ofgem Promoting choice and value
for all gas and electricity customers

Transmission Access Review – Enhanced Transmission Investment Incentives: Update and Consultation on Further Measures

Document type: Consultation

Ref: 110/09

Date of publication: 8 September 2009

Deadline for response: 6 October 2009

Target audience: Electricity transmission licensees, conventional and renewable generators, distribution network operators, suppliers and customers

Overview:

Ofgem is committed to playing a full role in helping to reduce carbon emissions to tackle climate change. Following completion of the joint Ofgem/Department for Energy and Climate Change Transmission Access Review, we identified a range of measures designed to reduce or remove electricity transmission grid-related access barriers to connecting new generation. These measures included the development of enhanced transmission investment incentives. The aim of enhanced transmission incentives is to encourage the electricity transmission operators (TOs) to anticipate future demand from generators and invest efficiently to meet that demand, whilst still protecting customers from having to pay for new capacity that isn't required or significant cost overruns.

This consultation provides an update to our work on TO Incentives and details the investment projects which are expected to commence during the current transmission price control period. It sets out our updated thinking on an appropriate framework to facilitate additional investment, and seeks views on our proposed way forward taking into account interactions between this work and the output of the RPI-X@20 project.

Contact name and details:

Cheryl Mundie, Senior Manager - Electricity Transmission Policy
(cheryl.mundie@ofgem.gov.uk, 0141 331 6003)
David Hunt, Senior Manager - Electricity Transmission Policy
(david .hunt@ofgem.gov.uk, 020 7901 7429)

Team: Electricity Transmission Policy and Compliance

Context

Energy plays a critical role in the continued economic prosperity of Great Britain. Increasing the contribution that renewable generation makes to meeting electricity demand in GB is a critical part of Government's energy policy goals. The Energy White Paper 2007 set out the Government's international and domestic energy strategy to meet the long-term challenges we face in addressing climate change and maintaining the security of our energy supplies. In that paper, the Government announced a joint review of transmission access by Ofgem and the Department of Trade and Industry (DTI) (now the Department of Energy and Climate Change (DECC)). The Transmission Access Review (TAR) focused on the framework for the delivery of new electricity transmission infrastructure, the management and operation of existing grid capacity, and the operation of the grid. The need for the review was driven by the delays that a large volume of renewable and conventional generation face when seeking connection to the transmission system and the potential effects this will have, if not addressed, on achieving the Government's climate change targets and maintaining security of supply.

Following Ofgem and DECC's TAR Final Report in June 2008, a range of measures are being pursued which will improve access to the transmission network. An important element of these measures is our work to deliver an appropriate regulatory framework through enhanced transmission investment incentives ("TO incentives") to encourage the Transmission Owners (TOs) to take on the additional risk associated with investing in anticipatory investment, whilst protecting consumers from unnecessary and inefficient investment. The Transmission Owners (TOs) have identified a considerable amount of further system reinforcement in the run up to 2020, which they have nominated for further funding consideration as part of our work on TO incentives.

In this work, our focus is on projects which could be commenced within the current transmission price control period. We will take into account any relevant interactions with our RPI-X@20 review which is looking more fundamentally at the current approach to network regulation and developing recommendations for the way we regulate all of the energy networks in the future.

Associated Documents

Transmission Price Control related documents are listed here:
http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR4/ConsultationDecisionsResponses/Pages/Consultationdocumentdecisionsresponses.aspx

- Transmission Investment for Renewable Generation – Final Proposals. December 2004.
- Transmission Price Control Review 2007-12 – Final Proposals. December 2006.

Meeting the Energy Challenge - A White Paper on Energy. May 2007.
http://www.berr.gov.uk/files/file39387.pdf

Final Conclusions Report - GB Queue Management. July 2007.
http://www.nationalgrid.com/NR/rdonlyres/47B95865-0225-45C2-B3BE-F753821B1E1B/18039/FinalConclusionpaper.pdf

RPI-X@20 project publications. March 2008 to date.
http://www.ofgem.gov.uk/Networks/rpix20/Pages/RPIX20.aspx

Transmission Access Review related documents are listed here:
http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/tar/Pages/Traccrw.aspx

TO Incentives documents:

- Transmission Access Review – Initial Consultation on Enhanced Transmission Investment Incentives. December 2008
- Transmission Access Review - Enhanced Investment Incentives Open Letter: Consultation on Short Term Measures. February 2009
- Transmission Owner (TO) Incentives Licence Modification. March 2009

Other transmission access review documents:

- A Call for Evidence for a Review of Transmission Access. August 2007.
- Short Term Access Governance Report – Report to the Secretary of State. October 2007.
- Transmission Access Review – Interim Report to the Secretary of State. January 2008.
- Transmission Access Review – Analytical Discussion Document. April 2008.
- Transmission Access Review – Final Report to the Secretary of State. June 2008.

Table of Contents

Summary

Background

We proposed a range of measures with DECC through the Transmission Access Review (TAR) to reduce or remove grid-related access barriers for renewable and other low carbon generators. These are aimed at accelerating the connection of new generation to help achieve the UK share of the 2020 EU renewable energy targets.

A critical component of the TAR reforms is to ensure that transmission investment is not a barrier to the timely connection of new generation, for which we initiated two major workstrands:

1. 2020 Transmission System Study ("ENSG study"); and

2. Enhanced transmission investment incentives ("TO incentives").

Following on from the ENSG study, the Transmission Owners (TOs) have put forward proposals for £4.7bn of investment that they consider is likely to be required to accommodate the new generation connections needed by 2020. This is in addition to the £4 billion of investment in new capacity and asset replacement allowed in the current electricity transmission price control that runs from 2007 to 2012.

For a significant proportion of the investment identified by the ENSG study is currently proposed to commence construction within the current transmission price control. Our work on TO incentives aims to develop appropriate funding arrangements, as enhancements to the arrangements under the current transmission price control, in order to encourage the transmission companies to help deliver the necessary investment in a timely manner without exposing customers to excessive risk/and or inefficient costs.

We are committed to developing arrangements for enhanced incentives in a way that does not impact on efficient investments which are needed to support customer needs and facilitate the delivery of Government's 2020 targets. In December 2008 we issued a consultation which discussed the current funding arrangements for transmission investment and explained why we consider change is now needed to provide a framework for anticipatory investment, and discussed a range of issues that will need to be considered in taking this forward. It also set out how we intend to strike a balance between the need to minimise delay to investment and to protect customers and to split our work on TO incentives into short term measures (to address immediate barriers to investment) and further measures (to provide an appropriate framework for anticipatory investment commencing within the current price control period). We explained our intention to implement short term measures in Spring 2009 and to consider, following consultation, whether further measures could be introduced in Winter 2009 to facilitate additional investments that could commence during the current transmission price control period.

In April 2009 we implemented our proposed short term measures by providing a total of £12.5m of funding for initial pre-construction work on specific projects which

were not already funded during the current price control period. We highlighted that this pragmatic approach aimed to allow the TOs the opportunity to develop a more detailed needs-case and cost assessment for our further consideration in the next stage of the TO incentives work. We were clear that in providing this funding we did not create any expectation about future funding arrangements.

Way forward

This document explains the background to our TO Incentives work and sets out our proposed way forward and timetable for our work on TO incentives further measures to provide an appropriate framework to facilitate additional investment within the current transmission price control.

The document details the projects which the transmission companies have nominated for further funding consideration. It also sets out our proposed approach to developing an appropriate funding framework and outlines our plans to appoint consultants to review the robustness of the overall GB plans and to consider in more detail the projects nominated by the TOs for further funding. The assessment of individual projects will be prioritised to reflect their urgency for clarification of funding. To avoid unnecessary delay to construction timescales we therefore intend to focus initially on those projects which are proposed to begin construction before or during 2010/11. We discuss the issues to consider in developing the appropriate funding arrangements for relevant projects, including the scope and form of funding, where it will be important to take into account differences in risk profile and urgency for clarification of funding, and interaction with the existing funding arrangements. For some projects it will also be necessary to provide an appropriate licensing framework, which we will take forward separately.

We invite comments on the project nominated by the TOs and on our proposed approach to developing appropriate funding arrangements for relevant projects.

Timing and interaction with RPI-X@20 project

Our original timetable envisaged finalisation of our TO incentives proposals in Winter 2009 to allow for implementation of the relevant licence changes in April 2010.

Our work on TO incentives will be carried out in parallel with the RPI-X@20 project. We expect there to be significant overlap with the issues being considered under these two projects, which has led us to consider whether to adopt an alternative approach which allows for improved alignment between their respective outputs. This document sets out two alternative approaches. Both options have the advantage of ensuring greater alignment with the outputs of RPI-X@20, but they also have disadvantages. We would welcome views on the merits of these alternative approaches.

1. Background

Chapter Summary

This chapter sets out the background to this document. It also sets out a summary of the structure of the rest of this document.

Question box

There are no questions in this chapter.

Transmission Access Review (TAR)

1.1. The TAR Final Report published in June 2008 set out a package of measures that are targeted at helping facilitate the 2020 targets, by reducing or removing grid-related access barriers to connecting new generation. This is important in achieving the Government's 2020 renewable energy targets.

1.2. The TAR Final Report described clear steps to remove grid-related access barriers and to create the appropriate regulatory and commercial framework and rules to enhance the speed with which new generation (renewable and conventional) could connect to the transmission system. The TAR package includes individual workstrands targeted at helping facilitate the achievement of the 2020 targets; designing an efficient and enduring solution to transmission access; and speeding up connections in the short term before the other arrangements are in place.

1.3. The TAR Final Report noted that potentially long lead times for expanding transmission capacity could prevent the achievement of the Government's renewable targets. To address this challenge we launched two workstrands:

1. **2020 Transmission System Study ("ENSG study")** – we asked the three electricity Transmission Owners(TOs) - National Grid Electricity Transmission (NGET), Scottish Power Transmission (SPTL) and Scottish Hydro Electric (SHETL) - to undertake system studies to look at investment scenarios that would be capable of supporting the Government's 2020 targets; these studies were conducted under the auspices of the Electricity Networks Strategy Group (ENSG), which is jointly chaired by Ofgem and the Department of Energy and Climate Change (DECC)[1]; and

2. **Enhanced transmission investment incentives ("TO incentives")** – work to develop appropriate funding arrangements, as enhancements to the arrangements under the current transmission price control, in order to encourage the transmission companies to help deliver the necessary

[1] Formerly chaired by BERR prior to machinery of Government changes which led to the creation of DECC

investment in a timely manner without exposing customers to excessive risk/and or inefficient costs.

1.4. Our TO incentives work, which focuses on transmission investment within the current transmission price control period, has the aim of ensuring that the funding arrangements do not create a barrier to the investment needed to facilitate achievement of the 2020 targets whilst providing appropriate incentivises for the transmission companies to invest ahead of signalled need from users, and maintaining appropriate protection to consumers from the costs of inefficient investment. It incorporates the development of new financial incentives on the TOs to anticipate future demand from generators and to invest efficiently to meet that demand. These financial incentives will allow the TOs to earn higher returns for taking on more risk by investing sooner to expand transmission capacity.

December Consultation on TO incentives

1.5. Our initial consultation on the TO incentives project was published in December 2008 (referred to as the "December consultation")[2]. The December consultation discussed the current funding arrangements for transmission investment and explained why we consider change is now needed to provide a framework for anticipatory investment. We defined anticipatory investment as capital expenditure based on anticipated future requirements, rather than prevailing contracted requirements.

1.6. The December consultation also discussed a range of issues that will need to be considered in developing a framework for anticipatory investment. We set out our view that the financial incentives for anticipatory investment should enable the transmission companies to earn higher rates of return where they take on additional risk, complete investments in a timely way and deliver projects in a cost-effective manner, while ensuring consumers are protected from excessive risk of stranded investment and significant cost overruns. Conversely we set out that the companies should earn lower rates of return when they complete investments late, at excessive cost or where investments are not adequately utilised.

