Each of these cables should be capable of linking 200MW to 350MW of offshore wind generation capacity to the onshore network. Smaller projects would typically have 1 or 2 cables linking their site to the shore while larger projects might have 3 to 5 cables³¹. These links could be thought of as spurs from the existing onshore transmission network, which typically operates at 400kV, to offshore wind generation sites. There would be no extension of the main network offshore. In these circumstances it is important to consider whether the investment in offshore electricity transmission could reasonably be considered to be contestable and subject to competitive pressure.
- 4.7. The process of developing offshore wind generation will involve a number of steps including obtaining the necessary consents and licences, arranging financing, procuring the wind turbines and associated infrastructure, arranging for appropriate connections and links to the onshore transmission system, managing construction processes and risks, and then, operating and

maintaining the wind turbines. Many of the steps associated with the provision of fixed assets will be a fully competitive process.

- 4.8. There are 15 R2 wind generation projects. They will be able to procure wind turbines from a range of manufacturers. Other companies will be able to supply the towers and there will also be a range of contractors able to provide construction services. Similar arrangements could also apply to the procurement and construction of offshore transmission links. There are a number of cable manufacturers capable of producing suitable sub-sea cables and a range of contractors that could assist with installation. In general cables are expected to be dedicated to individual wind farms or shared between two sites located within close proximity of each other. Arrangements where two independent ventures share the use of an asset can be dealt with by normal commercial arrangements and would appear not to create a significant barrier to a competitive process.
- 4.9. On this basis it would appear that a competitive process could provide for the efficient construction of offshore transmission links and is unlikely to create issues associated with monopoly power. Chapter 5 discusses the regulatory options for offshore electricity transmission, including licensed price control and licensed merchant approaches.

- ³¹ Econnect study, January 2005, http://www.dti.gov.uk/renewables/publications_pdfs/offshoregrid.pdf
- ³² Garrad Hassan "Offshore wind: economies of scale, engineering resource and load factors, December 2003."

³⁰ This references the January 2005 Econnect study commissioned by the DTI and the Renewables Advisory Board "Study on the development of the offshore grid for connection of the round two wind farms". http://www.dti.gov.uk/renewables/publications _pdfs/offshoregrid.pdf

³³ Garrad Hassan, 2003. Table 2.1: Published total technical capital costs for offshore wind farms. Note that these costs have been made comparable by inclusion of grid connection costs.

The costs of offshore transmission and generation

4.10. As noted above there is limited experience of wind development offshore either domestically or internationally. This means there is considerable uncertainty about future costs levels, although there are a number of studies that have examined the likely levels of capital and operating costs. These are summarised below.

Capital costs

- 4.11. Capital costs include wind turbine and tower supply, foundation supply, installation, and electricity transmission infrastructure and onshore connection.
- 4.12. In December 2003 the DTI published a report by Garrad Hassan which looked at the economics of offshore wind energy³². The report included a development and construction budget for a typical R1 project of 30 wind turbines with a capacity of approximately 100 MW. The construction budget included a grid connection of three 33 kV cables running 10km to the coast. The report estimated the base case costs at £1.2 million per MW.
- 4.13. A number of offshore wind projects have been built around the world. Vindeby wind farm (the first offshore wind farm, built in 1991) is estimated to have capital costs of £1.45 million per installed MW, while Horns Rev (built in 2002) is

estimated to have costs of £1.3 million per installed MW³³. Estimates for Nysted in Denmark (built in 2004) put capital costs at £1.19³⁴ million per installed MW.

- 4.14. More recent estimates have been provided by Oxera for the National Audit Office (NAO)³⁵ and Climate Change Capital (CCC)³⁶. Oxera use central case estimates of R2 offshore wind generation in the range £1.1 million to £1.3 million. In February 2005 CCC estimated the range to be £1.2 million £1.5 million, but in a more recent study for Ofgem in April 2005 use a base case of £1.2 million.
- 4.15. The offshore wind industry is at a relatively early stage of development and several studies suggest that costs can be expected to fall as learning efficiencies develop. The Garrad Hassan report predicted that each doubling of cumulative offshore capacity would see a 10 per cent reduction in capital costs³⁷. Oxera's report for the NAO study in February 2005 estimates that capital costs for offshore wind will fall from £1.1 million per MW in 2004/05 to £0.8 million per MW by 2019/20³⁸. However, the rate of offshore build to date is relatively slow, so estimates that the capital cost for offshore wind would fall in the near future to below £1 million per MW³⁹ may not be realised.
- 4.16. An important element of capital costs are the costs of the transmission links necessary to transport the electricity that is generated onshore. The DTI

- ³⁵ Oxera report for the NAO, "Economic analysis of the design, cost and performance of the UK Renewables Obligation and capital grants scheme" January 2005.
- ³⁶ "Financing and Funding of Round 2 Offshore wind, a study for the DTI by Climate Change Capital Ltd. February 2005."
- ³⁷ Garrad Hassan, December 2003. Section 2.4.2. page 5.
- ³⁸ Oxera report for the NAO, January 2005. Table A2
- ³⁹ Garrad Hassan; December 2003. Extrapolated from figures on page 12.

³⁴ Figures quoted in Garrad Hassan for Nysted reflect the latest estimate of capital costs available at time of publication.

commissioned Econnect to report on the cost of connecting each of the R2 projects individually and at the potential for sharing connections.

- 4.17. The report estimated the costs of linking each of the R2 projects to the onshore transmission network. These ranged from £117,000 per MW to £254,000 per MW, with the average cost for the best mix of joint and individual connections of £167,000 per MW⁴⁰.
- 4.18. Taking the Garrad Hassan figure of £1.2 million per MW for R1 projects, transmission costs for R2 projects would account for around 10 20 per cent of the capital cost.
- 4.19. From the studies cited above a plausible range for the present capital costs of offshore wind projects would be £1.1 million to £1.3 million per MW. As domestic and international experience of offshore wind generation costs increases these costs should fall, perhaps to £0.8 million to £1 million per MW. The development by a number of wind turbine manufactures of new larger and potentially more efficient 5MW turbines is evidence that the industry is continuing to evolve.

Transmission charges

- 4.20. Offshore transmission costs could either be recovered as part of the capital costs of a project or by a transmission licensee levying annual transmission charges on the offshore generator. This would be dependent on the regulatory arrangements discussed further in chapter 5.
- 4.21. In order to help inform the decision on the approach to regulation NGC has provided some initial estimates of the annual transmission charges that might be paid by R2 generators assuming that existing transmission charging arrangements were extended offshore. These arrangements are designed with the intention that charges reflect costs.
- 4.22. Generators are charged on an annual £/kW basis and these charges would in broad terms reflect the length of cable required to connect the generator⁴¹. The table on the next page provides estimates of possible transmission charges for offshore assets.

⁴¹ Source: Illustrative Transmission Charges For Offshore Networks, paper by National Grid Transco for Renewables.

⁴⁰ Econnect report, January 2005, http://www.dti.gov.uk/renewables/publications_pdfs/offshoregrid.pdf

Table 1: I	ndicative	offshore	electricity	transmission	charges
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REZ area	15km cable (£1400/MW/km)	60km cable (£1400/MW/km)	60km cable (£2000/MW/km)
Greater Wash	£4.90 - £6.70	£10.20 - £12.00	£13.20 - £15.00
Thames Estuary	£3.10	£8.40	£11.40
North West	£6.70 - £7.90	£12.00 - £13.20	£15.00 - £16.20

- 4.23. It should be noted that the longest cable length quoted here is 60km. The cable lengths for at least half the R2 projects are 60km or longer. The longest cable length is likely to be 115km. Transmission charges for those projects may therefore be higher than the estimates above.
- 4.24. Under either of the regulatory options developers will also pay the onshore tariff for the zone into which they connect. In the Greater Wash those tariffs range from £3.1/kW £4.9/kW; in the Thames Estuary £1.3/kW; and in the North West from £4.9/kW £6.1/kW.
- 4.25. Generators would also be liable for Balancing Services Use of System (BSUoS) charges, levied on a half hourly basis in proportion to flows in that period. Charges are presently in the region of £0.60/MWh.
- 4.26. Connection charges are calculated on a shallow basis. Only assets which do not have the potential to be shared by other users would be charged for via connection charges. Connection charges would vary on a case-by-case basis and

be negotiated between the user, transmission asset owner and system operator.

