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Zonal transmission losses - assessment of proposals to modify the Balancing and Settlement Code

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Overview:

This document is an impact assessment of and consultation on four modification proposals (P198, P200, P203, P204) and two alternatives (P198 Alternative and P200 Alternative) to the Balancing and Settlement Code (BSC) to alter the rules under which the costs of transmission losses are allocated to users of the electricity transmission system. Transmission losses are the amounts of energy that are lost (e.g. in the form of heat) through the process of transmitting electricity from generators to centres of demand. Losses across the GB transmission system have historically been around 2%. At current prices it reflects a cost of around £250m each year.

Each proposal seeks to allocate transmission losses on a locational basis. This would increase costs for some network users, and reduce costs to others – compared to the current rules, which do not depend on location. Users at remote parts of the transmission network will be most affected by the change. The proposals, if implemented, would also be expected to reduce over time the total volume of transmission losses, as generators (and to a lesser extent, demand customers) choose to operate differently.

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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. However, consumers also pay for the costs of the network.

Generators compete to sell their energy to suppliers and in turn suppliers compete to sell the energy to end consumers. The process of transporting energy from generators to end consumers 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 financial cost – as someone must pay for the lost energy. Under the existing market rules, these costs, which total around £250 million pounds a year, are allocated to generators and suppliers on a uniform basis.

This document analyses and consults on the impact of four proposals (and two alternatives) to change the transmission losses charging arrangements, namely 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. The Authority intends to publish its final decisions on the proposals before 20 September 2007. Further detail on the process is set out in Chapter 5.

Associated Documents

Letter relating to impact assessments for BSC Modification Proposals P198, P200, P203, P204 – Ofgem, November 2006 #200/06

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

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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 is consumed. This mismatch is equal to about 2% of annual demand and has a cost of approximately £250m per annum.

Rules relating to transmission losses are included in the Balancing and Settlement Code ("BSC"). The BSC sets out the terms by which National Grid Electricity Transmission plc ("NGET"), as GB system operator, is responsible for balancing the GB transmission system to ensure that demand and supply for electricity are in balance on a half-hourly basis.

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 existing BSC includes provisions for locational allocation of transmission losses, although these currently have no effect.

Ofgem asked Skyplex to prepare a factual report on the history of the issue of zonal transmission losses from vesting to the submission of the current modifications and to summarise the views which Ofgem had expressed on the issues over the years. We intend to make a copy of this report available to the Authority for information. A copy of this report will, therefore, be made available on the Ofgem website: www.ofgem.gov.uk.

Four proposed modifications and two alternative modifications to modify the BSC have been submitted to the Authority. These proposals seek to alter the way in which variable (distance related) transmission losses are charged for. A number of the proposals also address the way in which the transition to an alternative charging regime would be managed. Each proposal 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.

A change to the rules for loss charging would impact on different parties in different ways. Some network users will see higher costs and other users will see lower costs compared to the current rules, which do not depend on location. Users at remote parts of the transmission network will be most affected by the change. For example, proposals would lead to higher charges for generators in the north of Scotland. The proposals would also be expected to reduce over time the total volume of transmission losses, as generators (and to a lesser extent, demand customers) choose to operate differently.

This document aims to set out the impacts of the various proposals. For ease of exposition we have separated the impacts into 'direct' and 'indirect' impacts, and environmental impacts. The Authority will be required to make a decision on whether to approve or reject the proposals and, given the nature of the proposals and the timetable that we are working to, it is important to provide an opportunity for interested parties to express their views.

1. Background

Chapter Summary

This chapter explains what transmission losses are and why they arise, discusses the current arrangements for establishing how these losses are paid for, and summarises the different proposals to change the current arrangements. The chapter also provides background on the procedures and legal framework involved in developing, assessing and deciding upon the proposals for change.

What are transmission losses?

1.1. The purpose of a transmission system is to facilitate the bulk transfer of electricity from producers of electricity (generators) to centres of demand. 'Transmission losses' is the term given to the volume of energy lost, e.g. in the form of heat, through the physical process of transporting electricity across the transmission system[1]. As a result of transmission losses, the total amount of energy generated at any given time must exceed the total amount of energy consumed.

1.2. In 2006/07 NGET[2] estimate total transmission losses of 5.82 TWh, approximately 2% of total system demand, over the whole of GB. At an electricity price of £45/MWh[3] the total cost of losses for 2006/07 is £269m. In terms of emissions, transmission losses comprise around 2.5 MtCO2 (million tonnes carbon dioxide) or 0.68MtC (million tonnes carbon).

How are losses paid for currently?

1.3. There is a cost associated with transmission losses. Someone has to pay for the electricity that is generated but is not subsequently sold to consumers. The Balancing and Settlement Code (BSC) sets out the rules for how users of the transmission network pay for transmission losses.

1.4. Wholesale electricity is traded in half-hourly periods. For each half hour trading period the amount of electricity that each generator is contracted to sell is compared to the amount that they actually generate. An analogous calculation is done for each electricity supplier. Differences between contractual and metered volumes are termed 'imbalances'. The BSC sets out the rules for calculating these imbalances and charging (or paying) network users for them.

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[1] Energy is also lost through transporting electricity across the distribution system. Any references to 'losses' in this document are in the context of transmission losses.
[2]National Grid's forecast of incentivised balancing costs for Great Britain in 2006/07 www.ofgem.gov.uk
[3] This was OXERA's estimate of the annual average electricity price for 2006/07. It used this figure in its cost-benefit analyses which formed part of the Modification Groups' reports. For consistency we have used the same electricity price in this report.

1.5. The BSC rules factor in transmission losses to the calculation of imbalance. Transmission losses are allocated to BSC parties by scaling metered volumes in settlement through the application of transmission loss multipliers (TLMs). TLMs are calculated for each half hour such that the scaling of all generation and demand should exactly recover the level of transmission losses in that half hour, with 45% of the total volume of transmission losses allocated to generators and 55% allocated to demand.

1.6. The TLMs do not currently vary depending on where in GB the generator (supplier) is producing (consuming) its electricity, such that transmission losses are allocated to BSC parties on a "uniform" basis. The effect of this is that in order to avoid imbalance charges, all parties must deliver more electricity than they sell, and buy more than they offtake.

1.7. For example, a generation TLM of 0.99 means that, for 100 MWh of generation, the company would be attributed 99 MWh. Likewise, a demand TLM of 1.01 means that, for 100 MWh of actual demand, the supplier would be attributed 101 MWh. To illustrate, if the generator had contracts to deliver 99 MWh of electricity in a half hour period, then in order to avoid imbalance charges for that period they would have to have metered volumes of 100 MWh. In effect, the 1 MWh difference is that generator's allocation of transmission losses in that period.

1.8. There are formulae in the BSC for calculating TLMs. These are as follows:

- For all BM Units belonging to generators: TLM = 1 + TLF + TLMO+
- For all BM Units belonging to suppliers: TLM = 1 + TLF + TLMO-

1.9. The formulae make use of Transmission Loss Factors ("TLFs"). TLFs allow for TLMs to vary by location. The other parameters in the formulae are Transmission Loss Adjustments ("TLMOs"). These are used to calibrate the TLMs such that 45% of total actual losses are allocated to generators and 55% of total losses are allocated to suppliers, on the basis of metered volumes in the given half hour.

1.10. The TLF is currently set to zero so has no practical effect. This value can only be amended through a modification to the BSC. Therefore, under the current arrangements, the TLMs are only influenced by the value of the TLMOs. As a result, currently total transmission losses are allocated uniformly to generation and demand on a 45:55 basis.

What is the procedure for considering modification proposals?

1.11. A number of parties can make a proposal to modify the BSC including any person who is a party to the BSC. The process for modifying the BSC is managed by the BSC Panel and Elexon, the company who administers the BSC.

1.12. When a new modification proposal is made, the BSC Panel will decide, amongst other things, what procedure the modification proposal should follow.

P198, P200, P203 and P204 were all submitted to the Assessment Procedure. Where a modification proposal is submitted to the Assessment Procedure:

a. Elexon will consult on that modification proposal; and
b. the BSC Panel will establish or designate a Modification Group.

1.13. The rules for the make-up of a Modification Group are set out in the BSC (Section F, paragraph 2.4). The BSC Panel will also determine the terms of reference for the Modification Group. The terms of reference may require the Modification Group, amongst other things, to consult further with interested parties and/or to commission additional analysis from third parties with relevant specialist knowledge. P198, P200, P203 and P204 were all submitted to the Assessment Procedure and their respective Modification Groups each undertook industry consultation. Additionally, external analysis was commissioned from Siemens PTI[4] and OXERA[5].

1.14. The purpose of the Assessment Procedure[6] is to evaluate whether a modification proposal better facilitates achievement of the Applicable BSC Objectives[7] and whether any alternative modification would, as compared with the proposed modification better facilitate achievement of the Applicable BSC Objectives. The P198 Alternative and the P200 Alternative were developed as part of this process. Finally, the Modification Group will prepare a report for the BSC Panel concerning the proposed modification and any alternative modification.

1.15. The BSC Panel will decide, on the basis of a report prepared by the Modification Group (as described above), whether to proceed to what is described in the BSC as the Report phase. There is a further round of consultation at this stage.

1.16. A Final Modification Report ("FMR") is submitted to the Authority for its consideration. This report will contain, amongst other things:

a. the recommendation of the BSC Panel as to whether or not the modification proposal and/or any alternative should be made; and
b. the proposed implementation date for the implementation of the modification proposal and/or any alternative.

1.17. The BSC Panel recommended rejection of P198 and the P198 Alternative, P200 and the P200 Alternative, P203 and P204. It also proposed implementation dates of 1 April 2008 if the Authority reached its decision on or before 22 March

[4] "MP198 Load Flow Modelling Service", Siemens PTI, June 2006
[5] "What are the costs and benefits of zonal loss charging?", OXERA, July 2006, commissioned by the P198 Modification Group, and "What are the costs and benefits of annual and seasonal scaled zonal loss charging?", OXERA, September 2006, commissioned by the P204 Modification Group
[6] Section F, paragraph 2.6.2.
[7] The Applicable BSC Objectives, which reflect the objectives specified in paragraph 3 of standard licence condition C3, are set out below in section 1.52 below.

2007; or 1 October 2008 if the Authority reached its decision on or before 20 September 2007.

1.18. After receipt of the FMR, we follow our own process.

Impact assessment

1.19. Section 5A of the Utilities Act 2000 (Duty of the Authority to carry out an impact assessment) applies where: (a) the Authority is proposing to do anything for the purposes of, or in connection with, the carrying out of any function exercisable under or by virtue of Part 1 of the Electricity Act or the Gas Act; and (b) it appears to the Authority that the proposal is important within the meaning set out in section 5A, but does not apply where the urgency of the matter makes it impracticable or inappropriate for the Authority to comply with the requirements of section 5A. Where section 5A applies, the Authority must either carry out and publish an impact assessment or publish a statement setting out its reasons for believing that it is unnecessary for it to undertake an impact assessment.