1.7. The December consultation also explained why, in taking forward our work on TO incentives, we planned to split our work into short term measures (to address immediate barriers to investment) and further measures (to provide an appropriate framework for anticipatory investment undertaken within the current transmission price control period). The December consultation explained our intention to implement short term measures in Spring 2009 and to consider, following further consultation within 2009, whether further measures could be introduced in Winter 2009 to facilitate additional investments that could commence during the current transmission price control period. We also invited the TOs to nominate projects for funding consideration as part of our short term measures, by 30 January 2009.

[2] For the Transmission Access Review – Initial Consultation on Enhanced Transmission Investment Incentives please visit the following link: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=94&refer=Networks/Trans/ElecTransPolicy/tar

1.8. We received 23 responses to the December consultation, all of which are available on Ofgem's website.[3] Respondents generally agreed that there is a need to establish a framework for anticipatory investment and supported our proposed two stage approach. In particular, respondents welcomed our proposal to provide funding for the pre-construction costs for specific projects through our proposed short term measures. Respondents also commented on issues relevant to the development of further measures, which are discussed in chapter 3. A detailed summary of responses to our December consultation is set out in Appendix 2.

TO incentives short term measures

1.9. On 27 February 2009 we issued an open letter and statutory consultation (referred to as the "February consultation"[4]) setting out our proposed way forward for the short term measures. The February consultation incorporated a statutory consultation on the associated licence changes.

1.10. The February consultation discussed the responses to the December consultation and detailed pre-construction work associated with a subset of projects identified in the ENSG Study which the transmission companies had nominated for funding consideration as part of our short term measures. The nominated projects were chosen by the TOs on the basis that pre-construction works should start immediately on these projects in order to retain the widest range of future network options. The February consultation also set out our intention to provide funding for pre-construction work on the specific projects nominated by the transmission companies which were not already funded during the current price control period.

1.11. In allowing funding for pre-construction activities we highlighted that this did not create any expectation about the future funding arrangements - the focus of our short term measures was on developing a simple, pragmatic approach to providing additional funding for pre-construction works which would allow the TOs to provide a more detailed needs-case and cost assessment for our further consideration in the next stage of the TO incentives work.

1.12. We received eight responses to the February consultation, in addition to the letters received from each of the three licensees giving their consent to the proposed modifications to their respective licences. All eight respondents were in favour of the proposed changes. In light of the support for our proposed approach we implemented the licence changes to give effect to our proposed short term measures on 1 April 2009[5].

[3] For responses to the December consultation please visit the following link: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=94&refer=Networks/Trans/ElecTransPolicy/tar

[4] For Transmission Access Review - Enhanced Investment Incentives Open Letter: Consultation on Short Term Measures. February 2009 please visit the following link: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=99&refer=Networks/Trans/ElecTransPolicy/tar

[5] For the Transmission Owner (TO) Incentives Licence Modification, which includes a discussion of responses to our February consultation, please visit the following link:

ENSG study

1.13. Closely related to our work on TO incentives is the system planning work under the ENSG study described above, that was carried out by the TO's and published by the ENSG. The Full ENSG Report[6], published in July 2009, has identified a large number of major transmission system projects designed to support the connection of new generation in each of its areas of investigation. The ENSG study highlights reinforcements which the TOs consider are most likely to commence in the near future. Further reinforcements are also identified for potential future consideration. The classification of the reinforcements has been supported by cost-benefit analysis based on the application of the current NETS Security and Quality of Supply Standard (SQSS) and taking account of forecast constraint cost avoidance.

1.14. The findings of the ENSG Study are an important input to our work on anticipatory investments. However the investment study does not supplant the TOs normal and ongoing programme of transmission system reinforcement works. We therefore asked the transmission companies to identify and provide further information on those projects they consider require additional or earlier funding during the current transmission price control period.

RPI-X@20 project

1.15. A key area of interaction with our work on TO incentives is the 'RPI-X@20' review. The RPI-X@20 review is a major project, initiated by Ofgem in March 2008, to consider the workings of the current approach to regulating GB's energy networks and develop recommendations for the future direction of regulatory policy. The RPI-X@20 project[7] is looking fundamentally at the RPI-X regulatory framework, which has been used to regulate Britain's energy networks for nearly 20 years. Appendix 2 of December consultation provided further information on the RPI-X@20 project, including its rationale and guiding principles.

1.16. We recognise that stakeholders have discussed a number of issues relating to regulation of investment, including anticipatory transmission investment, in the context of the RPI-X@20 review. In our December consultation we set out our proposed approach to dealing with interactions between our work on TO incentives and the RPI-X@20 review. We clarified that our work on the TO incentives project under TAR is focussed on the arrangements to apply to projects within the current price control period, i.e. Transmission Price Control Review 4 (TPCR4), while the RPI-X@20 project, is looking to develop recommendations for the way we regulate in the future. We have been clear from the start that we will not implement conclusions from RPI-X@20 retrospectively. However, we have also been clear that where lessons emerge from the review that can be implemented before the conclusion of the review to the benefit of consumers, we would seek to implement these.

http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=123&refer=Networks/Trans/ElecTransPolicy/tar

[6] For the ENSG 'Our Electricity Transmission Network: A Vision for 2020' Full Report please visit the following link: http://www.ensg.gov.uk/index.php?article=126

[7] For more information see: http://www.ofgem.gov.uk/Networks/rpix20/Pages/RPIX20.aspx

1.17. In Chapter 4 we discuss further the interaction with the parallel work being undertaken through the RPI-X@20 project, and set out some options for dealing with these interactions.

Structure of this document

1.18. Building on the December consultation and implementation of short term measures we set out in this document our proposed approach to taking forward further measures under the TO incentives work, to facilitate additional investments that could commence during the current transmission price control period.

1.19. The remainder of this document is structured as follows: Chapter 2 discusses the projects nominated by the TOs for funding consideration as part of the TO incentives project. Chapter 3 discusses the development of an appropriate funding framework for these projects. Chapter 4 discusses the way forward taking into account interactions with the RPI-X@20 project.

2. Projects nominated for funding consideration

Chapter Summary

This chapter discusses the projects nominated by the TOs for funding consideration as part of the TO incentives project, and outlines some key issues to consider in taking forward work to develop appropriate funding arrangements for these projects.

Question box

Question 1: Do respondents have any comments on the information provided on the projects nominated for funding consideration?

Question 2: Do respondents agree with our proposed approach for taking forward the assessment necessary for consideration of all requests for further funding during the current price control period, including SHETL's requests in relation to Knocknagael and the Shetland connection?

Introduction

2.1. Since our December and February consultations, we have continued to work with the TOs to identify projects for funding consideration within the current transmission price control.

2.2. This chapter identifies the projects nominated for funding consideration, and sets out some key issues we will need to consider in taking forward work to develop appropriate funding arrangements for these projects.

Project Nominations

2.3. Table 1 below outlines the project nominations which have been received from each transmission company. For each project, the table sets out the company's current view on when construction is planned to commence together with company's current estimate of the project cost.

2.4. The table also notes, for reference, which projects have been provided with funding for pre-construction works carried out during 2009/10 through the short term measures which were implemented in April 2009 (discussed in Chapter 1); the remaining projects nominated by the TOs had already been provided some pre-construction funding under the current transmission price control. A more detailed description of the projects is provided in Appendix 3.

Table 1: Project nominations

TO	Construction funding requested	Project	Cost £m	Pre-construction funding included in short term measures
NGET	Before or during 2010/11	East Anglia	281	Yes
	During TPCR4	Anglo-Scottish incremental works	183	Yes
		London	186	Yes
		North Wales	419	Yes
	After 2012/13	Central Wales	262	Yes
		Humber	555	Yes
		South West	286	Yes
SPTL	Before or during 2010/11	SPTL-NGET interconnection	88	No
	During TPCR4	East Coast upgrade	137	No
		East West upgrade	83	No
SHETL	Before or during 2010/11	Beauly-Blackhillock-Kintore	83	No
		Beauly-Dounreay	73	No
		Knocknagael	41	No
		Shetland (incl. offshore hub)	548 (679)	No
		Western Isles	302	No
SPTL/SHETL	Before or during 2010/11	Hunterston-Kintyre	123	No
NGET/SPTL	During TPCR4	Western HVDC	698	Yes
NGET/SHETL	After 2012/13 (only NGET has submitted construction funding)	Eastern HVDC	350	Yes

Note: The costs forecasts include pre-construction and construction costs and are based on the latest estimates provided by the transmission companies.

Key issues to consider in developing funding arrangements

Interactions with existing funding arrangements

2.5. While the majority of the projects identified above were not envisaged at the time of setting the current transmission price control, for all projects there is a potential interaction with the existing funding arrangements. A specific area of interaction relates to the revenue drivers which apply to deep reinforcement works.

2.6. Revenue drivers were introduced under the current transmission price control and are designed to accommodate uncertainty as to the level and timing of future investment requirements at the time the current transmission price control was set. The revenue drivers supplement the baseline level of funding by allowing automatic adjustment of revenue applying in the situation that the generation connected and/or associated boundary flows are different to that assumed in setting the baseline. Details of the revenue drivers applying to each transmission licence were set out in the December consultation, and include local revenue drivers applying to transmission reinforcements works local to, and triggered by, individual generators and deep revenue drivers applying to deep reinforcement works associated with changes in boundary flows.

2.7. For SPT and SHETL, deep revenue drivers are in place for specific investments which would be triggered when the volume of generation connections in a given part of the network exceeds a given level. In the case of SHETL the current transmission price control settlement established a number of conditions reflecting the forecast

efficient total costs (£m) of works that might be needed to accommodate increased flows across certain boundaries in SHETL's network. We made similar provision in Special Condition J5 of SPT's licence but the licence does not specify any conditions in relation to specific deep reinforcements.

2.8. For NGET, the deep revenue drivers are applied to deep reinforcement works associated with changes in boundary flows across specific parts of the network, and therefore also take into account changes in demand. NGET's revenue drivers are defined in terms of forecast efficient unit costs (£m/MW) applied to the changes in the level of export from or input to defined zones, relative to given baseline values. In addition, for NGET a separate deep revenue driver, again defined in terms of forecast efficient unit costs (£/MW), applies to changes in the transfer capability across the network boundary between Scotland or England.

2.9. It will be important to take account of interactions with these existing deep revenue drivers in developing appropriate funding arrangements under our TO incentives work.

2.10. The need to take account of interactions with the revenue driver mechanism is particularly important for certain projects nominated by SHETL. In April 2009 SHETL formally requested a change to Table 1 of Special Condition J5 of its transmission licence which would allow the funding for Knocknagael reinforcement to be unbundled from the North of North West boundary revenue driver item and brought forward. SHETL has also confirmed that the project has received planning consent and is ready to commence construction. Shortly after providing notice to the Authority in relation to Knocknagael, SHETL also submitted a request to amend the relevant licence provisions in relation Beauly-Blackhillock-Kintore.

2.11. In determining any further funding allowances it will also be important to take account of funding already provided for relevant projects in relation to pre-construction works, whether under the current transmission price control or as part of the TO incentives short term measures discussed in Chapter 2.

Licencing issues

2.12. It will be necessary to provide an appropriate licensing framework for any projects which lie outside the authorised areas of a given transmission licensee. For example, further work is required to define the licensing framework for the proposed Shetland connection nominated by SHETL. Further work on the licensing framework may also apply in the event that the development of aspects of electricity transmission infrastructure is opened to competition. We will take forward our work on licensing issues separately to our work on TO incentives.

Assessment of project information

2.13. We are currently undertaking work to assess the requests for further funding during the current price control period, including SHETL's requests in relation to

Knocknagael and the Shetland connection. We are in the process of appointing consultants to assist our review of the projects nominated by the transmission companies.

2.14. We envisage that the consultant's work will comprise two elements. The first element will comprise a review of the TOs' overall investment plan for the GB transmission system, including the ENSG study; the second element will involve a detailed review of individual projects for which the TOs have requested funding within the current price control.

