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Zonal transmission losses - the Authority's 'minded-to' decisions

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Target Audience: BSC Parties and any other party who has an interest in the transmission arrangements

Overview:

This document sets out for consultation the Authority's minded to decisions and reasons for those decisions on the following Balancing and Settlement Code ("BSC") modification proposals: P198, the P198 Alternative, P200, the P200 Alternative, P203 and P204. These proposals seek to alter the rules under which transmission losses are allocated to users of the electricity transmission system such that losses are allocated on a locational basis.

This document invites views on further analysis undertaken by Ofgem in response to points raised by respondents to the impact assessment.

The Authority has considered the proposals against the BSC objectives, having regard to its principal objective and statutory duties and taking into account responses to the impact assessment. The decisions the Authority is minded to take are set out in chapter 8. In summary, and subject to consideration of points made in responses to this document, the Authority is minded to approve modification proposal P203 and to reject the other proposals. Respondents' views are sought on the decisions the Authority is minded to take.

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Context

The transmission system transfers electricity in bulk at high voltage from generators to large industrial users and to local distribution networks. There is a single transmission system for the whole of GB. An efficient transmission network helps provide consumers with reliable energy supplies. Consumers, in return, pay for the costs of the network.

The process of transporting electricity results in a proportion of energy being lost on the transmission network. Greater volumes are lost the further the energy is transported. As a result of transmission losses, more energy must be produced than is supplied to consumers.

Transmission losses have both an environmental cost (for example, in terms of carbon costs) and a financial cost – as someone must pay for the lost energy. Under the existing market rules, these costs, which total around £260 million a year in today's prices, are allocated to generators and suppliers on a uniform basis.

In February 2007, Ofgem issued an impact assessment and consultation document on four industry proposals (and two alternatives) to change the transmission losses charging arrangements. These proposals are BSC modification proposals P198, P198 Alternative, P200, P200 Alternative, P203 and P204. Each of these proposals would result in generators and suppliers making different contributions to the costs of losses based on their location.

On 24 May the Authority considered the modification proposals in light of responses to the impact assessment and our further analysis in a number of areas. The Authority reached a minded to position in respect of each of those proposals. This document sets out the Authority's minded to decisions, the reasons for those decisions and seeks respondents' views. This document also summarises respondents' views to our impact assessment and Ofgem's views on the key points raised by respondents.

The Authority currently intends to publish its final decisions on the modification proposals before 20 September 2007. Further detail on the process is set out in Chapter 8.

Associated Documents

P198 Final Modification Report - Elexon, 22 September 2006
P200 Final Modification Report - Elexon, 22 September 2006
P203 Final Modification Report - Elexon, 22 September 2006
P204 Final Modification Report - Elexon, 16 November 2006
www.elexon.com/ChangeImplementation/modificationprocess/modificationdocumentation/default.aspx

What are the costs and benefits of zonal loss charging? - OXERA, July 2006
www.elexon.com/documents/Consultations/Cost_Benefit_Analysis_Data_Correction_Consultation/P198CBA_(revised_20060731).pdf

What are the costs and benefits of annual and seasonal scaled zonal loss charging? - OXERA, September 2006
www.elexon.com/documents/modifications/204/Scaled_zonal_loss_charging_including_seasonal.pdf

Report: MP198 Load Flow Modelling Service - Siemens PTI, June 2006
www.elexon.com/documents/modifications/198/Report_MP198_Modelling_(2006)_v3.0__Final_Report.pdf

Zonal transmission losses - assessment of proposals to modify the Balancing and Settlement Code - Impact assessment and consultation, 23 February 2007 #32/07
www.ofgem.gov.uk

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Summary

The transmission of electricity results in a proportion of energy being lost as heat. These losses are caused in part by the energisation of equipment and in part by the distance over which power is transmitted. Losses mean that, in order to meet demand, more electricity has to be generated than consumed.

The Balancing and Settlement Code ("BSC") sets out the rules and governance arrangements for electricity balancing and settlement in Great Britain ("GB"). The BSC includes rules relating to transmission losses. Under the existing BSC rules, the costs of transmission losses are recovered from generators and suppliers on a uniform basis.

Losses have been treated on the same basis since Vesting in 1989. However, the debate on the appropriate allocation of transmission losses has a long history and indeed at Vesting the Pooling & Settlement Agreement set out the principle of reviewing and, if appropriate, implementing changes to the treatment of losses to reflect locational factors. The debate was subsequently developed during the NETA and BETTA processes. Today's climate of increased concern about the impact of energy generation on the environment and rising energy costs set the background for this latest set of industry proposals (four proposals and two alternatives) which have been put to the Authority. These proposals seek to alter the way in which variable transmission losses are charged.

Variable transmission losses increase with the power flow and length of line on which electricity flows, but the different locational impacts of generators' and suppliers' actions are not currently reflected in the charges they pay for losses. Each of the six proposals would, to varying extents, result in charges for transmission losses which would be dependent on the point at which electricity was put onto or taken off of the transmission network.

The proposals aim to better reflect in losses charges the locational impacts of parties' actions and, as a result, under each proposal losses charges for generators in northern England and Scotland would go up, and charges for southern generators would go down. In addition, charges for suppliers in northern England and Scotland would go down, whilst those for southern suppliers would go up.

In February 2007, Ofgem issued an impact assessment and consultation on these proposals, "Zonal transmission losses - assessment of the proposals to modify the Balancing and Settlement Code" ("the impact assessment").

On 24 May 2007 the Authority[1] considered the modification proposals in light of responses to the impact assessment and some further analysis that Ofgem had undertaken in the light of those responses (see further chapter 3 below). The Authority reached a minded to position in respect of each of those proposals. This

[1] Save where expressly provided, or the context requires, otherwise, the terms 'the Authority', 'Ofgem' and 'we' are used interchangeably in this document. Ofgem is the Office of the Gas and Electricity Markets Authority.

document sets out the Authority's minded to decisions, together with the reasons for those decisions, and seeks respondents' views. This document also summarises respondents' views to our impact assessment and sets out and invites views on our further analysis in a number of areas.

At its meeting of 24 May 2007, the Authority decided that, subject to its consideration of the points made in responses to this document, it is currently minded to approve P203. It also decided that, subject to its consideration of the points made in responses to this document, it is minded to reject P198 and its alternative, P200 and its alternative and P204. P203 proposes the introduction of a seasonal zonal transmission losses scheme, calculating a separate set of zonal transmission loss factors for each of the four seasons of the year and applying a scaling factor of 0.5 to ensure that only variable transmission losses are recovered locationally. P203 does not propose any mitigation techniques such as hedging or phasing, which were a feature of some of the other proposals.

The Authority considers that the introduction of zonal losses charges will promote efficiency by reducing losses. It will also benefit the environment by reducing carbon emissions. The Authority considers that, of all the proposals, P203 provides the greatest reduction in losses and therefore the highest savings - both environmental and financial. The Authority also considers that the introduction of P203 will have no material adverse impact on the development of renewable generation.

The Authority considers that P203 better facilitates the achievement of the applicable BSC objectives than the existing arrangements and is consistent with the Authority's legal duties. The Authority also considers that of the options available to it, P203 is the best calculated to further the Authority's principal objective to protect the interests of consumers, both present and future, wherever appropriate through the promotion of effective competition.

The reasons for the decisions the Authority is minded to take are set out in detail in chapters 4, 5, 6 and 7.

The Authority currently intends to publish its final decisions on the proposals before 20 September 2007.

1. Background

Chapter Summary

This chapter provides an overview of the proposals to change the current arrangements for charging for transmission losses. This chapter also discusses the legal framework and assessment framework against which the Authority has made its minded to decision and will make its final decision.

Background

1.1. The transmission of electricity results in a proportion of energy being lost as heat. Losses are caused in part by the energisation of equipment and the volume of losses varies depending on where a party puts energy on, or takes energy off, the transmission system. Putting energy onto the system further from centres of demand will therefore increase the volume of losses on the system. The pattern of generation in the current GB market means that there is an excess of generation in the north of GB, where the centres of demand are generally in the south.

1.2. Transmission losses mean that in order to meet demand, more energy must be generated than is consumed. Transmission losses have both an environmental impact, for example in terms of carbon emissions, and a financial impact, as someone must pay for the lost energy.

1.3. There are, broadly speaking, two types of losses from the electricity transmission system: fixed losses and variable losses. Variable losses increase with the current (and associated power flow), while fixed losses do not. Currently, the costs of both fixed and variable transmission losses are recovered from BSC Parties on a 'uniform' basis, i.e. the charges do not vary by location. A parameter for a locational allocation of some or all transmission losses – the transmission loss factor (TLF) – is included in the BSC but its value is set to zero. Therefore, currently the contribution parties make towards the total volume of transmission losses does not depend on where a party is putting energy on, or taking energy off, the network. There is therefore no incentive on individual parties through the current losses charging arrangements to minimise the financial and environmental impact of losses.

1.4. The issue of the locational treatment of transmission losses has a long history. At Vesting the Pooling and Settlement Agreement set out the principle of reviewing and, if appropriate, implementing changes to the treatment of losses to reflect locational factors. The debate was subsequently developed during the NETA and BETTA processes.

1.5. The BSC modification proposals summarised below are the first in relation to zonal transmission losses to be proposed since the implementation of BETTA. All of the modification proposals propose setting locationally varying TLFs across GB to reflect the different contributions parties make to variable transmission losses.

1.6. A more detailed summary of the proposals is set out in chapter one of the impact assessment document. That document also provides more detailed background information on what transmission losses are, why they arise and the current arrangements for establishing how these losses are paid for.

Overview of proposed modifications

1.7. There are four different BSC proposed modifications:

- P198 - Introduction of a Zonal Transmission Losses Scheme
- P200 - Introduction of a Zonal Transmission Losses Scheme with Transitional Scheme
- P203 - Introduction of a Seasonal Zonal Transmission Losses Scheme; and
- P204 - Scaled Zonal Transmission Losses.

1.8. P198 was proposed by RWE Npower plc in December 2005. P200 was proposed by Teeside Power Limited in April 2006. P203 was proposed by RWE Npower in June 2006. P204 was proposed by British Energy Power and Energy Trading Limited in July 2006.

1.9. In addition, during the assessment stage for both P198 and P200 the BSC Modification Group developed alternative modification proposals. No alternative modification proposals were developed for P203 and P204. In total, there are therefore six different modification proposals for the Authority to consider.

Common features

1.10. As discussed in more detail in the impact assessment, the six proposals are all variations on the same basic framework. They therefore share a number of common features.

Load flow model

1.11. Under each proposal the locational impact of losses would be calculated using a load flow model. The load flow model contains 'nodes' to represent points where energy flows on to or off the transmission system. It estimates the impact on the total flows on the transmission system of a 1MW increase in power at each node. The model can then be used to calculate the impact of the change in flows on the level of total losses from the transmission system.

Zoning

1.12. In the load flow model, each node would be allocated to a zone on the transmission network. The raw nodal marginal factors would then be averaged and scaled (see below) to calculate the zonal TLFs. These are then used in the settlement calculations. In all of the proposed modifications and alternative

modifications, the zones are based on the existing 14 Grid Supply Point ('GSP') Groups, leading to the calculation of 14 zonal TLF values applicable to both generation and demand.

1.13. Similarly, all the proposals continue to calculate Transmission Loss Multipliers (TLMs) to ensure that, in aggregate, 45% of total losses are allocated to generation and 55% of total losses are allocated to demand, taking both zonal and non-zonal allocations into account.

Allocation of variable losses on a locational basis

1.14. In each of the proposals, the marginal loss factors derived from the load flow model are scaled before being used to derive the zonal TLFs so as to ensure that the volume of losses allocated on a locational basis is that proportion which is related to power flows on the transmission system. Such losses are referred to as 'variable' losses, with the remainder of transmission losses characterised as 'fixed' losses, which do not vary with power flows. Under each proposal, fixed losses would continue to be allocated on a non-zonal basis.

TLFs fixed ahead of each year using settlement data for a previous year

1.15. Under all of the proposed and alternative modifications, the TLF values will be calculated annually on an 'ex-ante' (i.e. forecast) basis for each BSC Year, using metered volumes and network data from the 12-month period ending 31 August of the previous BSC Year (the "Reference Year"). The TLF values are published 3 months prior to the start of the BSC Year to which they apply.

Implementation date

1.16. All of the Final Modification Reports ("FMRs") proposed implementation dates of 1 April 2008 if the Authority reached its decision on or before 22 March 2007; or 1 October 2008 if the Authority reached its decision on or before 20 September 2007.

The individual proposals

1.17. The key features of the individual proposals are summarised in the table below.

Proposal	Key Features
P198	▪ Single set of zonal TLFs for each year i.e. **annual TLFs**. ▪ **Fixed scaling factor** of 0.5 is applied to the zonal TLFs to ensure only variable transmission losses are recovered locationally. ▪ Does not propose to apply any mitigation technique.
P198 Alternative	▪ Separate set of zonal TLFs for each of the four seasons of each year i.e. **seasonal TLFs**. ▪ **Fixed scaling factor** of 0.5 is used to ensure only variable transmission losses are recovered locationally. ▪ Would **phase-in** the introduction of locational TLFs in a linear fashion over five years. The phased TLFs would apply to all users.
P200	▪ **As for P198** above except that a **hedging** scheme would apply to qualifying generators based on their historical output levels in the 12 month period ending 31 March 2006 (the 'Baseline Period'). The scheme would not apply to generators not operating or not commissioned in the Baseline Period. ▪ Under the hedging scheme, a qualifying generator would always receive a uniform allocation of transmission losses based on the F-factor volume (fixed volume based on average monthly output), while the difference between its actual metered volume and the F-factor volume would be subject to the zonal TLFs i.e. if a generator's actual metered volume was the same as its F-factor then it would continue to pay for transmission losses on a uniform basis, and would not be exposed to locationally varying transmission losses. However, if its actual metered volume differed from its F-factor then the difference between these two figures would be subject to the locational TLF in whichever zone it was located. ▪ The hedging scheme would endure for 15 years and only apply to qualifying generators. It would not apply to suppliers.
P200 Alternative	▪ As for P200 above, except would calculate **seasonal TLFs.**
P203	▪ As for P198 above, except would calculate **seasonal TLFs**.
P204	▪ **Seasonal TLFs**. ▪ Would implement a **variable scaling factor** (i.e. not fixed at 0.5 as under the other proposals) to ensure that no party is allocated a negative volume of losses on a locational basis i.e. no party receives payments as a result of the zonal allocation of transmission losses. As a result, the most favourable allocation of variable losses would be zero and the party would only pay for its uniform allocation of fixed losses. ▪ Does not propose to apply any mitigation technique.

The legal and assessment framework

1.18. When the Authority makes decisions on BSC modification proposals it does so in the context of a prescribed legal framework. Where it is proposing to make a decision that is judged to be important (within the meaning of section 5A of the Utilities Act 2000) the Authority is required (save where the urgency of the matter makes it impracticable or inappropriate for it to do so) to undertake an impact assessment or to publish a statement setting out why it considers it unnecessary to carry out an impact assessment. An impact assessment must include an assessment of the likely effects on the environment of a proposal.

1.19. Having considered the FMRs in respect of the proposals the Authority considered that the proposed and alternative modifications were "important" for the purposes of section 5A of the Utilities Act in terms of the potential impact of the proposals on market participants and the potential impact on the environment.

1.20. On 23 February 2007 we published an impact assessment and consultation on the modification proposals, "Zonal transmission losses - assessment of the proposals to modify the Balancing and Settlement Code" ("the impact assessment"). In line with the impact assessment guidance we provided six weeks for respondents to submit views. An overview of the key themes raised by respondents' is provided in chapter 2 and a more detailed summary of responses is set out in appendix 2.

Assessment framework

1.21. In reaching its decision on whether it is minded to approve or reject each of the proposals, the Authority has undertaken a four stage process. The Authority will follow the same four stage process in making its final decisions.

- **Stage one**: The Authority first considered whether it considered that each of the proposals better facilitates the achievement of any one or more of the applicable BSC objectives as compared with the current provisions of the BSC. The applicable BSC objectives are set out in standard licence condition C3 of the electricity transmission licence of National Grid Electricity Transmission plc ("NGET") and are as follows:

  a. the efficient discharge by NGET of the obligations imposed upon it by its electricity transmission licence;
  b. the efficient, economic and co-ordinated operation of the GB transmission system;
  c. promoting effective competition in the generation and supply of electricity, and (so far as consistent therewith) promoting such competition in the sale and purchase of electricity; and
  d. promoting efficiency in the implementation and administration of the balancing and settlement arrangements.

- **Stage two**: The Authority then considered whether it considered that each of the proposals, on the balance of benefits and detriments, better facilitates the

achievement of the applicable BSC objectives as compared with the current provisions of the BSC when those objectives are considered collectively.

- **Stage three**: The Authority then considered whether each proposal is consistent with its legal duties, including those arising under European law.

- **Stage four**: Finally, the Authority considered which of the options available to it (including the option of rejecting all of the modification proposals) it considered to be best calculated to further the principal objective having regard to its statutory duties.