1.20. Section 5A(2) sets out the matters which would determine whether or not a proposal is "important" for the purposes of section 5A. These are where a proposal:

a. Involves a major change in the activities carried out by the Authority;
b. Has a significant impact on market participants in the gas or electricity sectors;
c. Has a significant impact upon persons engaged in commercial activities connected to the gas or electricity sectors;
d. Has a significant impact on the general public in GB or in a part of GB; and
e. Has significant effects on the environment.

1.21. Having considered the FMRs in respect of P198, P200, P203 and P204, the Authority considers that the proposed and alternatives modifications are "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. It is on this basis that the Authority has decided to publish this impact assessment.

What are the proposals for change?

Overview

1.22. Since December 2005, four modification proposals have been raised by industry parties to change the rules governing how the costs of transmission losses are allocated. All four proposals involve changes to the methods by which TLFs (and therefore TLMs) are calculated and applied. Under each proposal the TLMs would vary by location, i.e. the contribution of a user to the total cost of losses would depend on where on the network they were located.

1.23. 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.

1.24. 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 & Energy Trading Limited in July 2006.

1.25. In addition, during the assessment stage for both P198 and P200 the Modification Group developed alternative modifications. There are therefore six different proposals for change for us to consider in the light of the FMRs submitted by the BSC Panel.

1.26. There are a number of concepts underpinning the different proposals. In summary, the key concepts are:

- **Zoning:** Grouping individual points on the network into wider areas for the purposes of allocating losses.
- **Phasing:** Implementing a proposal gradually over time, rather than with full effect immediately.
- **Hedging:** Reducing a party's exposure to locational losses to the difference between its actual output and historical levels of output.
- **(Variable) Scaling:** Reducing the locational differentials to the extent necessary to ensure that no party is allocated a negative volume of locational losses.

1.27. Fuller, more technical explanations of these concepts as they are applied in the different proposals can be found in the FMRs. Links to these documents are provided in the associated documents section at the beginning of this paper.

Common features

1.28. The six proposals are all variations on the same basic framework. This basic framework has the following features.

Load flow model

1.29. A common feature of each proposal is that a load flow model would be built, containing 'nodes' to represent points where energy flows on to or off of the transmission system. The load flow model would be run by a Transmission Loss Factor Agent ('the TLFA') to calculate how a marginal increase in power at each individual node would affect the total losses from the transmission system. The output of the load flow model would be a raw marginal factor for each node.

Zoning

1.30. In the load flow model, each node would be allocated to a zone on the transmission network, and the raw nodal marginal factors would then be averaged and scaled (see below) to calculate the zonal TLFs which 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 14 zonal TLF values applicable to both generation and demand being calculated.

Allocation of variable losses on a locational basis

1.31. 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.

1.32. Similarly, all of the proposals continue to calculate 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.

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

1.33. 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

1.34. As noted above, all of the 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

Annual zonal TLFs (P198)

1.35. One proposal calculates a single set of zonal TLFs for each year. A fixed scaling factor of 0.5 is applied to the zonal TLFs. The scaling factor is applied to ensure that the total volume of losses allocated through the TLF is approximately the same as the total variable transmission losses, while fixed losses continue to be allocated on a non-zonal basis.

1.36. The aim of this approach is that variable losses would be allocated locationally according to the extent to which parties give rise to them. As a result, parties at a given location receive either a positive or negative allocation of variable losses, depending on whether their actions have the impact of reducing or increasing the total level of losses on the system. For example, a generator connecting closer to demand could reduce the use of the system by generators further from demand. By reducing the use of the transmission system that generator's actions would be expected to reduce total losses. This is P198.

Seasonal zonal TLFs (P203)

1.37. One proposal is, rather than calculating a single set of annual zonal TLFs, to calculate a separate set of zonal TLFs for each of the four seasons of each year. Again a fixed scaling factor of 0.5 is used to ensure only variable transmission losses are recovered locationally. This is P203.

Seasonal zonal TLFs with variable scaling (P204)

1.38. Under P198 and P203, parties at a given location can receive a negative allocation of variable losses if their actions reduce the total level of losses on the system.

1.39. One proposal seeks 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. The proposal seeks to do so by proposing a variable scaling factor (i.e. not fixed at 0.5 as under the other proposals) to ensure that all parties would contribute towards variable 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.

1.40. Like P203, the proposal would calculate a separate set of zonal TLFs for each of the four seasons of each year. Further, the variable scaling factors would also be calculated and applied on a seasonal basis. This is P204.

Phased seasonal zonal TLFs (P198 Alternative)

1.41. One proposal is to calculate a separate set of zonal TLFs for each of the four seasons of each year, using a fixed scaling factor of 0.5 - and then to move towards TLFs calculated on this basis over a number of years. The phasing would be done in a linear fashion over five years and apply to all users. In the first year of implementation the TLFs calculated would be multiplied by 20%, in the second year by 40%, and so on until the TLFs applied in full by year 5. This is the P198 Alternative.

Annual zonal TLFs with hedging scheme (P200)

1.42. One proposal is to calculate a single set of zonal TLFs for each year using a fixed scaling factor of 0.5 and to supplement this with a mandatory hedging scheme for some users.

1.43. The 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'). For each generator BM Unit, it would stipulate a fixed volume of energy (the 'F-factor') for each month, based on average monthly output in the Baseline Period. The scheme would not apply to generators not operating or not commissioned in the Baseline Period.

1.44. Under the hedging scheme, a qualifying generator would always receive a uniform allocation of transmission losses based on the F-factor volume, while the difference between its actual metered volume and the F-factor volume would be subject to the zonal TLFs.

1.45. To illustrate this, 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. If it were in a zone where its change in generation output increased total transmission losses then the generator would pay higher loss charges. If, however, it were in a zone where its change in generation output reduced total transmission losses then it would receive payment for that impact.

1.46. It is proposed that the hedging scheme would endure for 15 years and only apply to qualifying generators. This is P200.

Seasonal zonal TLFs with hedging scheme (P200 Alternative)

1.47. One proposal is to calculate a separate set of zonal TLFs for each of the four seasons of each year using a fixed scaling factor of 0.5 - and to supplement this with the same mandatory hedging scheme as proposed in P200. This is the P200 Alternative.

Summary

1.48. The following table sets out a summary of the key features of the proposed modifications and alternative modifications.

	Losses allocated locationally	**Scaling Factor**	**Applicable TLF Period**	**Mitigation of impacts**
P198	Variable only	0.5	Annual	None
P198 Alternative	Variable only	0.5	Seasonal	Phasing
P200	Variable only	0.5	Annual	Hedging
P200 Alternative	Variable only	0.5	Seasonal	Hedging
P203	Variable only	0.5	Seasonal	None
P204	Variable only	Variable	Seasonal	None

1.49. As the first proposal raised, P198 can be considered as representing the baseline model on which the other proposed modifications and alternatives were developed. The table demonstrates the following variations on the features on which P198 is based:

- Phasing - only the P198 Alternative includes provision for phasing;
- Hedging - both the P200 and P200 Alternative include hedging;
- Seasonal TLF - the P198 Alternative, P200 Alternative, P203 and P204 Proposals all include seasonal TLF values; and
- Scaling - only P204 proposes a variable scaling factor to ensure no negative allocations.

What is the legal framework for the Authority?

1.50. When we make decisions on BSC modification proposals we do so in the context of a prescribed legal framework. Where we are proposing to do something which is important (within the meaning of section 5A of the Utilities Act 2000) we are required (save where the urgency of the matter makes it impracticable or inappropriate for us to do so) to undertake an impact assessment or to publish a statement setting out why we consider 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.

1.51. As indicated at 1.21 above, we consider each of the six modification proposals to be important within the meaning set out in section 5A of the Utilities Act.

1.52. When it comes to make its decision on each of the six BSC modification proposals, the Authority must assess each modification proposal against the objectives which are set out at paragraph 3 of standard licence condition C3 of NGET's electricity transmission licence. We assess each proposal against each of the objectives and against all four objectives collectively. The objectives are:

a. the efficient discharge by the licensee of the obligations imposed upon it by this 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.

1.53. We must also assess the proposals in the light of the Authority's legal duties. A brief description of the Authority’s powers and duties is set out in Appendix 4.

Structure of document

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

- Chapter 2 is an assessment of the direct impacts of the proposals on the calculation of TLMs and the consequent allocation of volumes of transmission losses to network users.
- Chapter 3 is an assessment of the impacts that might subsequently flow from the direct impacts identified in Chapter 2, e.g. in respect of competition in the electricity wholesale market and market behaviour.
- Chapter 4 is an assessment of the environmental impacts.
- Chapter 5 sets out next steps in the process.

2. Direct impacts

Chapter Summary

This chapter summarises the evidence on how the proposed changes to the BSC rules will impact on the allocation of losses to different classes of network user, the resulting impact on the level of transmission losses, and the costs to introduce each proposal.

Question box

Question 1: Do respondents consider we have appropriately summarised the direct impacts of the proposed and alternative modifications?

Question 2: Do respondents consider there are additional direct impacts that have not been fully addressed?

Question 3: Do respondents wish to present any additional analysis that they consider would be relevant to assessing the proposals?

Introduction

2.1. We are assessing the impact of six proposals to change the way in which volumes of transmission losses are allocated to BSC parties. This chapter looks at the direct impact of the proposals on the allocation of losses in the first instance and over time – and the associated shifts in costs as a result of these different allocations. It also examines the potential impact on the total volume of losses over time if generators adapt their behaviour in the light of the new cost signals in the manner expected. Finally, it looks at implementation costs.

2.2. The material for this assessment of impacts is drawn from the work undertaken by the Modification Groups in developing the proposed and alternative modifications including the external cost-benefit analysis reports undertaken by OXERA[8].

Impact on the allocation of losses volumes

2.3. The most direct impact of the proposed and alternative modifications is to change how TLFs are calculated such that they vary on a locational basis. As explained in chapter 1, TLFs feed into the calculation of TLMs.

[8] The results presented here are based on the following OXERA scenarios, all of which use the same assumptions as to market conditions: P198 – July report, Central scenario; P203 – July report, Seasonal scenario; P204 – September report, Seasonal scenario

2.4. Estimates from the OXERA analysis of what TLMs might have been in 2006/07 on average over the relevant time period (using common assumptions about prevailing market conditions, e.g. demand growth and fuel costs) under the following three proposed modifications are set out in Tables 2.1a and 2.1b below:

- P198 – Annual TLFs
- P203 – Seasonal TLFs
- P204 – Scaled Seasonal TLFs

2.5. There are a number of points to note from the analysis and the results set out in Tables 2.1a and 2.1b.

- North to south trend: TLMs are lower in the north and higher in the south. A generator TLM of 0.98 means that a generator must produce 100 units to be credited with having sold 98 units in calculating imbalances. Conversely, a generator TLM of 1.01 means that a generator will be credited with having sold 101 units if they produce 100 units. The effect works in reverse for suppliers. Lower TLMs therefore increase costs for generators and reduce costs for suppliers.