2.15. Our review of the TOs' investment plans will include an assessment of the key assumptions underlying the TO's assessment of need for transmission capacity, the range of uncertainties the TOs took into account when evaluating this need, and the appropriateness of the methodology used to evaluate the costs and benefits associated with each investment.

2.16. The review of individual projects will cover the adequacy of the technical design, the appropriateness of the construction programme, and the TO's estimate of project costs.

3. Developing an appropriate funding framework

Chapter Summary

This Chapter sets out how we will take forward the development of our proposals for TO incentives further measures, with reference to the specific projects nominated by the TOs for funding consideration.

Question box

Question 1: Do respondents consider that we have appropriately summarised the views of respondents to our December consultation?

Question 2: Do respondents have any views on our proposed funding framework based on categorisation of projects in terms of risk profile and urgency for clarification of funding?

Question 3: Do respondents agree that our work should focus on projects which are planned to commence construction within the current transmission price control?

Question 4: Do respondents have any views on the appropriate scope and form of funding for projects with different risks?

Question 5: In terms of scope of funding, do respondents have any views on whether our funding consideration should include funding of pre-construction work in projects not due to commence construction within the current transmission price control? Do respondents have any views on the options for provision of such funding?

Question 6: Do respondents have any views on the appropriate "building blocks" for a funding mechanism and the principles which should be adopted in the development of funding mechanisms for the projects nominated for our consideration under TO incentives?

Question 7: Do respondents have any views on the interactions with the RPI-X@20 project or adoption of a competitive approach for the projects nominated by the TOs?

Introduction

3.1. Building on the December consultation and implementation of short term measures, this chapter sets out our proposed approach to taking forward further measures under the TO incentives work.

December consultation

3.2. The December consultation set out our view that the current arrangements could be adapted to develop an appropriate funding framework for additional investment

within the current price control period. Our December consultation also outlined the options for the design of incentives for anticipatory investment. We noted a number of factors that would need to be considered in designing an incentive mechanism including the length of the incentive period, the level of incentivised costs, the conditions under which the revenue stream is triggered, the range of allowed returns and the interaction between funding arrangements for anticipatory investment and other funding mechanisms already included under the price control. We also set out a potential incentive mechanism to reflect asset utilisation risk, with returns linked to the proportion of capacity that is utilised.

3.3. In the December consultation we also identified the interactions of the TO incentives work with the RPI-X@20 review and the next transmission price control. We noted that investment incentives will also be reviewed as part of the RPI-X@20 review and stressed that there must be consistency between both projects. In addition we highlighted that there may be scope to develop a competitive approach to transmission and stated that we believe that such an approach could bring significant customer benefits relative to the costs of introducing competitive processes.

Responses to our December consultation

3.4. Respondents to our December consultation had mixed views on the appropriate design of a framework for anticipatory investment. Five responses supported the introduction of financial incentives on the TOs based on asset utilisation risk, while six argued that higher returns are inappropriate on the basis that the asset utilisation risk is low. Some respondents also suggested that Ofgem should sign off 'no regret' investments where these had been identified by long term investment studies, such as the ENSG report. One respondent also requested a workshop on our further measures.

3.5. Six responses commented on the development of a competitive approach to transmission. Three respondents were opposed on the grounds that investment might be delayed while a further three considered that there might be merit in pursuing a competitive approach. A detailed summary of responses to our December consultation is set out in Appendix 2.

Discussions with the TOs

3.6. Since the publication of our December consultation we have continued to work with the TOs to identify appropriate funding mechanisms to facilitate additional investment during the current price control period.

3.7. NGET has stated that it is willing to accept an enhanced incentive mechanism that would provide higher returns for efficient investment in transmission capacity ahead of user commitment. The incentive mechanism NGET propose is based on the existing revenue drivers introduced during TPCR4. The mechanism would take the form of a profit-sharing incentive: 75% of costs would be automatically passed through without the need for an ex-post efficiency check; and the remaining funding

would be dependent upon actual utilisation of delivered capacity and a predetermined £/kW unit cost allowance (UCA). By removing the existing requirement for evidence of user commitment for the pass-through element of costs, NGET argue that the mechanism removes a potential barrier to anticipatory investment. In addition, NGET considers that its mechanism would provide a reward for undertaking investment in an efficient manner because the TOs would have an incentive to ensure that investments are not build which are not utilised.

3.8. SPTL has stressed that the 2020 Transmission Study has demonstrated there is a strong needs case for proceeding with the projects they have nominated during the current price control period. SPTL has therefore expressed a strong preference for a funding mechanism for these investments which is similar to the Transmission Investment for Renewable Generation (TIRG) mechanism. Under the TIRG mechanism, Ofgem sets an ex-ante funding allowance for each project that can subsequently be modified in the event of a variation in forecast costs.

3.9. SHETL believes that the existing deep revenue driver mechanism, though complex, could be modified to provide an appropriate framework for anticipatory investment. SHETL considers this could be achieved by allowing construction to begin before a clear needs case has arisen. SHETL therefore proposes that the existing revenue driver provisions be revised to cover the Knocknagael, Beauly-Blackhillock-Kintore and Beauly-Dounreay reinforcements be revised so as to provide earlier funding and to reflect up to date cost forecasts, and an additional revenue driver be created for the Western Isles link.

Categorisation of projects

3.10. We currently consider that the projects nominated for our consideration as part of our TO incentives further measures may be categorised according to:

- **The urgency for clarification on funding:** based on the TO's latest plans, in the case of eight projects construction is expected to begin before or during 2010/11, six projects are expected to commence during 2011/12 and four during TPCR5.

- **The risk profile of the projects:** discussions with the TOs suggest that the nominated projects vary in the extent to which the needs case for the project is based on anticipated (as opposed to contracted) requirements, and in the level of certainty that such requirements will materialise.

3.11. We expect that further information received from the TOs, together with the findings of our consultants discussed in Chapter 2, will clarify the appropriateness of these classifications and allow us to make a robust assessment of each of the classification that should apply to each investment.

Scope of funding arrangements

3.12. The options for the extent of funding provided to individual projects (the **scope of funding**) range between: providing no additional funding at this stage (and therefore deferring funding consideration until the next price control); and providing full funding including construction funding.

3.13. Taking into account the variations in the projects nominated by the TOs (in terms of urgency and risk profile as discussed above), we consider that our work to develop appropriate funding arrangements should focus on projects which are planned to commence construction within the current transmission price control. One approach would be to allow full funding of projects which are identified as standard risk. This would entail allowing both efficient pre-construction and efficient construction costs for these projects. Funding arrangements for such projects could potentially be based on existing mechanisms although, as highlighted above, it will be important to take into account interactions with existing revenue drivers.

3.14. Depending on the planned timing of construction work, projects which are identified as higher risk may also be eligible for full funding, provided there is adequate protection to consumers. For example, the funding mechanism for higher risk projects could provide for an enhanced return if the TO takes on additional risk and successfully anticipates future requirements.

3.15. For projects which are not planned to commence construction within the current transmission price control, we will need to consider whether it would be appropriate to provide pre-construction funding, over and above any pre-existing funding allowances. This might be achieved through an extension of the short term funding measures which were established in April 2009 for 2009/10. Options include: providing full pre-construction funding for the whole range of projects (in order to keep open a range of network options); or only providing funding for a limited number of specific projects, thereby minimising the risk of inefficient spend. Alternatively we could provide an aggregate allowance for pre-construction funding, and TOs could make their own judgements on the allocation of this funding between projects. In each of these cases, it will be important to clearly identify the scope of works covered by the relevant funding allowance, and to take account of interactions with potential future funding of construction work, where applicable. For some projects it may not be appropriate to provide any funding during the current transmission price control, deferring consideration for the next transmission price control review.

3.16. We welcome views on our proposed framework for identifying the scope of funding for individual projects consistent with their respective risk profile and the level of urgency for clarification of funding. We also seek respondents' views on whether our funding considerations should include funding of pre-construction work in projects not due to commence construction within the current transmission price control. We will set out our proposed scope of funding for individual projects in a future document.

Form of funding arrangements and parameters

3.17. In terms of the **form of the funding mechanism**, the options include using or adapting existing mechanisms, and developing a new mechanism. Our views on detailed mechanism design, including the detailed "building blocks" and application to individual projects will be informed by the views of interested parties, our assessment of the risk profile of the projects nominated for our consideration, and the work of the RPI-X@20 project.

3.18. For any given mechanism we will also need to define the **parameters**, or the specific values or ranges of values, which apply to relevant projects. For all types of funding mechanism we expect that the parameters will include an efficient cost allowance and will define any conditions which need to be met before the release of funding. We will also need to define the extent to which TOs are exposed to incentivised costs, the length of incentivised period, and also the applicable range of returns available to the transmission company under the incentive mechanism. We also anticipate that the overall returns for individual projects may need to be limited by a "cap and collar" arrangement.

3.19. Other design elements include the time period over which the applicable revenue allowances are recovered and the extent to which any profiling of that allowance is linked to actual expenditure. For example, under the current price control, the baseline allowances are based on an assumed profile of total capital expenditure. However, the additional allowances under the revenue drivers are linked to the profile of actual expenditure on the relevant works. As such, while the revenue stream for the baseline allowances apply from the same year in which the associated expenditure is assumed to occur, the revenue drivers incorporate a delay in the release of the revenue stream and provide for financing costs covering the period until the additional revenue allowance is reflected in an increased cashflow.

3.20. We note that if we were to adopt an approach which does not provide for deferred cashflow, then, depending on materiality of the relevant allowances this may have implications for the timing of changes which give effect to changes to transmission charges. This issue is discussed in more detail in Chapter 4.

3.21. We intend to set out our thoughts on the form of funding arrangements in our next consultation on enhanced TO incentives. We welcome views on the principles which should be adopted in the development of funding mechanisms for the projects nominated for our consideration under TO incentives.

Interaction with RPI-X@20 review

3.22. Going forward, we will continue to consider and reflect the interactions between the TO incentives work and the RPI-X@20 review. In particular, as discussed in Chapter 4, we will consider the appropriate timing of any suggested changes to incentives for future transmission investment.

3.23. In addition, as discussed in our December consultation, we are of the view that a number of the projects nominated by the transmission companies as part of our TO incentives work may be suitable candidates for a competitive approach. However we also believe that implementation of a competitive approach should not unduly delay efficient anticipatory investment. We intend to continue to consider the merits of pursuing a competitive approach to transmission and will provide an update in a future document.

4. Way forward

Chapter Summary

This chapter sets out our next steps and seeks views on options for the way forward, taking into account interaction with the RPI-X@20 project.

Question box

Question 1: Do respondents have any views on our proposed approach for taking forward our work on TO incentives further measures?

Question 2: Do respondents have any views on the potential adoption of an accelerated process for certain licence changes?

Question 3: Do respondents have any views on the options for alignment with the outputs of the RPI-X@20 project?

Introduction

4.1. This chapter considers the approach and timetable for taking forward further measures under our TO incentives work to facilitate further investment within the current transmission price control period. It also seeks views on alternative options which may provide for improved alignment between the framework for enhanced TO incentives and the outputs of the RPI-X@20 project. It also discusses the potential to adopt an accelerated process for the implementation of certain licence changes, taking into account the interaction with the transmission charge-setting process.

Next steps

4.2. As set out in Chapter 2, to support our development of appropriate funding arrangements for relevant projects, we are in the process of appointing consultants to review the robustness of the overall GB plans and to consider in more detail the projects nominated by the TOs for further funding.

4.3. The assessment of individual projects will be prioritised, reflecting the urgency for clarification of funding for the project in question. To avoid unnecessary delay to construction timescales we therefore intend to focus initially on those projects which are proposed to begin construction before or during 2010/11.

4.4. We are also considering holding an industry workshop, at an appropriate stage in our consultation process. Facilitated by Ofgem, this workshop would provide an opportunity for the TOs to present their proposed investments and views on an appropriate funding framework, and would include presentation of our consultants'

findings. We welcome views on this approach, which we will confirm in our next document.