Structure of document

1.22. The remainder of this document is structured as follows:

- Chapter 2 provides a very high-level overview of key themes raised in responses to the impact assessment;
- Chapter 3 sets out further analysis on a number of issues raised by respondents to the impact assessment which have not previously been consulted on and provides respondents with the opportunity to comment on that analysis;
- Chapter 4 sets out the Authority's assessment of each of the proposals against the applicable BSC objectives (stage one above);
- Chapter 5 sets out the Authority's assessment of each of the proposals against the applicable BSC objectives when considered collectively (stage two above);
- Chapter 6 sets out the Authority's assessment of whether the proposals are consistent with the Authority's legal duties (stage three above);
- Chapter 7 considers which of the options available to the Authority is the best calculated to further the principal objective having regard to the Authority's statutory duties (stage four above); and
- Chapter 8 sets out the minded to decision and way forward.

2. Responses to the impact assessment

Chapter Summary

This chapter provides a very high level overview of the key themes raised by respondents to the impact assessment. A more detailed summary of respondents' comments and Ofgem's views is set out in appendix 2.

This chapter also identifies those issues with respect to which Ofgem has undertaken further analysis. This further analysis, which was presented to the Authority in advance of, and in preparation for, its meeting of 24 May 2007, is set out in chapter 3.

Question box

Question 1: Do respondents consider that we have appropriately summarised the key themes of the responses to Ofgem's impact assessment on zonal losses?

Question 2: Are there any other themes which respondents consider should have been highlighted?

Respondents' views and Ofgem's response

2.1. We invited respondents to the impact assessment to indicate whether they considered we had appropriately summarised, in the impact assessment, the key direct, indirect and environmental impacts of the proposals. Respondents were also asked to identify any other such impacts which they considered to be relevant and which we had not considered in the impact assessment. Further, respondents were invited to present any additional relevant analysis in respect of the direct, indirect and environmental impacts of the proposals. Finally, respondents were asked for views on the process and timetable.

2.2. Ofgem received 25 responses to the impact assessment, two of which contained information that the respondent identified as being confidential. A high level overview of respondents' views is set out below. A list of respondents is set out in appendix 2, together with a more detailed summary of respondents' comments and Ofgem's views. All non-confidential responses are available on Ofgem's website.

2.3. Some respondents responded directly to the questions asked in the impact assessment document, whilst other respondents provided a more general response. The Authority welcomes all responses and has taken all views into account in considering these proposals and in reaching its minded to decisions as described in this document. In order to provide an overview of the comments provided, we have identified 8 key themes from responses and summarised in appendix 2 respondents' views under these themes. These key themes are set out below with a brief description of the issues being raised.

2.4. Some respondents expressed a view as to whether or not the Authority should approve one of the proposals. Of those who expressed a view on the specific modification proposals, 16 expressed the opinion that the Authority should reject all of them. Six respondents supported the approval of one of the modification proposals. Of these, two supported P203, one supported P200 or the P200 Alternative and one supported P198. The other two respondents, while supporting a losses modification in principle, did not express support for a specific modification proposal. The remaining three respondents did not indicate a view on whether to approve or reject a particular modification proposal.

Key themes

- **Oxera analysis and modelling:** a number of respondents said that there were short-comings in OXERA's analysis and raised concerns at what they perceived as Ofgem's over-reliance on that analysis in the impact assessment. There were also a number of comments on areas that it was claimed had been neglected in the impact assessment and in particular on the perceived inadequacy of Ofgem's assessment of the hedging proposals.

- **Interaction with TNUoS:** a number of responses focused on the potential interaction of locational loss charging arrangements with the existing locational charging arrangements for TNUoS and queried whether this would result in excessive locational charges and whether TNUoS charging arrangements should be reviewed.

- **Cost reflectivity:** responses were split on whether zonal losses would provide more cost-reflective signals. Those who considered they would facilitate greater cost-reflectivity argued they would result in the more efficient use of the system. Other respondents considered that inaccuracies in the analysis and weaknesses in the proposed approaches would actually produce less cost-reflective charges than at present.

- **Impact on risk:** there was a range of views on the impact of zonal losses on risk. A number of respondents believed the complexity of the proposed arrangements and volatility of charges would increase risk. Other respondents considered that risk was overstated and was mitigated by the BSC process and the time period pre-implementation.

- **Impact on renewable generation:** some respondents expressed concerns that renewable generators would predominately be located in areas where loss charges would be greatest and would be unable to respond to the signals. Others argued that other factors would outweigh zonal losses in deciding on location and highlighted the positive implications of greater renewable development outside the north of Scotland.

- **European issues:** some respondents considered zonal losses would be inconsistent with EU policy and might hamper cross-border trade.

- **Analysis of benefits:** a number of views were raised as to whether the benefits highlighted in Oxera's report would actually be realised and if so whether they

were material relative to total losses and to the distributional impacts of the proposals.

- **Process:** respondents broadly supported the intention of publishing a minded-to decision for consultation but a number considered this should be used to provide some additional analysis on matters that they considered had not been adequately covered in the impact assessment.

2.5. We noted the views of respondents that there were areas where additional analysis may be required. We therefore considered in further detail and developed additional analysis in relation to a number of the points raised by respondents. These points concerned:

- Interaction with TNUoS
- Impact on distributed generation
- Impact on different generation technologies
- Risk - impact on cost of capital
- Use of Oxera analysis
- Impact of fixed losses and System Operator (SO) actions
- Impact of mitigation techniques

2.6. That additional analysis was presented to the Authority and it is set out in chapter 3 of this document to provide parties with an opportunity to comment on it in their responses to this document. Any comments which respondents may have on this additional analysis will be taken into consideration by the Authority in making its final decisions.

3. Additional analysis

Chapter Summary

A number of respondents to Ofgem's impact assessment highlighted areas which they considered had either not been addressed or had not been adequately addressed in that document. We gave further consideration and undertook some analysis in relation to a number of the points raised by respondents. The additional analysis was presented to the Authority for the purposes of reaching its minded to decision.

This chapter sets out the further analysis that was undertaken and presented to the Authority. Interested parties are invited to comment on this analysis.

Question box

Question 1: Do respondents consider that the additional analysis we have provided addresses the concerns expressed by respondents to the impact assessment regarding analytical gaps in the impact assessment?

Question 2: Do respondents consider that there are any remaining aspects of the modification proposals that require to be addressed analytically?

Question 3: Do respondents have any additional analysis in relation to the impact of the modification proposals that they wish to bring to the attention of the Authority?

Introduction

3.1. As noted in chapter 2, a number of respondents to the impact assessment requested either: (1) specific additional analysis for the purposes of assessing the impact of the modification proposals; or (2) further consideration of various issues. This chapter describes some further analysis and some further consideration of a number of areas undertaken by Ofgem. The results of this work was presented to the Authority for the purposes of making its minded to decision.

3.2. We invite respondents to submit thoughts including any further analysis on any of the areas addressed below. However, we note that respondents have already had a number of opportunities to present their analysis both in response to Elexon's process and in response to Ofgem's impact assessment. Therefore, we would not expect that any additional analysis presented by respondents at this stage would be likely to raise material new issues.

Interaction with TNUoS

3.3. A number of respondents expressed the view that TNUoS charging arrangements already partially reflect locational losses, and that the introduction of locational loss charging arrangements would result in the overstatement of overall

locational signals. These respondents argued that because additional capacity is built to meet the GB Security and Quality of Supply ("GB SQSS") requirements, lines are less full and thus losses are lower than they would otherwise be. TNUoS charges are calculated reflecting the impact of security on the system. Therefore, there is the potential that TNUoS charges already reflect, to some extent, locational losses. NGET's response to the impact assessment also noted that while the effect of a party's actions on "on the day" transmission losses cannot be influenced by the long-term TNUoS signal it was recognised that any investment in the transmission system may impact on total system losses.

3.4. We have carried out joint analytical work with NGET[2] to undertake an initial assessment of the level of the interaction between TNUoS and losses locational signals. The analysis suggests that there is an overlap between TNUoS charges and fully marginal losses charges. Assuming that network investment results in capacity and resistance changes consistent with installing circuits (i.e. consistent with the modelling underlying the TNUoS methodology), this overlap is estimated as half the amount of the fully marginal losses costs, which is equivalent to the average losses costs. This result means that if the locational losses charge were to be based on fully marginal losses costs, there would be an overstatement in the total locational differentials, of a magnitude equal to one half the differentials contained in the fully marginal losses costs.

3.5. As noted in chapter 1, each of the modification proposals derives locational differentials from the raw marginal factors calculated from a load flow model. If the zonal losses scheme were to use these raw marginal factors directly, without any scaling, then the locational differentials would reflect full marginal losses costs. However, none of the modification proposals are based on fully marginal losses, as they all contain an element of scaling to the marginal TLF. This has the effect of reducing any overstatement in the total locational differentials. Moreover, the majority of the proposals apply a factor of 0.5, with the aim of ensuring that the volume of losses allocated locationally through the TLF is approximately the same as the volume of variable losses. The effect is to avoid the overstatement that would be associated with a fully marginal approach. The variable scaling approach contained in P204, which applies a constraint that no party receives a negative allocation of variable losses, would result in an even lower scaling factor. This may therefore understate the total locational differentials. It can be concluded therefore from this initial analysis that none of the modification proposals could be expected to lead to a material overstatement of the overall locational signals.

Impact on distributed generation

3.6. One issue raised in relation to competition was the impact of the modification proposals on distributed generation. A number of parties suggested that zonal losses would have a negative impact on embedded benefits for northern distributed generation, as it would erode the payments received via the supplier where the output of the distributed generator nets off the supplier's demand thereby reducing the supplier's losses charge. We consider that this does not present a full picture.

[2] See Appendix 3.

3.7. We note that embedded benefits arise as a consequence of distributed generation being treated as negative demand, rather than generation, within the methodology for allocating costs between demand and generation. The way this works in the context of transmission losses is as follows: the volume of losses allocated to a transmission connected generator is its output multiplied by (1 - TLMg), where TLMg is the generation TLM, whereas a distributed generator treated as negative demand reduces the supplier's charge by its output multiplied by (TLMd - 1), where TLMd is the supplier TLM. Therefore the losses-related embedded benefit, which is related to the difference in the TLMs, i.e. TLMd-TLMg, is a consequence of both avoiding the generation allocation and benefiting from the reduction in the supplier allocation.

3.8. None of the modification proposals change the current arrangements for treating distributed generators as negative demand, although they do impact on the losses charges which can be avoided or reduced through those arrangements. Therefore in assessing the impact of zonal losses on distributed generation it is necessary to consider the combined impact on the avoided generation charge and on the direct benefits associated with the charge to the supplier. This impact can be divided into two parts: the effect of introducing locationally varying TLMs, which allocates a proportion of losses differentially based on geographical location (north vs. south issue), and the impact on the level of the losses-related embedded benefit to a distributed generator at a given geographical location (distribution vs. transmission connected generation issue).

3.9. Under each of the modification proposals, both the generation TLM and the supplier TLM varies across the country as a result of locational variation in the TLF. For transmission connected generators, this TLF variation leads to higher loss charges in the north than in the south. For suppliers, the TLF variation has an equal and opposite effect on their loss charges. Then for distributed generators treated as negative demand, the same geographical differentials would apply through the locational element of the supplier TLM, as for transmission connected generators through the generation TLM. This means that the payments received via the supplier may be expected to decrease in the north, and increase in the south, to reflect the impact of the locational differentials on the supplier's loss charges. Therefore in terms of the locational competition, e.g. between generators in the north vs. south, the impact on distributed generation would be the same as that on transmission connected generation.

3.10. While the modification proposals would each result in TLM values which vary over the country there is only an impact on the losses-related embedded benefit if there is a change in their difference, TLMd-TLMg ("the TLM difference"), at any given location. Under each modification proposal, as is the case now, the TLM difference does not vary across the country, and is directly proportional to the amount of losses to be recovered non-locationally. The introduction of zonally varying TLFs would recover a certain amount of the losses locationally, hence reducing the amount to be recovered by the non-locational element. This would reduce the size of the losses-related embedded benefit accordingly.

3.11. To examine this quantitatively, OXERA's analysis of zonal transfers of overall loss charging revenues for generators and suppliers in the first year of the unmitigated zonal losses schemes has been used to derive the volume weighted-average generation TLM and the supplier TLM over the year. These average values do not vary between proposals given that they all recover loss revenue in the same proportions as now i.e. 45/55 from generation and demand, and they correspond to estimates, at 0.995 and 1.006 respectively, of the generation TLM and supplier TLM values which would apply under uniform losses for the same market conditions. We have used these results to estimate the change in the annual losses-related embedded benefit under each zonal losses proposal, relative to the status quo.

3.12. Table 1 highlights the impact of locational losses on the losses-related embedded benefits for distributed generation relative to a transmission connected generator at the same location. It shows that compared to a uniform losses scheme the TLM difference in any given zone reduces by 0.004 for P198 and P203 and by 0.001 for P204, resulting in a reduction in the losses-related embedded benefit, in volume terms, of less than 0.5% of the distributed generator's output in each case. The illustrative example in Table 1 highlights that a 10MW generator with a 30% load factor would have its total losses-related embedded benefits reduced by around £5k in the case of P198 and P203 and by just over £1k in the case of P204. This analysis uses an electricity price of £45/MWh, on the grounds that this is consistent with OXERA's data. However, we note that if the electricity price was lower, which it currently is (as was highlighted by a number of respondents), then the differentials between distributed generators and transmission connected generators would be reduced.

Table 1

Proposal	Losses-related embedded benefit	Change in losses-related embedded benefit vs. uniform losses		Change for 10MW distributed generator with 30% load factor	
	Volume as proportion of generation output (TLM difference)	Volume as proportion of generation output (TLM difference)	£/MWh*	Annual avoided losses allocation (MWh)	Annual benefit (£k)
P198	0.007	-0.004	-0.180	-105	-4.7
P203	0.007	-0.004	-0.180	-105	-4.7
P204	0.010	-0.001	-0.045	-26	-1.2

* based on electricity price £45/MWh

3.13. The above results showed that while the size of the losses-related embedded benefit does not vary over the country under any given scheme, its size is lower for a zonal losses scheme than for uniform losses. This effect will be reduced for schemes which reduce the locational differentials through scaling (P204) or phasing (P198 Alternative). The impact of hedging (P200 and P200 Alternative) is more complex in that a further factor is whether a given generator qualifies for the hedging scheme.

3.14. In conclusion, we note that each of the proposals would expose distributed generation to the same geographical locational signals as transmission-connected generation under the given zonal losses arrangements. We also note that as none of the proposals change the existing arrangements for treating distributed generation as negative demand, they would each continue to provide a losses-related embedded benefit in relation to the volume of losses allocated uniformly, albeit with minor reduction in the size of such benefit. Further, as is the case now, in no part of the country is that benefit higher than in any other. In addition, in situations where a distributed generator is supplying its own load, the net allocation of transmission losses would be zero, as is the case now.

Impact on different generation technologies

3.15. We note the particular point raised by one respondent that, given the potential under locational loss charging for higher loss charges in the north and lower charges in the south, more efficient renewable generation may be replaced by less efficient conventional generation. We do not consider that relatively lower losses charges in the south would inevitably result in a greater volume of less environmentally friendly generation connecting in the south. There is significant potential for both renewable and other forms of low carbon generation, such as CHP, to connect in the south of GB, including offshore wind. Equally, it is just as likely that changing signals may result in fossil fuel plants closing in the north. However, we have undertaken further analysis as follows.

3.16. Tables 2 and 3 below are based on data from the current Seven Year Statement (SYS) and show the broad geographical distribution of generation of different fuel types, both at present and under the projected SYS background for 2013/14. It shows that renewable generation is currently, and is planned to be, located across the country and that this is not confined to onshore wind generation. In particular, while there is a significant volume of onshore wind in Scotland there is also planned to be significant offshore wind generation in the south and also CHP.

Table 2 - Connected generation capacity in 2007/08

Plant type	England & Wales North (MW)	England & Wales South (MW)	Scotland (MW)	Total (MW)
Coal	14221	11235	3456	28912
Nuclear	4593	4002	2410	11005
Oil	0	3496	0	3496
Biomass	0	0	45	45
CCGT	12550	11458	1524	25532
CHP	1084	386	255	1725
Hydro	0	0	1028	1028
Interconnector	0	1988	80	2068
OCGT	0	579	10	589
Offshore Wind	140	0	0	140
Pumped Storage	1560	0	740	2300
Wind	0	0	1597	1597
Total	34148	33144	11146	78438

Source: NGET 2007 Seven Year Statement

Table 3 - Projected connected generation capacity in 2013/14

Plant type	England & Wales North	England & Wales South	Scotland	Total
Coal	14221	11235	3456	28912
Nuclear	3613	3532	2410	9555
Oil	0	3496	0	3496
Biomass	0	295	97	392
CCGT	17130	19803	1524	38457
CHP	1685	386	255	2326
Hydro	0	0	1136	1136
Interconnector	0	3308	80	3388
OCGT	0	579	10	589
Offshore Wind	1090	1500	0	2590
Pumped Storage	2004	0	740	2744
Wind	0	299	8118	8417
Total	39743	44433	17826	102002

Source: NGET 2007 Seven Year Statement

3.17. We have also undertaken further analysis of the impact of locational losses on the potential for renewable generation in the north to be replaced by less efficient conventional generation in the south, as follows. In order to get a sense of the actual impacts on plant, we have examined an example representative of the “worst-case” in terms of impact of network charges on the renewable generation in the north when competing against an efficient conventional technology generation such as CCGT in the south. First, the generation costs are derived (based on the typical

capital, operational and fuel costs as quoted in a paper by Lewis Dale (Regulation and Strategy Manager, NGET) et al published in the March 2003 edition of Power UK[3]), together with typical asset lives and load factors[4] for relevant generation types. Then the impact of ROC, TNUoS charges and locational losses are taken into account to derive the net cost for generators to produce electricity. An electricity price of £45/MWh has been used for consistency with other analysis in this document.