- Seasonal pattern: The estimates for P203 show, for each zone, a degree of variance around the annual average as set out in P198. In some seasons it is higher, in other seasons it is lower. This pattern of variance is different across zones. It is, however, generally the case that the differentials are sharpest in winter.

- Scaling: The impact of scaling for P204 is to suppress the variation in TLMs between zones and between seasons for a zone. This is because the scaling factor is set such that no zone receives a negative allocation of locational losses, with the effect that all the generation TLMs are less than 1 and all the demand TLMs are greater than 1.

- Locational spread: The spread between the maximum and minimum TLMs is greatest under P203, and smallest under P204. The range of TLMs is one indication of how locational a particular scheme is. The estimates for generation TLMs for P203 show a maximum of 1.018 and a minimum of 0.965 (in winter). This means that at that time, a generator in the South Scotland zone would on average need to generate 5.5% more electricity than a generator in the South Western zone in order to be credited with having sold the same amount of energy. The comparable figure for P198 is 3.5% (although this is an annual rather than seasonal difference). The comparable figure for P204 is 1%.

- Generation v demand: the pattern of locational differences in TLMs is identical for demand as compared to generation as they are based on the same zonal TLFs. The demand TLMs are higher than the generation TLMs by an identical amount in each zone (reflecting the 55% rather than 45% total allocation). This means that under P198 a supplier in the South Western zone would on average need to offtake 3.5% more electricity in order to purchase the same amount of energy as a supplier in the North Scotland zone. The comparable figure for P203 is 5.5% (although this is a seasonal rather than annual difference). The comparable figure for P204 is less than 1%.

Table 2.1a: Estimates of Generation TLMs, 2006/07

	P198	P203 Seasonal				P204 Scaled Seasonal			
Zone	Annual	Winter	Spring	Summer	Autumn	Winter	Spring	Summer	Autumn
North Scotland	0.979	0.980	0.974	0.975	0.995	0.992	0.992	0.990	0.994
South Scotland	0.980	0.965	0.981	0.980	0.974	0.989	0.991	0.992	0.990
Northern	0.987	0.984	0.984	0.989	0.986	0.993	0.993	0.994	0.993
North Western	0.990	0.988	0.992	0.995	0.989	0.994	0.994	0.995	0.994
Yorkshire	0.985	0.984	0.987	0.988	0.985	0.993	0.993	0.994	0.993
Merseyside & North Wales	0.993	0.991	0.995	1.000	0.992	0.994	0.995	0.996	0.994
East Midlands	0.996	0.998	1.000	0.997	0.998	0.995	0.996	0.996	0.996
Midlands	1.004	1.005	1.006	1.006	1.003	0.997	0.998	0.997	0.997
Eastern	1.003	1.007	1.001	1.001	1.008	0.997	0.997	0.997	0.998
South Wales	1.003	1.008	1.005	1.000	1.004	0.997	0.997	0.997	0.997
South Eastern	1.006	1.010	1.003	1.003	1.009	0.998	0.998	0.997	0.998
London	1.013	1.017	1.009	1.009	1.016	0.999	0.999	0.998	0.999
Southern	1.011	1.016	1.009	1.007	1.013	0.999	0.999	0.998	0.999
South Western	1.013	1.018	1.013	1.008	1.013	0.999	0.999	0.998	0.999

Table 2.1b: Estimates of Demand TLMs, 2006/07

	P198	P203 Seasonal				P204 Scaled Seasonal			
Zone	**Annual**	**Winter**	**Spring**	**Summer**	**Autumn**	**Winter**	**Spring**	**Summer**	**Autumn**
North Scotland	0.986	0.986	0.981	0.982	1.000	1.003	1.001	1.000	1.004
South Scotland	0.987	0.971	0.988	0.987	0.980	1.000	1.000	1.002	1.000
Northern	0.994	0.990	0.991	0.995	0.991	1.004	1.003	1.004	1.003
North Western	0.997	0.995	0.999	1.001	0.995	1.005	1.004	1.005	1.004
Yorkshire	0.992	0.991	0.993	0.995	0.991	1.004	1.003	1.004	1.003
Merseyside & North Wales	0.999	0.998	1.002	1.007	0.998	1.005	1.005	1.006	1.005
East Midlands	1.003	1.005	1.007	1.004	1.004	1.006	1.005	1.006	1.006
Midlands	1.011	1.012	1.013	1.012	1.009	1.008	1.007	1.007	1.007
Eastern	1.010	1.014	1.007	1.008	1.014	1.008	1.007	1.007	1.008
South Wales	1.010	1.014	1.011	1.006	1.009	1.008	1.007	1.007	1.007
South Eastern	1.013	1.017	1.010	1.009	1.015	1.009	1.007	1.007	1.008
London	1.020	1.024	1.016	1.016	1.022	1.010	1.009	1.008	1.010
Southern	1.017	1.023	1.016	1.014	1.019	1.010	1.009	1.008	1.009
South Western	1.020	1.025	1.020	1.015	1.019	1.010	1.009	1.008	1.009

How TLMs might change over time

2.6. The pattern of TLMs is likely to change over time. A key influence over this evolution is how generators respond to the TLMs in the previous years. If behaviour changes, i.e. particular generators produce more or less energy than they would have done otherwise, then this will feed in to the calculation of TLFs for the following year. The feedback loop will shape how TLFs (and therefore TLMs) evolve over time.

2.7. The OXERA analysis of the possible path of generator TLMs for P198 over an eight year period is set out in Table 2.2a below. Tables 2.2b and 2.2c set out similar estimates for Winter TLMs for generators under P203 and P204 respectively.

2.8. Significant points to note from this analysis would appear to be:

- The locational differentials under different scheme designs diverge over time. Given that all the scenarios are based on the same underlying market conditions, this divergence can be related to the differing strengths of the feedback effect between TLFs and metered volumes under each scheme.
- Over the period the locational differentials are greater under P203 than P198.
- As might be expected, P204, by reducing the strength of the locational signals, gives more stable TLMs over time.

Table 2.2a – Estimates of how Annual Generator TLMs might change over time under P198

Zone	2006	2007	2008	2009	2010	2011	2012	2013	2014
North Scotland	0.979	0.973	0.974	0.985	0.962	0.995	0.973	1.002	0.977
South Scotland	0.980	0.977	0.977	0.993	0.973	1.004	0.985	1.010	0.989
Northern	0.987	0.986	0.986	0.989	0.987	0.991	0.989	0.990	0.992
North Western	0.990	0.990	0.990	0.992	0.994	0.994	0.995	0.997	1.000
Yorkshire	0.985	0.985	0.985	0.984	0.987	0.985	0.987	0.987	0.989
Merseyside & North Wales	0.993	0.992	0.992	0.994	1.000	0.997	1.000	1.000	1.003
East Midlands	0.996	0.997	0.997	0.994	0.998	0.993	0.997	0.994	0.994
Midlands	1.004	1.005	1.003	1.003	1.009	1.003	1.009	1.006	1.009
Eastern	1.003	1.004	1.003	0.998	1.002	0.996	0.998	0.992	0.992
South Wales	1.003	1.004	1.005	1.004	1.006	1.003	1.007	0.997	1.002
South Eastern	1.006	1.008	1.007	1.002	1.006	0.998	0.999	0.993	0.996
London	1.013	1.014	1.014	1.008	1.011	1.004	1.006	1.001	1.003
Southern	1.011	1.012	1.011	1.008	1.011	1.005	1.007	1.001	1.007
South Western	1.013	1.014	1.014	1.013	1.008	1.011	1.015	1.007	1.012

Table 2.2b – Estimates of how Winter Generator TLMs might change over time under P203

Zone	2006	2007	2008	2009	2010	2011	2012	2013	2014
North Scotland	0.980	0.974	0.969	0.963	0.961	0.968	0.968	1.007	0.987
South Scotland	0.965	0.961	0.958	0.954	0.953	0.962	0.963	0.999	0.983
Northern	0.984	0.983	0.982	0.981	0.983	0.982	0.984	0.990	0.994
North Western	0.988	0.988	0.987	0.987	0.990	0.989	0.990	0.992	0.995
Yorkshire	0.984	0.984	0.984	0.984	0.986	0.983	0.985	0.984	0.986
Merseyside & North Wales	0.991	0.991	0.991	0.991	0.996	0.995	0.995	0.995	0.997
East Midlands	0.998	0.999	0.999	1.000	1.000	0.998	0.999	0.992	0.992
Midlands	1.005	1.006	1.007	1.007	1.009	1.008	1.008	1.004	1.006
Eastern	1.007	1.007	1.007	1.009	1.009	1.006	1.004	0.997	0.997
South Wales	1.008	1.009	1.012	1.013	1.010	1.011	1.010	0.998	1.002
South Eastern	1.010	1.012	1.013	1.014	1.014	1.010	1.007	0.999	1.002
London	1.017	1.019	1.020	1.021	1.021	1.018	1.016	1.008	1.011
Southern	1.016	1.018	1.019	1.021	1.019	1.017	1.015	1.007	1.010
South Western	1.018	1.020	1.023	1.024	1.013	1.021	1.020	1.010	1.014

Table 2.2c – Estimates of how Winter Generator TLMs might change over time under P204

Zone	2006	2007	2008	2009	2010	2011	2012	2013	2014
North Scotland	0.992	0.991	0.990	0.989	0.989	0.989	0.990	0.994	0.993
South Scotland	0.989	0.989	0.988	0.988	0.988	0.989	0.989	0.992	0.992
Northern	0.993	0.992	0.992	0.992	0.993	0.992	0.993	0.993	0.995
North Western	0.994	0.993	0.993	0.993	0.994	0.993	0.994	0.995	0.995
Yorkshire	0.993	0.993	0.993	0.992	0.993	0.993	0.993	0.993	0.993
Merseyside & North Wales	0.994	0.994	0.994	0.993	0.994	0.994	0.995	0.997	0.996
East Midlands	0.995	0.995	0.995	0.995	0.995	0.995	0.995	0.995	0.995
Midlands	0.997	0.996	0.996	0.996	0.996	0.997	0.997	0.998	0.998
Eastern	0.997	0.997	0.996	0.996	0.996	0.996	0.996	0.996	0.996
South Wales	0.997	0.997	0.997	0.997	0.997	0.997	0.997	0.997	0.997
South Eastern	0.998	0.997	0.997	0.997	0.997	0.997	0.997	0.997	0.997
London	0.999	0.999	0.998	0.998	0.998	0.998	0.998	0.999	0.999
Southern	0.999	0.998	0.998	0.998	0.998	0.998	0.998	0.999	0.999
South Western	0.999	0.999	0.999	0.999	0.997	0.999	0.999	0.999	1.000

Impact on the total volume of losses

2.9. The profiles of TLMs set out in Tables 2.2a to 2.2c are based on changing patterns of generation. This in turn implies changing volumes of total losses – as the balance between generation and demand is met differently, and therefore flows across the network are different.