4.5. In a future document, we will set out our detailed thinking on the appropriate funding framework for the projects nominated by the TOs for our consideration under the TO incentives work, with reference to the categorisation of projects in terms of urgency and risk profile as discussed in Chapter 3.

4.6. Our final proposals will set out our proposed funding mechanism and relevant parameters applicable to individual projects, to be implemented through changes to the transmission licences subject to statutory consultation.

Timing

4.7. We are committed to developing appropriate funding arrangements for anticipatory investment in a way that does not impact adversely on efficient investments which are needed to support customer needs and facilitate the delivery of the Government's 2020 targets. This is why we moved quickly to deliver pre-construction funding for the financial year 2009/10 for a number of projects through our TO incentives short term measures discussed in Chapter 1.

4.8. Our December consultation set out our intention to consider, following further consultation, whether further measures could be introduced in Winter 2009. This would facilitate additional investments that could commence during the current transmission price control period. We envisaged that the relevant licence changes would be implemented in April 2010, following finalisation of our proposals in Winter 2009. This timetable sought to ensure that the TOs have clarity of funding arrangements for priority investments which will proceed during the financial year 2010/11.

Interaction with transmission charge-setting

4.9. We note that our process of establishing appropriate funding arrangements for additional investment within the current transmission price control may interact with the parallel processes by which National Grid sets the Transmission Network Use of System (TNUoS) tariffs, through which revenue allowed to the three transmission licensees is recovered from users.

4.10. National Grid is responsible for calculating annual transmission charges that apply from 1 April each year. National Grid must provide 150 days notice at the end of October if it intends to modify transmission charges and must provide two months notice of the final TNUoS tariffs. This means that National Grid must provide notice of the final TNUoS tariffs for 2010/11 at the end of January.

4.11. Our proposed timetable, in which the licence changes would be implemented in April 2010, may imply that additional revenue allowances would be determined too late to be taken into account in setting 2010/11 TNUoS tariffs. In turn this might

mean that the TOs would be unable to recover an additional revenue stream in 2010/11 in relation to investments undertaken before or during 2010/11, although we would expect them to be able to recover the funding for these investments in the 2011/12 financial year.

4.12. We are considering whether there may be scope to implement licence changes through an accelerated process. Under this approach we could issue the relevant statutory consultation in timescales consistent with the transmission charge setting process, and which would allow the relevant licence changes to be reflected in final 2010/11 TNUoS tariffs published at the end of January.

4.13. Depending on mechanism design and timing of expenditure (discussed in Chapter 3), this approach may potentially provide for the TOs to receive an additional revenue stream in 2010/11, and avoid the need to provide for additional financing costs associated with deferred cashflows. It would also provide the relevant TOs with earlier certainty of the funding arrangements for relevant projects.

4.14. We consider that this approach, which would be subject to determination of an appropriate funding mechanism and parameters for relevant projects in the accelerated timescales, may only be suitable for a subset of projects. In particular, it is more likely to be suitable for projects which are suited to being funded under the existing price control mechanisms. It is therefore likely that, if this accelerated process were adopted for some licence changes, it would remain necessary to progress further licence changes through a longer process: the accelerated licence changes would need to be progressed separately from our final proposals for enhanced transmission investment incentives. We would welcome views on the merits of this approach.

Alignment with RPI-X@20 outputs

4.15. We have been considering the relationship between our work on TO incentives and our parallel work on the RPI-X@20 project. As highlighted in Chapter 1 and in our December consultation, we expect significant overlap with the issues being considered under these two projects. We set out below some alternative options which may provide for improved alignment between the outputs from our RPI-X@20 work and the TO incentives project.

4.16. Our current expectation is that the arrangements coming out of the RPI-X@20 review will apply from TPCR5 onwards. However, we have been clear from the start of the RPI-X@20 review that, where there are lessons emerging from the review that could be implemented ahead of this to the benefit of consumers, we would seek to implement them. A key question for our TO incentives work is how best to address projects which are expected to commence construction work before TPCR5. Based on current TO plans, of the overall £4.7b of investment identified by the TOs in their ENSG report, there are 14 of these projects, with a combined value of £3.2bn.

4.17. As discussed above, our current timetable for work on TO incentives would see finalisation of our proposals in Winter 2009, with implementation of relevant licence

changes in April 2010. However, the work of the RPI-X@20 project is not due to be completed until later in 2010. This gives rise to the prospect that the funding framework introduced through our work on TO incentives, might be supplanted shortly thereafter by a modified approach resulting from the RPI-X@20 review. This does not seem desirable. We consider that aligning the TO incentives work with the outputs of the RPI-X@20 project is likely to create a more stable investment environment. However, consistent with the objectives of our work, it is also important that this does not result in any unnecessary delay to required transmission investments.

4.18. With this in mind we have identified two alternative ways forward which would result in better alignment without creating funding uncertainty which would adversely impact on investments:

- Option 1 – delaying publication of our proposals under TO incentives
- Option 2 – reducing the scope of funding provided under TO incentives

4.19. Both approaches have the advantage that they would potentially allow better alignment between the final enhanced incentive mechanisms and the conclusions of the RPI-X@20 project. This would potentially avoid the situation where investments which are separated by only a short time interval are funded through different mechanisms, thereby potentially improving regulatory certainty. However, both options are also associated with potential disadvantages.

4.20. Under Option 1, we could delay our final proposals for TO incentives to March 2010. This would have the advantage of allowing more time to synchronise our proposals under the TO incentives work with the output of the RPI-X@20 project whilst still providing clarity of funding for investments which are due to commence in the year from 1 April 2010. However, this approach is likely to preclude adoption of the accelerated process set out above, and is therefore likely to mean that the TOs would be unable to recover an additional revenue stream until 2011/12. Depending on the scale of the investment planned to be undertaken before or during 2010/11 this may potentially place the TOs under increased risk of financial stress.

4.21. Under Option 2, we could potentially provide for split funding arrangements for projects which will begin before the RPI-X@20 project has concluded. Under this approach, relevant projects would receive partial funding under arrangements which would probably be in line with existing mechanisms. We would then expect that any further funding to be provided at a future stage, under potentially enhanced incentive mechanisms, would be consistent with the findings of the RPI-X@20 project. This approach would have the advantage of removing barriers to allowing the TOs to proceed with priority investment in a timely way whilst allowing the opportunity for any future funding to be provided, where appropriate, in line with the RPI-X@20 conclusions . However, it may create uncertainty as to future funding arrangements, which may have undesirable consequences. Further, under this approach it would be necessary to define appropriate breakpoints in relevant projects, such as completion of pre-construction work, with funding up to this point

provided through the TO incentives work. It is possible that the need to define such break-points will result in higher costs.

Way forward

4.22. We welcome views on the alternative options set out above. Following our review of respondents' views, we will provide updated thinking on our implementation approach in our next document.

Further information

4.23. Appendix 1 sets out both the details for responding to this consultation and the appropriate contact details should you have any questions. It also sets out a list of all the key areas where we have sought respondents' views in this document. Respondents' views are also welcomed on any other aspect of this document.

Appendices

Index

Appendix 1 - Consultation Response and Questions

1.1. Ofgem would like to hear the views of interested parties in relation to any of the issues set out in this document.

1.2. We would especially welcome responses to the specific questions which we have set out at the beginning of each chapter heading and which are replicated below.

1.3. Responses should be received by 6 October 2009 and should be sent, preferably in electronic format by e-mail to:

transmissionaccessreview@ofgem.gov.uk

or alternatively by post to:

Cheryl Mundie
Senior Manager - Transmission
Ofgem
70 West Regent Street
Glasgow
G2 2QZ.

1.4. Unless marked confidential, all responses will be published by placing them in Ofgem's library and on its website www.ofgem.gov.uk. Respondents may request that their response is kept confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

1.5. Respondents who wish to have their responses remain confidential should clearly mark the document/s to that effect and include the reasons for confidentiality. It would be helpful if responses could be submitted both electronically and in writing. Respondents are asked to put any confidential material in the appendices to their responses.

1.6. Any questions on this document should, in the first instance, be directed to Cheryl Mundie (e-mail: cheryl.mundie@ofgem.gov.uk, tel: 0141 331 6003) or David Hunt (e-mail: david.hunt@ofgem.gov.uk, tel: 020 7901 7429).

CHAPTER: One

There are no questions in this chapter.

CHAPTER: Two

Question 1: Do respondents have any comments on the information provided on the projects nominated for funding consideration?

Question 2: Do respondents agree with our proposed approach for taking forward the assessment necessary for consideration of all requests for further funding during the current price control period, including SHETL's requests in relation to Knocknagael and the Shetland connection?

CHAPTER: Three

Question 1: Do respondents consider that we have appropriately summarised the views of respondents to our December consultation?

Question 2: Do respondents have any views on our proposed funding framework based on categorisation of projects in terms of risk profile and urgency for clarification of funding?

Question 3: Do respondents agree that our work should focus on projects which are planned to commence construction within the current transmission price control?

Question 4: Do respondents have any views on the appropriate scope and form of funding for projects with different risks?

Question 5: In terms of scope of funding, do respondents have any views on whether our funding consideration should include funding of pre-construction work in projects not due to commence construction within the current transmission price control? Do respondents have any views on the options for provision of such funding?

Question 6: Do respondents have any views on the appropriate "building blocks" for a funding mechanism and the principles which should be adopted in the development of funding mechanisms for the projects nominated for our consideration under TO incentives?

Question 7: Do respondents have any views on the interactions with the RPI-X@20 project or adoption of a competitive approach for the projects nominated by the TOs?

CHAPTER: Four

Question 1: Do respondents have any views on our proposed approach for taking forward our work on TO incentives further measures?

Question 2: Do respondents have any views on the potential adoption of an accelerated process for certain licence changes?

Question 3: Do respondents have any views on the options for alignment with the outputs of the RPI-X@20 project?

Appendix 2 – Summary of responses to December consultation

This appendix provides more detail on the responses received to the December consultation. It follows the same structure as the questions asked in that document. We have also included comments made not in direct response to a question.

Chapter 2: Transmission investment funding arrangements

Do respondents agree that there is a need to put in place a framework for anticipatory investment in order to facilitate the achievement of the 2020 targets?

Thirteen respondents agreed that there is a need to establish a framework for anticipatory investment. Of these respondents, eight argued that this framework is needed to facilitate the achievement of the 2020 targets. However, one response questioned the meaning of the word 'anticipatory' on the grounds that there is a known requirement to reinforce the transmission system, while a further six respondents recommended a 'strategic' approach to transmission reinforcement. Of these six respondents three specifically noted that a strategic approach is needed to realise the 2020 targets.

Do respondents agree that such arrangements should be developed for application to transmission projects commencing within the current transmission price control?

Eleven respondents agreed that new funding arrangements should be developed for application to transmission projects commencing during the current price control period. Of these eleven respondents one noted that delaying consideration of this issue until TPCR5 would put greater stress on the need to deliver capacity quickly to meet the 2020 targets, thereby increasing the risk that consumers pay for unnecessary or premature investment.

Do respondents agree that this work should first focus on identifying and addressing the barriers to investing ahead of need, before putting in place appropriate incentives to undertake investment ahead of need?

Eleven respondents supported our proposed two stage approach, though three of these respondents, together with one other, stressed that the barriers to investing ahead of need were already well understood. Two respondents argued that all work should be progressed in parallel, while a further respondent expressed concern that the two stage approach might delay the implementation of a framework for anticipatory investment. In addition one respondent rejected the expression 'investing ahead of need' because it is well established that investment in transmission capacity is needed now.

Chapter 3: Developing a framework for anticipatory investment

Do respondents have any views on the proposals received from the transmission companies?

Ten respondents commented on the proposals submitted by the transmission companies, though a further two required further information. Two respondents agreed that a portion of project costs should be passed through and four supported enhanced incentives for anticipatory investment. Of these four respondents, two agreed with the Scottish transmission companies that these incentives should apply to individual projects.