Operating costs

4.27. Offshore wind generators also face a series of operating costs. These include costs associated with scheduled and unscheduled maintenance, management and insurance costs. NGC has estimated annual operating costs at £24,000 per MW⁴² while Oxera's NAO report estimated these costs to be £35,000 per MW⁴³. In addition offshore generators will also face the cost of their Crown Estate leases. The cost of these leases is around £1/MWh. Companies will also face onshore transmission charges and under the price regulated approach offshore transmission charges as well. On the present charging methodology these are in the region of £1 to £2/MWh. Bringing these estimates together (and assuming a load factor of 35 per cent) would give an overall range for operating costs of about £10 - £15/MWh. CCC estimated a range of operating costs from $\pounds 12 - \pounds 17/MWh$.

⁴² This figure is based on the mid point between the highest opex estimate (DTI £36k per MW per year) and Middlegrunden (£12k per MW per year).

⁴³ This figure is taken from the Oxera report for the NAO, January 2005. Table A2.6 reflects the central estimate (£35k per MW) extrapolated over time.

Revenues for renewable electricity

- 4.28. The revenue that an offshore wind generator could expect is also uncertain. There are two underlying sources of revenue – revenue from the sale of renewable energy and capital grants. The revenue from renewable energy is determined by the RO, the Climate Change Levy (CCL), wholesale energy prices and other market related factors.
- 4.29. The Government has offered £117 million in capital grants support to twelve R1 offshore wind farms to assist with their development. This accounts for about 10 per cent of the development costs – which would broadly cover their connection costs. Capital grants have to date been limited to R1 projects.

Renewables Obligation

- 4.30. The market price of Renewable Obligation Certificates (ROCs) is dependent on the level of installed renewable capacity relative to the target. The present market price of a ROC is approximately £45/MWh⁴⁴.
- 4.31. There is a degree of uncertainty over the market price of ROCs over this period, as levels of renewable capacity are unknown. There is also a degree of self-correction associated with the price of ROCs. If the level of renewable electricity generation is relatively low then the market price of ROCs will increase, incentivising the construction of further generation. Similarly a low ROC price would discourage construction. The DTI is seeking to address the issue of

falling ROC prices as renewable generation increases in the current review of the RO.

The climate change levy

4.32. A wind generator should receive additional revenue as the sale of its energy is exempt from the CCL. CCL Levy Exemption Certificates (LECs) are issued to renewable generators by Ofgem. The present value of a LEC is £4.30/MWh. The CCL exemption is intended to be in place until 2008, with an option for the scheme to be extended.

Sales of energy

- 4.33. Offshore generators will also receive revenue through the sale of energy. There is a degree of uncertainty over the price at which offshore wind generators will be able to sell their energy. To some extent, this will be determined by the degree of predictability over output and the correlation between periods of generation, peak conditions and energy price going forwards.
- 4.34. For the year ahead forward prices vary between about £30/MWh and £60/MWh depending on the time of year, over the period 2006/7 to 2007/08 the range reduces to around £37/MWh to £50/MWh. The intermittency of offshore wind electricity may make it difficult to secure these prices, but a conservative range for energy sales might be £30/MWh to £40/MWh. It should be noted that over the past year power prices have been rising.

⁴⁴ http://www.nfpa.co.uk/id8_auct.cfm?pid=13&id=38

Other market factors

- 4.35. In order to secure project finance many offshore generation projects will need to enter into long-term energy sales agreements with electricity supply companies. The terms that are available from supply companies may not reflect the present market prices of ROCs, LECs or short-term energy prices. The cause of this may be a variety of factors including differing expectations about future market prices, the desire of suppliers to charge a premium for managing the risks associated with longterm contracts, a lack of market liquidity and the possible excise of market power. It is not clear how these factors will affect R2 wind projects, particularly as a number of the projects involve large supply businesses.
- 4.36. Taking a longer-term view of ROCs varying between £30/MWh and £45/MWh and energy prices of £30/MWh to £40/MWh suggests a range for revenues of between £60/MWh and £85/MWh. The mid point for this range is £72.5/MWh.

Present value analysis

- 4.37. The following analysis takes a very simple approach to calculating present values, nonetheless it brings together all the costs and revenues discussed above. It uses lower and higher estimates of costs of £1.1 million to £1.3 million per MW for capital costs and £10/MWh to 15/MWh for operating costs. It also uses lower and higher estimates of revenue of £60/MWh and £72.50/MWh for revenue.
- 4.38. In addition to these assumptions the following analysis uses typical estimates of project life (15 years), load factors (35 per cent) and discount factors (12 per cent).
- 4.39. Projects with positive present values would be economic in terms of a normal investment appraisal test. The scenarios show mixed results with lower cost higher revenue scenarios producing positive present values while other scenarios show negative present values.

	Lower Cost & Higher Revenue	Higher Cost & Higher Revenue	Lower Cost & Lower Revenue	Higher Cost & Lower Revenue
Project life (years)	15	15	15	15
Project capacity (MW)	400	400	400	400
Fixed costs (£m/MW)	1.1	1.3	1.1	1.3
Variable costs (£/MWh)	10	15	10	15
Revenue (£/MWh)	72.5	72.5	60	60
Gross profit (£/MWh)	62.5	57.5	50	45
Load factor (%)	35	35	35	35
Discount rate (%)	12	12	12	12
Gross profit pa (£m)	77	71	61	55
Present value (£m)	522	480	418	376
Total FC (£m)	440	520	440	520
Project NPV (£m)	82	-40	-22	-144

Table 2: The Economics of offshore transmission and generation

Views invited

- 4.40. Views are invited on any aspect of the issues raised in this chapter and in particular on:
 - the economics of offshore transmission assets and the scope for the provision of these assets through a competitive process;
 - the estimates of capital costs of £1.1 million to £1.3 million per MW and the higher estimates of £1.5 million mentioned in paragraph 4.14 and whether respondents have evidence of either lower or higher costs;
 - the scope for learning efficiencies to reduce these costs and the extent and timing of any such reductions;
 - the estimates of operating costs of £10/MWh to £15/MWh;
 - the likely levels of revenues for offshore wind electricity and the impact of the market factors described above;
 - the appropriateness of the other assumptions on project life (15 years), load factors (35 per cent) and discount factors (12 per cent) underlying the present value analysis; and
 - the overall conclusions that at this stage there remains some uncertainty about the economics of offshore electricity transmission and generation.

5. Regulatory options

- The Energy Act provides powers for the 5.1. Secretary of State to develop a regulatory regime for offshore electricity transmission. There are a number of options that could be adopted for the regulation of offshore electricity transmission. These include the option of extending the existing onshore regulations offshore and taking a licensed price control approach to offshore transmission with conditions governing the charges that could be levied for the recovery of efficiently incurred costs. An alternative approach would be a licensed merchant approach with no price controls and the development of offshore networks largely left to the discretion of the developers of offshore wind generation sites.
- 5.2. This chapter discusses the above two options and issues relating to offshore transmission charges and seeks views from respondents on the most appropriate way forward.

Options for a regulatory regime offshore

5.3. The onshore transmission and distribution networks are subject to price control regulation. There are distribution cables linking certain islands to the main onshore distribution networks and there have been discussions about developing large-scale wind generation projects on Scottish Islands that might require the extension of the onshore transmission network. These assets are (or could be) subject to price control regulation. At the

same time, other offshore network assets in GB include electricity distribution connections required to link R1 wind generators to onshore distribution networks, interconnectors (with mainland Europe, Northern Ireland and Eire) and offshore gas pipelines (that bring gas from fields in the North Sea and elsewhere to the onshore transmission network). In broad terms these assets are subject to a merchant regime. The distribution connections for R1 wind generation stations hold a licence exemption granted by the Secretary of State, interconnectors will be subject to a licensing regime pursuant to the Energy Act, and the DTI has responsibility for regulating offshore gas pipelines.