2.10. As noted above, this evolution can be partially explained in terms of changes in generation output patterns as a result of short-term despatch decisions being influenced by the zonal allocation of transmission losses. OXERA analysed this effect by comparing the generation outputs under zonal losses with those for an equivalent scenario based on the existing uniform losses arrangements, and calculating the change in the total volume of transmission losses as a result.

2.11. OXERA's analysis highlighted that the introduction of zonal losses charging resulted in a general shift of generation from north to south across all the market scenarios. The impacts were more pronounced for models that applied seasonal rather than annual TLFs. OXERA did not assess the impact for proposals which mitigate the impact of the introduction of locational TLFs through phasing or hedging.

2.12. OXERA further noted that, albeit to a lesser extent, the introduction of zonal loss charging also resulted in shifting between generation with different fuel sources[9]. This fuel switching was primarily from coal to gas, which OXERA noted may be largely explained by the shift away from Scotland which contains proportionally more coal-fired generation.

2.13. OXERA estimated the reduction in the volume of losses each year relative to the current arrangements of allocating losses on a non-locational basis, as a result of these changes in short-term despatch. Table 2.3a set out these results.

Table 2.3a: Reduction in the total volume of losses (GWh)

Scenario	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
P198	90	235	107	420	73	165
P203	491	373	497	545	538	252
P204	231	97	279	385	122	126

2.14. Across each scenario, the level of annual loss savings varies considerably from year to year, which OXERA attribute to approximations in the modelling approach used. However, the table highlights the general result that the calculation of TLFs on a seasonal rather than annual basis leads to higher estimated loss savings, and that the loss savings are reduced where the TLFs are scaled under the approach used for P204.

[9] The environmental impact of fuel switching is considered in Chapter 4.

2.15. OXERA also expressed the above savings in transmission losses in monetary terms, based on its estimates of electricity market prices for each year. These results are set out in Table 2.3b.

Table 2.3b: Value of reduction in the total volume of losses (£m)

Scenario	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
P198	3.4	9.0	1.6	12.0	1.9	4.5
P203	17.8	13.1	13.5	13.8	15.7	7.1
P204	8.3	3.4	7.7	10.4	3.2	3.5

2.16. Extending this analysis to future years, OXERA derived estimates of the average annual savings in transmission losses over the period to 2015/16, as a result of generation redespatch. These results are set out in Table 2.3c.

Table 2.3c: Average annual benefits due to generation redespatch (£m)

Scenario	Average annual loss savings to 2011/12	Average annual loss savings to 2015/16
P198	5	2.9
P203	14	8.9
P204	6	4.7

2.17. OXERA attributed the lower loss savings in later years to the development of new build in the south.

Impact on the distribution of costs

2.18. Changes to the rules for allocating volumes of losses will have associated distributional impacts. Some generators and suppliers will be faced with a larger allocation of losses than they would be if the rules were not changed, while other generators and suppliers will be faced with a smaller allocation of losses than they would be if the rules were not changed. The costs associated with losses will therefore be redistributed, while the total allocation over all generation and over all suppliers will be unchanged.

2.19. As part of its cost-benefit analysis, OXERA analysed the overall transfers of loss charging revenues between generators and between suppliers in the different charging zones in the first year following implementation of the zonal losses scheme. This section summarises the key findings of that analysis.

Generators

2.20. Table 2.4a sets out estimates of the transfers of costs for generators in 2006/07 if P198, P203 and P204 had applied in 2006/07, relative to the current rules for allocating losses. The results are presented in £m and in £/MWh (assuming a £45 per MWh price of electricity).

2.21. The main points to note from this analysis are:

- Around £90m would be transferred between generators under P198 and around £80m under P203.
- Generators in Scotland face the largest increase in costs, while generators in southern England see the largest reductions in costs. In total the costs of generators in Scotland would increase by around £43m under both P198 and P203. At the same time the biggest reduction would be in the South Eastern zone where costs would be reduced by around £26m under P198 and £23m under P203.
- The amount transferred and the maximum and minimum transfers are much lower under P204, at around 20% of the total for P198. For example, the costs to Scottish generators would increase by around £10m, while in the South Eastern zones costs would only reduce by £6m.

Suppliers

2.22. Table 2.4b similarly sets out estimates of the transfers of costs for suppliers in 2006/07 if P198, P203 and P204 had applied in 2006/07, relative to the current rules for allocating losses. The results are again presented in £m and in £/MWh (assuming a £45 per MWh price of electricity).

2.23. The main points to note from this analysis are:

- Around £90m would be transferred between suppliers under P198 and around £80m under P203.
- Suppliers in Scotland face the largest reduction in costs, while suppliers in southern England see the largest increase in costs. In Scotland the costs of suppliers would be reduced by around £40m under P198 and by £35m under P203. At the same time charges for suppliers in London would increase by £24m under P198 and by £21m under P203.
- The amount transferred and the maximum and minimum transfers are much lower under P204, at around 20% of the total for P198. For example, the reduction in costs to Scottish suppliers would be significantly lower at around £8m, while in London costs would rise by around £5m.

Table 2.4a – Estimated cost transfers for generators under P198, P203 and P204 (if in force in 2006/07)

	£m			£/MWh		
Zone	**P198**	**P203**	**P204**	**P198**	**P203**	**P204**
North Scotland	-9.26	-5.89	-1.10	-1.03	-0.74	-0.16
South Scotland	-34.07	-39.66	-9.10	-0.92	-0.94	-0.22
Northern	-3.46	-3.63	-0.75	-0.43	-0.45	-0.09
North Western	-4.09	-3.28	-0.78	-0.24	-0.19	-0.04
Yorkshire	-34.85	-29.97	-6.22	-0.46	-0.41	-0.09
Merseyside & North Wales	-2.99	-1.29	-0.33	-0.12	-0.06	-0.02
East Midlands	4.79	6.83	1.17	0.11	0.15	0.02
Midlands	6.17	6.55	1.25	0.41	0.44	0.08
Eastern	11.17	9.28	2.29	0.45	0.40	0.09
South Wales	6.69	6.66	1.44	0.42	0.42	0.09
South Eastern	26.20	23.18	5.38	0.60	0.52	0.12
London	2.59	2.10	0.46	0.86	0.70	0.17
Southern	16.14	11.01	2.40	0.77	0.79	0.17
South Western	14.97	14.45	2.97	0.83	0.80	0.17

Table 2.4b – Estimated cost transfers for suppliers under P198, P203 and P204 (if in force in 2006/07)

	£m			£/MWh		
Zone	**P198**	**P203**	**P204**	**P198**	**P203**	**P204**
North Scotland	13.83	9.13	2.01	1.26	0.83	0.18
South Scotland	26.71	26.19	5.99	1.11	1.09	0.25
Northern	10.96	11.23	2.29	0.61	0.62	0.13
North Western	10.83	9.68	2.12	0.42	0.37	0.08
Yorkshire	17.88	16.47	3.45	0.64	0.61	0.12
Merseyside & North Wales	5.49	4.09	0.89	0.29	0.23	0.05
East Midlands	2.14	1.23	0.37	0.07	0.04	0.01
Midlands	-8.41	-8.62	-1.66	-0.25	-0.25	-0.05
Eastern	-10.59	-9.36	-2.31	-0.26	-0.24	-0.06
South Wales	-3.30	-3.01	-0.69	-0.24	-0.23	-0.05
South Eastern	-10.24	-7.98	-1.93	-0.41	-0.33	-0.08
London	-23.87	-20.74	-4.53	-0.70	-0.63	-0.13
Southern	-21.95	-20.55	-4.70	-0.58	-0.56	-0.12
South Western	-9.48	-8.84	-1.81	-0.68	-0.63	-0.13

Implementation costs

2.24. All of the proposals to introduce zonal transmission loss arrangements will involve costs associated with changes to systems and processes compared to the current arrangements. These costs relate to the initial set up and ongoing operation of the scheme, each of which can be separated into central costs associated with the administration of the BSC arrangements and direct costs to market participants associated with making changes to their systems and processes as a result of the proposed and alternative modifications. For the avoidance of doubt it should be noted that the central implementation and operational costs incurred by Elexon will still ultimately be charged out to market participants.

2.25. These costs were assessed by Elexon as part of the development of each proposal and are set out below.

Central implementation and operational costs

2.26. There would be a range of central costs involved in implementing all of the proposals. The bulk of these costs would be those associated with the new role of the TLFA (the party responsible for calculating zonal TLFs) and the Load Flow Model Reviewer (the party appointed to verify the compliance of the load flow model with its specification). In addition, Elexon would incur some costs in updating documentation, undertaking procurement of the TLFA and Load Flow Model Reviewer and testing the TLFA system. Logica CMG would incur costs in testing the functionality of the systems used to calculate TLFs.

2.27. In terms of the ongoing operational costs, these primarily relate to the activities required to calculate the TLFs for the following year and to allocating TLF values to any new BM units which register during a year. A summary of the total central implementation and operational costs for each of the proposed and alternative modifications is set out in Table 2.5[10].

Table 2.5: Estimates of central costs

Proposal	Total Central Implementation costs (£k)	Total Central operational costs per year (£k)
P198	467	158
P198 Alternative	477	157
P200	854	158
P200 Alternative	864	157
P203	477	157
P204	491	167

[10] These costs are indicative and were presented in the FMRs with tolerance levels around their value.

2.28. This table highlights that the implementation costs are broadly comparable for each of the proposed and alternative modifications, with the exception of the P200 Proposal and the P200 Alternative which have additional costs associated with the proposed hedging scheme. The inclusion of the hedging scheme approximately doubles the total central implementation costs as compared to the unmitigated schemes. This is mainly attributed to the additional costs to Logica CMG in creating new databases in central systems to receive and store monthly F-factor data sent via a new manual interface with Elexon.

2.29. In relation to ongoing operational costs, these are comparable for all of the models. Only P204 involves marginally higher operational costs of around £10k due to the calculation and application of the variable scaling factor.

Participants' costs

2.30. There are four key categories of participants affected by the proposals, NGET, vertically integrated generators, other generators and industrial and commercial retailers. NGET's costs would include supporting Elexon in establishing and maintaining the Network Mapping Statement[11] and supporting the TLFA in updating the load flow model. The other parties would incur costs in making changes to their systems to take account of zonal TLF values.