However, one respondent expressed concern that the transmission companies could earn higher rates of return than under standard price control conditions for anticipatory investment. The respondent noted that a number of projects identified by the ENSG report should not be eligible for an enhanced rate of return as these are 'no regret investments' for which a firm need has been established under a range of scenarios. The same respondent also argued that the risk borne by the transmission companies is reduced if Ofgem approves the investment. One other response suggested that the incentive mechanisms developed by Scottish Power and NGET may be pitched too high, as both proposals allow rates of return which exceed that available under the Transmission Investment for Renewable Generation (TIRG) mechanism. A further response similarly noted that both proposals have a favourable profile, though the respondent felt that the central case rates of return appeared reasonable, while another argued that the upper rate of return proposed by Scottish Power is disproportionately generous.

One respondent noted the differences between NGET's proposal and those of the Scottish companies, and therefore suggested that it may be appropriate to introduce distinct incentive schemes for each TO to reflect their particular circumstances. A further respondent questioned the inclusion of local works in NGET's proposal, while another expressed concern that the deep revenue driver UCAs may not be applicable to Scotland. Commenting on the Scottish Power submission, one respondent also stressed that obtaining consents is not entirely beyond the control of the transmission companies as planning proposals should be sympathetic to the demands of objectors.

Do respondents consider that we have appropriately considered the impediments to anticipatory investment identified by the transmission companies?

Three respondents agreed that we correctly identified the current barriers to anticipatory investment, though one noted that the risk of disallowance should also be addressed as part of the review of existing regulatory funding arrangements. A further respondent argued that the only barrier is the lack of confidence that anticipatory investment will be remunerated, though it was also noted that the transmission companies have statutory and licence duties to develop an efficient, coordinated and economical system of electricity transmission irrespective of the provisions of the current price control settlement.

Do respondents consider that it is appropriate to take the current arrangements as a starting point for developing a framework for anticipatory investment?

Six respondents agreed that the current arrangements are a suitable starting point for developing a framework for anticipatory investment. Of these six, one respondent argued that this framework should closely reflect standard price control arrangements given current capital market conditions. In contrast one response

opposed the use of existing arrangements on the grounds that under existing funding arrangements the transmission costs borne by users are highly uncertain and lack transparency.

Have we identified the relevant issues to consider in taking this work forward?

One respondent agreed that the relevant issues were identified in the December consultation document. Two respondents argued that a framework for anticipatory investment should be founded on the findings of the ENSG study, while four responses stressed the importance of a flexible approach which can accommodate new and changing demands for capacity. Of these four one argued that the certainty of future demand for capacity varies and stressed that while the current focus is on expanding system capacity to meet the 2020 targets, the economic life of new infrastructure requires consideration of how generation might develop beyond 2020.

One response stressed the importance of agreeing a definition of 'anticipatory' investment while another highlighted the risk that investment which should form part of the baseline during the price control period is overlooked and is then declared as anticipatory. A further respondent highlighted the difficulty of determining whether investment is utilised, noting that utilisation can vary over time. In addition one respondent argued that, compared to NGET, the Scottish transmission companies have less user commitment information.

One respondent suggested that third parties, such as the Crown Estate, could provide the required user commitment, while another suggested that there may be opportunities to learn from other regulated industries that have delivered large investment programmes. A further respondent noted that it is important to consider how information arising from TAR developments (which will better signal the nature of user requirements) will inform the selection of alternative network development options. One respondent noted that any requirement on the transmission companies to disclose details of future investment may increase the risks (particularly planning risks) associated with new investments or affect competition in the generation market, while another suggested that we consider how to support future connections of emerging technologies such as wave and tidal energy. In addition one response stated that it is necessary to consider more innovative ways of financing transmission investment, such as using the proceeds of the EU ETS.

Do respondents have any views on the appropriate balance of risk and reward in relation to investment undertaken on an anticipatory basis?

Five respondents suggested that the transmission companies should receive a higher rate of return for investing ahead of user commitment in capacity which is subsequently utilised, but a lower rate of return if anticipated demands do not ultimately materialise. A further respondent argued that early delivery of capacity and the use of new technology should be rewarded with a higher rate of return, while another argued that there is merit in lowering the rate of return for investments which are deferred and therefore delay the connection of new generation.

One respondent supported our view that the incentive mechanism should be consistent with the risks and returns available in other contexts and also stressed, together with another, that the level of returns must reflect the risk profile of the

investment. A further respondent noted that there is a risk of discouraging future investment if the transmission companies do not receive appropriate allowances for anticipatory investment, while another noted that the balance between risk and reward must take account of current financial market uncertainties. In addition one response stated that as investment is necessary to meet the UK's renewable obligations, the risk exposure of the transmission companies should be reduced by removing the ex post tests of user commitment or utilisation.

Six respondents, however, argued that the transmission companies are not exposed to significant asset utilisation risk as there is a known requirement to reinforce the transmission system. Of these six, one respondent therefore opposed the use of an incentive mechanism, arguing instead that Ofgem should sign off specific projects on the basis of a long term investment study such as the ENSG and award a rate of return which reflects the lower risks to which the transmission companies are exposed. A further three also noted that 'no regret' investments or those started on the basis of full user commitment should be identified immediately but not subject to a premium rate of return, though another doubted Ofgem's ability to scrutinise (potentially) large numbers of projects and determine efficient costs and completion dates.

Two respondents also stated that risks should be shared equally between consumers, generators and the transmission companies. A further respondent stressed the need to achieve a balance between timely delivery of capacity and protecting consumers from inefficient or premature investment, especially because the costs and urgency of investment are substantial.

Do respondents have any views on our proposed way forward, including our proposal to separate short term work to address current and immediate barriers, from further measures, developed over a longer timescale to allow funding for investments that could be commenced under the current transmission price control?

Eleven respondents agreed with our proposed way forward. A further respondent endorsed the introduction of short term measures that will allow a range of reinforcement options to be explored and developed prior to user commitment. In addition one respondent argued that further measures should take account of the ENSG report, the GB SQSS review, the offshore transmission regime and Transmission Access Review and must be fully consulted upon, while a further response urged that 'no regret' investments are progressed as soon as possible.

Do respondents have any views on how we propose to address interactions with the RPI-X@20 project?

Five respondents stressed that the findings from the RPI-X@20 review should not disturb the arrangements established for anticipatory investment for projects commencing during the current transmission price control. One respondent stressed that our work on TO incentives must be consistent with RPI-X@20, while another argued that the longer term solutions should be developed in the context of this project. In contrast one response questioned whether the focus and objectives of the RPI-X@20 review are suited to addressing the barriers and issues associated with anticipatory investment and stressed, along with another respondent, that the proposed further measures should be implemented before the review concludes.

Chapter 4: Addressing short term barriers to anticipatory investment

Noting the large allowances that have already been made, what measures could be taken to enhance the regulatory treatment of pre-construction costs, whilst protecting consumers from expenditure that turns out not to be efficiently incurred?

Eleven respondents welcomed our proposal to provide funding for the pre-constructions costs associated with specific projects. Of these respondents one argued that pre-construction engineering studies are especially important where new technologies or innovative approaches might be used, five noted that pre-construction costs make up only a small proportion of the total investment and three stated that allowing pre-construction work to proceed can reduce the delivery time of projects. A further respondent urged that pre-construction works should be undertaken for a range of reinforcement options, so that there are a number of potential schemes ready to proceed once demand for capacity becomes more certain.

In contrast, one respondent stressed that though pre-construction costs are small it is important that any investment is appropriate, while another argued that to the extent that an allowance has already been made for these costs additional funding should not be required. In addition, one respondent argued that too much emphasis is being placed on the funding of pre-construction works at the possible expense of other areas and, together with one other, suggested that there is no clear definition of 'pre-construction costs'.

There were mixed views on the potential approaches for providing earlier funding for pre-construction costs for specific projects. Two respondents supported a mixture of pass-through and incentivisation, while another argued that an approach which requires Ofgem to set the allowed costs ex-ante would maintain an efficiency incentive. A further response also argued that costs should be set ex-ante, but suggested that all agreed costs should be passed through rather than subject to a mixture of pass through and incentivisation. Another response recommended that pre-construction costs are funded in line with expenditure, while a further respondent supported the 'logging-up' of expenditure and proposed a mechanism to allow pre-construction costs to be shared between users and transmission companies. One respondent however argued that this approach creates regulatory uncertainty over funding, while another stated that 'logging-up' expenditure would weaken the efficiency incentive and might result in steeper price changes than consumers were expecting.

Do you agree with our view that there is a less compelling case to revise the existing local works revenue driver provisions, and that short term improvements could be better focused on finding arrangements for deep infrastructure works?

Six respondents stated that there is a less compelling case to revise existing local works revenue driver provisions. A further response agreed that the current local revenue driver mechanism is adequate, but noted that there are certain locations where shared assets may be required to establish new connections in an area and therefore it may be worthwhile revising the relevant revenue driver. One respondent stressed that the provision of local works remains an important area of regulatory oversight, while another argued that the option for anticipatory investment should be

retained for local works as such works may require a higher level of user commitment than can be reasonably supported by generators.

What are your views on the enhancements that could be made to the funding arrangements for deep infrastructure works, and do you consider that we should focus our attention on delivering quick wins in the short term?

One respondent commented in detail on the deep revenue driver mechanism. It was noted that the mechanism, though extremely complex, is capable of funding efficient reinforcement of the transmission system. Instead, the problem is the limited application of the mechanism in the current drafting of the licence, particularly because the trigger for the release of funding is dependent upon the volume of generation connected to the system. The respondent therefore proposed that the trigger condition be revised to reflect the volume of 'contracted generation capacity' and also requested greater clarity on the process for modifying the revenue driver. A further respondent stressed that the deep revenue driver arrangements should be designed to cover both boundary investment and additional 'collectors'.

Two respondents recommended that the short term focus should be on funding pre-construction costs for specific projects. A further four noted that certain projects could be advanced ahead of user commitment. Of these four, one argued that Ofgem should urgently identify and agree regulatory funding for 'no regret' reinforcements similar to the Transmission Investment for Renewable Generation (TIRG) mechanism, while two responses stressed that if projects are advanced strong oversight will be required to avoid inefficient investment and discrimination, particularly where the TO has generation interests. A further respondent noted that the focus on short term wins should not obscure the importance in the long term of aligning investor and operator incentives with those of users and end customers.

Chapter 5: Way forward

Do respondents have any comments on our proposed approach?

Five responses supported our proposed approach. One requested a workshop on the proposed further measures and argued that the key issues going forward (such as capex and risk allocation) might be better accommodated within a constructive engagement framework with direct consumer representative involvement, provided this were appropriately funded. One respondent also suggested that, once agreed, further measures must be kept under review while another stressed their preference for regulatory support for connecting renewable generation rather than creating discriminatory commercial arrangements.

Do respondents have any views on our proposed consultation process for taking forward the development of our proposed short term measures and further measures?

One response supported the proposed timetable. In contrast one argued that deferring the further measures until winter 2009 is unnecessary, while another expressed concerns that the proposed further measures may not be delivered in time to facilitate the achievement of the 2020 targets. Similarly, a further respondent argued that an enduring solution might need to be developed over an extended

period and as such intermediate measures may be required to ensure specific works can progress in 2010/11. In addition, one respondent urged that short term measures are delivered by spring 2009, while another recommended that the interaction of our TO incentives work with the CAP161-166 proposals should be considered.

Other comments

Information availability

One respondent suggested that the transmission owners and the GB System Operator should be required to publish information on network investments. This information would allow generator developers to monitor the development of new capacity and therefore would assist project location decisions.

Cost recovery

One response noted that the December consultation estimates £6 billion of investment could be required to meet the 2020 targets. The respondent argued that it is unclear how much of this investment could be advanced and how this would impact upon transmission charges.