3.18. The results are summarised in Table 4 below. This highlights that even with the highest TNUoS and losses charge, wind generation in the north remains competitive against an efficient conventional technology generation such as CCGT situated in the south. As a result, it would not be expected that locational loss charging arrangements would result in more environmentally efficient renewable generation being replaced by less environmentally efficient conventional generation.

Table 4

		ROC impact		TNUoS impact		Losses impact		
	Total generation cost (£/MWh)	ROC (£/MWh)	**Generation cost with ROC (£/MWh)**	maximum TNUoS differential (£/kWyr)	Convert to energy cost (£/MWh)	maximum average TLF differential	Convert to energy cost (£/MWh)	**Total generation cost with ROC & network charges (£/MWh)**
South CCGT	**20.97**	0	**20.97**	-8.57	-1.22	-2%	-0.9	**18.85**
North offshore wind	**31.53**	-35	**-3.47**	21.59	8.22	3%	1.35	**6.09**
North onshore wind	**22.69**	-35	**-12.31**	21.59	8.22	3%	1.35	**-2.74**

Risk and cost of capital

3.19. Another issue raised by respondents with respect to competition is in relation to the impact of a change in the arrangements for losses on risk and cost of capital. Primarily, we consider that it is for businesses to manage their own risks, it is not the role of the regulator to manage risk on their behalf. We note that the proposer of P200 submitted a paper produced by NERA on regulatory risk and option theory. The paper considered how regulatory risk can lead to an increase in the rate of return required by investors, or cause parties to delay investment in the presence of uncertainty. The P200 and P200 Alternative hedging scheme seeks to mitigate this risk by protecting market participants from windfall gains and losses on sunk investments, both under its associated zonal losses scheme and any future changes to the losses arrangements.

3.20. We consider that the regulatory risk described by NERA's paper is associated with an uncertainty which will be resolved over time, i.e. it is related to the issue of parties deferring an investment decision until the uncertainty is removed. In the particular context of the zonal losses proposals, this type of regulatory risk only

[3] "A shift to wind is not unfeasible" – Lewis Dale, David Milborrow, Richard Slark and Goran Strbac - Platts Power UK, Issue 109, March 2003

[4] Asset life assumption: 25 years for CCGT and 20 years for wind generation. Load factor assumption: 80% for CCGT and 30% for wind generation.

applies in the period until the decision is made, whereas making that decision (whether it is to approve or reject) removes the risk by removing the uncertainty. We note that more generally, regulatory risk is an inherent feature of the current governance arrangements in which industry parties can propose modifications which may have a significant commercial impact on other parties. We consider that this risk is minimised where the Authority's decisions on those proposals are made in accordance with a sound regulatory process and against clear objectives and duties. We also consider, as set out in chapter 4, that given the history of this subject, parties should have anticipated the potential for industry proposals to be raised to introduce locational losses. Therefore, we do not believe that making a decision to approve any of the zonal losses proposals would have a significant impact on risk and cost of capital.

Use of OXERA analysis

3.21. A number of respondents raised concerns with OXERA's analysis and its use in the impact assessment. We note that OXERA were the independent experts commissioned by Elexon to undertake the cost-benefit analysis of the proposals, and consider it entirely appropriate that we consider that information in our impact assessment. However, we recognise that some respondents did not consider OXERA's analysis to be robust. Their arguments largely focus on the snapshot approach used to calculate TLFs, the methodology used for modelling despatch impacts, and the level of the energy price used in the analysis. These respondents considered that the despatch benefits identified by OXERA's analysis may be an overestimate, or may not be realised in practice. Our views on these aspects of OXERA's analysis are set out as follows.

3.22. In relation to the snapshot approach we consider that using loading conditions at points of high, medium and low demand for each of the four seasons would provide a reasonable approach to modelling load flows on the network and could reduce the amount of computations and the associated complexity that would otherwise be required in generating TLFs for the purposes of a 10 year cost-benefit analysis. This view is reinforced by the results of the validation exercise undertaken by OXERA, which showed the TLFs calculated by OXERA are broadly consistent with those derived by Siemens-PTI with each season represented by a much larger set of sample periods. In relation to the comments that OXERA's cost-benefit analysis was based on the assumption of economic despatch, and as such might not be representative of realistic market conditions, we note that locational signals provided by zonal TLFs will primarily influence decisions at the margin, which will be primarily driven by economic considerations. We further note that OXERA also took into account environmental and transmission constraints, such as emissions limits and the capacity of the Scotland-England interconnector, in modelling despatch. In relation to the energy price, we agree that a lower figure for the first year of the scheme may have been more reflective of the market at present, and we note that the value used by OXERA varied over the study period. We also note that in general the energy price fluctuates and therefore the benefits of the proposal will also fluctuate. They will be higher when the electricity price is higher and lower when the electricity price is lower. The most important point is that, whatever the price used,

locational losses leads to more efficient levels of despatch and better longer-term signals than the status quo.

3.23. Some respondents also highlighted that the benefits identified by OXERA reduce over time, and considered that this had been overlooked in our impact assessment. We noted in the impact assessment that the despatch benefits identified by OXERA would be lower in later years, reducing from average savings per annum of around £14m for P203, £6m for P204 and £5m for P198 (for the period to 2011/12), to around £9m for P203, £5m for P204 and £3m for P198 (for the period to 2015/16). This is the effect that would be expected as parties change their behaviour in response to the signals from zonal losses and thus the marginal impact of further changes would be reduced, creating less scope for further reduction in losses. We also note that if, as some parties have argued, the OXERA analysis overstates the despatch impacts in the early years of the scheme, then it may also understate the impact in later years as the marginal benefit of changes to despatch will be higher. Some respondents also highlighted the year-on-year variation in despatch benefits calculated by OXERA. We consider that this variation can be attributed to the snapshot approach used by OXERA and the feedback effect between market behaviour in one year and the TLFs applicable to the next. Therefore we consider it is more meaningful to examine the trends than the results for individual years and as noted above, the OXERA results show a trend where the annual reductions in losses reduce over time as the system becomes more locationally balanced as parties respond to locational losses. Through the feedback effect, the losses signals would then provide incentives, absent under uniform losses, on parties to retain that level of locational balance.

Impact of fixed losses and SO actions

3.24. A number of respondents highlighted that the impact assessment focussed on the treatment of variable losses whereas total transmission losses also include fixed losses. Some parties sought further analysis on the respective proportions of fixed and variable losses, and of the cost drivers of fixed losses.

3.25. Given that the proposals relate to the treatment of variable losses we consider it entirely appropriate that our impact assessment focussed in this area. However, we note that the P204 modification group gave consideration to the appropriate methodology to use for identifying fixed and variable losses for the purposes of deriving an appropriate scaling factor. As part of this assessment, NGET and Elexon undertook analysis which suggested that on average the volume of fixed losses is approximately 100MWh in a given half hour settlement period, representing an average level of 200MW of generation in that period. However, NGET's analysis suggested that while the actual level of fixed losses does not vary significantly with load, it can vary according to the weather conditions, e.g. in high humidity or wet weather it may be around 100MW higher. NGET noted that fixed losses are therefore difficult to forecast but estimated that in general they comprise approximately 20-30% of total losses. The P204 modification group concluded that for the purposes of calculating a scaling factor for P204, it would be appropriate to estimate the level of variable losses using the load flow model, and then apply the constraint that no party

receives a negative allocation of those losses. We note that this avoids the need to estimate the level of fixed losses directly.

3.26. Some respondents also commented that OXERA's analysis excludes the effect of fixed losses in calculating the TLMs applicable to generation and demand and that the results are therefore unreliable. We note that the despatch impacts modelled by OXERA are based on the locational differences in TLMs, which do not vary with the level of fixed losses.

3.27. Another issue raised by respondents was the effect of SO actions on the level of losses. Some parties also suggested that there may be some interaction between a zonal losses scheme, which would provide signals to market participants in relation to their impact on variable losses, and the SO incentives arrangements put in place by Ofgem to encourage NGET to take account of the impact of its actions on overall transmission losses. We welcome views on this in the context of the ongoing development of the SO incentive arrangements.

Impact of mitigation measures

3.28. A number of respondents considered that there had been insufficient assessment of the impact of modification proposals which mitigate the impact of a zonal losses proposal by including phasing or hedging. As set out in the impact assessment, we note that no specific analysis is provided either by the Modification Group or in the impact assessment of the impact of the phasing solution proposed by the P198 Alternative or the hedging solutions proposed by P200 and the P200 Alternative. This reflects the difficulty in modelling these scenarios to provide meaningful data and indeed no respondent provided any further data on these scenarios. However, we do consider that it is possible to qualitatively assess the likely impact of the mitigated proposals (P198 Alternative, P200, P200 Alternative), both on individual parties and on the overall level of losses, relative to the assessment undertaken for the unmitigated zonal losses proposals (P198, P203, P204). This is set out as follows.

Phasing

3.29. We note that by reducing the magnitude of the total locational signal, phasing would be expected to dampen the efficiency of the signal and thus reduce the potential total loss savings during the period of phasing. In the first year phasing would reduce the strength of the signal to 20% of the total. This is a significant reduction and could have an equally significant impact on the efficiency of parties' decision-making and thus on the scope for reducing losses. Clearly, in subsequent years as the impact of phasing diminishes and the locational signal strengthens, then we would expect the scheme to have a more beneficial impact. However, over the period of phasing the aggregate levels of savings in losses would be likely to be significantly lower than if phasing were not applied. Therefore, while producing more efficient signals than the status quo, in terms of loss savings, we would expect a zonal losses scheme which included phasing to facilitate lower short term efficiency benefits than one which did not. However, the scope for further benefits beyond the

period of phasing would also be increased, as the marginal impact of changes to behaviour would be greater. A comparison of results between P203 and P204 can provide an indication of the effect of phasing. The initial impact of P198 Alternative may be expected to be similar to that for P204, and to become closer to that for P203 in the longer term.

3.30. We therefore agree with the respondents who noted that the use of phasing would delay the realisation of the full efficiency benefits of introducing zonal transmission losses, while reducing the short term distributional impacts on all parties.

Hedging

3.31. In practice, the proposed hedging scheme adopted by P200 and the P200 Alternative could be described as a "grandfathering" scheme as it allows for the qualifying generator to retain a non-zonal share of transmission losses for its F-factor volume of losses over a period of 15 years. Unlike phasing which would reduce the impact of locational losses for all parties, the specific impact of the hedging scheme on individual parties will depend critically on its detailed design in that this will determine (a) whether they qualify for the hedging scheme and (b) what their F-factor volumes are.

3.32. The proposed hedging scheme specifically excludes Supplier Volume Allocation (SVA) registered BM Units and new entrant generation. It only applies to existing generator BM Units that are part of a Trading Unit with a net annual export during the baseline period of 1 April 2005 – 31 March 2006. For these qualifying BM Units, monthly F-factors would be calculated based on metered volumes during the baseline period, and would remain fixed for the duration of the 15 year transitional scheme, while all other BM Units would have an F-factor fixed at zero. Incumbent generators qualifying for the hedging scheme would be locked in to the uniform losses arrangements for their F-volume and only exposed to the zonal TLFs to the extent that they deviate from this volume, while new entrants would be fully exposed to the zonal TLFs applicable to the unmitigated scheme. The impact of the hedging scheme is that two generators at the same location could be subject to different losses charges purely by virtue of whether or not they were operational in a single historical year, and the extent of that difference would also depend on their particular behaviour, and that of other BM Units in the same Trading Unit, within each month of that period.

3.33. We further note that in developing the detail of the scheme the P200 modification group identified two potential approaches to the qualification criteria and F-factor calculation, and that for some parties the choice of approach affected whether they qualified for the scheme and also impacted on their F-factor volumes. We note that the choice between these two approaches could be considered arbitrary, and that the choice particularly affected generators which are part of a Trading Unit which includes either significant demand or other generation with which their output is not well correlated. It also affected embedded generation. We also consider that by basing the baseline period for F-factors on a single (historical) year, the F-factor volume for a given qualifying generator may not necessarily be typical of

its output under a uniform losses scheme. For example, it may include unrepresentative data for individual generators due to plant outages, or relate to a period of unusual market conditions.

3.34. In terms of the impact on losses, a number of respondents argued that the hedging arrangements should preserve the marginal signals of the associated zonal losses scheme. We agree that if the marginal signals are preserved then it would be expected that efficiency benefits such as the reduction in total losses should also be preserved. However, with the allocation of losses being determined based on historic volumes from a single historical year, over time the F-factor volumes are likely to become less reflective of parties' positions, and thus to lead to less accurate signals and ultimately to less efficient decision making on the part of industry participants. While the arrangements would preserve some of the locational signals and thus reduce total losses, over time the reduction in losses would be expected to be lower than if the zonal losses scheme were implemented without hedging. Further, as noted above, there are a number of specific features of the proposed approach that would undermine the accuracy of signals. Most notably the proposal that F-factors would be set on the basis of one year's historic data. The impact of fixing the allocation of losses based on historic volumes could be seen to lead to inaccuracies in signals and thus ultimately to inefficiency for the market as a whole.

4. Stage one - Assessment against applicable BSC objectives

Chapter Summary

This chapter sets out the Authority's assessment of whether the six modification proposals better facilitate the achievement of the applicable BSC objectives.

Question box

Question 1: Do respondents consider that the modification proposals have been appropriately assessed against the applicable BSC objectives?

Question 2: Do respondents consider that there are any aspects of the modification proposals that have not been adequately assessed in relation to the applicable BSC objectives?

Applicable BSC objectives

4.1. The first step in the assessment process is to consider whether a modification proposal better facilitates the achievement of one or more of the applicable BSC objectives. The applicable BSC objectives are set out in standard licence condition ("SLC") C3 of NGET's electricity transmission licence and are as follows:

a. the efficient discharge by NGET of the obligations imposed upon it by its electricity transmission licence;
b. the efficient, economic and co-ordinated operation of the GB transmission system;
c. promoting effective competition in the generation and supply of electricity, and (so far as consistent therewith) promoting such competition in the sale and purchase of electricity; and
d. promoting efficiency in the implementation and administration of the balancing and settlement arrangements (as described in NGET's licence).

Applicable BSC objective (a) - efficient discharge by NGET of the obligations imposed upon it by its electricity transmission licence

4.2. Having considered the views of the BSC Panel and respondents to the industry consultation and our impact assessment, and the additional analysis set out in chapter 3, the Authority's assessment is as follows.

4.3. The Authority considers that the most relevant issue in relation to applicable BSC objective (a) is in relation to discrimination. SLC C7 of NGET's electricity transmission licence prohibits the licensee from discriminating between any persons or class or classes of persons in the provision of use of system or in the carrying out of works for the purpose of connection to the GB transmission system. In addition,

NGET has a number of other licence obligations which require it to put in place arrangements that facilitate, amongst other things, the efficient, economic and coordinated operation of the GB transmission system and that facilitate effective competition in the generation and supply of electricity. NGET is also required by its licence to set charges which reflect, as far as is reasonably practicable, the costs incurred by transmission licensees in their transmission businesses. The introduction of locational loss charging arrangements would be likely to have a positive impact in relation to each of these areas. Those impacts were considered in more detail as part of the Authority's assessments against applicable BSC objectives (b) and (c) below, while the Authority, in its assessment against applicable BSC objective (a), focused primarily on the issue of discrimination.

4.4. The Authority noted the views expressed regarding locational charging arrangements removing the scope for discrimination associated with uniform charging arrangements. In general, the Authority is of the view that, to the extent that any of the modification proposals result in more cost reflective charging, they would also be likely to reduce any scope for discrimination and therefore would be expected to provide a benefit relative to the status quo.

4.5. However the Authority considered that the issue of discrimination has particular relevance to the hedging scheme proposed by P200 and the P200 Alternative. The Authority noted that the proposed transitional hedging schemes raised a number of concerns among both respondents and Panel Members in relation to discrimination where the scope for discrimination was highlighted at a number of levels.

4.6. As discussed in chapter 3, the hedging scheme does not apply to all users, with the specific impact on individual parties depending critically on its detailed design. Firstly, the scheme specifically excludes Supplier Volume Allocation (SVA) registered BM Units. Arguably, therefore, suppliers would be hindered from obtaining a benefit that would be available, under this proposal, to generators. Secondly, there are some generators' BM Units that would not qualify for the hedging scheme. Further two generators at the same location could be subject to different losses charges purely by virtue of whether or not they were operational in a single historical year, and under the given scheme design the extent of that difference would also depend on their particular behaviour, and that of other BM Units in the same Trading Unit, within each month of that period. On this basis, the Authority considers that modification proposals P200 and the P200 Alternative could result in the discriminatory treatment of some parties.