2.31. All of the participants including NGET broadly considered that all of the proposed and alternative modifications would involve comparable costs however some considered the hedging arrangements under P200 would involve additional costs with £50k being the maximum additional cost identified.

2.32. Table 2.6 sets out the estimated total implementation costs across each category of participant.

Table 2.6: Estimates of participants' implementation costs

Participant[12]	**Total Participants' Costs £k**
Vertically integrated generators	896
Other generators	528
I & C retailers	132
Transmission company	40
Total	**1596**

[11] Document established by Elexon on behalf of the BSC Panel to map power flows on the GB transmission system by node. This information is ultimately used to calculate the nodal TLFs.
[12] Different BSC parties indicated a range of costs of implementing the modification proposals. The table sets out estimated total costs for each class of participant.

Total costs

2.33. Taking both central and participant costs into account, each of the unmitigated zonal losses schemes (P198, P203, P204) have total implementation costs of approximately £2m and total operational costs of approximately £0.3m per year, although the costs are slightly higher for P204 than for P198 or P203. For the P198 Alternative, the addition of a phasing scheme does not have a significant impact on these total costs, while the addition of the hedging scheme for P200 and the P200 Alternative leads to additional implementation costs of around £0.4m compared to the unmitigated schemes.

Impact of mitigation techniques

2.34. There was no specific quantitative analysis undertaken by the Modification Groups in developing the proposals on the impact of phasing or hedging. However, given both approaches have been proposed to mitigate the impacts of fully locational charging arrangements then the impacts of those proposals in relation to TLFs and subsequently in terms of the distributional impacts and the impact of the total level of losses can be inferred. The impacts of both phasing and hedging are considered in turn below.

Phasing

2.35. The P198 Alternative is the only solution which proposes to mitigate the impacts of locational losses through linear phasing, and it applies this mitigation scheme to the seasonal zonal TLFs scheme.

2.36. The proposal involves phasing the locational TLFs over the first four BSC Years of the scheme. As a result, TLFs would be 20% of their full value in BSC Year 1, 40% in BSC Year 2, 60% in BSC Year 3, 80% in BSC Year 4, and 100% in BSC Year 5 and all subsequent years. Given the P198 Alternative is based on the seasonal zonal TLFs scheme then the appropriate comparison for the impact of phasing is with the TLFs produced for P203. These were highlighted for generators and suppliers in Tables 2.1a, 2.1b and 2.3b above.

2.37. The fact that phasing reduces the TLFs in the first four years of the scheme the proposal will have an associated impact on distributional effects and loss savings. In relation to distributional effects, during the period of phasing these would be expected to be lower than those of P203. Tables 2.4a and 2.4b highlighted the potential transfers of revenue between zones for the three key zonal loss schemes. In the first year of phasing, transfers of revenue would be expected to be close to those of the results for seasonal scaled zonal TLFs (P204), which are approximately 20% of the magnitude of the P203 revenue transfers. However, over the following 3 years the level of distributional effects under phasing would be expected to move closer to P203.

2.38. Similarly, phasing would be expected to result in lower total savings in losses over the period in which phasing applies. The annual loss savings would be expected to become closer to those under P203 in each subsequent year until the full unmitigated locational signals apply.

Hedging

2.39. In the case of hedging, the impacts are more difficult to predict. While the proposed method of phasing would apply to all generators and suppliers and would have a linear impact of TLFs, hedging would have differential impacts due to its application to some generators only.

2.40. Generally, by reducing the total level of exposure to locational loss charges, hedging would have a lower impact in terms of the distributional effects and be expected to produce weaker signals than the unmitigated models. Hedging would be expected to have a lower impact in reducing losses than the unmitigated scheme.

2.41. Given P200 is based on Annual Zonal TLFs (P198) and the P200 Alternative is based on Seasonal Zonal TLFs (P203) then, given the higher level of annual loss savings indicated in Table 2.2 for seasonal values, it would be expected that the P200 Alternative would have a greater impact in reducing total losses than the P200 Proposal.

3. Indirect impacts

Chapter Summary

The direct impacts of the proposals discussed in the previous chapter will have a number of possible indirect effects e.g. on the accuracy of the allocation of losses, on competition between generators, on transmission costs and on suppliers and thus prices to consumers. This chapter discusses the potential indirect impacts.

Question box

Question 1: Do respondents consider we have appropriately summarised the indirect impacts of the proposed and alternative modifications?

Question 2: Do respondents consider that there are any indirect impacts of the proposed and alternative modifications that have not been fully assessed?

Question 3: Do respondents wish to present any additional analysis that they consider would be relevant to assessing the proposals?

Introduction

3.1. The previous chapter considered the direct impacts of the various proposed and alternative modifications to introduce locationally varying TLFs. It focussed on the evidence presented by OXERA and Siemens PTI on values of TLFs and the associated impact on users' charges.

3.2. This chapter sets out the indirect impacts that flow from changing the TLFs (and the associated allocation of volumes of losses). This chapter considers the impact on:

- accuracy of allocation of losses;
- competition between generators;
- transmission costs; and
- suppliers and prices to consumers.

3.3. These impacts are further considered in chapter 4 in the wider context of the environmental impacts of the proposals.

Accuracy of allocation of losses

3.4. One impact we are interested in is whether the proposed changes improve the accuracy with which transmission losses are attributed to different network users. If losses are not attributed accurately, then there is a form of cross-subsidy - some parties contribute more than an accurate allocation would suggest is appropriate, while other parties contribute less than might be considered appropriate on the basis of a technically accurate allocation. Assessing this impact has two elements. First, how the TLFs are calculated. Second, how the TLFs are applied.

Calculation of TLFs

3.5. Currently, the TLF is set to zero. The proposed changes all involve the introduction of zonal TLFs. All the proposals base the calculation of the TLFs on estimates of marginal losses derived from a load flow model. A load flow model is a model of the transmission network which seeks to analyse how electricity might be expected to flow across the network in different circumstances, e.g. with a particular geographical dispersion of generation and demand.

3.6. Load flow models seem to be a generally accepted way of estimating marginal losses. Further there also seems to be a general acceptance of the premise that losses do vary by location. Hence, an estimate of marginal losses derived from an appropriately specified load flow model would appear to represent a more accurate reflection of physical reality than allocating losses without reference to location.

3.7. However, estimates derived from a model, and updated once a year, will not be the most accurate method of allocating losses when compared with all possible methods. The impact of some of the assumptions adopted in all six proposals is to simplify, and therefore abstract from the physical reality to some extent. The material simplifications would appear to be:

- Using zones rather than nodes
- Setting the TLFs in advance
- Setting the TLFs once a year
- Applying a scaling factor to the marginal loss factors derived from the load flow model
- Applying the same TLF across a period of time (a year in the case of P198 and P200, and a season within a year in the case of the other four proposals)

3.8. The impact of relaxing any of these simplifying assumptions would be to permit estimates of TLFs which would have the potential to be more accurate at any point in time.

- **Zones versus nodes:** The proposed zones are relatively large. There are 14 zones for generation and for demand across the whole country. This means that within each zone there will be variation in underlying nodal TLFs. Some nodes will benefit from the averaging effect implicit in zoning, while other nodes will pay more under a zoning approach than they would under a nodal approach. This issue was analysed by the P198 Modification Group. The analysis demonstrated that variations within zones could be significant - particularly for geographically remote nodes within a zone. On this basis, the Modification Group considered a nodal approach but unanimously concluded that such an approach was not appropriate for a scheme which included both generation and demand – since TLFs for demand and embedded generation could only be applied at the GSP Group level, and the Modification Group considered that it was essential that the zones for generation and demand were the same[13].

- **Setting TLFs in advance:** If the sole objective was to reflect losses as accurately as possible from a physical perspective, then it would probably not be appropriate to set TLFs in advance. Calculating TLFs on an ex-post basis, by waiting to see what flows actually were and how the network was configured at that time, and then calculating TLFs, would be more (or at the very least, equally) accurate as compared to setting TLFs in advance.

- **Setting TLFs once a year:** Re-setting TLFs each year would be likely to result in more accurate TLFs than re-setting TLFs less frequently (e.g. leaving them unchanged indefinitely). Similarly, re-setting TLFs more frequently than once every twelve months would enable TLFs at any point in time to be more accurate.

- **Applying a fixed scaling factor of 0.5:** There is an assumption in all of the proposals, with the exception of P204, that application of a fixed scaling factor of 0.5 ensures that the locational variations in the allocation of losses relates to the marginal impact on the level of losses associated with an increase in power flow from each point on the network. While the premise might be correct, the manner of quantification - 50% in all instances - is clearly an approximation. If the objective was to make TLFs as accurate as possible, then the treatment of 'fixed' losses would probably be more sophisticated.

- **Applying a variable scaling factor to ensure no energy credits:** P204 constrains the calculation of TLFs such that no party receives a negative allocation of locational losses. It does so by scaling down the locational variations in the allocation of losses until this constraint is met. A negative allocation of locational losses would result if, for example, additional generation at a particular point (and therefore less generation somewhere else - in the context of a balanced system) resulted in a reduction in total losses. If this is feasible - which it would appear to be - then restricting the calculation of TLFs in the manner proposed under P204 would appear to detract from (or at least not improve) the accuracy of the TLFs.

- **TLFs fixed over periods of time:** It is also a simplifying assumption that TLFs should not vary more frequently than (at most) seasonally. This approach abstracts from variations by month, day or time of day. Analysis undertaken and published by Siemens PTI as part of the process of developing these proposed and alternative modifications illustrated material variations by season in some zones (most notably in Scotland) - and also concluded that (as might be expected) seasonal TLFs provided a better fit with the underlying monthly and daily TLFs, when compared with annual TLFs.

[13] The views of the Modification Group on zoning are set out in more detail in the FMR for P198.

Application of TLFs

3.9. In terms of allocating losses accurately from a technical perspective, the most effective approach would be to identify an accurate way of calculating TLFs and then to apply it immediately. None of the proposals are based on immediate implementation. Rather, they are based on a minimum 12 month lag between a decision to approve a proposal by Ofgem and implementation. Further, under some of the proposals the full application of the more accurate TLFs is designed to be delayed for a further period of time (in the context of phasing or hedging schemes).

3.10. The proposals which implement the method of calculating TLFs later by design (i.e. those which have an element of phasing or hedging) will, by definition, result in a less accurate allocation of losses from the perspective of reflecting physical reality. To illustrate, during the proposed 15 year hedging period under P200 and its Alternative, a user who is in the scope of the hedging scheme will make a locational contribution to losses based on its metered output relative to a reference level of output (the 'F-factor') - but the F-factor is based on output levels for a historical reference year and is independent of the physical reasons for losses on the system at any point of time to which it is applied. Further, the user will be allocated a non-zonal share of transmission losses on the basis of its F-factor, irrespective of its output at any point in time. Hence, hedging in the form proposed through P200 and its Alternative can only reduce the accuracy with which losses are allocated to users.