Competitive approach to major projects

One respondent was in favour of developing a competitive approach for the provision of transmission infrastructure, and another suggested that we should consider the benefits of opening up new projects to competition. Two respondents suggested there might be merit in pursuing a competitive approach where this would deliver discernable cost benefits and did not delay investment. It was also noted that this issue requires further consideration, and should take account of the offshore transmission regime. Three respondents opposed a competitive approach, on the grounds that a competitive process would delay construction and increase costs.

Other approaches for delivering transmission capacity

Two respondents argued that it is necessary to ensure that the transmission companies maximise the use of existing assets. Another argued that the TOs should be incentivised not just to build new lines but also to increase capacity by any means possible, for example through innovative control and protection techniques.

Interaction with the offshore transmission regime

One respondent argued that the proposals should be extended to include investment in offshore transmission assets where appropriate. More specifically, a further respondent noted that it is difficult for a potential offshore transmission owner (OFTO) to undertake pre-construction works before they have been selected by competitive tender. It was therefore proposed that any party should be able to undertake and recover the costs of design works.

Current financial market uncertainties

Two respondents highlighted that current market conditions have made it more difficult to raise finance. One noted that the cost of capital is now significantly above that assumed in TPCR4, while another argued that the transmission sector should not be overlooked should any form of public sector support be necessary to safeguard the achievement of the 2020 targets.

Interconnection with Europe

One respondent stressed that early discussion and co-ordination with Ofgem's European counterparts will be essential in creating the appropriate regulatory framework.

Appendix 3 – Projects nominated for funding consideration

1.1. This appendix provides more information on the projects nominated by the transmission companies for funding consideration during the current transmission price control period as part of our TO incentives work. The appendix is divided into three sections, one for each of the transmission companies. Each section provides a high level overview of the nominated projects and the latest cost forecast of each project profiled by year. In addition each section details the increase in the capacity of relevant transmission boundaries as the proposed projects are commissioned.

1.2. The information set out in this appendix was provided by the transmission companies in response to an information request we issued on 13 August 2009. We have not yet assessed this information but are in the process of appointing consultants to support our review of the individual projects for which the TOs have requested funding within the current price control. We will provide an update on our consultant's work in our next consultation document.

National Grid Electricity Transmission

Project nominations

The table below lists the nine projects that NGET has nominated for funding consideration during the current price control period. Note that the Western HVDC link and the Eastern HVDC link have also been nominated by SPT and SHETL respectively.

NGET project nominations

Project	Description
Anglo-Scottish incremental	Series compensation of the Harker-Hutton 400kv circuits. Reconductor Harker to Hutton and Hutton to Quernmore Tee 400kV circuits.
Central Wales	New Central Wales to Ironbridge 400kV circuit and new 400kV Central Wales substation for the connection of multiple TAN8 wind generation sites.
East Anglia	Reconductor Bramford to Norwich to Walpole 400kV circuits. Extend Bramford 400kV substation. New 400kV overhead line circuit from Bramford to Twinstead Tee.
Eastern HVDC link (with SHETL)	HVDC link from Hawthorne Pit to Peterhead. New 400kV substation at Hawthorne Pit and uprating of Hawthorne Pit - Norton to 400kV operation.
Humber	HVDC link from Humber to Walpole and associated substation works at Humber and Walpole.
London	Hackney to Waltham Cross 400kV upgrade. Tilbury to Warley to Elstree 400kV upgrade (pre-construction funding only).
North Wales	Series compensation Pentir-Deeside and Trawsfynydd to Treuddyn circuits. Second Pentir to Trawsfynydd 400kV circuit. Reconductor Trawsfynydd to Treuddyn Tee 400kV circuit. New Wylfa to Pentir circuit. Replace SPT (Manweb) 132kV circuits. New 400/132kV substation at Penisarwuan. New 400kV substation at Wylfa. Extension of Pentir 400kV substation.
South West	New 400kV overhead line to Seabank, cutting into existing Hinkley-Melksham route to create Hinkley-Seabank, plus Melksham-Bridgewater. Extend Seabank substation and modify Bridgewater substation. New 400kV substation at Hinckley.
Western HVDC link (with SPT)	HVDC sub-sea cable from Hunterston to Deeside. New 400kV substation at or near Hunterston. New 400kV substation at Deeside.

Costs breakdown

1.3. The tables below show the latest cost profiles broken down by year of the nine projects nominated by NGET. Note that as part of our short term measures we provided funding for all nine projects for specific pre-construction works undertaken in 2009/10 only. We will take this funding into account when determining future funding allowances.

Anglo-Scottish incremental

£m (2008/9 prices)	**09/10**	**10/11**	**11/12**	**12/13**	**13/14**	**14/15**	**15/16**	**16/17**	**17/18**	**Total**
Pre-construction	1.5	5.0	4.0	1.0						11.5
Construction			47.0	73.0	43.0	8.0				171.0

Central Wales

£m (2008/9 prices)	**09/10**	**10/11**	**11/12**	**12/13**	**13/14**	**14/15**	**15/16**	**16/17**	**17/18**	**Total**
Pre-construction	0.5	2.2	2.8	3.0	2.0					10.5
Construction				15.0	80.0	91.0	65.0			251.0

East Anglia

£m	**09/10**	**10/11**	**11/12**	**12/13**	**13/14**	**14/15**	**15/16**	**16/17**	**17/18**	**Total**
Pre-construction	2.2	3.7	3.6	3.0						12.5
Construction		16.0	58.3	32.1	60.2	49.7	40.5	11.3		268.1

Note: The East Anglia project comprises four reinforcements. NGET provided the costs of two of these reinforcements in 2008/9 prices and two in 2009/10 prices. The figures above therefore represent a mix of 2008/9 prices and 2009/10 prices.

Eastern HVDC

£m (2008/9 prices)	**09/10**	**10/11**	**11/12**	**12/13**	**13/14**	**14/15**	**15/16**	**16/17**	**17/18**	**Total**
Pre-construction	0.2	0.8	2.8	0.3						4.1
Construction										0.0

Note: Only NGET has nominated the Eastern HVDC for construction funding at this time. The pre-construction costs shown will be shared between SHETL and NGET.

Humber

£m (2008/9 prices)	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	Total
Pre-construction	1.0	1.5	3.5	7.0	7.0					20.0
Construction					45.0	175.0	175.0	140.0		535.0

London

£m (2008/9 prices)	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	Total
Pre-construction	0.5	3.0	2.0				2.0			7.5
Construction			4.0	52.3	69.9	43.0	9.4			178.6

Note: The pre-construction funding requested in 2015/16 is for the proposed Tilbury to Warley to Elstree 400kV upgrade. NGET has not requested any construction funding for this project.

North Wales

£m (2008/9 prices)	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	Total
Pre-construction	0.8	4.5	7.2	7.0	3.0					22.5
Construction			17.0	65.0	114.0	110.0	70.0	20.0		396.0

South West

£m (2008/9 prices)	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	Total
Pre-construction	0.6	2.0	2.0	3.0	3.0	2.0				12.6
Construction				8.0	90.0	110.0	55.0	10.0		273.0

Western HVDC

£m	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	Total
Pre-construction	2.5	5.1	4.4							12.0
Construction			25.0	49.0	84.0	81.0	35.0			274.0

Note: While the Western HVDC link has also been nominated by SPT, the costs shown here are for NGET only. The works undertaken by NGET will include the development of a new substation at Deeside and (together with SPT) the construction of a sub-sea HVDC cable from Hunterston to Deeside. NGET provided the costs of the substation in 2009/10 prices and the costs of the HVDC cable in 2008/9 prices.

Transmission boundary capacity

1.4. The tables below show the increase in the capacity of relevant transmission boundaries as the projects nominated by NGET are commissioned. The tables are presented by region.

(1) Anglo Scottish

Boundary AS1 (B1)

GW	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Baseline	2.8					2.8						2.8
Approved reinforcements												
TIRG related	-					0.5						0.5
TO incentives projects												
Anglo-Scottish incremental	-					-						1
Western HVDC	-					-						1.75
Eastern HVDC	-					-						1.5
Total	2.8					3.3						7.55

Boundary AS2 (B7)

GW	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Baseline	3.7					-						-
Approved reinforcements												
TIRG related	-					3.25						3.3
TO incentives projects												
Anglo-Scottish incremental	-					1.25						1.5
Western HVDC	-					2.5						2
Eastern HVDC	-					0.5						1
Total	3.7					7.5						7.8

Boundary AS3 (B7a)

GW	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Baseline	5.3					-						-
TO incentives projects												
Anglo-Scottish incremental	-					5.45						5.75
Western HVDC	-					-						2
Eastern HVDC	-					-						1
Total	5.3					5.45						8.75

(2) East Anglia

Boundary EC3

GW	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Baseline	4.5					4						1.75
TO incentives projects												
East Anglia	-					-						2.5
East Anglia+Humber	-					-						0.75
Total	4.5					4						5

Note: One component of the East Anglia project involves the installation of Quadrature Boosters in the Norwich to Walpole circuit. This reinforcement is closely linked to the Humber project. In this table the combined impact of both on the capacity of Boundary EC3 is shown as East Anglia+Humber.

Boundary EC4

GW	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Baseline	11.25					13						9.25
TO incentives projects												
East Anglia	-					-						3.75
East Anglia+ Humber	-					-						0.25
Total	11.25					13						13.25

Note: One component of the East Anglia project involves the installation of Quadrature Boosters in the Norwich to Walpole circuit. This reinforcement is closely linked to the Humber project. In this table the combined impact of both on the capacity of Boundary EC4 is shown as East Anglia+Humber.

Boundary EC5

GW	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Baseline	5					3.5						2.75
TO incentives projects												
East Anglia	-					1.25						4.75
East Anglia+Humber	-					-						0.5
Total	5					4.75						8

Note: One component of the East Anglia project involves the installation of Quadrature Boosters in the Norwich to Walpole circuit. This reinforcement is closely linked to the Humber project. In this table the combined impact of both on the capacity of Boundary EC5 is shown as East Anglia+Humber.

Boundary EC6

GW	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Baseline	4					4						3.5
TO incentives projects												
East Anglia	-					1						2
Total	4					5						5.5

(3) Humber

Boundary EC1

GW	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Baseline	4.25					4.25						5.5
TO incentives projects												
Humber	-					-						2.25
Total	4.25					4.25						7.75

(4) London

Boundary LN1 (B14)

GW	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Baseline	10.3					11.5						12.25
TO incentives projects												
London	-					-						1.5
Total	10.3					11.5						13.75

(5) North Wales

Boundary NW1

GW	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Baseline	1.32					1.32						1.32
TO incentives projects												
North Wales	-					-						4.18
Total	1.32					1.32						5.5

Boundary NW2

GW	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Baseline	1.6					1.6						1.6
TO incentives projects												
North Wales	-					-						3.25
Total	1.6					1.6						4.85

Boundary NW3

GW	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Baseline	3.5					3.5						3.25
TO incentives projects												
North Wales	-					2						2
Total	3.5					5.5						5.25

Boundary NW4

GW	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Baseline	5.25					4.5						5.5
TO incentives projects												
Western HVDC	-					-						1
Total	5.25					4.5						

Note: The Western HVDC link providing any 'capability' on Boundary NW4 is subject to the ability to reverse the HVDC link post fault; the ability to achieve this has not been confirmed.

(6) South West

Boundary SW1

GW	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Baseline	4.5					4.5						3.25
TO incentives projects												
South West	-					-						3
Total	4.5					4.5						6.25

Note: The maximum secured power flow across SW1 is limited by stability constraints and the capacity quoted for this boundary in 2020/21 is reflective of this limitation, which would arise during typical summer conditions.