5.4. This suggests that there are two broad options for a regulatory regime offshore a licensed price control approach or a licensed merchant approach. Ofgem has also explored whether a licence exempt merchant approach would have been feasible. The requirements of the IMED for regulated third party access imply that a licence exempt approach is not feasible.

Option 1: price control regulation

5.5. A price control approach to offshore electricity transmission would resemble the onshore approach to the regulation of transmission activities. Participation in offshore transmission would be a licensable activity, with offshore transmission licences having broadly similar standard licence conditions as onshore transmission licences, with such amendments as would be necessary to account for any relevant differences in onshore and offshore networks. For instance, it would be important to decide whether transmission Security and Quality of Supply Standards (SQSS) are sufficiently flexible to apply onshore and offshore.

- 5.6. As is the case onshore, transmission owners would be responsible for planning investment in networks, following consultation with the SO. As noted above it would be for consideration whether the existing SQSS are sufficiently flexible to encompass the economics of offshore wind generation. These decisions could be important to the costs of providing offshore electricity transmission, as existing onshore standards provide a relatively high degree of security by requiring some duplication of transmission assets. These standards are principally designed to secure supplies for final consumers. Conditions are different offshore where the transmission links would connect wind generators to the onshore system and there would be no consumers relying directly on the transmission assets for supply.
- 5.7. The offshore TO licences would contain special licence conditions establishing price controls similar to those for onshore assets. This would allow the TO licensee to recover its efficiently incurred costs from the SO. As explained below, it would be for Ofgem to determine according to its statutory responsibilities what would constitute efficient costs. The SO would recover both SO and TO costs via its charging methods. At present NGC is GBSO and levies charges on both generators and suppliers.

- 5.8. Setting the TO price control would involve Ofgem assessing the efficient levels of costs and determining levels of allowed revenue for each year of the price control period. In setting these price controls Ofgem could draw information from a range of sources. It would be appropriate to consider the costs actually incurred by developers and benchmark comparisons across different projects (perhaps both on a national and international basis) to try and assess whether costs had been efficiently incurred. It would also be necessary to consider over what period assets should be remunerated and at what cost of capital. In the final proposals for Transmission Investment in Renewable Generation in 2004 Ofgem allowed a real cost of capital of 8.8 per cent (equivalent to around 11.5 per cent in nominal terms). The next transmission price control review will consider the period over which this investment should be remunerated.
- 5.9. It would be for consideration as to whether to extend NGC's remit as GBSO to encompass system operation offshore. If there is to be a price control approach to the regulation of offshore electricity transmission there would be advantages in terms of simplicity and consistency (with the market for wholesale electricity) if there were a single SO. The GBSO could then be responsible for the balancing of generation and demand across the onshore and offshore transmission system in real time and the implementation and administration of a charging regime, designed to recover the allowed revenues set within all onshore and offshore price controls and the costs of system balancing. Any decision on these matters will be taken after careful consultation with NGC.

5.10. If a price control approach were to be adopted the regulation of transmission charges would be an important part of the overall regulatory framework. Matters relating to the structure of any regulated offshore electricity transmission charges are discussed later in this chapter.

Characteristics of a price control approach

Protecting the interests of consumers

- 5.11. Where competition can be effective then consumers' best interests are protected by competition rather than regulation, but where there is monopoly power then a regulated approach may be necessary. As noted in chapter 4 the information presently available suggests that offshore electricity transmission does not generally have the characteristics of a natural monopoly and could be provided for as part of the development of offshore wind generation projects. Balanced against this are the advantages of consistency in extending price controls offshore and wider considerations relating to environmental policy. These are discussed below.
- 5.12. Under a price control approach there is a risk that the costs of stranded assets or other inefficient investment decisions will be borne by consumers rather than generators. While steps can be taken to limit these risks it is not clear that they can be eliminated.
- 5.13. An advantage of a price control approach would be consistency with onshore arrangements. For instance, at present the developer of a generation project onshore needs to meet the security provisions of CUSC rather than directly

funding investment in transmission links - although the onshore project will pay transmission charges once it starts to operate. If a different approach were adopted offshore, even if in broad terms this appeared equivalent in present value terms, this might distort investment decisions. Developers might prefer onshore projects where they could pay for transmission via annual charges rather then having to meet the total costs of transmission links at the start of a project. This could distort competition in the market for renewable energy that would not be in the interests of consumers and have negative implications for the achievement of the Government's renewable energy targets.

The environment and sustainable development

- 5.14. It will be important that any decisions on the approach to the regulation of offshore electricity transmission do not unreasonably frustrate the development of R2 wind farms which are a key part of achieving the Government's 2010 target. Without a significant contribution from R2 wind farms, the target cannot be achieved.
- 5.15. The Government's RO provides strong incentives for electricity generation from renewable energy sources. There is no evidence that in the longer term a price control approach to offshore would be inconsistent with these incentives. Nevertheless, there would be important interactions between regulated charging arrangements and the underlying economics of offshore wind generation. These are discussed below.

- 5.16. As noted in paragraph 5.13 there might be advantages for competition between onshore and offshore generators in having similar arrangements for charging for transmission onshore and offshore.
- 5.17. While price control regulation provides incentives for efficiency these will generally not be as effective as the incentives created by a competitive market. The imposition of prescriptive regulations and standards may also blunt incentives for developers to investigate alternative and more efficient methods of design, construction and operation of transmission links.
- 5.18. Implementing a price control regime would be a more complex exercise than developing a merchant approach to regulation. There would be a risk in the shorter term that some offshore wind generation projects would be delayed while the uncertainties with respect to new price control arrangements for offshore electricity transmission were resolved. It would be possible to try and adopt flexible approaches so to minimise any such delays. For instance, Ofgem has already published a letter designed to explain to the developers of offshore electricity transmission its initial thinking on the operation of any future price control regime (see Annex 1).

Securing diverse and viable longterm energy supplies

5.19. Competitive wholesale markets are the best way of providing diverse and viable long-term energy supplies. These competitive markets need to be complemented by appropriate levels of efficient investment in transmission and distribution systems. There is no evidence to suggest that a price control approach to regulation leads to underinvestment in transmission capacity. In carrying out its regulatory functions, Ofgem is under a statutory obligation to ensure that licence holders that are operating efficiently are able to finance their activities.

5.20. Increasing generation from renewable energy sources will help to increase the diversity of the energy supply mix in terms of fuel type and geographical source and in the longer term this should enhance security of supply. However, intervening in the market to favour one technology over others may increase perceptions of uncertainty and deter investment in other capacities.

Charging under a price control approach

- 5.21. A key aspect of the present arrangements for transmission charging onshore is that charges should reflect the costs that system users impose on the transmission network. Extending this to offshore electricity transmission would in broad terms mean that offshore generators paid for the costs of offshore assets on the basis of an annuity rather than as a lump sum at the start of the project.
- 5.22. The present arrangements for GB onshore charging are made up of three elements:
 - Balancing Services Use of System (BSUoS) charges – these are a nonlocational £/MWh charge on generators and suppliers reflecting the cost of balancing the transmission system;

- ii) Connections charges these are sitespecific charges that fund the immediate connection of (usually) individual directly connected transmission system users. Assets that are shared by more than one user are not included as connection assets; and
- iii) Transmission Network Use of System (TNUoS) charges. The present method for calculating GB TNUoS charges seeks to provide transmission users with signals that reflect the cost of establishing transmission to meet requirements in specific areas. The TNUoS methodology calculates a network tariff which is composed of two components:
- a locational varying element which reflects the costs imposed on the system
- b) a non-locational element that is set so that the total TNUoS revenue is equal to that allowed under the price control and such that it is recovered 73 per cent from suppliers and 27 per cent from generators.
- 5.23. The recovery of 73 per cent of charges from suppliers and 27 per cent of charges from generators does not imply that there is a cross-subsidy between users. For instance in 2005/06 the generators in the highest cost zone pay about £23/kW and those in the lowest zone receive a rebate of about £8/kW. If these charges were to increase uniformly by £1/kW then they would be £24/kW and a rebate of £7/kW. Over time generators would reflect these increased costs in wholesale contracts and so wholesale prices would increase by about £1/kW. The generators would be no worse off – in that they would pay higher transmission charges but also

receive higher revenue from wholesale prices. Assuming a counterbalancing change in suppliers' transmission charges then they would experience a reduction equivalent to £1/kW. Competition should ensure that this is passed on to consumers and balance the £1/kW increase in wholesale prices. On this basis the overall proportion of transmission charges that is met by suppliers / generators does not have a long-term impact on the economics of generation (or supply). However, the absolute differences between high cost and low cost generator charging zones do have an impact on the economics of generation in particular locations.