3.11. It should also be noted that the proposals which permit variations in TLFs within a year may be expected to be more consistent with more accurate allocations of losses at any point in time than proposals which do not permit variations in TLFs within a year.

Competition between generators

3.12. The introduction of locational charging for transmission losses would alter, to some extent, the economics of generating electricity for sale in the GB wholesale market thereby impacting on the terms on which generators compete against each other. It would also introduce an additional factor for participants to take into account when making short and long-term decisions in relation to their use of the transmission network.

3.13. For any given level of transmission losses, the proposals will allocate the costs of those losses differently. Some generators will see their costs relative to other generators fall as a result, while other generators will see theirs costs relative to other generators increase as a result. Consequently, we might expect to see changes in market outcomes, i.e. the pattern of generation, as a result of different locational signals provided by locational loss charging.

3.14. These changes can be considered in the context of existing locational signals provided through charges generators and suppliers pay for using the transmission system. The method used by NGET for setting its transmission network use of system ("TNUoS") charges has a number of charging zones with generator charges being higher in the north and lower in the south. The pattern of charges is reversed for suppliers. These charges reflect the costs of the network assets that enable power flows from generators to centres of demand, rather than the cost of transmission losses.

3.15. Table 3.1 illustrates the possible magnitude of the impact on generators of locational loss charging under P198 in various parts of the country. The table uses as its basis the estimated generation TLMs produced by OXERA based on annual zonal TLFs for 2006/07. These reflect the information presented above in Table 2.4. Table 3.1 also sets the estimates in context by comparing the estimated losses charges with the TNUoS charges in those regions.

3.16. Given TNUoS charges are calculated on a £/kW basis, we have converted the loss charge for each zone to £/kW assuming an electricity price of £45/MWh and using annual load factors of 30% to represent lower load factor generation and 85% to reflect higher load factor generation. Finally, we note that the generation zones for loss charging and generation TNUoS zones do not directly map on to one another. On this basis, the TNUoS charges we have highlighted reflect the TNUoS charge that would be paid by the majority of the generation in the respective loss charging zone.

Table 3.1: Losses charges for different load factor generators (£/kW)

	30% load factor			85% load factor			TNUoS
Zone	**Now**	**P198**	**Change**	**Now**	**P198**	**Change**	**(£/kW)**
South Western	0.85	-1.54	-2.39	2.40	-4.36	-6.76	-9.15
Eastern	0.85	-0.35	-1.20	2.40	-1.01	-3.41	1.22
Northern	0.85	1.54	0.69	2.40	4.36	1.95	8.89
South Scotland	0.85	2.37	1.52	2.40	6.70	4.30	12.14
North Scotland	0.85	2.48	1.63	2.40	7.04	4.63	20.52

3.17. Table 3.1 highlights three key points. First, that the pattern of locational loss charging echoes the pattern of TNUoS charges. Second, the increase in the 'locational-ness' of the charging regime overall as a result of P198 would be relatively small when compared with the strength of the existing locational signals provided by TNUoS charges. Third, as demonstrated by the magnitude of the change in charges, the signals from locational loss charging would be even smaller for lower load factor generation, such as wind.

Impact on short-term despatch

3.18. 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.

3.19. OXERA analysed the impact of the introduction of zonal losses on generation despatch and the associated impact on the volume of losses. The results of this analysis were set out in the discussion of direct impacts in chapter 2 of this document.

Impact on long-term decisions

3.20. 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.

3.21. OXERA concluded that the introduction of zonal transmission losses would not have a material impact on medium term siting decisions of new plant, over and above those already provided through TNUoS charges. However, OXERA do consider that the proposals may have longer term impacts (beyond 2015/16) on generation locational decisions, while noting that there is considerable uncertainty in this respect. At the margin, the introduction of locational loss charging will change the point at which a previously economic project becomes uneconomic. However, whether this has a practical impact will depend on the other factors determining whether projects proceed or not, such as planning consent. The longer term impacts are discussed in more detail in chapter 4, the context of these other factors.

3.22. OXERA's central estimate of the long-term (post 2015/16) annual benefits as a result of the impact of zonal losses on generation locational decisions was £10.6m for both the Annual TLFs scheme (P198) and the Seasonal TLFs scheme (P203). OXERA did not derive equivalent estimates for the Scaled Seasonal TLFs scheme (P204), but noted that they may be reduced as a result of the scaling approach used for P204.

Impact on perceptions of risk

3.23. The proposals to set TLFs on a different basis will, as illustrated above, impact on the costs that generators face in order to participate in the GB wholesale market. Whether a change in costs driven by a change to loss charging in the BSC represents an increase in risk for generators, however, is a more subjective question – and relates directly to the question of how the consequential distributional effects resulting from each of the proposals might be characterised. There are three possible impacts:

- No change;
- Increased perceptions of risk; or
- Reduced perceptions of risk.

3.24. In the longer term, any changes in risk might be expected to be factored into investment and pricing decisions by generators - and hence on end prices to consumers.

3.25. If the prospect of change to commercial positions driven by changes to BSC is well understood by market participants, in general and in the specific case of transmission losses, then the approval of one of the six proposals might have no impact on perceptions of risk going forward. In effect, the risk of change would have already been priced in.

3.26. However, if the change in commercial positions resulting from an approval of one of the proposals was viewed as a surprise, and therefore revealed new information about the nature of risk in the wholesale electricity market, then there might be an impact on perceptions of risk going forward. There might be an increase in perceptions of risk if, for example, the potential for change under the BSC and the administrative process underpinning such change management, was not well understood (and therefore change per se came as a surprise).

3.27. Conversely, if the approval of a proposal was interpreted as the sensible implementation of a soundly based proposal that had been developed through an open and rigorous process of consultation, then the decision might be viewed as reducing perceptions of regulatory risk going forward. It would be evidence that the regulatory and commercial regime could handle complex and contentious changes in an organised way. A decision to approve one of the proposals would be likely to reduce uncertainty in respect of the specific issue of transmission losses.

Transmission costs

3.28. The introduction of different TLFs will, as noted above, impact on the costs faced by different generators in the GB market. It will also provide information about costs that might be incurred by parties considering entering the market, or costs that would be avoided by exiting the market.

3.29. A discussion of the shorter term potential impacts on generation despatch is set out above. In the longer term (and potentially in the short-term) this, in turn, will impact on transmission costs. The location of generation relative to demand is an important driver of the costs of transmission, and any changes in the geographic pattern of generation will have an impact on how much transmission investment is required.

3.30. The effect of any changes to TLFs in this process is very difficult to isolate, given the long-term nature of such effects – and the other commercial factors shaping investment and operational decisions by generators and demand-side users over time. However, while difficult to quantify, it should be recognised as a potential impact.

3.31. If the TLFs result in users of the transmission network facing more accurate costs, relative to the physical reality of operating a transmission system, then decisions about where to locate (or close) and how to operate will be better informed (from the perspective of reflecting the costs of transmission). This is turn might be expected to promote, over time, more efficient levels of transmission investment.

Impact on suppliers and prices to consumers

3.32. The prices consumers pay for electricity depends, at a high level, on the costs incurred by the parties who contribute towards providing the service. This includes generators and suppliers. Both of these groups of market participants will see changes to their costs if TLFs are set on a different basis, which will in turn impact on prices to consumers.

3.33. In the short-term, changes to the total volumes of losses are likely to be relatively small as a consequence of any of the proposals being implemented. The more material effect is on the geographical allocation of those losses. The impact on the costs generators and suppliers by zone is illustrated in chapter 2.

3.34. The introduction of TLFs which vary by location will increase the geographical differences in the costs incurred by suppliers. Some suppliers will see their costs increase, e.g. if they have a concentration of customers in areas where loss charges are increasing. While other suppliers will see their costs fall. This might be expected to influence pricing in a competitive market – although the precise form of the response is difficult to predict. Over time, however, if the cost of supplying customers in a specific area (e.g. Scotland) falls, then prices should also fall. Conversely, we might expect upward price pressures in some areas as a result of changes to how losses are charged out.

3.35. In the longer term we might expect consumers, in aggregate, to benefit as the total volume of losses falls – and as those demand users who are able to respond to the locational signals created by locational loss charges change their behaviour. As part of its analysis referred to in chapter 2, OXERA estimated this potential demand-side response to the introduction of zonal loss charging, based on assumptions as to the long-run electricity price elasticity for domestic and industrial and commercial (I&C) customers. OXERA's central estimates of the longer term annual benefits from the demand side response are set out in Table 3.2.

Table 3.2: Average annual benefits due to demand-side response (£m)

Scenario	Average annual loss savings to 2015/16
P198	0.6
P203	0.8
P204	0.4

Other

3.36. We have published guidance on how we will conduct impact assessments. Section 5.4 of our current guidance[14] sets out a number of areas which we may, where appropriate, seek to address when undertaking an impact assessment. The areas identified include: security of supply; health and safety issues; distributional effects; and the impact on small businesses.

3.37. In conducting this impact assessment we have not identified any additional impacts which fall within the above-mentioned categories. However, we would welcome respondents' views on whether they consider that there are any relevant impacts that we should be considering in relation to these or any other areas.

[14] This is available of Ofgem's website: www.ofgem.gov.uk

4. Environmental impacts

Chapter Summary

This chapter sets out an assessment of the environmental impacts of the proposed and alternative modifications in relation to zonal transmission losses.

Question box

Question 1: Do respondents consider that we have appropriately outlined the key environmental impacts of the different proposals?

Question 2: Do respondents consider that there are other environmental impacts that should be assessed?

Question 3: Do respondents have any additional analysis in relation to environmental impacts that they wish to present?

Utilities Act 2000

4.1. Pursuant to section 5A(2) of the Utilities Act 2000, it is a requirement of an impact assessment undertaken by Ofgem to include an assessment of the impact on the environment of the proposal being considered. This section sets out an assessment of the environmental impact of the proposed and alternative modifications - P198, P198 Alternative, P200, P200 Alternative, P203, and P204.

4.2. In considering the impact of the modifications we assess the potential short and long-term environmental impacts from the proposals. This assessment is also relevant to our duties regarding the environment and sustainable development, and also the duty to have regard to any social and environmental guidance issued by the Secretary of State pursuant to section 3B of the Electricity Act 1989, which identifies the contribution the Secretary of State considers Ofgem should make towards the attainment of the Government's social and environmental policies.

Overview of electricity transmission losses

4.3. For the current GB charging year, 2006/07, NGET estimate total GB transmission losses of around 5.82TWh, approximately 2 per cent of total system demand. However, losses vary by geographical location and may be higher for generators in remote locations. In addition to the cost in terms of electricity lost and capacity on transmission networks there is an environmental impact of generating and distributing the lost units. In terms of emissions, losses comprise around 2.50 $MtCO_2$ (million tonnes of carbon dioxide) or 0.68 MtC (million tonnes of carbon)[15].