Overall

4.7. It is the Authority's view that P200 and the P200 Alternative would not better facilitate applicable BSC objective (a) due to the specific issues in relation to discrimination under the hedging scheme. In relation to each of the other proposals the Authority does not consider that any significant additional benefits have been identified in relation to applicable BSC objective (a) but at the same time it has not identified any dis-benefits. On this basis, the Authority considers that P198, the P198 Alternative, P203 and P204 are on balance all neutral in relation to applicable BSC objective (a).

Applicable BSC objective (b) – the efficient, economic and co-ordinated operation of the GB transmission system

4.8. Having considered the views of the BSC Panel and respondents to the industry consultation and our impact assessment, the Authority's assessment of the modification proposals against applicable BSC objective (b) included consideration of the following areas:

- Accuracy of locational signals
- Impact on total losses
- Impact on efficiency of different types of generators including renewable generators
- Interaction between locational TNUoS and losses

4.9. Each of these areas is considered in turn below.

Accuracy of locational signals and associated efficiency benefits

Annual vs. seasonal TLFs

4.10. One issue relevant to a consideration of the accuracy of locational signals is the use of annual or seasonal TLFs. The Authority noted the views expressed by both the BSC Panel and respondents to Ofgem's impact assessment that seasonal TLFs would provide more accurate signals. The analysis undertaken by Siemens PTI clearly demonstrates that losses would vary by season. This could be considered to make sense since losses can vary as a result of changes to demand and weather, both of which vary by season. On that basis, the Authority considered that the use of seasonal TLF values should provide a more accurate allocation of losses than the use of annual values, thereby leading to more efficient despatch and a greater reduction in the level of losses. The OXERA cost-benefit analysis demonstrates the increase in efficiency benefits associated with seasonal models.

The impact of phasing, hedging and variable scaling

4.11. The impact of phasing and hedging is discussed in chapter 3. The Authority agreed with respondents who expressed the view that the application of phasing (P198 Alternative) results in less accurate charges for an initial period following implementation. The Authority considered that, the use of phasing would therefore delay the realisation of the full efficiency benefits of introducing zonal transmission losses. However, it also considered that in each successive year the solution would become more cost-reflective as the impact of phasing diminishes.

4.12. In the case of hedging (P200, P200 Alternative), while the Authority recognised respondents' views that a hedging proposal would preserve the marginal signals of zonal losses, there are a number of specific features of the proposed approach that would undermine the accuracy of signals. Most notably, it is proposed that the F-factors would be set on the basis of one year's historic data. The impact of fixing the

allocation of losses based on historic volumes is likely to lead to inaccuracies in signals and thus ultimately to inefficiency for the market as a whole.

4.13. Finally, the impact of variable scaling (P204) is to reduce the strength of the signal sent by losses charges, by applying the constraint that no party receives a negative allocation of losses. Again this would reduce the accuracy of the locational signal and diminish the associated efficiency benefits.

4.14. We note that no specific analysis is provided either by the Modification Group or in our impact assessment of the impact of the phasing solution proposed by the P198 Alternative or the hedging solutions proposed by P200 and the P200 Alternative. Further information on the impact of phasing and hedging is set out in chapter 3 under the section entitled 'Impact of mitigation measures' (sections 3.28 - 3.34).

OXERA's analysis

4.15. The Authority recognised that some respondents did not consider OXERA's analysis to be robust. Their arguments largely focus on the snapshot approach used to calculate TLFs, the methodology used for modelling despatch impacts and the level of the energy price used in the analysis. These areas are discussed in further detail in chapter 3 in the section entitled 'Use of OXERA analysis' (sections 3.21-3.23).

4.16. Overall, the Authority did not consider that any evidence was provided that undermined the reliability of the analysis undertaken by either OXERA or Siemens PTI. The Authority considered that, when taken together, the information they provide demonstrated significant efficiency benefits associated with the introduction of more accurate locational charging arrangements for losses.

Impact on total losses

4.17. A key element of assessing the efficiency of the modification proposals is to assess their impact on the total level of losses. In the short-term, the main impact of changes in the allocation of transmission losses will be changes in the pattern of generation despatch as parties take locational loss charging into account in operational decisions. Changes in the pattern of generation despatch will in turn impact on the total volume of losses. OXERA analysed the impact of the introduction of zonal losses on generation despatch and the associated impact on the volume of losses. OXERA also considered the impact of locational variations in the allocation of transmission losses on generators' long-term investment decisions in relation to both new and existing plant.

4.18. Using data from OXERA's cost-benefit analysis, Table 5 below highlights the estimated total average annual loss savings both in terms of volume and in £m terms for modification proposals P198, P203 and P204, in the initial years following implementation of the given scheme. This is based on 2006 data.

Table 5

Average annual loss savings to 2010/11			
Scenario	**Reduction in total volume of losses (GWh)**	**Reduction in losses due to generation re-despatch (£m)**	**Reduction in losses due to demand-side response (£m)**[5]
P198	185	5	0.6
P203	489	14	0.8
P204	223	6	0.4

4.19. This table highlights a number of key factors. First, the reduction of losses under P203 is estimated to be more than double that of P204. Given the only difference between P203 and P204 is the inclusion in the latter of variable scaling then it highlights that variable scaling more than halves the efficiency benefits (at least in terms of loss savings) of a zonal losses scheme with seasonal TLFs. Second, average annual loss savings under P204 are marginally greater than those under P198. This demonstrates that while variable scaling may reduce the efficiency benefits of a zonal losses proposal, the benefits of using seasonal TLFs are still greater than a scheme that uses annual TLFs i.e. P198 and P200.

4.20. OXERA's analysis highlighted that these benefits would reduce over time to average savings per annum (for the period from 2006-2015) of around £9m for P203, £5m for P204 and £3m for P198. This is the effect that would be expected as parties change their behaviour in response to the signals from zonal losses and thus the marginal impact of further changes would be reduced.

4.21. As noted in chapter 3, we did not consider it was practicable to model the loss savings under the phasing (P198 Alternative) or hedging (P200, P200 Alternative) modification proposals in a way that would provide robust data. However, we have undertaken a qualitative assessment of the likely impact on total losses, relative to the unmitigated schemes.

4.22. The P198 Alternative proposed linear phasing with seasonal TLFs. In terms of the impact on the reduction of losses these two elements of the proposal would be expected to have conflicting effects. As noted above, using seasonal TLFs would be expected to produce better signals and have a greater impact in reducing losses than using models with annual TLFs (P198 and P200). However, as discussed in chapter 3, reducing the magnitude of the total locational signal phasing would be expected to dampen the efficiency of the signal and thus reduce the potential total loss savings. Clearly, in subsequent years as the impact of phasing diminishes and the locational signal strengthens, then we would expect the benefits of the P198 Alternative to increase. However, by that stage the aggregate levels of savings over the time period in which locational losses had been applied would be likely to be significantly

[5] To note – these figures were actually derived as an average for the period to 2015/16. However, the values should not change significantly and are included to give an indication of the magnitude of the savings from demand-side response.

lower than many of the other modification proposals. Therefore, while producing more efficient signals than the status quo, in terms of loss savings, we would expect the P198 Alternative to facilitate lower efficiency benefits than a number of the other modification proposals.

4.23. As noted by a number of respondents, hedging arrangements should preserve the marginal signals of a proposal. If the marginal signals are preserved then it would be expected that efficiency benefits, such as the reduction in total losses, would also be preserved. However, as noted previously, under the P200 and the P200 Alternative proposals, the allocation of losses would be determined based on historic volumes from a single historical year. Over time this data is likely to become less reflective of parties' positions and thus to lead to less accurate signals and ultimately to less efficient decision making on the part of industry participants. While the arrangements would preserve some of the locational signals and thus reduce total losses, the reduction would be expected to be lower than a number of the other models. The Authority also noted that the P200 Alternative includes seasonal TLFs whereas P200 includes annual TLFs. While the accuracy of both signals would be expected to diminish over time, the P200 Alternative would still be expected to provide more efficient signals than P200 and thus to have a greater impact on reducing total losses.

Interaction between locational TNUoS and losses

4.24. The Authority noted that a number of respondents expressed the view that TNUoS charging arrangements already partially reflect locational losses and that the introduction of locational loss charging arrangements without reviewing TNUoS charges would result in the overstatement of locational signals. This issue is discussed in more detail in chapter 3 and in appendix 3.

4.25. The Authority agreed that a key issue for the efficient operation of the transmission system is that parties are given appropriate signals regarding the use of that system. One argument against the existing uniform treatment of losses is that the charges do not provide any signal to transmission users regarding their impact on the costs of transmission losses and thus results in the inefficient development of the network. Equally, if the locational signals were too strong then the same potential for inefficiency exists.

4.26. The joint analytical work we carried out with NGET (see appendix 3) highlighted that while there was scope for some overstatement of locational signals, any such overstatement would be reduced and indeed, theoretically, removed by applying a scaling factor to marginal losses.

Impact on efficiency of different categories of generator

4.27. The Authority noted the particular point raised by respondents that, given the potential under locational loss charging for higher loss charges in the north and lower charges in the south, more efficient renewable generation may be replaced by less efficient conventional generation.

4.28. As highlighted in chapter 3 in the section entitled 'Impact on different generation technologies' (sections 3.15-3.18), we undertook some additional analysis to try and get a sense of the actual impacts on plant of changes in transmission loss charges. Our results highlighted that, even with the highest TNUoS and losses charge, wind generation in the north remains competitive against a CCGT situated in the south. As a result, the Authority reached the view that it would not be expected that locational loss charging arrangements would result in more efficient renewable generation being replaced by less efficient conventional generation.

Overall

4.29. The Authority considered that the introduction of locational loss charging arrangements, by ensuring that transmission users will pay charges that reflect their impact on the network, would result in those users making more efficient decisions regarding their use of the GB transmission system. As noted above, the impact of better decision making is to reduce the level of total losses and in doing so promoting a more efficient, economic and co-ordinated operation of the GB transmission system.

4.30. All of the modification proposals propose to charge for losses on a locational basis. The Authority considered that each of the proposals would better facilitate applicable BSC objective (b) than the current uniform losses arrangements. The Authority also noted that the models which do not propose to mitigate those locational signals (i.e. P198, P203) are likely to have a more beneficial impact on efficiency than models which propose to reduce or alter locational signals over a transitional period by phasing (P198 Alternative) or hedging (P200, P200 Alternative), or on a permanent basis by variable scaling (P204). However, the Authority would expect that all of the modification proposals would have a beneficial impact on efficiency relative to the status quo.

Applicable BSC objective (c) - promoting effective competition in the generation and supply of electricity, and (so far as consistent therewith) promoting such competition in the sale and purchase of electricity

4.31. Having considered the views of the BSC Panel and respondents to the industry consultation and our impact assessment, the additional analysis and assessment (including the analysis of the impact on distributed generation and the impact on different generation technologies) set out in chapter 3, the Authority's assessment of the modification proposals in relation to applicable BSC objective (c) has included consideration of the following areas:

- the distributional impacts of the modification proposals
- the impact on the stability and predictability of the commercial and regulatory arrangements and the associated issues of risk; and
- the impact on barriers to competition and the total level of competition.

4.32. Each of these areas is considered in turn below.

Distributional impacts

4.33. There would be distributional impacts associated with the introduction of locational loss charging arrangements. These would broadly result in suppliers in the south and generators in the north paying higher charges while suppliers in the north and generators in the south would pay lower charges.

4.34. The level of distributional impacts varies between the proposals. Based on OXERA's analysis the greatest total redistribution of revenue is under P198. A marginally smaller range is evident under P203. The amount transferred and the maximum and minimum transfers are much lower with variable scaling under P204, at around 20% of the total for P198. The distributional impact would be lower still under phasing (at least during the first two years). Under hedging the distributional impact will be lower for those parties whose positions are hedged.

4.35. The Authority noted the views of a number of respondents that significant distributional impacts would hamper competition. There is arguably some merit in these arguments. The competitive process works less effectively, and delivers less efficient outcomes, if market participants are subject to large changes in costs at short notice. It is for such reasons that phasing is often considered a practical solution. A phased implementation would allow locational signals to be provided whilst reducing the burden for parties in the short-term and giving them time to adjust their positions. On this basis, a more measured transition could in principle be argued to be more consistent with the objective of facilitating competition.

4.36. However, on the other hand, the Authority noted that the potential introduction of locational charging arrangements for losses is not a new issue and it could be argued that parties have already had time to consider their positions thereby negating the need for a further period of phasing to reduce the impact on competition. This issue is discussed in further detail below in the context of regulatory risk.

4.37. In addition, under the existing arrangements variable losses are charged on a uniform basis and thus parties are not paying charges that reflect their impact on the network. As a result, generators in the south are cross-subsidising generators in the north while suppliers in the north are cross-subsidising suppliers in the south. The existence of cross-subsidies in itself undermines competition. Unwinding those cross-subsidies is consistent with promoting effective competition. Phasing distorts locational signals in the initial years because it is less cost reflective than a solution which is fully cost-reflective and which does not embody a phased implementation. Moreover, it could also be argued that phasing (and the degree of arbitrariness that is inevitably involved; e.g. in the choice of timescales and starting point for phasing) in itself creates rather than reduces regulatory risk.

4.38. The other potential option for reducing distributional effects is hedging. Indeed, the party who proposed the hedging scheme cited distributional effects as one of the

key drivers for those modification proposals. The hedging proposals would affect individual parties differently depending on: (1) whether they are part of the scheme; and (2) their level of output relative to their F-factor. Both are difficult to model in a simple manner that would enable any additional value to be gained from that analysis. However, the P200 Modification Group considered the implications of two potential approaches to defining the qualification criteria and associated F-factor calculation, and found that for some parties the choice of approach can make a significant difference to whether they qualified for the scheme and if so what their F-factor volumes were. Under P200 and the P200 Alternative, the generators who are subject to the hedging arrangements will not be fully exposed to locational TLFs as they would be under a model without hedging while parties who cannot hedge their position may be exposed to a greater impact than they would under a model without hedging.

4.39. Having considered the range of respondents' views on the distributional impacts of the modification proposals, on balance, the Authority did not consider that the distributional effects would have a significant negative impact on effective competition. Therefore, the Authority did not consider that a case for phasing or hedging of locational losses can be made based on the distributional impacts.

Stability and predictability and risk implications

4.40. The Authority agreed with respondents that stable and predictable market rules are, other things being equal, likely to facilitate competition as they would be expected to reduce the risk parties face in making decisions regarding connecting to and using the network. There are a number of factors which could influence perceptions of stability and predictability under the modification proposals.

4.41. The first relevant consideration is the frequency with which TLFs are reviewed. Under P198 and P200 the TLFs would be reviewed, and thus change, on an annual basis. Clearly, this provides greater stability than the other modification proposals where TLFs change by season, although under the seasonal modification proposals all four seasonal values are set once a year at the same time as the annual value would be set. Both approaches provide less stability than the existing arrangements whereby TLFs are fixed at zero.

4.42. Another relevant issue is the extent to which the TLFs and their method of calculation are transparent. The Authority noted that TLFs under all of the modification proposals would be published annually, three months prior to their use in the settlement calculation for the year. This notice period is consistent with the notice period for TNUoS charging and facilitates greater transparency.

4.43. A further relevant consideration is the extent to which the introduction of locational loss charging arrangements could have been predicted by market participants. Respondents' views were divided on this issue, with some highlighting the long history of discussion of zonal losses while others argued that Ofgem’s and DTI’s actions had not suggested locational loss charging was a likely outcome. The Authority considered that, given the history of this subject, parties should have

anticipated the potential for such future development. Moreover, we do not accept that there have been any developments which ruled out the potential for future modification proposals on locational losses. Indeed we consider it is clear that the Secretary of State's position at BETTA was that the issue was not being dismissed permanently but rather that it required further review in a GB context. However, even ignoring the history of this subject, we note that the proposed implementation date of the modification proposals is 1 October 2008. Such a time period would seem to give parties time to adjust their positions to reflect any revised charging arrangements.

4.44. The final issue raised by respondents which is relevant to the stability of the modification proposals is the impact on the cost of capital. In the Authority's view, commercial risk is an inherent feature of the current governance arrangements in which industry parties can propose modifications which may have a significant commercial impact on other parties, and this risk is minimised where the Authority's decisions on those proposals are made in accordance with a sound regulatory process against clear objectives and duties. This issue is discussed further in chapter 3.

4.45. Once again, while the Authority agreed with some respondents that the modification proposals may have some impact on perceptions of the stability and predictability of the existing arrangements, on balance the Authority considered that any associated risk is manageable and its impact would be outweighed by the positive impact on competition of introducing locational charging arrangements which are more reflective of costs.