- 5.24. Other approaches to charging could also be considered for offshore electricity transmission. For instance, it has been suggested that if the level of transmission charges that would apply offshore would be likely to deter renewable development in areas that the Government has identified as being particularly suitable for such development, it might be appropriate to find a way of capping these charges.
- 5.25. As an example of how this might work, it might be possible for the Secretary of State to put in place a scheme to provide that offshore transmission charges above a specified amount would be reduced. and that the shortfall would be recovered from other users of the transmission system in GB. The shortfall could either be recovered from across all generators and suppliers or focused on a single category of system users. The Section 185 Energy Act power specifies that transmission charges imposed on suppliers will be adjusted to recover the shortfall caused by limiting transmission charges imposed on renewables generators.

Characteristics of charging arrangements that reflect costs

Protecting the interests of consumers

- 5.26. Competitive wholesale and retail electricity markets best protect the interests of consumers. In order that overall efficiency is retained and enhanced it is important that participants in these markets take account of the costs they impose on transmission companies in deciding on their actions. Cost reflective transmission charges provide a mechanism that creates these incentives for efficiency. Without such incentives the pattern of electricity flows on the network could encourage inefficient investment, with these extra costs falling on consumers. In this context, cost reflective transmission charges may best protect the interests of electricity consumers.
- 5.27. However, high transmission charges may discourage the development of renewable energy given that the best resources are often located some distance from centres of demand. This could make it more difficult for the Government to meet its targets for renewable energy which will contribute to the long-term goal of reducing carbon dioxide emissions.

The environment and sustainable development

5.28. Providing a cross-subsidy for offshore electricity transmission would tend to increase the amount of offshore electricity generation from renewable energy sources. This would make it more likely that the Government will meet its 10 per cent target for electricity to be supplied from renewable energy sources, contributing to the long-term goal of reducing carbon dioxide emissions.

Securing diverse and viable long-term energy supplies

5.29. Cost reflective transmission charges were designed to promote the efficient operation of the wholesale electricity market and overall efficiency. As such they are consistent with both diverse and viable long-term energy supplies. Charging that is not cost-reflective could promote renewable generation and would have advantages of encouraging diversity, but would have the disadvantages described in paragraph 5.20.

Option 2: a licensed merchant approach

- 5.30. A licensed merchant approach to offshore electricity transmission would involve the minimum regulatory arrangements consistent with the IMED and Renewables Directive. This would provide a relatively light touch regulatory regime. The transmission licence could authorise the developer to carry out both SO and TO activities with respect to a particular offshore cable. While offshore transmission would be a licensable activity, the licence conditions would be limited to conditions such as requiring any surplus transmission capacity to be offered to third parties on nondiscriminatory terms.
- 5.31. A key aspect of the licensed merchant approach is that offshore wind generation developers would have to meet all the costs of developing the transmission links and raise the associated finance.

- 5.32. These transmission licences would not contain special conditions establishing a price control mechanism. However, it is likely that they would need to contain standard conditions dealing with the interface between the offshore cable and the onshore transmission system and obligations to sign up to the relevant related documents (such as the Grid Code and the CUSC).
- 5.33. With a licensed merchant or price control approach the developers of offshore wind generation could be the transmission licensee, subject to complying with the conditions of IMED relating to the separation of activities. The licensed merchant approach would provide the developer with maximum flexibility to specify and procure the transmission cables and other assets most suitable for their needs. The only interaction with transmission price controls would be through the onshore transmission charging arrangements. Where the merchant transmission assets connect to the onshore transmission system the merchant operator or developer would need to pay transmission network charges. These transmission charges differ across zones reflecting the different costs of transmission across GB.
- 5.34. This approach to regulating offshore electricity transmission would be different to the approach used to regulate onshore transmission. As noted in paragraph 5.13 this would be a significant disadvantage if it were to distort competition because of differences in charging arrangements. Nevertheless, the underlying cost characteristics of offshore transmission

(where economies of scale are much reduced) suggest that offshore assets might not need to be subject to price control regulation and consumers interests could be protected by competition.

- 5.35. Compared to other options there might be reduced incentives to invest in offshore wind generation and a reduced probability that the Government would deliver its 2010 goal of reducing carbon dioxide emissions.
- 5.36. The Econnect report suggests there will be some situations where there are economies of scale in constructing transmission links to more than one wind generation project. For instance there may be circumstances where it would be more efficient for two offshore wind generators to share the same transmission link to the onshore system. Nevertheless the basic economics of the existing offshore electricity transmission technology suggests that a full-blown network of offshore transmission cables would not be viable. On this basis any economies of scale should be relatively straight forward to capture, perhaps by two wind generation projects coming together to form a consortium or joint venture.
- 5.37. Any party could apply for a licence, which would be granted assuming all necessary criteria were met. This would ensure that the possibility of contestability existed and increase competition. In principle ownership could rest with any licensed party with there being scope to provide transmission services to offshore wind generation projects on the basis of negotiated long-term contracts.

Characteristics of a licensed merchant approach

Protecting the interests of consumers

- 5.38. With a licensed merchant approach there is scope for the competitive process associated with the construction and development of offshore wind generation to also encompass the provision of the associated transmission assets. This should ensure that assets are provided efficiently and that there is no risk of the costs of stranded assets being recovered from consumers.
- 5.39. As explained above a licensed merchant approach would not be consistent with the arrangements onshore and so might distort competition between generators. This would not be in the interests of consumers and could reduce the probability that the Government would meet its targets for renewable generation.

The environment and sustainable development

- 5.40. As noted above the Government's RO provides strong incentives for electricity generation from renewable energy sources. A licensed merchant approach would not be inconsistent with these incentives but would not provide any additional incentives on offshore wind generation to proceed and so make it less likely that targets for renewable energy and reductions in carbon dioxide emissions will be met.
- 5.41. An advantage of the licensed merchant approach is that it would be straightforward and timely to implement. It would also eliminate uncertainty

associated with the level of regulated offshore transmission charges. Taken together these two factors would provide some assistance to offshore wind generation projects to take early decisions with respect to investment. However, the need for developers to meet the upfront costs themselves may outweigh any of these advantages.

Securing diverse and viable long-term energy supplies

5.42. These issues are discussed in paragraphs 5.19 and 5.20.

Tendering for offshore licences

- 5.43. As noted in chapter 3, the Energy Act provides the option of holding a tender process for the allocation of TO licences.
- 5.44. While a tender process could be implemented under either of the regulatory options suggested above, arguments for implementing a tender process might be stronger under a price controlled approach. A licensed merchant approach would see developers facing strong incentives for efficiency. A price control approach might provide weaker incentives for efficiency, even if charges reflect underlying costs. A tendering process for offshore electricity transmission might strengthen the incentives for efficiency as it could open up the provision of offshore transmission links to a competitive process.
- 5.45. There may be disadvantages to a tender process. For instance it could add a degree of complexity and uncertainty to a process establishing investment specifications and for setting price controls. There would also be

administrative and other costs associated with a tender process. It would also take time to consult and work out the details of a tender process. These factors might delay investment in offshore wind generation and or increase costs to developers.

5.46. There is no requirement for Government or Ofgem to hold tender processes under either the price control or licensed merchant approaches.