Boundary SW2

GW	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Baseline	2.5					3.25						4
TO incentives projects												
South West	-					-						1.25
Total	2.5					3.25						5.25

(7) Wider System

Boundary WS01 (B8)

GW	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Baseline	11					10.5						8.75
TO incentives projects												
Humber	-					-						2.25
Total	11					10.5						11

Boundary WS02 (B9)

GW	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Baseline	12					12						11
TO incentives projects												
Humber	-					-						1
Total	12					12						12

Scottish Power Transmission

Project nominations

1.5. The table below provides a high level overview of the five projects SPT has nominated for additional or advanced funding consideration during the current price control period. Note that Western HVDC link and the Hunterston-Kintyre link have been jointly nominated with NGET and SHETL respectively.

SPT project nominations

Project	Description
East Coast upgrade	Uprate the existing transmission corridor south from Kincardine towards Edinburgh to 400kV operation to create an east coast 400kV transmission corridor from Kintore (in SHETL's licensed) area to Kincardine, Grangemouth and on to a new substation called Harburn (near Livingstone).
East West upgrade	Uprate the northern side of the Strathaven-Wishaw-Kaimes route to 400kV operation. Uprate the cable sections on the Torness-Eccles double circuits by installing a second 400kV cable per phase on both circuits.
Hunterston-Kintyre	Install 132kV subsea cables between southern Kintyre and Hunterston.
SPT-NGET interconnection	Series compensation of SPT-NGET interconnection by installing Series Capacitors at Strathaven, Elvanfoot, Moffat and Eccles.
Western HVDC	HVDC sub-sea cable from Hunterston to Deeside. New 400kV substation at or near Hunterston. New 400kV substation at Deeside.

Costs breakdown

1.6. The tables below show the cost profile broken down by year of the projects nominated by SPT. Note that as part of our short term measures we provided funding for the Western HVDC link for specific pre-construction works undertaken in 2009/10 only. In addition under the current transmission price control SPT was provided with funding for pre-construction

works on the East Coast upgrade, East West upgrade and SPTL-NGET interconnection. We will take these allowances into account when determining future regulatory funding.

East Coast upgrade

£m (2009/10 prices)	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	Total
Pre-construction	0.2	0.4	1.3							1.9
Construction			7.0	24.0	43.0	42.0	19.0			135.0

East West upgrade

£m (2009/10 prices)	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	Total
Pre-construction	0.2	0.5	1.9							2.6
Construction			8.0	14.0	24.0	24.0	10.0			80.0

Kintyre-Hunterston

£m (2009/10 prices)	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	Total
Pre-construction	0.9									0.9
Construction		22.8	34.9	36.5	27.7					121.9

Note: The table shows the total costs of the project that will be shared between SPT and SHETL.

SPT-NGET interconnection

£m (2009/10 prices)	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	Total
Pre-construction	0.3	0.6	2.0							2.9
Construction		5.0	15.0	27.0	27.0	11.0				85.0

Western HVDC: SPT costs

£m (2009/10 prices)	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	Total
Pre-construction	2.5	5.1	4.4							12
Construction			25.0	74.0	126.0	122.0	53.0			400

Note: While the Western HVDC link has also been nominated by NGET, the costs shown here are for SPT only.

Transmission boundary capacity

1.7. The tables below show the increase in the capacity of relevant transmission boundaries as the projects nominated by SPT are commissioned.

Boundary B4

MW	**09/10**	**10/11**	**11/12**	**12/13**	**13/14**	**14/15**	**15/16**	**16/17**	**17/18**	**18/19**	**19/20**	**20/21**
Baseline	1650	1650	1650	1650	1650	1650	1650	1650	1650	1650	1650	1650
Approved reinforcements												
TIRG - Inverarnan	-	150	150	150	150	150	150	150	150	150	150	150
TIRG - Beauly-Denny	-	-	-	-	1250	1250	1250	1250	1250	1250	1250	1250
TO incentives projects												
East Coast upgrade	-	-	-	-	-	-	700	700	700	700	700	700
Total	1650	1800	1800	1800	3050	3050	3750	3750	3750	3750	3750	3750

Boundary B5

MW	**09/10**	**10/11**	**11/12**	**12/13**	**13/14**	**14/15**	**15/16**	**16/17**	**17/18**	**18/19**	**19/20**	**20/21**
Baseline	2650	2650	2650	2650	2650	2650	2650	2650	2650	2650	2650	2650
Approved reinforcements												
TIRG - B5 Works	100	550	550	550	550	550	550	550	550	550	550	550
TPCR4 - Interconnector	-	-	500	500	500	500	500	500	500	500	500	500
TO incentives projects												
East Coast Upgrade	-	-	-	-	-	-	450	450	450	450	450	450
Western HVDC link	-	-	-	-	-	-	250	250	250	250	250	250
Total	2750	3200	3700	3700	3700	3700	4400	4400	4400	4400	4400	4400

Boundary B6

MW	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Baseline	2200	2200	2200	2200	2200	2200	2200	2200	2200	2200	2200	2200
Generation Closures	-	-	-	-	-	-	-	-300	-300	-300	-300	-300
Approved reinforcements												
TIRG - Interconnector	-	600	600	600	600	600	600	600	600	600	600	600
TPCR4 - Interconnector	-	-	500	500	500	500	500	500	500	500	500	500
TO incentives projects												
East Coast Upgrade	-	-	-	-	-	-	-	250	250	250	250	250
East West Upgrade	-	-	-	-	-	-	200	200	200	200	200	200
SPTL-NGET Interconnection	-	-	-	-	-	900	900	900	900	900	900	900
Western HVDC							1600	1600	1600	1600	1600	1600
Total	2200	2800	3300	3300	3300	4200	6000	5950	5950	5950	5950	5950

Note: Delivery of 900MW increment in B6 capacity via Series Compensation in 2014/15 is contingent upon completion of the Torness-Eccles cable reinforcement. The capital expenditure associated with this cable reinfocement is captured as part of the East-West upgrade.

Scottish Hydro Electric Transmission Ltd

Project nominations

1.8. The table below lists the seven projects SHETL has nominated for additional or advanced funding consideration during the current price control period. Note that the Eastern HVDC link and the Hunterston-Kintyre link have also been nominated by NGET and SPT respectively. However SHETL has only requested pre-construction funding for the Eastern HVDC link.

SHETL project nominations

Project	Description
Beauly-Blackhillock-Kintore	Reconductor existing 275kV double circuit with higher capacity conductor.
Beauly-Dounreay	Install second circuit on existing 275kV tower structures and install Quadrature Boosters on the 132kV circuits between Beauly and Shin. At Dounreay substation install second Supergrid Transformer and upgrade 275kV and 132kV busbars to double configuration.
Eastern HVDC (with NGET)	HVDC link from Hawthorne Pit and Peterhead. New 400kV substation at Hawthorne Pit and uprating of Hawthorne Pit - Norton to 400kV operation.
Hunterston-Kintyre link (with SPT)	132kv sub-sea link between Hunterston and southern Kintyre.
Knocknagael	Establish new 275kV substation at Foyers tee point, marshal circuits and move Inverness demand centre from congested 132kV network to Knocknagael substation.
Shetland link (incl. offshore hub)	Install 600MW HVDC link between Kergord on Shetland and Blackhillock, with intermediate offshore hub.
Western Isles link (incl. Lewis infrastructure)	450MW HVDC link between Grabhir on Lewis and Beauly. Install 132kV infrastructure between HVDC terminal at Grabhir and Stornoway GSP.

1.9. Three of the seven projects (Beauly-Blackhillock-Kintore, Beauly-Dounreay and Knocknagael) currently fall under the existing deep revenue driver mechanism introduced as part of the current price control. The details of the relevant revenue drivers are specified on a project-by-project basis in Special Condition J5 of SHETL's licence. SHETL has also previously requested a price control adjustment in relation to two of the seven projects. In March 2008 SHETL advised that they intended to request that Ofgem modify its price control allowances to enable it to fund investment in both projects. The Shetland link and Western Isles link have now been nominated for funding consideration as part of our TO incentives work.

1.10. As detailed in the table, the Shetland project involves the installation of a 600MW HVDC link between Lewis and Beauly. In response to a call for projects by the European Commission under its European Economic Plan for Recovery (EEPR) SHETL has also submitted an application for funding to provide an intermediate offshore platform in the Shetland link and increased rating of the portion of the link to the south. If successful this funding would be for half of the estimated £130m incremental cost of works.

Costs breakdown

1.11. The tables below show the cost profile broken down by year for the projects nominated by SHETL. Separate tables are provided for the Shetland link and the Shetland link including offshore hub. Note that SHETL did not request any funding for pre-construction costs as part of our short term measures as under the transmission price control we provided pre-construction funding for a range of projects.

Beauly-Blackhillock-Kintore

£m (2009/10 prices)	**09/10**	**10/11**	**11/12**	**12/13**	**13/14**	**14/15**	**15/16**	**16/17**	**17/18**	**Total**
Pre-construction	1.2	1.1								2.3
Construction	5.1	13.0	3.0	11.2	36.3	12.3				81.0

Beauly-Dounreay

£m (2009/10 prices)	**09/10**	**10/11**	**11/12**	**12/13**	**13/14**	**14/15**	**15/16**	**16/17**	**17/18**	**Total**
Pre-construction	1.2									1.2
Construction		21.3	24.0	26.0						71.3

Eastern HVDC

£m (2009/10 prices)	**09/10**	**10/11**	**11/12**	**12/13**	**13/14**	**14/15**	**15/16**	**16/17**	**17/18**	**Total**
Pre-construction	0.2	0.8	2.8	0.3						4.1
Construction										0.0

Note: While NGET has nominated the Eastern HVDC for pre-construction and construction funding, SHETL has requested pre-construction funding only at this point in time. The pre-construction costs shown will be shared between SHETL and NGET.

Kintyre-Hunterston

£m (2009/10 prices)	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	Total
Pre-construction	0.9									0.9
Construction		22.8	34.9	36.5	27.7					121.9

Note: The table shows the total costs of the project that will be shared between SPT and SHETL.

Knocknagael

£m (2009/10 prices)	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	Total
Pre-construction										0.0
Construction	5.9	24.9	10.0							40.7

Shetland link

£m (2009/10 prices)	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	Total
Pre-construction	0.4	0.3								0.7
Construction		123.6	117.7	190.5	99.3	16.0				547.0

Shetland link including offshore hub

£m (2009/10 prices)	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	Total
Pre-construction	0.6	1.1								1.6
Construction	0.1	152.6	158.7	237.4	112.2	16.0				677.0

Western Isles link including Lewis infrastructure

£m (2009/10 prices)	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	Total
Pre-construction	0.4	0.0								0.4
Construction	8.0	101.9	106.1	75.2	10.7					301.8

Transmission boundary capacity

1.12. The tables below detail the increase in the capacity of relevant transmission boundaries as the projects nominated by SHETL are commissioned. The tables do not include the Western Isles and Shetland connections as these projects are

within zones rather than across boundaries and as such do not directly impact on the boundary capacity figures. The Eastern HVDC link would impact on boundaries 2 and 4 in SHETL's area but is also not included because SHETL has not requested construction funding for this project at this point in time.

Boundary B0

GW	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Baseline	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
TO incentives projects												
Beauly-Dounreay	-	-	-	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	0.15	0.15	0.15	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25

Boundary B1

GW	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Baseline	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Approved reinforcements												
Beauly-Denny	-	-	-	-	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
TO incentives projects												
Knocknagael	-	-	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Beauly-Blackhillock-Kintore	-	-	-	-	-	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Total	0.4	0.4	0.475	0.475	1.275	1.775	1.775	1.775	1.775	1.775	1.775	1.775

Boundary B3

GW	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Baseline	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
Approved reinforcements												
Inverarnan substation		0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Future reinforcements												
Kintyre-Hunterston					0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Total	0.21	0.35	0.35	0.35	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5

Note: The proposed Kintyre 132kV reinforcement is required to address non-compliance of the network within Boundary 3.

Appendix 4 – The Authority's Powers and Duties

1.1. Ofgem is the Office of Gas and Electricity Markets which supports the Gas and Electricity Markets Authority ("the Authority"), the regulator of the gas and electricity industries in Great Britain. This Appendix summarises the primary powers and duties of the Authority. It is not comprehensive and is not a substitute to reference to the relevant legal instruments (including, but not limited to, those referred to below).