Level of competition and barriers to entry

4.46. The Authority agreed with the respondents who noted the beneficial impact of cost-reflective charges on competition. Competition is more likely to be effective if costs which parties impose are reflected in the charges they pay and thus are appropriately factored into their decisions. Therefore, the introduction of more cost-reflective charging arrangements would be expected to promote more effective competition. More cost reflective charging arrangements is likely to inform decision making and in doing so promote competition. This would be expected to take the form of increased operation of plant in the south, which would face lower aggregate costs, and reduced output of plant in the north. In the longer term, the introduction of location loss charging arrangements would be expected to inform decision making that may lead to the promotion of market entry at sites closer to centres of demand.

4.47. This conclusion is supported by OXERA's cost benefit analysis report[6] which, although noting that the medium term affect of the modification proposals on the siting decisions for new plant was uncertain, highlighted potential benefits in the longer term (beyond 2015/16) of between £1m and £20m. Further detail on this subject was set out in the impact assessment.

[6] 'What are the costs and benefits of zonal loss charging', Elexon, July 2006 - Chapter 5, page 54

4.48. Barriers to entry hamper effective competition as they prevent new parties entering, or limit the ability of new parties to enter, the market in a short timeframe thereby potentially enabling existing parties to secure excessive benefits unchallenged. Barriers to entry can take a number of forms, including the level of charges. We note that the increase in charges for generators in northern GB associated with the modification proposals could be argued to provide a financial barrier to entry to some generators. At the same time we note that the reduction of charges to generators in the south could remove an equivalent financial barrier to connecting in that area. The most important consideration for effective competition is whether those charges provide a level playing field for all generators and suppliers. A locationally based charging mechanism would be expected to provide more cost-reflective charges and thus remove cross-subsidies. All of the models propose a more locationally based charging mechanism than the baseline.

Overall

4.49. There is a trade-off in the relative benefits of the different modification proposals in relation to applicable BSC objective (c). P203 and P198 would have the biggest distributional effects; however as they produce more cost-reflective charges than the other proposals then they are most likely to result in more efficient decision-making and to reduce barriers to entry, both of which would facilitate more effective competition. The other modification proposals would have significantly lower distributional impacts but would not have the same positive impact in terms of promoting efficient decision-making.

4.50. The Authority recognised that the modification proposals, by increasing charges for some parties, may impact on the ability of some parties to compete in the short-term. However, in the long-term more cost-reflective charging arrangements would be expected to promote more effective competition overall. Under the existing arrangements in respect of transmission losses transmission users are not paying charges that fully reflect their impact on the transmission network. Generators in the north and suppliers in the south are paying lower charges than they should be paying with the result that generators in the south and suppliers in the north are paying greater charges than actually reflects their impact on the system. As a result, effective competition between parties using the network is skewed. Therefore, the Authority considered that all of the modification proposals, by introducing charging arrangements which better reflect the impact of parties on the network, would be more consistent with promoting effective competition. However, the Authority recognised that as locational charging arrangements create some greater volatility and uncertainty then their impact would not be wholly positive.

4.51. Overall, the Authority considers that, on balance, each of the proposals would better facilitate applicable BSC objective (c) than the current uniform losses arrangements.

Applicable BSC objective (d) - promoting efficiency in the implementation and administration of the balancing and settlement arrangements

4.52. Having considered the views of the BSC Panel and respondents to the industry consultation and our impact assessment and the additional analysis set out in chapter 3, the Authority's assessment of the modification proposals in relation to applicable BSC objective (d) has included consideration of the efficiency of the design solutions proposed to introduce zonal transmission losses, the central costs of their introduction and the ongoing implications for costs and complexity. Each of these areas is considered below.

Costs of the modification proposals

4.53. The Authority concurred with respondents' views that all of the proposals to introduce zonal transmission loss arrangements would involve higher costs and would marginally increase complexity relative to the status quo. The FMRs highlighted implementation costs for the majority of the modification proposals of around £470k. The exception was the hedging solutions under P200 and the P200 Alternative which were estimated to be significantly more expensive to implement at around £850k. The ongoing operating costs of all of the models were estimated to be around £160k per annum.

4.54. The Authority considered that these costs are relatively immaterial in the context of the annual loss savings identified by OXERA of between £5-£14m for the different modification proposals. Even the total loss savings associated with the phasing proposal under the P198 Alternative would be expected to exceed the costs of introducing and running the models.

Complexity of design solutions

4.55. Other things being equal, it would be expected that an increase in complexity would have a detrimental effect. Increased complexity can reduce transparency and in doing so create a barrier to effective competition in the market. However, it is clear that the levels of complexity involved are not material in respect of P198. A Direct Current Load Flow ("DCLF") model is already used in calculating TNUoS charges and thus its principles are largely understood by the industry. The introduction of seasonal TLFs as proposed by P203 would involve slightly greater complexity. The combination of this approach with linear phasing would add further complexity. The most complex models are the variable scaling model proposed by P204 and the hedging models proposed by P200 and the P200 Alternative.

4.56. In the case of P204 the approach to introduce variable scaling does add greater additional complexity and therefore could be considered to reduce transparency and to reduce the scope for effective competition. However, crucially the Authority noted that the additional complexity is not reflected in higher implementation costs or ongoing operational costs. These are comparable to the other models. Therefore,

contrary to views expressed by some respondents, the Authority did not consider that P204 would fail against applicable BSC objective (d).

4.57. The proposed hedging model adds significant complexity. The scheme involves considerable additional work for Logica in the calculation and registration of F-factors. Moreover, while no specific additional costs have been identified, the impact of introducing the hedging scheme is likely to have long term administrative consequences associated with monitoring F-factors and the registration/ re-registration of BMUs. The impact of these additional responsibilities could be considered to be inconsistent with the promotion of efficiency in the BSC arrangements.

Overall

4.58. In relation to both cost and complexity, the Authority considered that P198, the P198 Alternative and P203 are each broadly neutral in relation to the promotion of efficiency in the implementation and administration of the BSC arrangements.

4.59. Given its additional complexity, the case for P204 against applicable BSC objective (d) is less clear cut. However, the Authority noted that the costs of the models are again comparable to the other models and on balance consider that modification proposal also to be broadly neutral against applicable BSC objective (d).

4.60. The Authority further considered that the proposed hedging arrangements under P200 and the P200 Alternative are significantly more complex than the other models and combined with their higher implementation costs would not promote efficiency in the implementation and administration of the BSC arrangements. The Authority considered that neither P200 nor P200 Alternative would better facilitate applicable BSC objective (d).

5. Stage two - Assessment against applicable BSC objectives when those are considered collectively

Chapter Summary

This chapter sets out the Authority's assessment of the six modification proposals against the applicable BSC objectives when those objectives are considered collectively.

Question box

Question 1: Do respondents consider that the Authority has appropriately assessed the modification proposals against the applicable BSC objectives when considered collectively?

Question 2: Do respondents consider that there are any aspects of the modification proposals that have not been adequately assessed in relation to the applicable BSC objectives when considered collectively?

Basis of collective assessment

5.1. This chapter sets out the Authority's overall assessment of each proposal against the applicable BSC objectives when those objectives are considered collectively, taking into account the benefits and disbenefits in relation to each individual objective which are set out in chapter 4. At this stage the proposals continue to be assessed separately relative to the current uniform losses arrangements, although it does include the Authority's assessment of alternative proposals against original proposals in the cases of P198 and P200. However, to avoid repetition, where appropriate the assessment refers to the additional impact of specific design features of each proposal compared to that for P198, drawing on the more detailed discussion in chapters 3 and 4.

P198

5.2. By introducing charging arrangements for losses which better reflect the impact of parties on the network, the Authority considered that the model proposed under P198 would better facilitate applicable BSC objectives (b) and (c) than the current uniform losses arrangements. It would result in arrangements which encourage more efficient decision-making by parties both in terms of use of the network in the short-term and in connecting to the network in the future. By removing existing cross-subsidies it should also facilitate the promotion of more effective competition in the market. The Authority considered that P198 is broadly neutral in relation to applicable BSC objectives (a) and (d).

5.3. On that basis, the Authority considers that P198 better facilitates the achievement of the applicable BSC objectives overall, compared with the existing provisions of the BSC.

P198 Alternative

5.4. Compared to P198, the introduction of phasing would reduce cost-reflectivity in the short-term and would reduce the benefits of efficient decision-making during the period of phasing. However, the introduction of seasonal TLFs could ultimately produce charging arrangements that are more reflective of costs than those based on annual TLFs and thus have a greater impact in reducing total losses. Overall, the Authority considers that the P198 Alternative would better facilitate applicable BSC objectives (b) and (c) than the current uniform losses arrangements. The Authority also considers that P198 Alternative is broadly neutral in relation to applicable BSC objectives (a) and (d).

5.5. On that basis, the Authority considers that the P198 Alternative better facilitates the achievement of the applicable BSC objectives overall, compared with the existing provisions of the BSC. In addition, the Authority considers that, on balance, the P198 Alternative does so to a lesser extent than P198.

P200

5.6. The Authority considers that the locational loss charging arrangements under P200 would better facilitate applicable BSC objectives (b) and (c) than the current uniform losses arrangements. However it also considers that these benefits are reduced by the inclusion of the hedging scheme, the design of which undermines the accuracy of the signals over time and could ultimately lead to less efficient decision making on the part of industry participants. The hedging scheme also raises significant concerns in relation to discrimination. It also introduces additional cost and complexity and could be considered not to be consistent with the efficient implementation and administration of the BSC.

5.7. In light of this, the Authority considers that while P200 would better facilitate applicable BSC objectives (b) and (c), it would not better facilitate applicable BSC objectives (a) and (d). However, the key factor in the Authority's assessment of P200 is in relation to applicable BSC objective (a). Non-discrimination is a key principle of NGET's transmission licence. It is critically important as it ensures parties have the opportunity to compete on a fair basis and therefore can have a knock-on effect on wider efficiency arguments. In line with the views of respondents and a number of the BSC Panel the Authority considered that P200 raises a number of concerns in relation to discrimination. Combining those concerns with its higher costs and complexity under applicable BSC objective (a) the Authority considers that these factors outweigh the benefits of the proposals in relation to applicable BSC objectives (b) and (c).

5.8. On balance, the Authority does not consider that P200 better facilitates the achievement of the applicable BSC objectives overall, compared with the existing provisions of the BSC.

P200 Alternative

5.9. The P200 Alternative proposes exactly the same hedging scheme as P200. It therefore raises exactly the same concerns in relation to applicable BSC objectives (a) and (d). The key difference from P200 is that the P200 Alternative proposes the introduction of seasonal TLFs which would be likely to produce charging arrangements that are more reflective of costs than those based on annual TLFs and thus have a greater impact in reducing total losses. Therefore, the P200 Alternative could be considered to better facilitate applicable BSC objective (b) to a greater extent than P200.

5.10. However, overall, the Authority does not consider that the P200 Alternative would better facilitate applicable BSC objectives (a) and (d) and therefore on balance, and for the same reasons as those set out above for P200, it does not consider that the P200 Alternative better facilitates the achievement of the applicable BSC objectives taken collectively, compared with the existing provisions of the BSC.

P203

5.11. As noted above, we consider that a locational loss charging arrangement with seasonal TLFs would encourage more efficient use of the network and as a result facilitate more effective competition in the market. This was highlighted by OXERA's analysis which demonstrated that P203 would have the greatest impact in reducing total losses and thus the greatest benefits in £m terms. The Authority therefore considers that P203 would better facilitate applicable BSC objectives (b) and (c).

5.12. Again the Authority considers that P203 is broadly neutral in relation to applicable BSC objectives (a) and (d). On that basis, the Authority considers that P203 better facilitates the achievement of the applicable BSC objectives overall, compared with the existing provisions of the BSC.

P204

5.13. Like phasing, the introduction of variable scaling would reduce the cost-reflectivity of the charging arrangements and thus the benefits of introducing seasonal TLFs. Further, given that scaling would not be a short-term measure then it would reduce benefits over a longer period than the proposed 4 year phasing under the P198 Alternative. However, again the model would better reflect parties' impacts on the network than the existing arrangements and in doing so improve the efficiency of decision-making and create a more level playing field for effective competition. Overall, therefore, the Authority considers that P204 would better facilitate applicable BSC objectives (b) and (c) than the existing uniform losses arrangements.

5.14. In relation to applicable BSC objective (d) the Authority noted that the modification proposal does introduce some additional complexity. However, this complexity does not translate into additional cost, and therefore the Authority

considers that on balance P204 is broadly neutral in relation to applicable BSC objective (d).

5.15. Again, the Authority considers that P204 is broadly neutral in relation to applicable BSC objective (a).

5.16. On that basis, the Authority considers that P204 better facilitates the achievement of the applicable BSC objectives overall, compared with the existing provisions of the BSC.

6. Stage three - Assessment against Authority's legal duties

Chapter Summary

This chapter sets out the Authority's assessment of the six modification proposals against its legal duties, including those arising under European law.

Question box

Question 1: Do respondents consider that the Authority has appropriately assessed the modification proposals against its duties?

Question 2: Do respondents consider that there are any aspects on the modification proposals that have not been adequately assessed in relation to the Authority's duties?

The Authority's duties

6.1. The Authority has a number of duties and obligations. These include its primary duty to carry out its functions under Part 1 of the Electricity Act 1989 in the manner it considers is best calculated to further its principal objective having regard to its statutory duties. The Authority's principal objective is, in summary, to protect the interests of consumers, wherever appropriate by promoting effective competition. Chapter 7 sets out further detail of the Authority's thinking in relation to which of the options available to it it considers is best calculated to further the principal objective.

6.2. The Authority's other duties under the Electricity Act 1989 include:

- the promotion of efficiency and economy on the part of persons authorised by licences or exemptions to undertake regulated activities in the electricity industry to contribute to the achievement of sustainable development
- to secure a diverse and viable long-term energy supply; and
- to have regard to the effect on the environment of activities connected with the generation, transmission, distribution or supply of electricity.

6.3. The Authority also has to comply with the requirements of European law. This includes the requirements contained in Directive 2003/54/EC concerning the common rules for the internal market in electricity (the “IMED”) and Directive 2001/77/EC on the promotion of electricity produced from renewable energy sources in the internal market (the “renewable energy Directive”)

6.4. This chapter describes the Authority's assessment of the modification proposals against its duties under the Electricity Act and against the requirements of applicable EC law. This chapter does not, however, seek to address all of the Authority’s duties or all relevant requirements of EC law; it only seeks to address those the Authority considers to be most relevant to the assessment of the modification proposals.

Duties under the Electricity Act

Environment and sustainability

6.5. The Authority has an obligation to have regard to the effect on the environment of activities connected with the generation, transmission, distribution and supply of electricity. The Authority also has a closely related obligation which is to contribute to the achievement of sustainable development. The impact of each of the modification proposals on the environment and sustainability can be measured in a number of ways. These include the impact on: (1) the total level of losses; (2) the level of emissions; (3) the change in fuel-mix/ renewables development; and (4) the size and development of the network.

Total losses

6.6. As set out in table 5 in chapter 4, the introduction of locational charging arrangements for losses would be expected to reduce total transmission losses. In the short term, it would be expected to reduce the volumes generated by plant located far from the centres of demand and, in the longer term, it would be expected to inform a plant's locational decisions such that it would be more likely to site closer to areas of significant demand.

6.7. All of the modification proposals would be expected to reduce total losses. OXERA's analysis highlighted that P203 would produce the greatest total loss savings. The modification proposals that involve some form of mitigation factor e.g. phasing would be expected to produce the lowest total loss savings. Moreover, as they produce more accurate locational signals, models which propose seasonal TLFs would be expected to have a greater impact in reducing total losses than models which propose calculating TLFs on an annual basis.

Total emissions

6.8. In our impact assessment we presented evidence to suggest that zonal loss charging would result in lower losses due to a north to south shift in generation together with fuel switching away from coal generation towards more gas generation. In doing so it would have a favourable impact in terms of reducing carbon emissions. Table 6 summarises the estimated carbon savings[7].

[7] Further information on the calculation of carbon emissions savings was set out in Appendix 3 of the impact assessment on zonal transmission losses.

Table 6

Value of carbon emissions savings in period 2006-2011		
Scenario	**Value of savings using £35-£140/tC (£m)**	**Value of savings using central estimate £70/tC (£m)**
P198	18.1 ~ 72.6	36.3
P203	32.1 ~ 128.4	64.2
P204	9.7 ~ 38.8	19.4

6.9. The Authority considered that this highlights that P203 has a significantly greater impact on reducing carbon emissions than P198 or P204. This reflects the combination of more focused reallocation of losses during different times of the year and larger movement away from coal generation.

6.10. Once again we were not able to directly measure emissions savings for phasing (P198 Alternative) or hedging (P200 and P200 Alternative) as sufficient data was not available. However, by reducing the strength of locational losses the Authority considered that it would expect that the phasing arrangement proposed by the P198 Alternative would create weaker signals for parties to locate close to demand and would result in reduced emissions savings. By allowing qualifying generators to hedge their positions, the proposed hedging scheme would also reduce the strength of the signals to some parties. Once again this would be expected to reduce the level of emissions savings.

6.11. The Authority noted the views of some respondents that the environmental benefits of the modification proposals have been overstated. The Authority disagreed with this view. The value of carbon savings has been calculated based on the level of total emissions set out in NGET's Seven Year Statement and the social cost of carbon used by DTI. Going forward the expectation is that this value may increase. As a result, the values of emissions savings are likely to be at the higher end of our estimates.