4.4. In 2004 electricity generation accounted for about a third of UK CO_2 emissions. A reduction in losses could make a contribution to the UK's emission reduction commitments under the Kyoto Protocol, and meeting the domestic targets of a reduction in CO_2 to 20 per cent below 1990 levels by 2010, and 60 per cent below 1990 levels by 2050.

4.5. Much of the electricity generated is produced by power stations burning fossil fuels. Therefore transmission losses increase emissions of greenhouse gases and other pollutants. In addition there are other environmental impacts of the transmission system including the resources used to maintain the network and also visual impacts on the landscape.

4.6. Zonal transmission loss charging has the potential to reduce the total level of losses by providing signals for generation and demand to locate closer together, this will have short-term and long-term effects.

Overview of short-term and long-term environmental impacts

4.7. Other things being equal, an accurate cost signal would be expected to reduce the total volume of transmission losses. In the short-term, the change should be beneficial to generators located close to demand, and this would be expected to result in a greater share of output from the more efficiently located generators. In the longer term, generators would be more likely to make efficient locational decisions and site relatively closer to areas of significant demand. The overall effect should be a reduction in total losses which will also have an impact on the level of carbon emissions.

4.8. We note the analysis produced by OXERA (discussed in Chapters 2 and 3) which highlighted that zonal transmission losses may not have a material impact on medium-term siting decisions but may impact on longer term decisions. In addition, we note that the actual impact of changing loss signals on use of the transmission network is dependent on the extent to which the signal is accurate. If the signal is inaccurate or not sufficiently material to alter operating decisions, the modification proposals would not be expected to alter the volume of losses.

Short-term impacts

4.9. We have used the results from the cost benefit analysis reports OXERA produced for Elexon as part of the Modification Group's assessment process to look at the impact on carbon emissions and air quality pollutants.

4.10. Our analysis draws on OXERA's estimates of the changes in generator outputs by fuel type, for the three scenarios on which the results presented in

[15] Calculated using the DEFRA emission factor for grid electricity (see appendix 3)

chapter 2 are based representing P198[16], P203 and P204 respectively[17]. We used DTI calorific values and typical conversion efficiencies to derive emission factors[18] to calculate the changes in carbon emissions, sulphur dioxide (SO2), and nitrogen oxide (NOx) emissions.

4.11. The following table contains the estimated total savings in avoided overall losses, carbon emissions, SO2, and NOx emissions for the period 2006 – 2011. An individual breakdown by year and modification can be found in appendix 3.

Table 4.1: Emission savings by fuel type as a result of zonal loss charging 2006-2011

	P198	P203	P204
Savings in losses over period (GWh)	1088	2789	1238
Emission Savings (MtC)	0.52	0.92	0.28
Value of savings at £70 /tC. (£M)	£36.3	£64.2	£19.4
Value of savings at £35-£140/tC (£M)	(£18.1 - £72.6)	(£32.1 - £128.4)	(£9.7 - 38.8)
SO2 Savings (kt)	25.41	33.25	8.70
NOx Savings (kt)	6.33	8.77	2.49

4.12. Other things being equal, zonal loss charging will reduce costs for generators located close to demand and increase the costs for remote generators. The impact of this reallocation of costs is assessed in chapters 2 and 3, with OXERA's analysis highlighting that it results in a general shift in generation from north to south, and also shifting between generation with different fuel sources. This increase in efficiency leads to greater loss savings, and the fuel switching towards more gas generation under the scenarios will have a favourable impact in terms of carbon, SO2, and NOx emissions. Other changes towards oil, pumped storage and OCGT in later years are minor and have little effect in terms of emissions, in each scenario.

4.13. There are greater fuel impacts for P203 than P198. This is due to the more focused reallocation of losses during different times of the year. From 2007 there

[16] OXERA constructed market scenarios around variations in fuel costs (relative costs of coal and gas) and demand growth. The results for P198 are based on the July report central scenario which used mid-range assumptions. In this scenario the continued favourability of coal prices means coal plants are well utilised throughout the model, prices fall in the early years due to falling fuel costs but then rise to support new capacity from 2010 onwards following continued demand growth.

[17] The results for P203 and P204 are based on the July report seasonal scenario and September report seasonal scenario respectively. These scenarios use a variant of the methodology used in the central scenario, but the market outcomes are the same.

[18] See Appendix 3 for the emission factors used in the analysis.

is a larger movement away from coal generation for P203 in comparison to P198, which will result in lower emissions.

4.14. In comparison to P198 the avoided emissions under P204 are less at 0.28 MtC for the period. The effect on SO2 and NOx emissions is much the same, with savings lower in comparison to the P198 scheme. This is due to the weaker despatch signals under P204.

Long-term impacts

4.15. The introduction of zonal loss charging by encouraging more efficient locational decision-making could have a positive impact on the environment. The appropriate signals will ensure that when making decisions on future location of generation plants their effects on losses will be taken into account.

4.16. However, as reflected in OXERA's analysis, the specific effect the proposals will have on long-term locational decisions is very uncertain. Other factors will influence the need for new generation and the preferred type of generation, these include Government policy on energy efficiency and incentives for distributed generation, the funding of particular types of generation such as nuclear, and market conditions. New technologies may mean that there are significant benefits to locating at existing sites, where planning issues are likely to be more straightforward.

4.17. We have used the scenario of annual longer term benefits presented in the OXERA report to estimate the associated change in emissions from P198. Table 4.2 below presents the carbon emissions avoided when a proposed 1 GW CCGT plant is relocated to the Southern zone from the Yorkshire, Eastern and South Scotland zones. Savings in terms of carbon are 0.01MtC to 0.03 MtC per year.

Table 4.2: Longer term annual effects of Zonal loss charging P198 (beyond 2015/16)

	Zone		Est. loss reduction	Emission Reductions		Social Cost of Carbon	
GW relocated	From	To	GWh	Mt CO2	MtC	£70/tC (£m)	£35-£140/tC (£m)
1	Yorkshire	Southern	286	0.10	0.03	£2.1	£1.0 - £3.9
1	Eastern	Southern	149	0.05	0.01	£0.7	£0.5 - £2.0
1	South Scotland	Southern	208	0.07	0.02	£1.4	£0.7 - £2.9

4.18. OXERA concluded that the introduction of zonal loss charging strengthens the locational signals for building power stations closer to demand, however the strength of this signal relative to other changes is uncertain.

4.19. OXERA also emphasise there are other factors that should be taken into consideration when deriving a realistic estimate of the longer term benefits[19], these are:

- zonal loss charging is only one of the factors that might affect the location of generation, factors such as Transmission Network use of system charges (TNUoS), and planning permission may have a greater influence;
- scenarios are based on the relocation of base load plant, which would change flow patterns, with potential beneficial effects on losses during all time periods. If zonal loss charging changes the location of mid-merit or peaking plant, loss reductions would only occur during periods of higher demand; and
- the methodology OXERA used to derive the potential loss reductions above will overestimate the effect of generation relocation on losses - it does not take into account the fact that as generation is switched between zones, the marginal loss benefit of switching further generation will tend to fall.

Locational decisions of renewables

4.20. One potential consideration for the environment is the implication of any proposal for the locational decisions of renewable generators. Zonal loss charging will provide price signals affecting the locational decisions for renewable generation. Given the likely changes in charges, it should provide price signals encouraging development of renewable generation in the South relative to the North. However, these would be likely to have a lower impact than the signals from other factors such as TNUoS charges which are of a much greater magnitude.

4.21. The UK government has a target for 10 per cent of electricity supplied to be provided by renewable generation sources by 2010. It also has targeted 20 per cent of energy to be produced by renewable generation by 2020. The Scottish Executive has targeted 18 per cent of energy from renewable sources by 2010 and 40 per cent by 2020. The OXERA analysis concluded that zonal charging will have a very marginal financial impact on renewables. It noted that it was unlikely to affect the build of renewables and therefore unlikely to materially impact on the probability of meeting the Government's renewables target during the period up to 2015/16.

4.22. There might be some slight distributional effects, given that large volumes of renewable generation are either connected to, or seeking connection in, northern England and Scotland. On this basis, there is a potential risk that an increase in costs will reduce the viability of the most marginal plant and slightly reduce the volume of renewable connections in northern areas. However, by the same token, any marginally economic plant in the south may benefit. Overall, in their report, OXERA find that locational signals from zonal transmission losses are likely only to have a minor impact on the growth of renewable new build.

[19] OXERA took these factors into account in deriving the central estimates set out in Chapter 3 (paragraph 3.22). Further information is available in OXERA's July report (section 5.3).

4.23. Given the significant volumes of renewable generators currently seeking capacity in Scotland and the fact that offers have been made for connection as far out as 2016, it is not clear that the additional charges will cause an overall decline in the volume of renewables connecting. Northern areas are often more suitable for renewables as they have advantages in terms of resource, costs and output. OXERA in their cost benefit analysis reports provide information that indicates that there may be no overall net welfare losses or benefits for renewable generation associated with the introduction of zonal loss charging. Other factors such as delays in planning permission, obtaining access to the transmission system, and the impact of the Renewables Obligation will also impact on the development of renewable generation. These factors have the potential to outweigh the impact of the introduction of zonal transmission loss charging arrangements.

4.24. From a wider environmental perspective it should be noted that it is not just renewable technologies which reduce greenhouse gas emissions. There are a range of technologies which reduce emissions including combined heat and power (CHP) plants and microgeneration. Therefore, while the increase in charges for losses in northern GB could negatively impact on the economics of remote renewable plant, at the same time the reduction in loss charges for generators in the south of GB could increase the viability of low carbon plant in those areas. Therefore, while locational losses may negatively impact on some remote renewables, the overall impact on the environment of any longer term changes in the generation mix may not be negative. Substitution to less congested areas of the transmission network may also allow plant to connect more quickly and have a positive overall effect on environmental targets.

Visual amenity

4.25. A key issue for the environment is the size and make-up of the transmission network. Changes in the size of the transmission network have a number of environmental impacts. For example, a reduction in the need for double circuit connections could result in fewer (or smaller) transmission towers. This could have a positive environmental impact as there is evidence to suggest that those in the vicinity of transmission lines suffer from a reduction in visual amenity. Evidence on consumers' value amenity[20] was set out as part of the TPCR process.

4.26. The appropriate pricing signals for transmission losses could potentially encourage more local, embedded and on-site generation schemes, as they will be able to benefit from the reduction in their transmission costs. Locating closer to demand in the long-term could result in a reduction in the need to invest or upgrade in additional transmission assets, such as overhead transmission lines.