Views invited

- 5.47. Views are invited on any aspect of the issues raised in this chapter and in particular on:
 - whether the main options for regulating offshore electricity transmission are a licensed price control approach or a licensed merchant approach;
 - the advantages and disadvantages of a price control approach, cost reflective charging, some degree of charge capping and cross-subsidy for offshore wind generators and a licensed merchant approach;
 - the approach that should be adopted to regulating offshore electricity transmission and the reasons that this approach should be adopted; and
 - what role if any should there be for a tender process in granting licences for offshore electricity transmission.

6. Key issues for consultation

- 6.1. This document discusses options for the regulation of offshore electricity transmission. Views are invited on any aspect of the issues raised in this consultation and in particular on:
 - the implications for the regulation of offshore electricity transmission of the regulatory precedents described in chapter 3.
- 6.2. Views are also sought on the issues raised in chapter 4 (on the economics of offshore transmission and generation):
 - the economics of offshore transmission assets and the scope for the provision of these assets through a competitive process;
 - the estimates of capital costs of £1.1 million to £1.3 million per MW and the higher estimates of £1.5 million mentioned in paragraph 4.14 and whether respondents have evidence of either lower or higher costs;
 - the scope for learning efficiencies to reduce these costs and the extent and timing of any such reductions;
 - the estimates of operating costs of £10/MWh to £15/MWh;
 - the likely levels of revenues for offshore wind electricity and the impact of the market factors described above;

- the appropriateness of the other assumptions on project life (15 years), load factors (35 per cent) and discount factors (12 per cent) underlying the present value analysis; and
- the overall conclusions that at this stage there remains some ambiguity about the economics of offshore electricity transmission and generation.
- 6.3. In addition views are sought on the issues raised in chapter 5 (on the regulatory options for offshore electricity transmission):
 - whether the main options for regulating offshore electricity transmission are a licensed price control approach or a licensed merchant approach;
 - the advantages and disadvantages of a price control approach, cost reflective charging, some degree of charge capping and cross-subsidy for offshore wind generators and a licensed merchant approach;
 - the approach that should be adopted to regulating offshore electricity transmission and the reasons that this approach should be adopted; and
 - what role if any should there be for a tender process in granting licences for offshore electricity transmission

Annex 1 Comfort Letter

30 December 2004

Dear Sirs

OFFSHORE ELECTRICITY TRANSMISSION

Ofgem has received a request from [a consortium] representing [a number of] Round 2 offshore wind generation schemes. The consortium anticipates that its connections to the onshore transmission system would be fit for purpose, economic and efficient. It has requested reassurance that if these assets were to be subsequently included within the scope of a transmission licensee's price control then the consortium would be reimbursed the costs that it had incurred in building the connections.

The Energy Act 2004 provides the Secretary of State with enabling powers to put in place a regulatory regime to encompass offshore transmission. The form of this regime has yet to be determined and so it is necessary to consider how to best deal with this uncertainty. This letter provides information and guidance on an informal basis and should not be treated as binding on the Authority. Nothing in this letter is to be construed as granting any rights or imposing any obligations on the Authority. It does not fetter the Authority's discretion with respect to the regulation of offshore electricity transmission.

Pursuant to the Energy Act 2004 the Secretary of State can modify transmission licence conditions for the purposes of offshore transmission and extend the GB System Operator's transmission licence offshore. Once these arrangements have been put in place it will be for Ofgem, consistent with its principal statutory objective of protecting the interests of consumers, to:

- enforce these licence conditions; and
- from time to time bring forward any modifications to the licence conditions.

The Secretary of State would retain powers to veto any licence modifications proposed by Ofgem.

While the Energy Act provides the Secretary of State with powers to modify the electricity licensing regime for the purposes of offshore transmission (as noted above) it does not prescribe in detail the form of the regulatory framework.

The modified licence conditions could encompass the regulation of offshore electricity transmission either on a merchant or a price control basis.

Ofgem's initial view is that there are a number of arguments that suggest there would be significant benefits in the regulation of offshore transmission on a merchant basis and that

this approach would be consistent with Ofgem's statutory objectives. Nevertheless, it will be important to reconsider this position in the light of responses to future consultations on these matters. The benefits of a merchant approach could include the potential to promote the efficient connection of offshore wind generation and minimise any unnecessary increase in the scope of regulation. This could involve the owners of offshore wind generation licensed to own and operate the transmission cables linking the wind generation to the onshore system. These transmission licences would allow each wind generation scheme to comply with Section 4 of the Electricity Act (as amended) and the EU Internal Electricity Market Directive (2003/54/EC) but would not contain price control conditions. The wind generation scheme would then be able to operate freely in the market for renewable energy. It would be responsible for recovering all its costs, but would only pay NGC transmission charges according to the point of its onshore connection to the transmission system. This appears to be an approach that would encourage the efficient development of offshore wind generation and be fully consistent with protecting the interests of consumers.

It may be that a more extensive price control system of regulation is appropriate. This could involve setting price controls via the introduction of special licence conditions on offshore transmission operator licensees. The costs of the transmission cables linking wind generation to the onshore transmission systems would be recovered via transmission use of system charges. In introducing or modifying any such price control conditions Ofgem would seek to make allowances for costs incurred by the consortium, in relation to the development and installation of transmission cables prior to the granting of a relevant transmission licence, provided all the following conditions were satisfied:

- the costs had been properly incurred and were necessary for the purposes of offshore transmission;
- the level of costs was no more than an efficient level of costs, to be determined on a basis considered appropriate by Ofgem, including benchmark comparisons with the costs of developing and installing offshore transmission cables on a national or international basis; and
- at the time the investment is made reasonable forecasts show that, on the basis of cost reflective transmission charges, there would be sufficient demand (and over a long enough time period) for the use of the transmission cables to justify the investment.

It is the intention to publish a consultation paper on the options for the regulation of offshore transmission in early 2005. This would provide an opportunity to explain in more detail the legal powers that the Secretary of State will have to create a regulatory framework for offshore transmission and discuss further the relative merits of a merchant and price control approach to regulation.

Yours faithfully

Andrew Walker

Director – Transmission Networks Regulation Authorised on behalf of the Gas and Electricity Markets Authority

Annex 2 Illustrative Transmission Charges For Offshore Networks

Paper by National Grid Transco

Introduction

- The RAB Offshore Working Group requested that the transmission charges that might be levied on an offshore transmission network should be calculated for illustrative purposes.
- This paper describes the charges that might be derived if the recently approved GB charging methodologies are applied to recover the cost of potential offshore network designs. Capital cost estimates for deriving appropriate tariff parameters are based on work by NGT, Econnect¹ and Sinclair Knight Merz².
- Illustrative network use of system tariffs have been calculated for the following locations:
 - a. The North West strategic area (offshore connections from Pentir in North Wales and Heysham)
 - b. The Greater Wash strategic area (offshore connections from the Humber Bank and also Walpole)
 - c. The Thames Estuary strategic area (offshore connections from Sizewell and Kemsley).

Background

- 4. National Grid Company (NGC), as the transmission licensee authorised to co-ordinate and direct the flow of electricity onto and over a transmission system within Great Britain (i.e. as Great Britain System Operator) has the following duties under the Electricity Act:
 - a. Develop and maintain an efficient, co-ordinated and economical system of electricity transmission; and
 - b. Facilitate competition in generation and supply.
- A requirement of the transmission licence (Standard Condition C7) requires NGC to determine a use of system charging methodology approved by the authority and conform to it.
- In accordance with the approved methodologies, NGC will raise three types of transmission charges in Great Britain under the British Electricity Trading and Transmission Arrangements (BETTA):
 - Balancing Services Use of System (BSUoS) charges – these are a non-locational £/MWh charge on transmission (generators and suppliers) reflecting the cost of balancing the transmission system.

¹ Study on the development of the offshore grid for the connection of Round 2 windfarms, Econnect, 23 December 2004.