Fuel mix/ renewable development

6.12. The Authority accepted the view expressed by a number of respondents that renewable generation connecting or seeking connection in the north of Scotland will be exposed to higher losses charges by the introduction of zonal losses. However, the Authority does not consider that the introduction of efficient locational loss signals will significantly hamper the development of renewable generation in Scotland nor that it would hamper the various targets set by the UK Government, the Scottish Executive and the EU for the contribution to be made by renewable generation sources.

6.13. First, the Authority noted that there are a number of factors which affect renewable generators and their decisions on where to connect. These include the availability of resource, the levels of load factors, transmission charges and the support provided by the Renewables Obligation. The ongoing demand for

connections, particularly in the north of Scotland, suggests that the effect of other factors such as the Renewables Obligation continue to outweigh any negatives in terms of charges and the Authority did not consider that this position would change in the event that it were to approve one of the modification proposals. In particular, the Authority noted OXERA's cost benefit analysis report on the modification proposals which concluded that, reflecting the impact of the Renewables Obligation, the introduction of zonal loss charging will have little, if any, impact on renewable new build across the period to 2015/16[8].

6.14. Second, the Authority agreed with respondents who highlighted that the north of Scotland was not the only potential area of renewable development. As highlighted in the section on the impact on different generation technologies in chapter 3, there are sites throughout GB that are suitable for renewable development and indeed from an offshore perspective there is at present greater scope for the development of renewable generation outside Scotland. Approving one of the proposals might therefore create incentives for greater volumes of renewable generation to locate in the areas where locational loss charges would be lower. At present, the majority of renewable generation connected to the network is onshore wind. By encouraging renewable generation to locate in different areas it may encourage the development of more diverse forms of renewable generation, which is likely to contribute to the achievement of sustainable development. The Authority also considered that should zonal losses reduce the output from conventional plant in the north (as noted below in paragraph 6.25) and encourage renewable generation in the south, then this would be expected to have a positive environmental impact.

6.15. In addition to creating incentives that may promote renewable generation in the south of GB, the modification proposals would also be expected to provide incentives for large scale private sector investment in other low carbon technologies in southern GB such as carbon capture and storage and Combined Heat and Power (CHP).

Size of the transmission grid

6.16. There is evidence to suggest that consumers value visual amenity. This has been particularly evident in the current public inquiry into the upgrading of the transmission line between Beauly and Denny where, following protests from local communities, organisations such as the National Trust for Scotland and the Highland Council have expressed deep concern regarding the impact of pylons on visual amenity and landscape character. In the Authority's view, although it is unlikely that the decision on zonal losses would in itself significantly influence the decision on Beauly-Denny, cost reflective loss charges which alter the long term pattern of generation connections and encourage generation to locate closer to demand may be expected to have positive environmental impacts in this respect.

[8] 'What are the costs and benefits of zonal loss charging', Elexon, July 2006 - Chapter 5, p 56 www.elexon.co.uk/documents/Consultations/Cost_Benefit_Analysis_Data_Correction_Consultation/P198CBA_(revised_20060731).pdf

6.17. Models proposing seasonal TLFs are expected to have a bigger impact on locational decision-making than those with annual TLFs. Further, models which propose to mitigate the strength of the signal or which propose to scale TLFs reduce the locational signal. On that basis, P203 is most likely to reduce the need to increase the size of the grid, closely followed by P198. Models involving a form of mitigation may reduce the size of the grid but to a lesser or slower extent. Hedging may result in inefficient decisions regarding parties' use of the system which could affect the efficiency of the GB transmission system as a whole.

Overall impact on environment and sustainable development

6.18. To the extent that all of the models propose more locationally-based charging arrangements than those that exist today then they are likely to foster better decision-making by parties in relation to connection and use of the system. That is good for the environment in terms of less use of the transmission system and therefore lower transmission losses. Generally models that produce most cost-reflective charges such as P203 and P198 are more likely to have positive environmental benefits.

6.19. However, the Authority recognises that the debate on the environment and achieving sustainable development is not all one sided in the sense that cost-reflective charges may also increase transmission charges in areas of high renewable potential and therefore models that produce more cost-reflective charges may also make some marginal renewable generators non-viable. However, there are specific mechanisms such as the Renewables Obligation and Climate Change Levy which, DTI have estimated, would provide support to the renewables industry of up to £1billion per year by 2010. The Authority considered that, if any of the modification proposals on locational losses were to be approved then the actual impact on renewable generation would be determined by a wider range of factors than just charges for losses.

6.20. To the extent that the proposed modifications do impact on parties' decision-making, the Authority notes that while loss charges may increase in the north of Scotland they would also decrease in southern GB where there is significant potential for CHP and biomass plant. The Authority also notes that the most likely location for offshore wind is in southern GB where losses charges would be lower. In addition, greater efficiency created by the locational losses signals may result in reduced output from less efficient conventional plant and increased output from new, more efficient, plant. The Authority therefore considers that the introduction of locational charges for losses should not adversely impact upon the achievement of sustainable development.

Efficiency and economy

6.21. Another of the Authority's duties under the Electricity Act is to promote efficiency and economy on the part of persons authorised by licences or exemptions to undertake regulated activities in the electricity industry.

6.22. The Authority considered that the introduction of locational loss charging arrangements, by ensuring that transmission users will pay charges that reflect their impact on the network, would result in those users (both generators and suppliers) making more efficient decisions regarding their use of the GB transmission system. The key arguments regarding efficiency were set out in more detail in the assessment against applicable BSC objective (b) in chapter 4.

6.23. In relation to the efficient use of distribution systems, zonal losses arrangements under each of the proposals would expose distributed generation to the same geographical locational signals as transmission-connected generation. The Authority considers that this will promote the more efficient use of both systems. The key arguments on this issue were set out in the section on distributed generation in chapter 3.

Security of supply

6.24. The Authority considers that cost-reflective charging arrangements which encourage parties to make the most efficient decisions regarding connection to and use of the system are the best way to ensure system security. An effective working energy market is the most effective way to deliver GB's generation requirements. If there were any issues identified with regard to the future security of the system then the Authority would expect the GB system operator to take the actions necessary to address these going forward. We note one respondents' example of constraining on plant as relevant in this regard.

Secure reasonable demands for electricity are met

6.25. In the short term, an increase in charges to generators in the north may be expected to bring forward the closure of marginal plant, particularly thermal generation facilities in Scotland. However, there are significant volumes of generation seeking immediate connection in these areas, suggesting there would not be a sustained reduction in capacity. In the event that reserve services are required from these plants, the system operator would be expected to contract for them to ensure they continue to be provided. An accurate signal may also send the appropriate signals to marginal plant in the south to continue operating or increase output. In the longer term, stronger incentives to locate closer to demand might be expected to reduce the likelihood of system faults causing the disconnection of consumers. Overall, the Authority considers that all of the modification proposals would have a minimal impact on the ability to secure that all reasonable demands for electricity are met.

Securing a diverse and viable long-term energy supply

6.26. If locational charges are more reflective of costs they are likely to provide more effective signals about efficient investment. More economic decisions are more likely to foster the development of generation projects that are viable in the long-term. While the Authority considered that all of the modification proposals produce more cost-reflective charging arrangements than the existing uniform charging

arrangements, modification proposals P203 and P198 produce more cost-reflective charging arrangements than the other proposals and therefore are more likely to secure a diverse and viable long-term energy supply.

European law obligations

6.27. The Authority also considered the modification proposals against the requirements of applicable EC law. In addition to the key principles of European law relating to non-discrimination and proportionality, the Authority also had regard to other requirements of European legislation including those which require that charging structures are non-discriminatory and cost-reflective.

Discrimination

6.28. The Authority considered whether the introduction of a zonal TLF scheme would give rise to unjustified discrimination.

6.29. Transmission users have different impacts on the total level of losses depending on their location on the system. However, under the existing arrangements all parties pay uniform charges. On this basis, the introduction of locational losses, by facilitating more cost-reflective charging arrangements, would be expected to reduce the scope for discrimination.

6.30. Under all of the proposals, the methodology proposed for calculating and applying zonal TLFs does not discriminate between parties as it would apply in the same way to all parties and there is no apparent justification for doing otherwise. However, the proposed hedging arrangements under P200 and the P200 Alternative do raise a number of concerns in relation to discrimination in that they would not apply to all parties and would treat new entrants differently from existing users. The Authority does not consider there to be any justification for the differential treatment of parties that would be the result of approving P200 or the P200 Alternative. These arguments were set out in more detail in relation to the Authority's assessment against applicable BSC objective (a).

Proportionality

6.31. The Authority also considered the concept of proportionality. One aspect of this is that the proposed action taken should not exceed that which is necessary to achieve a stated objective.

6.32. The Authority noted that the costs of implementing and operating any of the modification proposals are relatively low in absolute terms and far lower than the associated benefits. The majority of models (excluding P200 and the P200 Alternative) have implementation costs of around £400k and ongoing operational costs of £150k per annum. The total savings in losses are estimated at around £5-

14m per annum. Moreover, this is not taking into consideration other potential savings in relation to reduced emissions and demand-side response.

6.33. The Authority noted and accepted respondents' views that some zones would see significant changes in their contribution to total loss charges. However, this is not an indication that the proposals have a disproportionate impact. Rather it reflects the fact that at present parties are not paying charges that reflect their contribution to losses. In other zones transmission users would see reductions in charges and overall the distributional effect would cancel out as the same pot of money is being recovered. In future locational charges should result in parties making more efficient decisions regarding use of the system which would feed through into lower charges overall.

6.34. The Authority noted that a number of respondents have raised issues regarding the scope for the proposed modifications to have a disproportionate impact on different classes of party including renewable generation, small suppliers and microgeneration.

6.35. In the case of renewables the Authority recognises that there is a higher proportion of renewable generation either connected to, or seeking connection to, the network in the north of Scotland. However, this reflects wider considerations including advantages in terms of resource, costs and output. Renewable generation can and does connect in various other parts of the network. If it does connect in Scotland then the charges should be proportionate to the impact on the network. The locational loss charging arrangements proposed by the various modification proposals should therefore result in more proportionate charging arrangements. In addition, as noted earlier in this chapter, the ongoing demand for connections, particularly in the north of Scotland, suggests that the effect of other factors such as the Renewables Obligation continue to outweigh any negatives in terms of charges and the Authority does not consider that this position would change in the event that it were to approve one of the modification proposals.

6.36. Equally, the Authority does not consider that the impact of the modification proposals on small suppliers and microgeneration can be considered to be disproportionate. Changes in the charges that parties pay will be proportionate to their production in the case of generators and their consumption in the case of demand. Depending on where they are connected that effect could be positive or negative. The same argument is relevant for parties that are only connected in single sites compared to other parties in multiple sites. Where charges change by different amounts according to location then parties who are connected in multiple locations are likely to have the impacts whether negative or positive, offset to a degree. The key consideration is that the charges reflect the impact of those parties on the network.

Overview of assessment against the Authority's legal duties

6.37. Locational charging arrangements as set out in the modification proposals would be expected to result in the reduction of total losses, with associated

environmental benefits. Cost-reflective charging arrangements are also more likely to be consistent with the European law principles of non-discrimination and proportionality. Finally, the Authority considers that the modification proposals are consistent with its other duties including securing a diverse and viable long-term energy supply and facilitating sustainable development.

6.38. Once again P200 and P200 Alternative raise a number of concerns with regard to the Authority's legal duties. In particular, the fact that the detailed design of the proposed hedging scheme may result in discrimination and result in inefficient decision-making which could hinder any environmental benefits associated with more cost-reflective charging arrangements and create discriminatory and disproportionate outcomes.

6.39. In relation to the other modification proposals the Authority noted that phasing (P198 Alternative) is not likely to result in the same level of total loss savings, at least in the short-term. Variable scaling (P204) while resulting in comparable total loss savings to P198 was demonstrated to result in far lower reduction in emissions than P198 and P203.

7. Stage four - Assessment against the principal objective

Chapter Summary

The Authority has a duty to carry out its functions under Part 1 of the Electricity Act 1989 in the manner it considers is best calculated to further the principal objective. This chapter sets out the Authority's view on which of the options available to it is best calculated to further the principal objective, having regard to its statutory duties.

Question box

Question 1: Do respondents have any comments on any of the issues set out in this chapter?

The principal objective

7.1. The Authority's principal objective is to protect the interests of consumers, both present and future, wherever appropriate through the promotion of effective competition. There are a number of factors which are relevant to an assessment of the modification proposals against the Authority's principal objective.

Protecting consumers' interests

7.2. The introduction of locational losses charges would be expected to protect the interests of consumers by introducing more cost reflective charging arrangements that will facilitate lower prices. Cost-reflective charging arrangements facilitate lower prices in two respects: (1) by encouraging more efficient decision making regarding use of the system and thus the more efficient development of the GB transmission system as a whole; and (2) by removing the scope for cross-subsidisation between network users and thereby facilitating effective competition between parties which use the network. Under the existing arrangements, losses are allocated and thus charged for on a uniform basis. The introduction of locational charging arrangements would be expected to produce more cost-reflective tariffs by ensuring that generators and suppliers pay charges which reflect their impact on variable losses. As noted, if parties charges better reflect their impact on the network then they are likely to make more efficient decisions regarding use of the system which would result in lower costs for losses overall which would be expected to result in lower prices to consumers. This will be a particular benefit to those consumers who are in fuel poverty.

7.3. The models that do not mitigate full locational signals (i.e. P198 and P203) would be expected to produce more cost-reflective charges and thus put more pressure on lowering prices than the other modification proposals. The Authority noted the views of respondents that savings would not be passed on to consumers.

However, the Authority noted that competition would ultimately determine the impact and should ensure that savings are passed through to consumers.

7.4. The Authority's assessment of the impact of the modification proposals on effective competition was set out in relation to applicable BSC objective (c) in chapter 4. The Authority considers that the modification proposals, particularly P198 and P203, would be likely to facilitate more effective competition and thus would be more likely to put downward pressure on prices. In addition to the impact on prices, the Authority considers that facilitating more effective competition will encourage more generation to enter the market. This will further protect the interests of consumers as this would be expected to have a positive impact on security of supply. On that basis, a decision to approve one of those modification proposals would, in the Authority's view, be likely to further its principal objective.

Environment

7.5. The interests of consumers are not purely financial. Another issue that is relevant to consumers is the environment. Recent research by Ofgem[9] has highlighted that consumers value the environment and indeed will pay more to tackle climate change. UK consumers already contribute to a number of schemes that support energy efficiency and renewable energy, which amounts to about £15 out of the average yearly household bill.

7.6. Other things being equal, an accurate locational cost signal would be expected to reduce the total volume of transmission losses and provide environmental benefits. Models that produce the most cost-reflective charges such as P203 and P198 are more likely to have more positive environmental benefits than those which reduce or alter the locational signals by phasing (P198 Alternative), hedging (P200 and P200 Alternative) and variable scaling (P204). The estimated environmental benefits of the modification proposals were set out in detail in chapter 6 in relation to the Authority's legal duty to have regard to the effect on the environment of activities connected with the generation, transmission, distribution and supply of electricity.

7.7. Taking this analysis into consideration, the Authority considered that the modification proposals, particularly P203 and P198 would be likely to facilitate greater environmental benefits. On that basis, those modification proposals would be likely to further the principal objective.

Option best calculated to further the principal objective

7.8. The Authority went on to consider which of the options available to it it considered was best calculated to further the principal objective at the present time. The Authority considered that the following options are available to it:

[9] 'Stimulating World - Ofgem First Deliberative Report of Findings' - June 2007, #144/07

- Approve one of the modification proposals to apply from 1 October 2008.
- Approve one of the modification proposals and direct a different implementation date.
- Reject all of the modification proposals.

7.9. Each of these options is considered in turn below.

Approve one of the modification proposals

7.10. The previous chapters describe the Authority's assessment of the pros and cons of each of the modification proposals within the relevant legal and assessment framework. The discussion in those chapters highlights a number of issues.

7.11. First, the hedging scheme proposed by P200 and the P200 Alternative raises a number of fundamental concerns in relation to discrimination, cost and complexity while providing fewer benefits compared to some of the other modification proposals. In the Authority's view neither P200 nor the P200 Alternative would be better than the status quo.

7.12. Second, to the extent that sudden changes in charges could negatively impact upon competition then phasing, as proposed by the P198 Alternative, could be considered to have a positive impact. However, given the history of the discussion of zonal losses and the lengthy implementation timetable that has been proposed the Authority is not convinced that the proposals raise sufficient concerns regarding stability and predictability to merit the use of phasing. Certainly we do not consider that any positive impact on stability is sufficient to offset the downsides of phasing including delays to the realisation of the full efficiency and competition benefits associated with unphased locational charges. While the Authority considers the P198 Alternative would better facilitate the applicable BSC objectives and its wider duties than the baseline arrangements, it does not consider that it is the best option available to further the principal objective.