1.2. The Authority's powers and duties are largely provided for in statute, principally the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Act 2004, as well as arising from directly effective European Community legislation. References to the Gas Act and the Electricity Act in this Appendix are to Part 1 of each of those Acts.[8]

1.3. Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This Appendix must be read accordingly[9].

1.4. The Authority's principal objective when carrying out certain of its functions under each of the Gas Act and the Electricity Act is to protect the interests of existing and future consumers, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the shipping, transportation or supply of gas conveyed through pipes, and the generation, transmission, distribution or supply of electricity or the provision or use of electricity interconnectors.

1.5. The Authority must when carrying out those functions have regard to:

- the need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met;
- the need to secure that all reasonable demands for electricity are met;
- the need to secure that licence holders are able to finance the activities which are the subject of obligations on them[10];
- the need to contribute to the achievement of sustainable development; and
- the interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[11]

1.6. Subject to the above, the Authority is required to carry out the functions referred to in the manner which it considers is best calculated to:

[8] entitled "Gas Supply" and "Electricity Supply" respectively.
[9] However, in exercising a function under the Electricity Act the Authority may have regard to the interests of consumers in relation to gas conveyed through pipes and vice versa in the case of it exercising a function under the Gas Act.
[10] under the Gas Act and the Utilities Act, in the case of Gas Act functions, or the Electricity Act, the Utilities Act and certain parts of the Energy Act in the case of Electricity Act functions.
[11] The Authority may have regard to other descriptions of consumers.

- promote efficiency and economy on the part of those licensed[12] under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems;
- protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity; and
- secure a diverse and viable long-term energy supply.

1.7. In carrying out the functions referred to, the Authority must also have regard, to:

- the effect on the environment of activities connected with the conveyance of gas through pipes or with the generation, transmission, distribution or supply of electricity;
- the principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed and any other principles that appear to it to represent the best regulatory practice; and
- certain statutory guidance on social and environmental matters issued by the Secretary of State.

1.8. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation[13] and therefore part of the European Competition Network. The Authority also has concurrent powers with the Office of Fair Trading in respect of market investigation references to the Competition Commission.

[12] or persons authorised by exemptions to carry on any activity.
[13] Council Regulation (EC) 1/2003

Appendix 5 - Glossary

A

Access Rights

The rights to flow specified volume of electricity, usually from a specified location (node or zone) to an explicitly or implicitly defined destination (e.g. market hub), and for a defined period. For firm access rights, a failure to deliver access due to insufficient network capacity is associated with financial compensation. For non-firm access rights, the flow is terminated without compensation when capacity is unavailable.

The Authority/ Ofgem

Ofgem is the Office of the Gas and Electricity Markets, which supports the Gas and Electricity Markets Authority (GEMA), the body established by section 1 of the Utilities Act 2000 to regulate the gas and electricity markets in GB.

B

Baseline

Baselines define the reference levels of capacity that the transmission licensee is to release. Baselines also determine the levels above (or below) which incremental capacity is defined.

Baseline Capital Expenditure

Baseline capital expenditure is the total amount of capex required in association with the baseline. It includes both load related capex and non-related capex.

British Electricity Trading and Transmission Arrangements (BETTA)

The arrangements for the trading and transmission of electricity across Great Britain which are provided for by Chapter 1 of Part 3 of the Energy Act 2004, which have replaced the separate trading and transmission arrangements which existed prior to 1 April 2005 in Scotland and in England and Wales. BETTA introduced a single GB-wide set of arrangements for trading energy and for access to and use of the transmission system which came fully into effect at BETTA go-live (1 April 2005).

C

Capital Expenditure (Capex)

Expenditure on investment in long-lived transmission assets, such as gas pipelines or electricity overhead lines.

Connection Entry Capacity (CEC)

A measure of the maximum capability, expressed in MW, of a connection site and the associated generation units' connection to the transmission system.

Connection and Use of System Code (CUSC)

Multi-party document creating contractual obligations among and between all users of the GB transmission system, parties connected to the GB transmission system and National Grid is relation to their connection to and use of the transmission system.

Consents

The process of obtaining Consents for the construction of a new overhead line to serve, for example, a wind farm can essentially be broken down into two distinct areas. Consents to be obtained from the Secretary of State/ Planning authorities etc in relation to permission allowing a line to be built and secondly, and more practically, consents from landowners who will be affected by the construction of the new line. For a new line consent under section 37 of the 1989 Act will be required.

In addition to section 37 consent, the DNO/TO must also obtain consent from the landowners over whose land the line will run. If a voluntary agreement cannot be struck, then either the land will have to be compulsorily purchased, under the provisions of section 10 and Schedule 3 (which is usually used for substations), or a Necessary Wayleave obtained over it, under the provisions of section 10 (Schedule 4 paragraphs 6-8).

Constraints

In the event that the pattern of generation may exceed the safe operational limits of a particular line or transmission system equipment, the GBSO will take actions to reduce the output of generators at specific locations on the system. At present these actions are taken in the Balancing Mechanism in the form of bids, and also via ancillary services, such as Pre-Gate Closure Balancing Mechanism Unit Transactions (PGBTs). Where a user's output is constrained down at a point on the system, the overall balance of energy will need to be retained, and costs will be incurred by the GBSO in bringing replacement energy onto the system.

Contracted background

This is the planning background against which National Grid assesses applications for connection and use of system. The contracted background includes all users that have entered into an (ongoing) agreement with National Grid for connection or use of system.

D

Deep reinforcement

Deep reinforcement refers to the works conducted on the wider transmission system in order to accommodate a change in the generation and demand pattern.

G

National Electricity Transmission System Operator (NETSO)

The entity responsible for operating the GB transmission system, onshore and offshore, and for entering into contracts with those who want to connect to and/or use the GB transmission system. National Grid is the NETSO.

GB Transmission System

The system of high voltage electric lines providing for the bulk transfer of electricity across Great Britain.

K

Kilowatt (kW)/Megawatt (MW)/Gigawatt (GW)

A kW is the standard unit of electricity, roughly equivalent to the power output of a one-bar electric fire. A MW is a thousand kilowatts. A GW is a thousand megawatts.

Kilowatt hour (kWh)/Megawatt hour (MWh)/Gigawatt hour (GWh)

One kilowatt hour is the amount of electricity expended by a one kilowatt watt load drawing power for one hour. A MWh is a thousand kilowatt hours. A GWh is a thousand megawatt hours.

L

Load Related Capex

The installation of new assets to accommodate changes in the level or pattern of electricity or gas supply and demand.

Long-run marginal costs (LRMC)

In the context of electricity transmission, long-run marginal costs are the marginal costs of establishing and using network capacity. They include, for example, marginal costs for network reinforcement, as well as resulting network losses and residual congestion costs.

Local works

Those works required to provide a generator with a connection to the transmission network that would enable it to export power.

N

National Grid Electricity Transmission (NGET)

The electricity transmission licensee in England & Wales.

Non-Load Related Capex

The replacement or refurbishment of assets which are either at the end of their useful life due to their age or condition, or need to be replaced on safety or environmental grounds.

O

Operating Expenditure (Opex)

The costs of the day to day operation of the network such as staff costs, repairs and maintenance expenditures, and overhead.

R

Regulatory Asset Value (RAV)

The value ascribed by Ofgem to the capital employed in the licensee's regulated transmission or (as the case may be) distribution business (the 'regulated asset base'). The RAV is calculated by summing an estimate of the initial market value of each licensee's regulated asset base at privatisation and all subsequent allowed additions to it at historical cost, and deducting annual depreciation amounts calculated in accordance with established regulatory methods. These vary between classes of licensee. A deduction is also made in certain cases to reflect the value realised from the disposal of assets comprised in the regulatory asset base. The RAV is indexed to RPI in order to allow for the effects of inflation on the licensee's capital stock. The revenues licensees are allowed to earn under their price controls include allowances for the regulatory depreciation and also for the return investors are estimated to require to provide the capital.

RPI-X

The form of price control currently applied to network monopolies. Each company is given a revenue allowance in the first year of each control period. The price control then specifies that in each subsequent year the allowance will move by 'X' per cent in real terms.

Re-openers

A process undertaken by Ofgem to re-set the revenue allowances (or the parameters that give rise to revenue allowances) under a price control before the scheduled next formal review date for the relevant price control.

Revenue Driver

A means of linking revenue allowances under a price control to specific measurable events which are considered to influence costs. An example might be to allow a specified additional revenue allowance for each MW of new generation connecting to the network. Revenue drivers are used by Ofgem to increase the accuracy of the revenue allowances.

S

Safety net

A mechanism that would trigger a review of allowances in the event of a major shortfall of investment relative to allowances.

Security and Quality of Supply Standard (SQSS)

As referred to in the electricity Transmission Licence Standard Conditions C17 and D3, this is the standard in accordance with which the electricity transmission licensees shall plan, develop and operate the transmission system.

Scottish Hydro-Electric Transmission Limited (SHETL)

The electricity transmission licensee in northern Scotland.

Scottish Power Transmission Limited (SPTL)

The electricity transmission licensee in southern Scotland.

Sliding scale

This term is used generically to describe incentive schemes which involve profit (and loss) sharing around a fixed target costs, such as the current form of SO incentives in gas and electricity.

T

Transmission Asset Owner (TO)

There are three separate transmission systems in Great Britain, owned by three Transmission Asset Owners, National Grid Electricity Transmission plc, Scottish Hydro Electric Transmission Ltd and Scottish Power Transmission Ltd. National Grid also has the role of system across the whole of Great Britain.

Transmission Entry Capacity (TEC)

Defines a generator's maximum allowed export capacity onto the GB transmission system. The holder of the TEC has the right to export the specified number of megawatts onto the transmission system at any one time, and is eligible for compensation if NGET cannot accommodate this export on the network.

Transmission Investment for Renewable Generation (TIRG)

In the context of this document, this means the regulatory mechanisms developed before the start of the next main price control in 2007, to fund a number of specific network enhancement projects required to provide transmission capacity for new renewable generation plants.

Transmission Owners (TO)

Companies which hold transmission owner licenses. Currently there are three electricity TOs; NGET, SPTL and SHETL. NGG NTS is the gas TO.

Transmission Price Control Review (TPCR)

The TPCR will establish the price controls for the transmission licensees which will take effect in April 2007 for a 5-year period. The review applies to the three electricity transmission licensees, NGET, SPTL, SHETL and to the licensed gas transporter responsible for the gas transmission system, NGG NTS

Transmission Network Use of System (TNUoS) charges

Charges that allow National Grid to recover the costs of providing and maintaining the assets that constitute the GB transmission system.

U

Unit Cost Allowance (UCA)

A parameter of the revenue drivers for the three TOs. For SHETL and SP Transmission the local works revenue drivers uses a £ per MW funding allowance, and for NGET both the local and deep revenue drivers use a £ per MW funding allowance. Funding allowances that increase or decrease expenditure entitlements by a set amount for each MW above or below baseline assumptions are UCAs.

W

Weighted Average Cost of Capital (WACC)

The weighted average of the expected cost of equity and the expected cost of debt.

Wider Works (WW)

The transmission works identified for a given generator which comprise deep reinforcement works required to provide capacity to support the additional generation coming online.

Appendix 6 - Feedback Questionnaire

1.1. Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

1. Do you have any comments about the overall process, which was adopted for this consultation?
2. Do you have any comments about the overall tone and content of the report?
3. Was the report easy to read and understand, could it have been better written?
4. To what extent did the report's conclusions provide a balanced view?
5. To what extent did the report make reasoned recommendations for improvement?
6. Please add any further comments?

1.2. Please send your comments to:

Andrew MacFaul
Consultation Co-ordinator
Ofgem
9 Millbank
London
SW1P 3GE
andrew.macfaul@ofgem.gov.uk