² Technical evaluation of transmission network reinforcement expenditure proposals by licensees in Great Britain, Sinclair Knight Merz, August 2004 at http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/8259_19604_tirg_skmreport.pdf

- b. Connection charges these are site-specific asset-based charges that fund the establishment and maintenance of transmission assets that form the immediate connection of (usually) an individual directly connected transmission customer. Such charges follow a "super shallow" (the so-called "plugs") methodology under which assets that are shared by more than one user are not included in connection charges (and effectively only the costs of supergrid transformers are recovered using this charge).
- c. Transmission Network Use of System (TNUoS) charges – a locational tariff applied to generation capacity and half-hourly and non-half hourly metered demand which provides the majority of the funding required to develop and maintain the transmission networks owned by the three transmission licensees in Great Britain. The tariff for 2005/6 is summarised in Appendix 1. The remainder of this paper concerns potential values for this tariff if it were to recover the costs of offshore transmission facilities.
- 7. The Energy Act 2004 requires that electricity transmission activities offshore be subject to licence. It also provides the Secretary of State with powers to extend the role of a licensee authorised to co-ordinate and direct the flow of electricity onto and over a transmission system (i.e. the GBSO) to cover offshore if required. This paper assumes that such extension is made such that the costs incurred by offshore transmission licensees are recovered by

the GBSO using charging methodologies similar to those currently approved for GB onshore.

- 8. In this paper, the cost of offshore platforms and cable marshalling equipment are assumed to be the equivalent of onshore generation connection substations and so would be funded by the TNUoS tariff rather than via connection charges. The remainder of the paper seeks to identify how offshore network costs would be represented in the TNUoS tariff in a manner consistent with the current charging methodology. In deriving illustrative values it is assumed that the approved TNUoS methodology is subject to minimal developments. However, in practice and in accordance with the transmission licence (Condition C5), NGC is required to keep the charging methodology at all times under review such that it achieves the following relevant objectives:
 - a. They facilitate effective competition in generation and supply.
 - b. They reflect, as far as is reasonably practicable, the costs incurred by transmission licensees in their transmission businesses.
 - c. In so far as is consistent with a) and
 b) above, and as far as is reasonably
 practicable, they properly reflect
 developments in transmission
 licensees' transmission businesses.
- Proposed developments to the methodologies must be subject to consultation with CUSC users prior to seeking approval.

Charging Methodologies

- 10. The GB TNUoS charging methodology seeks to provide transmission users with efficient signals that reflect the cost of establishing transmission to meet requirements in specific areas. Such signals, when incorporated in the individual financial appraisals of market participants, ensure an overall economic development of the transmission system.
- 11. Given the often 'lumpy' nature of transmission reinforcements, methodologies which charge users the cost of the actual reinforcements required to accommodate them (so-called "deep connection" charges) have the disadvantage of producing charges that may vary according to whether the user happens to precipitate a major reinforcement or happens to be able to make use of previously established capacity. This may result in users who are located in the same area and making a similar use of the transmission network facing very different charges.
- 12. To avoid such issues, the GB TNUoS methodology derives locational signals from a calculation of the incremental transmission capacity required to serve an additional 1 kW of generation (or demand) at each node. The locational element of the TNUoS tariff is derived by calculating either the annual charge needed to fund this incremental transmission capacity for one year or, in the case of a reduction in the need for capacity, the benefit of delaying the financing of investment by 1 year. The cost of incremental transmission capacity is based on average unit costs for the transmission technology most likely to be required.

- 13. The majority of transmission requirements with Great Britain can be met using overhead lines and so GB tariff differentials (illustrated in Appendix 1) tend to be dominated by the unit costs of such lines, taking into account the most efficient voltage level. However, in some areas environmental issues dictate the use of underground cables. As high voltage cables are many times the cost of overhead lines, tariff differentials in these areas tend to be proportionately larger.
- 14. At present there are no standard unit costs in use for undersea cables and so, to derive a tariff for windfarm connections, unit costs of the relevant undersea cable technology need to be estimated. For this purpose, three sets of cost estimates have been used:
 - a. Costs from some generic offshore wind farm connection designs undertaken by NGT – see Appendix 2.
 - b. Costs from specific connection designs performed by Econnect as part of a study for the RAB offshore working group.
 - c. Costs from illustrative undersea cable designs by Sinclair Knight Merz concerning connections to windfarms on the islands of Shetland, Orkney and Lewis.
- 15. In general, the revenues resulting from tariff differentials between the locations of generators and loads will not be sufficient to fund all the transmission costs and for this reason the TNUoS tariff contains a non-locational element which is added to both generation and demand charges. This non-locational element is added such that the total tariff payments by generation and demand is in the ratio 27:73.

Illustrative Capital Costs – NGT Generic Designs

- The generic network designs are explained in Appendix 2. Two scenarios have been examined:
 - a. Connection of a 250MW wind farm
 15km from an onshore connection point.
 - b. Connection of a 1000MW wind farm 60km from an onshore connection point.
- 17. The designs are derived from judgements made by National Grid Transco concerning an appropriate performance/cost trade-off given our views on the cost of technology options and the service that wind customers may find appropriate. The key considerations were:
 - i) The appropriate voltage for the offshore network given cable costs.
 132kV cables could be appropriate for both scenarios although higher voltage cables might soon become a proven option for application as a single cable in case a) and as three cables in case b).

- ii) The number of cables, and given that more than one cable is required in both of the scenarios, a decision not to include additional cables for redundancy/reliability/loss optimisation purposes.
- iii) The number of offshore interface points. One has been assumed in both scenarios.
- iv) The nature of the onshore connection point. It has been assumed that there is an existing transmission substation close to the shore such that additional lines/cables are not required.
 However, it is assumed that some additional transformer capacity would be required.
- 18. No estimate has been made for the onshore reinforcement costs. For the purpose of this illustration it is assumed that the onshore use of system tariff adequately reflects the long-run cost of such works.
- 19. The illustrative capital costs are as follows:

	a) 250 MW @ 15km	b) 1000 MW @ 60km
Total capital cost	£22.5m	£146.5m
Distance related component	£6.0m	£96.0m
Unit investment cost of transmission £/MW/km	£1430/MW/km (for 280MW)	£1430/MW/km (for 1120MW)
Element not dependant on distance	£61/kW	£51/kW

20. Compared to the unit investment cost of 400kV overhead transmission, the offshore cables are 12.6 times more expensive. (i.e. the connection point may be considered to be 12.6 times more distant than for a standard 400kV overhead line connection, for the purposes of calculating transmission charging differentials.) It should be noted, however, that a locational security factor of 1.8 is applied to onshore overhead line unit costs to represent the additional costs associated with meeting the GB security standards. Given that the offshore design seeks to include an adequate level of security for the wind farm, it may be appropriate to exclude such a factor from the offshore costs. In this case the offshore tariff differentials would be expected to be 7 = 12.6/1.8 times larger per km.

Illustrative Capital Costs – Econnect Designs

21. A summary of the results of site by site connection designs is given by Econnect in the following graph.





Figure 10.1 Individual Connection Unit Cost against Route Length (determined by longest cable length) for different connection voltages

22. Econnect note that unit costs are strongly proportional to route length. From the above data it is observed that Econnect's 132kV connection designs average circa £2000/MW/km with a cost element that is not distance related of circa £50/kW. The results for 245kV connection designs, would appear to be circa £1400/MW/km with a distance unrelated cost element of circa £80/kW.

	Econnect 132kV designs	Econnect 245kV designs
Unit investment cost of transmission £/MW/km	£2000/MW/km	£1400/MW/km
Element not dependant on distance	£50/kW	£80/kW

- 23. Econnect also derive shared connection designs. These can result in economies of circa 10% in some circumstances. It is understood that such economies primarily result from the sharing of facilities that would give some redundancy in the connection and would permit some capacity in the event of a cable fault. Such cost savings may reduce end costs and the distance related unit cost for subsea connections in some areas. However, for the purposes of this paper and to demonstrate the effect of a generic unit cost for subsea connections, this effect has not been represented in the tariff calculations.
- 24. The distance related unit costs are 17 and 12 times the onshore 400kV overhead line expansion costs for the 132kV and 245 kV designs respectively. Econnect state that they believe their designs include sufficient partial redundancy to provide adequate security for the wind farm operators. On this basis, the unit costs in these designs (unlike onshore 400kV overhead line costs) would not need to be scaled by a locational security factor.