7.13. Third, the benefits and dis-benefits of variable scaling, as proposed by P204, are finely balanced. The main impact of variable scaling is to reduce significantly the short term distributional impacts associated with locational losses. This provides greater stability and predictability, reducing the risk that transmission users face in making decisions in connecting to and using the network and thus might arguably have a marginally positive impact on competition. It is also notable that, given that it proposes to introduce seasonal TLFs, the losses savings of P204 are second only to P203. However, P204 dampens cost-reflective signals and thereby would be likely to reduce the efficiency of the GB transmission system as a whole and therefore produce lower competition benefits overall than modification proposals that provide fully cost reflective signals. It also has a significantly smaller impact on reducing emissions and thus provides lower environmental benefits than a number of the other modification proposals. Once again while the Authority considers that P204 would better facilitate the applicable BSC objectives and its wider duties than the status quo, it does not consider that is it the option best calculated to further its principal objective.

7.14. Fourth, the modification proposals which propose the introduction of seasonal TLFs would be expected to better reflect the impact of parties' actions on losses during the year. To the extent that charges are more cost-reflective then parties should make more efficient decisions and the efficiency of the network as a whole should be maximised. The Authority notes that P198 does not propose the introduction of seasonal TLFs. As discussed in more detail in chapters 4, 5 and 6, the Authority considers that P198 would better facilitate the applicable BSC objectives and its wider duties than the existing arrangements. However, the Authority does not consider that it is the option best calculated to further the principal objective as there is an alternative proposal, P203, that provides the same benefits as P198 and in addition does propose the introduction of seasonal TLFs. P203 is the only modification proposal which proposes seasonal TLFs without hedging, phasing or variable scaling. The Authority considers that P203 has significant benefits in terms of reducing losses and emissions and in encouraging more efficient decision-making by parties both in terms of use of the network in the short-term and in connecting to the network in the future.

Overall view

7.15. On this basis, the Authority considers that P203 is the modification proposal which is best calculated to further the principal objective.

Approve one modification proposal with a different implementation date

7.16. The BSC Panel has proposed an implementation date of 1 October 2008 if the Authority's final decision is to approve one of the modification proposals and the Authority's decision is received on or before 20 September 2007. However, in accordance with Paragraph 4c of SLC C3 of NG ET's electricity transmission licence and Section F, paragraph 2.11.7, of the BSC, the Authority may direct a different implementation date for a modification proposal that it has approved. That implementation date can be either early or later than the implementation date proposed by the BSC Panel.

7.17. The Authority does not consider it would be appropriate to direct an earlier implementation date on the grounds that Elexon has identified a number of changes to existing arrangements that would not be feasible to introduce in a condensed timeframe. Moreover, a 12 months implementation period will provide transmission users with more time to prepare for the introduction of locational charging arrangements thereby reducing uncertainty and the associated risk.

7.18. The Authority also does not consider it would be appropriate to direct a later implementation date on the grounds that, having identified the benefits of the modification proposals in relation to greater efficiency, reduced losses and environmental benefits, proposing a later implementation timeframe would delay the receipt of those benefits and allow less efficient arrangements to continue in the meantime.

7.19. On this basis, the Authority is not minded to direct an alternative implementation date for P203.

Reject all of the modification proposals

7.20. As set out in chapters 4, 5 and 6, the Authority considers that a number of the modification proposals: (1) better facilitate the achievement of the applicable BSC objectives as compared to the current provisions of the BSC; and (2) are consistent with the Authority's legal duties and applicable EC law requirements. In deciding which of the options available to the Authority was best calculated to further its principal objective, the Authority considered that a rejection of all of the modification proposals was not the best option. Relevant to this conclusion are the following points:

- Efficiency – variable losses increase with the power flow and length of line on which electricity flows, but the different locational impacts of generators' and suppliers' actions are not currently reflected in the charges they pay for losses. As a result, parties are not making the most efficient decisions about their use of the system. This reduces the efficiency of the GB transmission system as a whole, as demonstrated by the increase in variable losses since the introduction of BETTA.

- Discrimination - to the extent that proposals promote or further cost-reflectivity they could be argued to also promote or further non-discrimination. Conversely, if parties are not facing charges which accurately reflect the costs they impose, then the argument could be made that the existing arrangements result in discriminatory outcomes.

- Competition – if transmission users are not paying charges that reflect their impact on the transmission network the relative cost position will be skewed, thereby inhibiting effective competition between parties using the network.

- Environment – the existing arrangements could be considered not to be consistent with the most efficient development of the GB transmission system. Less efficient decision-making is likely to lead to higher losses, higher carbon emissions and less efficient future development of the network.

- Consumers – the interests of consumers are best facilitated by cost-reflective charging arrangements that promote the efficient and lowest cost development of the transmission system and by effective competition between generators and suppliers which drives down prices. For example, under the existing arrangements the fact that Scottish consumers are in close proximity to generation stations is not reflected in the charges they pay for losses.

- Costs – the implementation costs of the modification proposals are not large and are significantly lower that the estimated benefits of those proposals.

8. Conclusions and way forward

Chapter Summary

This chapter sets out the minded to position of the Authority in relation to the six BSC modification proposals on zonal transmission losses.

Question box

Question 1: Do respondents wish to raise any specific issues regarding the Authority's minded to position?

Question 2: Do respondents have any views on both the process and timetable that are proposed for the Authority making its final decisions on the modification proposals and for publishing those decisions?

Authority's minded to position

8.1. For the reasons set out in Chapters 4 to 7, the Authority is minded-to:

- Approve modification proposal P203; and
- Reject all of the other modification proposals.

8.2. The Authority does not consider that there is any justification either to bring forward or delay the implementation of P203 and therefore is not minded to direct an alternative implementation date.

Way forward and timetable

8.3. This document provides five weeks for respondents to submit any comments.

8.4. The Authority will consider any responses to this “minded-to” document before reaching its final decisions. The Authority currently intends to publish its decisions on each of the proposed modifications by 20 September 2007.

Further information

8.5. Appendix 1 sets out both the details for responding to this 'minded to' decision 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 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 31 July 2007 and should be sent to:

Robert Hull
Director of Transmission
Ofgem
9 Millbank
London
SW1P 3GE
0207 901 7050
robert.hull@ofgem.gov.uk

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. Next steps: Having considered the responses to this consultation, Ofgem intends to publish its decision letters in relation to all six proposed and alternative modifications.

1.7. Any questions on this document should, in the first instance, be directed to:

Lesley Nugent
Senior Manager - Transmission Policy
Ofgem
70 West Regent St
Glasgow
0141 331 6007
lesley.nugent@ofgem.gov.uk

CHAPTER: Two

Question 1: Do respondents consider that we have appropriately summarised the key themes of the responses to Ofgem's impact assessment on zonal losses?

Question 2: Are there any other themes which respondents considered should have been highlighted?

CHAPTER: Three

Question 1: Do respondents consider that the additional analysis we have provided addresses the concerns expressed by respondents to the impact assessment regarding analytical gaps in the impact assessment?

Question 2: Do respondents consider that there are any remaining aspects on the modification proposals that require to be addressed analytically?

Question 3: Do respondents have any additional analysis in relation to the impact of the modification proposals that they wish to bring to the attention of the Authority?

CHAPTER: Four

Question 1: Do respondents consider that the modification proposals have been appropriately assessed against the applicable BSC objectives?

Question 2: Do respondents consider that there are any aspects of the modification proposals that have not been adequately assessed in relation to the applicable BSC objectives?

CHAPTER: Five

Question 1: Do respondents consider that the Authority has appropriately assessed the modification proposals against the applicable BSC objectives when considered collectively?

Question 2: Do respondents consider that there are any aspects on the modification proposals that have not been adequately assessed in relation to the applicable BSC objectives when considered collectively?

CHAPTER: Six

Question 1: Do respondents consider that the Authority has appropriately assessed the modification proposals against its duties?

Question 2: Do respondents consider that there are any aspects on the modification proposals that have not been adequately assessed in relation to the Authority's duties?

CHAPTER: Seven

Question 1: Do respondents have any comments on any of the issues set out in this chapter?

CHAPTER: Eight

Question 1: Do respondents wish to raise any specific issues regarding the Authority's minded to position?

Question 2: Do respondents have any views on both the process and timetable that are proposed for the Authority making its final decisions on the modification proposals and for publishing those decisions?

Appendix 2 – Summary of responses and Ofgem's views

List of Respondents

List	Name
1	Airtricity
2	Alcan
3	Bizz Energy
4	British Energy
5	British Wind Energy Association
6	Centrica
7	CHPA
8	Drax
9	EDF
10	Energywatch
11	E.ON UK
12	HIE
13	Immingham CHP
14	International Power
15	Lewis Wind Power
16	Magnox
17	National Grid Electricity Transmission plc
18	Ralph Turvey
19	RWE
20	Scottish Power
21	Scottish Renewables Forum
22	Scottish and Southern Energy
23	Teeside Power
24	Unison Scotland
25	Uskmouth Power

Summary of Responses

1.1. Responses received by Ofgem which were not marked as being confidential have been published on Ofgem's website www.ofgem.gov.uk. Copies of non-confidential responses are also available from Ofgem's library.

1.2. The following is a summary of those responses which were received.

Oxera analysis and modelling

Respondents' views

1.3. Twelve respondents questioned the robustness of OXERA's analysis or raised issues with the data presented.

1.4. One respondent stated that there were flaws in the quoted results from the Oxera modelling set out in tables 2.1a and 2.1b of the impact assessment. The respondent commented that the impact assessment states that the seasonal estimates for P203 show a degree of variance around the annual average for P198 but this is not the case for East Midlands and South of Scotland. This respondent also considered that P203 produces extreme signals that it considered cannot be a better reflection of the costs of transmission losses than uniform allocation of losses.

1.5. Two respondents considered that the use of snapshots during the year was unreliable. One respondent considered that the sample used in the load flow analysis was too small. Several respondents also noted that Oxera's analysis uses an out of date energy price of £45/MWh rather than the current price of £30/MWh. One respondent further considered that use of 2005/06 data results in distorted TLMs as this was a period of high gas prices.

1.6. Respondents also commented that Oxera's analysis excludes the effect of fixed losses. These respondents noted that the material impact of the proposals is more than suggested when fixed losses are taken into account.

1.7. A number of respondents further commented that Oxera's analysis is not a true reflection of the current or anticipated market as it assumes that all plant is centrally despatched. Respondents noted that this does not reflect NETA and BETTA. One respondent noted that for 95% of the market, short-term re-despatch decisions will only be taken within the generator's own portfolio. The Oxera model therefore overestimates the level of re-despatch.

1.8. Seven respondents commented on Ofgem's use of Oxera's analysis. A number of these respondents commented that Ofgem has placed undue reliance on Oxera analysis, which some respondents considered to be simplistic, unreliable and limited in scope relative to the matters the Authority must consider in reaching its decision. One respondent considered Ofgem's assessment to be impartial and inaccurate. Another commented that Ofgem's environmental analysis should not rely on OXERA's data but Ofgem should provide their own analysis

1.9. One respondent noted that Oxera's analysis shows an increase in losses in 2015/16. The respondent stated that this "worrying trend" was not explained in the impact assessment. This respondent also commented that the impact assessment did not publish cost benefit analysis data beyond 2011, and not by GSP group.

1.10. Thirteen respondents highlighted issues that they considered had been ignored in the analysis presented in the impact assessment. These included:

- impact of fixed losses on parties' costs
- impact on distributed generation including erosion of embedded benefits
- impact of alternative approaches to reducing losses e.g. investment in transmission system assets to increase efficiency and targeting losses on distribution system which are far greater
- the existing incentive arrangements put in place by Ofgem to encourage NGET to reduce overall transmission losses. Should consider whether this is duplication of incentives/ signals
- impact on different types of generator
- impact on participants who do not hold diverse or geographically dispersed portfolios - larger players can diversify effect through dispersed portfolios
- does not explicitly highlight the existing cross-subsidies in the system and therefore underestimates benefits of the proposals
- not sufficient attention to the impact on demand
- that prices for consumers will rise because larger players will be able to pass the cost through in their contracts and tariffs.

1.11. Eight respondents considered that the impact assessment had provided insufficient analysis of the hedging proposals under P200 and the P200 Alternative and that this constituted preferential treatment of the other modification proposals. The majority of those respondents requested that this was remedied by providing more detailed analysis of hedging in the 'minded to' document. Another respondent considered that the merits of linear phasing had not been fully considered.

Ofgem's views

1.12. Ofgem notes parties' views in respect of OXERA's analysis and its use in the impact assessment. As set out in chapter 3, we consider it appropriate to use OXERA's analysis in our impact assessment and we have set out in that chapter our response to the views expressed by a number of respondents in respect of the robustness of Oxera's analysis. Chapter 3 also provides additional analysis in respect of a number of the issues respondents considered were not addressed or not adequately addressed in the impact assessment and invites respondents' views on this further analysis.

Interaction with TNUoS

Respondents' views

1.13. Nine parties raised the issue of the potential interaction of locational loss charging arrangements with the existing locational Transmission Network Use of System (TNUoS) charging arrangements.

1.14. Three parties argued that TNUoS charges already provide a locational signal and that by introducing locational charging arrangements for losses then the cumulative signal would be too extreme. Another two respondents argued that as

TNUOS already provides a locational signal then locational losses would provide no additional benefit. Another respondent noted that while the effect of a parties actions on "on the day" transmission losses cannot be influenced by the long-term TNUoS signal it recognised that any investment in the transmission system may impact on total system losses. Therefore, there is potential for a limited interaction between the TNUoS signal and that proposed for losses.

1.15. One party argued that as a result of the interaction between locational TNUoS and losses a TNUoS charging review needs to be carried out before any locational losses modification is implemented. This respondent noted that Ofgem had previously suggested that a review of TNUoS charges may be required in its December 1999 paper on losses but that this point was missed by the Skyplex report.

1.16. In its response NGET, in its role as GB system operator, noted that if any modification were approved then to ensure no inappropriate interaction between the signals it would review this aspect of the TNUoS methodology.

1.17. One party highlighted a number of additional issues in terms of the interaction with TNUOS, these included:

- the scope for contradictory locational signals by the two methodologies in certain zones i.e. zones near the centre of the system might have a negative TNUoS charge but a positive losses charge; and
- TNUoS charges are very volatile year-on-year and losses charges are likely to be more volatile.
-

Ofgem's views

1.18. We note respondents' views as to the potential for an overlap in the signals provided by locational transmission charges and those provided by locational charges for losses. We have undertaken additional joint analysis (set out in chapter 3 and appendix 3) with NGET in order to more fully understand the magnitude of the effect. As set out in more detail in chapter 3, it can be concluded from this analysis that none of the modification proposals would be expected to lead to a material overstatement of the overall locational signals.

Cost reflectivity

Respondents' views

1.19. Four parties argued that zonal losses would improve cost-reflectivity. They argued that:

- the existing uniform treatment of losses is not cost-reflective;
- accurately reflecting parties impact on the network (both generation and demand) would result in more efficient use of the system;

- losses have increased considerably in recent years. The best way to address this is through cost-reflective charging arrangements; and
- cost-reflective charges will enhance competition.

1.20. Six parties argued that zonal losses would not improve cost-reflectivity. The issues they raised included:

- not more cost reflective than the existing allocation methodology as do not believe the existing methodology suffers from cross subsidies
- combination of simplification techniques applied across the proposals means the factors proposed are not cost-reflective e.g. aggregation from nodes to zones and constraining those zones to replicate the TNUoS zones; aggregation in time, from half hourly to seasonal or annual; using ex-ante factors that will be more than a year out-of-date etc.
- inaccuracies pervading the impact assessment analysis (as discussed above) will lead to non-cost reflective charges, which in turn will create a form of cross-subsidy
- allocation of marginal losses to all generation is not an accurate reflection of physical reality or therefore an accurate means of allocating losses e.g. applying negative losses to some generators
-

1.21. One respondent questioned the merits of cost-reflectivity and noted that the commitment by the regulator to cost reflective charging runs counter to Government objectives to promote renewables and tackle climate change.

Ofgem's views

1.22. Ofgem notes the views of respondents that considered that the proposals would improve cost reflectivity. Ofgem's views on cost-reflectivity are set out in more detail in chapters 4 to 7, but in general Ofgem considers that a methodology that allocates losses charges to reflect the extent to which parties have given rise to those losses to be more cost reflective than the current uniform allocation. We also agree that to the extent that the proposals are cost reflective, then they can be considered to be non-discriminatory and enhance competition.

1.23. We note that some parties do not consider that the existing treatment of losses results in a cross subsidy, and therefore consider that none of the proposals would result in more cost reflective charging. We note that variable losses increase with the distance travelled by electricity. As a result, parties at different parts of the network will impact on the level of variable losses to different extents. Under the existing arrangements, the differential impact of parties is not reflected in the charges they pay. Therefore, we consider that the introduction of locational loss charges would result in more cost reflective charges.

1.24. We note respondents views in respect of the simplification techniques used under each proposal. We note that a model which charged for half-hourly losses on a nodal basis using ex-post data would be expected to provide more accurate allocation of losses. However, we consider it would also lead to greater volatility and less certainty, as well as being more complex and costly to implement. The use of simplification techniques such as zoning, seasonal TLFs and ex-ante factors is to

provide greater certainty for parties using the system as well as providing a more accurate reflection of parties' impacts on costs than the existing arrangements.