Illustrative Capital Costs – SKM Designs

25. SKM report their outline island connection projects as follows:

	Generation served/ capacity provided MW	Cable length km	Cable investment cost £m	Cable Unit investment cost £/MW/km	Land OHL km	Onshore reinforcement £m	Unit onshore network cost £/MW/km
Western Islands	1150	60	207	3000	100	150	1304
Orkney	160	30	19	3958	150	40	1667
Shetland	560	170	175	1838	150	40	476
Orkney & Shetland	720	200	194	1347	150	74	385

- 26. In terms of undersea cables to serve wind generation projects, SKM's designs show unit costs between £3000/MW/km and £4000/MW/km for the shorter cable routes, falling to circa £1800/MW/km for the longer route to Shetland. It is understood that this lower unit cost reflects the proposed use of HVDC technology which is anticipated to be the most economic over such distances. For all three islands it is understood that the cable capacities are chosen to match the planned generation capacity closely so that no significant spare capacity results.
- 27. It is also understood that SKM's designs do not include any security capacity that would permit the generation on the islands to continue to export, even to a limited extent, in the event of a cable fault.
- 28. The unit costs calculated by SKM include end costs. For the shorter routes these may be extracted by assuming that the distance related unit costs for Lewis and Orkney will be similar. See graph below.



SKM Connection Costs

29. The observed distance related unit costs and end costs are then:

	SKM designs
Unit investment cost of transmission £/MW/km	£2000/MW/km
Element not dependant on distance	£57/kW

Illustrative Capital Costs – SKM Designs

- Results from the three design studies for wind connections using undersea cables identifies distance related unit costs between £1400/MW/km and £2000/MW/km with end costs between £50/kW and £80/kW (excluding HVDC link solutions).
- 31. NGT's 132kV unit costs are lower than the average observed from the Econnect studies. This may due to the omission of the reactive compensation cost from the distance related component. Also the unit costs derived from the NGT study assume maximum utilisation of cable capacity, which for actual wind farm designs, may not be possible.
- 32. The SKM study, although derived for onland costs at both ends, provides support for distance related unit costs circa £2000/MW/km. It also provides broadly consistent costs for HVDC where longer routes may justify the higher end costs.

- 33. The distance related unit costs for Econnect's 245kV cable designs, while lower than the 132kV designs, do not fall in inverse proportion to the voltage level (as would be expected from the reduced current capacity required). This reflects the importance of insulation and other voltage related costs in higher voltage cables.
- 34. On the basis of these study results, it is assumed for the purposes of this paper that incremental offshore capacity costs will be in the range £1400/MW/km and £2000/MW/km. It is assumed that the end costs and other costs not related to distance would be recovered using the non-locational tariff element (see description of TNUoS tariff below).

Revenue Requirements

35. Assuming that offshore network financing costs are price regulated in an equivalent manner to onshore network costs, and the allowed costs of operating and maintaining such assets are similar to NGC's onshore assets, then the additional revenue that would need to be raised to finance the assets in the NGT generic designs would be as follows:

	250MW at 15km £m	1000MW at 60km £m
Total Capex	22.5	146.5
Regulatory depreciation allowance (40 years) Regulated return on capital (6.25% real pre-tax) Opex (1.8% of Capex/year)	0.6 1.4 0.4	3.7 9.2 2.6
Revenue Adjustment (yr1)	2.4	15.5

- The graph of Econnect results show that similar revenue requirements would be required for both their 132kV and 245kV designs at 50km.
- 37. It is likely that these financing costs are an underestimate of those that will be required to finance offshore network assets in practice. For example, it is likely that transmission regulated returns will increase to match those allowed in the recent distribution price control review. Moreover, a return premium may be required given the additional risks that will exist for offshore network investments, e.g. heightened exposure

to premature termination by connectees and asset stranding, risks associated with adoption by new licensees of partially developed assets. A 40-year asset life may also be optimistic given environmental conditions and the rate of potential wind technology change (it would assume that cables would continue to be used when wind turbines are replaced after their 20 year design life). It is also likely that offshore operation and maintenance costs will differ from onshore rates (although, compared to overhead lines, higher cable repair costs may be offset by better reliability).

38. The revenue requirements calculated above assume a straight-line regulatory depreciation model and so would represent the revenues required in the first year only. Revenues in subsequent years will reduce as the assets are depreciated. To avoid this time variation in the TNUoS tariff differentials, the charging methodology uses annuities. An annuity calculated using the above parameters would result in a revenue recovery of 8.43% of the capital investment per annum. Assuming that the distance related unit costs derived above were incorporated in the tariff model, undersea cable expansion coefficients for the tariff would be as follows:

Unit Capital Cost £/MW/km	Tariff expansion coefficient £/MW/km/yr
1400	118.0
2000	168.6
For comparison, 400kV overhead line	9

These expansion coefficients include no locational security factor.

Transmission Network Use of System (TNUoS) Charge

- 39. As noted above, the TNUoS methodology calculates a network tariff which is the sum of the following components:
 - a. A locationally varying element, derived from a linearised loadflow model, which reflects the cost of financing (or the benefit of delaying) the incremental network capacity required to support an injection or off-take at each node.
 - b. A non-locationally varying element which is set such that the total revenue recovered is equal to that allowed under the price control and such that the proportion of total revenue collected from generators and suppliers is maintained.
- 40. Given the size of the expected undersea cable expansion coefficient, it is likely that offshore nodes would require the formation of new tariff zones.
- 41. The illustrative offshore values resulting the TNUoS charging methodology is as follows:

				15km Cable @ £1400/MW/km		60km Cable @	£1400/MW/km	60km Cable @	E2000/MW/km
Strategic area	Onshore connection node	Zone	Onshore tariff £/kW/yr	Tariff diffential £/kW/yr	Approx total tariff £/kW/yr	Tariff differential £/kW/yr	Approx total tariff £/kW/yr	Tariff differential £/kW/yr	Approx total tariff £/kW/yr
North West	Pentir	12	6.122	1.8	7.9	7.1	13.2	10.1	16.2
	Heysham	11	4.906	1.8	6.7	7.1	12.0	10.1	15.0
Greater Wash	Walpole	14	3.120	1.8	4.9	7.1	10.2	10.1	13.2
	Killingholme	11	4.906	1.8	6.7	7.1	12.0	10.1	15.0
Thames	Sizewell	15	1.323	1.8	3.1	7.1	8.4	10.1	11.4
Estuary	Kemsley	15	1.323	1.8	3.1	7.1	8.4	10.1	11.4

- 42. In this table the column labelled current zonal tariff represents the relevant onshore zonal tariff for 2005/6. The columns labelled "Tariff differential" shows the annual amount per kW that would be required to finance the specified cable length and unit capital cost. For example, the tariff differential of £7.1/kW/yr would mean that a 1000MW windfarm would pay £7.1m/per annum towards cables with estimated capital cost of £96m.
- 43. The columns labelled "Approximate total tariff" is simply the onshore zonal average plus the tariff differential to the offshore node. This illustrates the approximate magnitude of the offshore tariff but ignores the following details:
 - a. The differential should add to the specific onshore nodal tariff (rather than the zonal average). Note, however, that the onshore node should be within +/-£1/kW of the zonal average before the additional generation is added.
 - b. The onshore nodal value will vary as the power flow from the offshore node changes the onshore power flow pattern. This effect will be small compared to the offshore differential due to the size of the onshore expansion coefficient.

However, this effect could require a modification to be made to onshore zoning.

- c. Both onshore and offshore tariff values will be adjusted by a non-locational factor to reflect:
- i) The need to recover revenues associated with financing the network costs that do not vary with distance (i.e. switching facilities offshore and onshore).
- ii) The need to ensure that the revenue recovered from generation and suppliers remains in the ratio 27:73.

Both these effects are likely to be small compared to the size of the offshore tariff differential.

- 44. The above calculations assume the security factor for offshore networks is 1.0 i.e. the unit costs reflect the fact that adequate security/redundancy has been incorporated in the offshore network designs. If additional security is required, the tariff differentials will increase proportionately.
- 45. The above analysis also assumes that standard undersea expansion coefficients are used. In practice location specific expansion factors could be used, for example, reflecting the particular cable designs adopted. In bringing forward developments to the TNUoS charging methodology for Ofgem approval, NGC will need to consult and demonstrate that the developments meet the relevant objectives (facilitates effective competition, cost-reflectivity and takes account of developments to the transmission business).

Conclusions

- 46. This note has sought to illustrate the current GB transmission charging methodology and how tariffs for offshore networks could be derived should this methodology be extended to offshore areas. Illustrative network designs and associated capital cost estimates have been examined for this purpose. All annual figures assume that offshore assets receive regulated funding allowances consistent with onshore transmission assets in England & Wales (regulatory depreciation assumes 40 year asset life and the cost of capital is assumed to be 6.25% real pre-tax).
- 47. The examples calculated illustrate how certain parameters and unit costs used in the calculation of the tariff may need to be adjusted to reflect actual designs and network costs used offshore.

NGT Lewis Dale 12 April 2005.

Appendix 1: GB TNUoS Tariff for 2005/6

The GB TNUoS tariff, while calculated on a nodal basis, is presented as zonal averages. Generation tariff zones are chosen such that the nodal values are usually within +/-£1/kW of the zonal average. As supplier demand is resolved by the settlement system to GSP groups only (i.e. to the respective distribution network), the demand tariff is calculated for GSP group averages. These zones are shown on the following map and the 2005/6 tariff values are presented in the following tables.

2005/06 TNUoS Generation Zones

400kV Substations	
275kV Substations	
132kV Substations	
400kV CIRCUITS	
275kV CIRCUITS	
132kV CIRCUITS	
M 1 0 11 011	

Major Generating Sites Including Pumped Storage

Connected at 400kV Connected at 275kV Hydro Generation

0 0 0



2005/6 Final Tariff

Generation				
Zone No.	Zone Name	Zone Tariff(£kW)		
1	Peterhead	18.162236		
2	North Scotland	20.929759		
3	Skye	23.095483		
4	Western Highland	18.920247		
5	Central Highlands	15.360647		
6	Cruachan	15.852828		
7	Argyll	13.441972		
8	Stirlingshire	12.610665		
9	South Scotland	11.820471		
10	North East England	8.090616		
11	Humber, Lancashire & SW Scotland	4.906290		
12	Anglesey	6.122706		
13	Dinorwig	8.705520		
14	South Yorks & North Wales	3.120190		
15	Midlands & South East	1.322966		
16	Central London	-5.712196		
17	North London	-0.220327		
18	Oxon & South Coast	-0.698936		
19	South Wales & Gloucester	-2.552479		
20	Wessex	-4.951295		
21	Peninsula	-8.044943		

Demand					
Zone No.	Zone Name	HH Zonal Tariff (£/kW)	NHH Zonal Tariff (p/kWh)		
1	Northern Scotland	0.041110	0.005610		
2	Southern Scotland	4.114438	0.561693		
3	Northern	7.393664	0.970234		
4	North West	11.137060	1.461966		
5	Yorkshire	11.182059	1.487585		
6	N Wales & Mersey	11.210216	1.512416		
7	East Midlands	13.465848	1.804975		
8	Midlands	15.026957	2.062601		
9	Eastern	14.028455	1.909865		
10	South Wales	18.315906	2.368863		
11	South East	15.989410	2.167559		
12	London	18.516693	2.454909		
13	Southern	17.833397	2.446575		
14	South Western	20.489868	2.728435		

NB.

Generation tariffs are in respect of generation capacity as defined by the agreed Transmission Entry Capacity. Utilisation of this capacity must be demonstrated in negative charge zones.

The demand tariffs are in respect of the triad demand measured for half hourly (HH) metered customers and in respect of units delivered to non-half hourly (NHH) metered customers between 16:00hrs and 19:00hrs.

Appendix 2: Illustrative Network Designs

The capital cost estimates below relate to intervening assets between a sample wind farm (either 250MW at 15km or 1,000MW at 60km) and an existing onshore transmission system substation. They are illustrative only, are not based on any specific enquiries to equipment suppliers, and take no account whatsoever of any site-specific study or of physical or system conditions at any particular connection point.

The technical specification (e.g. voltage selection, number of cables etc) has not been optimised in any way to take account of local factors such as restrictions on siting onshore transformer stations, practicalities of multiple cable installation, or individual project's valuation of losses and redundancy. Those best placed to provide refined capex estimates are

250MW at 15km	£m
Offshore 33/132kV substation	3.00
Offshore platform	7.00
132kV, 3 core 140MVA cables (X2 @ £200k per km installed)	6.00
132/400kV transformer (X1)	1.38
400kV bay	1.50
Shunt reactor & bay	0.70
Sub Total	19.58
15% contingency	2.94
Total	22.52

the wind farm developers who have experience of Round 1 schemes or have generated outline connection schemes for the purposes of their Round 2 lease applications.

The capex estimates are intended as inputs of an appropriate order to the NGC transmission charging model with the purpose of deriving an indication of TNUoS tariffs that would result if that charging model were to be applied offshore.

The two designs are as follows:

- i) 250MW wind farm at 15 route km from onshore grid connection point (£23m)
- ii) 1,000MW wind farm at 60 route km from onshore connection point (£147m)

1,000MW at 60km	£m
Offshore 33/132kV substation	12.00
Offshore platform	9.00
132kV, 3 core 140MVA cables (X8 @ £200k per km installed)	96.00
132/400kV transformers (X5)	6.90
400kV bay	1.50
Shunt reactor & bay	2.00
Sub Total	127.40
15% contingency	19.11
Total	146.51

Assumptions

Technical solution

- AC solutions assumed, i.e. HVDC not considered.
- No optimisation to take account of specific local factors, or of particular project's valuation of losses or redundancy.

Asset boundaries

The boundaries of the assets under consideration are assumed to be;

- Offshore, on the busbar side of the switches at the end of the cables for each string of turbines where they terminate on a single offshore marshalling platform
- ii) Onshore, on the busbar side of the switchbays at the NGC substation where incoming circuits connect.

These boundary assumption exclude the gathering system of cables between individual turbines as well as the onshore substation. The new assets in question therefore comprise:

- The (single) offshore platform at which the cables at the end of turbine strings are gathered
- The switchgear on the platform (except the terminal switch on each string)
- The step-up transformers on the platform
- Export cables all the way to the onshore transmission system node to which they connect

- Terminal switchgear at the onshore grid connection point
- Reactive compensation equipment where necessary
- Transformation up to transmission voltage (For the purposes of this example it is assumed that additional transformer capacity would be required and no suitable existing capacity exists)

As more than one cable would be required to achieve the required rating in both scenarios, it is assumed that users and operators of the offshore network would not require additional cable routes to provide redundancy and full capacity in the event of a fault. (I.e. both users and operators would be satisfied with restricted capacity until cable repairs could be undertaken).

NGT Paul Neilson, 12th October 2004

ANNEX 3: The DTI Consultation Code of Practice Criteria

- 1. Consult widely throughout the process, allowing a minimum of 12 weeks for written consultation at least once during the development of the policy.
- 2. Be clear about what your proposals are, who may be affected, what questions are being asked and the timescale for responses.
- 3. Ensure that your consultation is clear, concise and widely accessible.
- 4. Give feedback regarding the responses received and how the consultation process influenced the policy.
- 5. Monitor your department's effectiveness at consultation, including through the use of a designated consultation co-ordinator.
- 6. Ensure your consultation follows better regulation best practice, including carrying out a Regulatory Impact Assessment if appropriate.

The complete code is available on the Cabinet Office's web site, address http://www.cabinet-office.gov.uk/servicefirst/index/consultation.htm



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