1.25. We note comments that the allocation of marginal losses to all generation is not an accurate reflection of physical reality or, therefore, an accurate means of allocating losses. We note that locational charges will be derived using a model which seeks to derive charges which best reflect on parties the costs they impose on the system relative to other parties. We accept that these charges do not fully reflect the physical reality, but rather the marginal economic impact.

1.26. We note one respondent considered that cost reflective charging runs counter to the Government's target to promote renewables and tackle climate change. It is our view that cost reflective charging is an important principle in promoting efficient decision making regarding connection to and use of the system. We note that the Authority's decision in respect of these proposals must be consistent with its statutory duties and guidance provided to the Authority by government consistent with those statutory duties.

Risk

Respondents' views

1.27. Eight respondents expressed the view that the complexity of new arrangements and volatility of loss charges year-on-year increases risk for users of the system and deters investment.

1.28. Respondents commented that locational charges might result in marginally lower losses but significantly higher electricity prices, due the increased risk of operation. Respondents also commented that understanding, forecasting and managing the variation in locational TLFs will be difficult and impose further transactional costs on the market

1.29. One respondent stated that inclusion of 132kV as transmission in Scotland exacerbates the zonal differentials and increases risk for parties in Scotland.

1.30. One respondent considered that risk is increased as locational losses charges create “mirage” signals which disappear when a generator changes its location.

1.31. A number of respondents considered that the additional regulatory uncertainty caused by the imposition of a zonal losses scheme based on short term loss factors and with no opportunity to hedge the position, will affect the cost of capital of all industry participants.

1.32. Other respondents commented that the introduction of locational losses charges was not inevitable and not necessarily something the market could predict/expect. The reasons given by respondents for this view included that the Secretary of State noted that zonal losses would not form part of the BETTA arrangements; previous such proposals have been rejected; and Ofgem’s approval of

a series of expansions of the transmission network in northern GB and DTI granting planning permission created a legitimate expectation that locating in northern GB was appropriate.

1.33. Two parties considered that the stated increase in risk was misleading. They noted that the issue of locational losses was not a new one and that a rigorous BSC modification process combined with a sufficient period before introduction of revised arrangements mitigated such concerns.

Ofgem's views

1.34. We note that a number of respondents considered that the complexity and volatility of locational losses charges increase risk and deter investment. Ofgem's views on this are set out in chapter 4 in the section which assesses the modification proposals in relation to effective competition (applicable BSC objective (c)).

1.35. We note some parties considered that operating costs will increase and in doing so result in higher electricity prices, and that locational losses charging will impose further transactional costs on the market. We note that there may be some transactional costs for parties in relation to managing variations in TLFs. However, we consider these costs should be small and will be outweighed by the efficiency benefits of the proposals. In addition, a small increase in operating costs is an element of risk that we would expect any business to manage.

1.36. We note that one party commented on the inclusion of 132 kV in Scotland. Ofgem does not agree that the inclusion of 132 kV in Scotland increases the risk for parties in Scotland. We note that 132kV lines in Scotland are transmission circuits and therefore it is appropriate that they are included as part of a zonal loss charging model.

1.37. We note one party identified an increased risk as a result of "mirage" signals being created. We note that it is true that the TLFs change if parties' short and long term behaviour changes. However, this is not a mirage – it simply reflects the fact that parties' impacts on the network have changed.

1.38. We note a number of parties considered increased regulatory uncertainty will affect the cost of capital. Our views on the impact on cost of capital are set out in chapter 3.

1.39. We note that a number of parties commented on industry expectation in respect of the potential for locational losses to be introduced. We do not agree with the views presented. We consider that given the history of the locational losses debate, as a minimum, parties could have anticipated the potential for future development. With regard to the Secretary of State's position at BETTA, it was clear that the issue was not being dismissed permanently but rather that it was not an issue that could appropriately have been taken forward within the timeframe of that project. Indeed, the DTI explicitly noted that it was possible, through the modifications process, for the industry to reconsider the issue of transmission losses

in the context of a GB market and in the light of experience of operation under a GB market.

1.40. We agree with those parties that considered that the stated increase in risk was misleading. We also agree that the BSC and Ofgem consultation process, and implementation timescales for the proposals should mitigate such concerns.

Impact on renewable generation

Respondents' views

1.41. Ten respondents argued that the proposals would have an adverse impact on renewable generation. The issues raised were that:

- renewable generators cannot respond to the signals. The impact of this being that certain projects may no longer be viable, which is likely to impact on meeting government and European targets for renewables.
- renewable generation is locationally constrained and resource in remote locations e.g. north of Scotland where loss charges would be highest
- increases in zonal losses charges in the north would result in renewables cross-subsidising less environmentally sustainable generation
- cumulative effect of high TNUoS charges, grid queue, changes to RO, rising community benefit payments, high business rates and political uncertainty increase risk profile for renewable generation.
- Contravene EU Directive 2001/77/EC by discriminating against renewable generation.

1.42. One respondent argued that none of the proposals would adversely affect renewables. The respondent noted that this is reflected in GB queue and the fact that other factors outweigh impact of losses charges. They also considered that locational losses may foster greater development of projects in the south of GB – a less congested area of the network.

Ofgem's views

1.43. Ofgem notes the views of respondents that the proposals have an adverse impact on renewable generation. Ofgem carried out additional analysis on the impact of the proposals on different classes of generation, including renewable generation. This additional analysis is set out in chapter 3.

1.44. Ofgem also notes the comments made by one respondent that the proposals do not have an adverse impact on renewable generation. Ofgem agrees that it is not clear why a proposal to charge parties on a locational basis, to reflect the different impact parties have on the network, would adversely impact on renewable generation. We note that parties can connect in a number of parts of GB, and also note that factors other than locational charging will influence where a renewable generator chooses to locate.

European Issues

Respondents' views

1.45. Four respondents considered zonal losses would be inconsistent with EU policy. Respondents commented that zonal losses would take GB further away from harmonisation with the Europe. Respondents also considered that by changing the cost base for GB generators compared to generators in other Members States who allocate losses on an average basis, the zonal allocation of losses would impact on competition in the European wholesale market.

1.46. One respondent further commented that the European Council meeting in March 2007 reaffirmed EU commitment to renewable generation and endorsed targets for energy from renewables sources. The respondent stated there was a need for cross-border and EU wide synergies to meet these targets. It considered that zonal losses would put those targets at risk.

Ofgem's views

1.47. We note the views of respondents in respect of harmonisation with EU policy. Ofgem considers that locational losses charging is consistent with the principles of EU law. We also note that parties considered there would be an impact on competition in the European wholesale market. We do not agree with this view. We consider that competition is best fostered by parties paying charges that reflect their impact on the system. We consider this is more likely to be achieved by marginal than by uniform pricing. These issues are discussed in more detail in Chapter 6.

1.48. We have noted above that we do not consider it is clear why a proposal to charge parties on a locational basis to reflect the different impact parties have on the network, would adversely impact on renewable generation such that these targets are affected. We note that renewables can connect in a number of parts of GB.

Benefits

Respondents' views

1.49. Six respondents highlighted benefits of zonal losses including: removal of existing cross-subsidies; more efficient short-term despatch; less discriminatory; more cost-reflective charges will enhance competition; reduce total losses; reduce CO2 emissions.

1.50. Eleven respondents consider that the benefits highlighted by OXERA were overstated. Another respondent considered they were uncertain. A further respondent considered that the benefits were small. The arguments were:

- Main quoted benefit, i.e. north-south re-despatch, not likely to materialise. Differential between coal and gas prices is too large for there to be a switch between these fuels. Any perceived benefits are exaggerated.

- There is considerable uncertainty concerning the likelihood of benefits materialising
- Benefits identified are significantly outweighed by distributional impacts and therefore are disproportionate

Ofgem's views

1.51. We note that a number of respondents identified benefits of the proposals. However we also note that a number of respondents considered the benefits to be overstated, uncertain or small.

1.52. We have set out in more detail our views in respect of the potential benefits of the proposals in chapters 4 to 7.

Process

Respondents' views

1.53. The vast majority of respondents support the publication of the planned minded to document. Two of those supported a six week consultation period for that document. Only one party noted that they did not see the need for minded to as it would delay the final decision and increase uncertainty.

1.54. One respondent argued that the impact assessment should have provided a summary of arguments for and against proposals raised at the Modification Group level in developing the modification proposals. The respondent considered that such a summary would have been useful to anyone new to the losses debate. The same respondent considered that the impact assessment suggested a leaning towards approving one of the modifications to the extent that there are factual inaccuracies in the text supporting zonal losses.

1.55. Another respondent argued that small parties lacked the resource to participate fully in modification process. They argued a key issue was the complexity of the proposals and the fact that consultation papers were too detailed.

Ofgem's views

1.56. Ofgem notes respondents' views in respect of the publication of this 'minded to' decision document. We continue to believe that publishing the minded to document is an important part of a robust decision making process and will provide parties with an opportunity to comment on the further analysis undertaken and on the decisions the Authority is minded to take.

1.57. We do not agree with the respondent that considered the impact assessment suggested a leaning towards approving one of the proposals. We consider that the impact assessment set out an impartial and factually accurate account of the impact of the proposals and we note that this view was supported by a number of respondents. The decision is a matter for the Authority and will be taken as described in this document. We note that this respondent also considered that the

impact assessment should have included a summary of arguments for and against proposals raised at the Modification Group. We note that that these arguments are set out in documents available on Elexon's website and did not therefore consider it necessary to summarise these in the impact assessment.

1.58. We note comments with regard to participation in the modification process. We consider that any party can contribute views to the modification process. We accept that larger parties may be better placed in terms of resource to dedicate more time to this. However, we also note that there are a number of organisations that represent the views of smaller parties in these processes and monitor developments on their behalf. Indeed, we note that these organisations have contributed views to the consultation processes, including to the impact assessment.

Appendix 3 – Analysis of interaction between losses and TNUoS

Introduction

As noted in chapter 3, a number of respondents expressed the view that TNUoS charging arrangements already partially reflect locational losses, and that the introduction of locational loss charging arrangements would result in the overstatement of overall locational signals. We have carried out joint analytical work with NGET to undertake an initial assessment of the level of the interaction between TNUoS and losses locational signals. This analysis is set out as follows.

Analysis

Let:

Transfer level = G,
Total transmission cost T = Ci+Co,

Where:
Ci is the investment cost, which can be expressed as a multiple of transfer level G: $Ci = x \cdot G$;

Co is the operational cost, which, without losing generality, is taken as purely the cost of losses here, and can be expressed as a function of G and Ci (assuming resistance is inversely proportional to capacity and hence in turn to investment Ci):

$$Co = \frac{G^2}{Ci} \cdot B$$

,

where B is a constant, which is a product of a number of parameters including line unit resistance, line length, energy price, and load factors and loss load factors.

The marginal total transmission cost at a certain level of investment x is:

$$\frac{dT}{dG} = \frac{dCi}{dG} + \frac{dCo}{dG}$$

Before substituting Co and Ci with x and G to simplify the above equation, it is worth first transforming the second term with Co as a generic function of Ci and G and considering the meaning of each resulting term:

$$\frac{dT}{dG} = \frac{dCi}{dG} + \frac{\partial Co}{\partial G} + \frac{\partial Co}{\partial Ci} \cdot \frac{dCi}{dG}$$

.

The first term is the investment marginal cost with respect to the transfer level, hence is equivalent to the TNUoS signal. The second is the marginal cost of losses with respect to transfer G at a fixed investment level, hence is equivalent to marginal

losses cost. The existence of the third term, which is non-zero due to the impact of investment on losses, clearly indicates that the sum of TNUoS and marginal losses costs are not the same as the true marginal total transmission cost.

Now substituting Co and Ci with variables x and G, we can examine more closely the relationship between each of these terms:

$$\frac{dT}{dG} = x + 2\frac{G}{x \cdot G} \cdot B + \left[-\frac{G^2}{(x \cdot G)^2} \cdot x \right] = x + 2\frac{B}{x} - \frac{B}{x}$$

It can be seen that:

TNUoS = x

Marginal losses = $2\frac{B}{x}$

"overlap" = $\frac{B}{x}$.

The sign of the third term means that adding TNUoS and marginal losses costs together would overstate the marginal transmission costs, and that the overstatement is equal to half of the marginal losses cost.

However, if the locational losses charge is set at "average" instead of "marginal" losses cost, ie half the marginal losses cost, then the sum of TNUoS and locational losses changes becomes:

TNUoS + 0.5 marginal losses = $x + \frac{B}{x}$ = marginal total transmission cost.

The conclusion here, therefore, is that applying TNUoS and average losses costs together would be equivalent to applying the true marginal total transmission cost.

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.[10]

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[11].

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 consumers, present and future, 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[12]; and
- The interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[13]

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:

[10] entitled "Gas Supply" and "Electricity Supply" respectively.
[11] 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.
[12] 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.
[13] The Authority may have regard to other descriptions of consumers.

- Promote efficiency and economy on the part of those licensed[14] 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;
- Contribute to the achievement of sustainable development; 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[15] 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.

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

Appendix 5 - Glossary

A

The Authority/ Ofgem

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

B

Balancing and Settlement Code (BSC)

Multi-party document governing the wholesale electricity balancing and settlement arrangements for GB.

Balancing Mechanism (BM)

The mechanism for making and accepting offers and bids pursuant to the arrangements contained in the BSC.

Balancing Services Use of System (BSUoS) charges

Charges levied by NGET on users of the GB electricity transmission network to recover the costs of balancing the system. Parties are liable for BSUoS charges based on their energy taken from or put onto the transmission network in each half-hour settlement period.

BM Unit (BMU)

A unit registered as such under the BSC, and metered separately from other BM units for the purposes of balancing and settlement.

British Electricity Trading and Transmission Arrangements (BETTA)

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).

BSC Panel

The Panel established pursuant to section B of the BSC. Amongst other things, the BSC Panel is responsible for the implementation of the procedures for modification of the BSC.

BSC Year

Each successive period of 12 months beginning on 1st April in each year.

E

Elexon

Elexon Limited fulfils the role of BSCCo as defined in the BSC.

F

Final Modification Report (FMR)

The report submitted by the BSC Panel to the Authority in respect of a proposed modification to the BSC. This report contains the Panel's recommendation as to whether the proposed modification or any alternative modification should be made on the basis of whether it better facilitates the achievement of the applicable BSC objectives.

G

GB transmission system

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

GB transmission use of system charging methodology

The methodology which NGET is required to have in place by its transmission licence and which is used to calculate the charges to customers for use of the GB transmission system. The GB transmission use of system charging methodology is in practice comprised of two separate methodologies – a BSUoS charging methodology (defined above) and a TNUoS charging methodology (defined below).

Grid Supply Point (GSP)

A system connection point at which the transmission system is connected to a distribution system.

Grid Supply Point (GSP) Group

A distinct electrical system containing one or more GSPs. A GSP Group is formed in accordance with section K1.8 of the BSC. There are currently 14 GSP Groups in GB.

I

Imbalances

Imbalances are the difference between a party's contracted position and the actual metered volume of energy generated/consumed by that party.

K

Kilowatt (kW)/ Megawatt (MW)

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.

L

Load Flow Model

A model used for estimating impact of a marginal increase in power at each individual node in the network on total flows on the transmission system.

Logica CMG

Logica CMG is an agent of Elexon and provides services in a number of areas such as settlement and reporting and data collection and aggregation.

M

Modification Group

Has the meaning given in the BSC.

N

National Grid Electricity Transmission (NGET)

The company who undertakes the functions of transmission owner in England & Wales and system operator for the GB transmission system.

Node

A transmission node is a point on a network at which circuits meet.

R

Renewables Obligation (RO)

The Government's main support programme for renewable energy generation, under which electricity suppliers must source a proportion of their supply from renewable generation. In this document references to the Renewables Obligation include the Renewables Obligation (Scotland). The Schemes are administered by Ofgem for the DTI and the Scottish Executive.

S

System Operator (SO)

The entity responsible for the day to day operation of the GB transmission system and for entering into contracts with those who want to connect to and/or use the GB transmission system. NGET is the GB system operator.

T

Transmission Losses

The amount of energy that is lost through the process of transmitting energy from generators to centres of demand.

Transmission Loss Factors (TLFs)

TLFs are a component of the formulae in the BSC which are used to calculate TLMs. TLFs allow for TLMs to vary by location.

Transmission Loss Multipliers (TLMs)

TLMs are applied to metered volumes of electricity in order to factor transmission losses into the calculation of imbalances.

Transmission Network Use of System (TNUoS) charges

Charges levied by NGET on users of the GB electricity transmission network to recover the costs of providing and maintaining the general network infrastructure assets. TNUoS tariffs vary by location on a zonal basis, and are different for generators and for suppliers. TNUoS tariffs comprise a locational element, derived from the DCLF ICRP model, and a non-locational residual element.

V

Vesting

The date at which the regulated gas and electricity transmission and distribution companies were privatised.

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:

- Does the report adequately reflect your views? If not, why not?
- Does the report offer a clear explanation as to why not all the views offered had been taken forward?
- Did the report offer a clear explanation and justification for the decision? If not, how could this information have been better presented?
- Do you have any comments about the overall tone and content of the report?
- Was the report easy to read and understand, could it have been better written?
- Please add any further comments?

1.2. Please send your comments to:

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