Summary

4.27. In the short-term the BSC modification proposals, by introducing locationally varying charges, are likely to better reflect the costs of transmission

[20] The overview of valuation of visual impacts of Transmission Price Control Review (TPCR) - EFTEC March 2006

losses and thus result in existing generation being used more efficiently. The resulting reduction in overall transmission losses will mean less energy is required and result in a reduction in carbon, SO2 and NOx emissions.

4.28. In the longer term the proposals have the potential to encourage more local, distributed and on-site generation. It could encourage the more effective location of plants, and encourage the development of the otherwise marginally uneconomic plant in GSP areas. There might be some distributional effects for the location of renewables from the North to the South; however it is likely this effect will be marginal.

4.29. Zonal charging will have the most significant beneficial effect in terms of avoided carbon emissions. Locational charging arrangements should send signals to the market to find the lowest cost way of reducing carbon emissions. The result should be the reduction in overall losses and the more efficient operation of location and operation of the transmission system.

4.30. In terms of the comparative impacts of the different modification proposals, the analysis set out both above and in Appendix 3 demonstrates that:

a. P203 would be expected to have a greater impact on reducing emissions and on total loss savings than P198; and
b. the despatch signals under the P204 are weaker than the signals under P198, resulting in lower loss savings and avoided emissions and thus a less positive impact on the environment as a whole.

4.31. No analysis was carried out by OXERA on the impacts of phasing and hedging. However, if P198 and P203 were considered to produce more accurate locational signals than the existing arrangements then, as with P204, proposals which dilute those signals would be expected to reduce environmental benefits. These arguments were set out in further detail in considering the different mitigation techniques in chapter 2.

5. Process and way forward

Chapter Summary

This chapter sets out the process that we intend to adopt in order to reach decisions on the proposed and alternative modifications and identifies a timetable for the publication of that decision.

Question box

Question 1: Do respondents have any views on both the process and timetable that are proposed for taking forward this assessment of the proposed and alternative modifications?

Intended process

5.1. In line with our published guidance on impact assessments, this document provides six weeks for respondents to submit any comments.

5.2. The current intention is that the Authority will consider the modification proposals, together with the responses to this impact assessment and consultation, at its meeting in May 2007. Given that the Authority will be considering these six important and mutually exclusive proposals at the same time and that this is the first opportunity that we have had to consult on the issues raised by the modification proposals, the Authority will, if it considers it to be appropriate (and, in particular, if the timetable permits), reach "minded-to" views only at its May meeting. If the Authority considers that this approach is an appropriate one, we will consult on the Authority's "minded-to" views in advance of the Authority reaching final decisions. The period for any such consultation would be likely to be shorter than the period for this consultation.

5.3. Finally, having considered any responses to a “minded-to” document, the Authority would publish its decisions on each of the proposed modifications.

Timetable

5.4. Should the Authority decide that it would be appropriate to consult on "minded-to" decisions, we would anticipate that consultation document being published either at the end of May 2007 or in early June 2007.

5.5. The Authority would then consider respondents' comments on its "minded-to" views and reach its final decisions. Decision letters would be published shortly thereafter. It is currently intended that the decision letter will be published by 20 September 2007, the date by which the BSC Panel have indicated a decision is needed to allow for any approved modification to be implemented by 1 October 2008.

Further information

5.6. Appendix 1 sets out both the details for responding to this impact assessment 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 relation to the contents of this document. Respondents' views are also welcomed on any other aspect of this impact assessment.

Appendices

Index

Appendix 1 - Consultation Response and Questions

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

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

1.3. Responses should be received by 10 April 2007 and should be sent to:

Robert Hull
Director of Transmission
Ofgem
9 Millbank
London
SW1P 3GE
0207 901 7339
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 a minded-to statement in relation to all six proposed and alternative modifications and to invite views on that position. Any questions on this document should, in the first instance, be directed to:

Grant McEachran
Head of Transmission Charging
Networks
70 West Regent St
Glasgow
0141 331 6011
grant.mceachran@ofgem.gov.uk

CHAPTER: Two

Question 1: Do respondents consider we have appropriately summarised the direct impacts of the proposed and alternative modifications?

Question 2: Do respondents consider there are additional direct impacts that have not been fully addressed?

Question 3: Do respondents wish to present any additional analysis that they consider would be relevant to assessing the proposals?

CHAPTER: Three

Question 1: Do respondents consider we have appropriately summarised the indirect impacts of the proposed and alternative modifications?

Question 2: Do respondents consider that there are any indirect impacts of the proposed and alternative modifications that have not been fully assessed?

Question 3: Do respondents wish to present any additional analysis that they consider would be relevant to assessing the proposals?

CHAPTER: Four

Question 1: Do respondents consider that we have appropriately outlined the key environmental impacts of the different proposals?

Question 2: Do respondents consider that there are other environmental impacts that should be assessed?

Question 3: Do respondents have any additional analysis in relation to environmental impacts that they wish to present?

CHAPTER: Five

Question 1: Do respondents have any views on both the process and timetable that are proposed for taking forward this assessment of the proposed and alternative modifications?

Appendix 2 – Additional clarification from OXERA

Basis for clarification

1.1. On 21 December 2006 Ofgem wrote to the BSC Panel chairman setting out a list of points on which we sought additional clarity from OXERA with regard to analysis set out in the FMRs. On 12 January 2007 Elexon wrote to Ofgem forwarding a copy of the response they received from OXERA.

1.2. Following consideration of the response Ofgem contacted Elexon on 16 January 2007 requesting that it seek further clarification from OXERA in relation to one of the questions. Elexon subsequently passed on this request and forward OXERA's response to us on 17 January 2007.

1.3. This appendix sets out OXERA's response both to Ofgem's original letter and in relation to its supplementary question.

Ofgem questions and OXERA response

Question 1: Explain the modelling approach in more detail

We seek further clarification on: (i) the approach used to derive the uniform losses scenario against which the impact of zonal losses charging are compared from 2007/08 onwards; (ii) what are the new entry assumptions you have made under uniform loss charging and are these the same under the locational TLFs, and if not, why are they different.

Answer

(i) The approach to the modelling of generator behaviour under the alternative loss charging arrangements (uniform or zonal) is identical. First, the OXERA wholesale electricity model is run for the appropriate snapshot periods. The wholesale model (as described in Appendix 1) is a despatch model based on a comprehensive database of GB grid-connected stations (defining capacity, thermal efficiency, operating costs, fuel type, grid zone, etc). Stations are despatched on the basis of short-run marginal cost including a transmission loss charge. The resulting despatch for the three snapshot periods is then fed into the load-flow model to estimate the transmission losses for the current year and the implied TLMs to be applied in the subsequent year's despatch.

The same underlying assumptions on market conditions are used for the wholesale market modelling under zonal and uniform loss regimes. Differences between the two sets of results may arise for the following reasons:

- in the first year of comparison, the different TLMs under the uniform and zonal regimes alter the merit order and hence change the pattern of output used in the load flow model;
- in subsequent years, the calculation of the zonal and uniform loss factors would be on the basis of different TLFs;
- over time, the differential locational investment incentives may alter the geographic supply-demand balance (though, as highlighted in the report, this effect was not present in the model runs undertaken).

(ii) New entry is determined endogenously within the model according to market characteristics, with the potential projects defined in Table 2.4 (2.3) of the July (September) report. Whereas there are differences in the level and timing of new entry between scenarios, as indicated in section 2.4, the new entry patterns were identical under uniform and zonal loss charging arrangements for a given scenario. For example, Table 2.6 in the July 2006 report is presenting the modelled entry for the zonal and uniform charging regime under the Central scenario. The implication of this is that the zonal charging arrangements had no material impact on investment decisions (over levels or location of capacity) within the model.

Question 2: Clarify the snapshot approach used for seasonal scenarios

Answer

The reports set out the modelling approach by which the results for annual scenarios are derived as being based on results from three snapshot periods (peak, midpoint and trough). While results for seasonal scenarios are based on BSC season, it is unclear whether each season is similarly divided into three snapshots or whether the seasonal results are derived from weighted averages of the annual snapshot results. We seek further clarity on the use of snapshot periods for scenarios based on seasonal TLFs.

Each season was divided into snapshot periods—the re-despatch effects in each season in each snapshot period are presented in section 3.2 and are based on time-weighted snapshot averages in each season, not a season-weighted average of an annual result.

Question 3: Issue of information on uniform losses base cases for each scenario

Answer

The analysis of annual loss savings reports the level of variable losses in the uniform losses base case scenario against which the zonal losses scenario results are compared, in addition to the change in losses between these scenarios. We note that in other analysis where the report shows the impact of the zonal losses scheme it does not show the equivalent results for a uniform losses scheme e.g. the analysis of changes in annual output by zone and by fuel type. We seek further clarity on the reasons for the exclusion of this analysis and the implications for the overall consideration of the cost and benefits of the proposed schemes.

The cost-benefit analysis is conducted with reference to the difference between the out-turn generation profile under uniform and zonal loss charging arrangements and therefore the exclusion of the actual out-turn figures under a uniform loss charging arrangement does not affect the conclusions reached in the reports. This was a presentational issue, where it was decided that the relative performance under uniform and zonal loss charging was the most relevant result to highlight.

Question 4: Explain the difference between the results for the uniform losses base cases of the central and seasonal scenarios.

Answer

The analysis of annual loss savings discussed in Question 2 includes zonal losses scenarios which are based on the same underlying market assumptions but differ according to whether the given zonal losses scheme is based on annual TLFs (the Central scenario) or seasonal TLFs (the Seasonal scenario). The results of OXERA's analysis show a significant difference between annual and seasonal loss scenarios, with the base case variable losses being significantly higher for seasonal scenarios than the equivalent annual scenario.

We seek further clarification on this difference in light of the fact that the base case variable losses for seasonal and annual scenarios are based on the same underlying market assumptions according to the Central scenario.

The difference arises because the analysis in the seasonal scenario measures losses using snapshots for each season rather than three snapshots covering the whole year. The extra granularity in the seasonal scenario implies greater variation in how the overall load is met (i.e. the despatch patterns show a wider variation between seasons). The consequence of this is that the patterns observed for the seasonal scenario are likely to show higher losses since they differentiate to a greater extent periods of low demand and periods of high demand where optimal despatch conditions may vary. As the comparison of the low demand and central scenarios show on an annual basis, the periods of low demand are likely to lead to higher variable losses.

The fact that there are differences between the central and seasonal scenarios on a uniform losses basis does not, however, affect the analysis since no comparisons are made between these two results. The important comparisons are between the zonal and uniform outcomes under either the annual (central) or the seasonal scenario.

Supplementary question: Are the time-weighting factors applied the 3 snapshot periods used to represent a given season are the same as those used for the 3 snapshot periods used to represent a given year?

Answer

In response to the additional query, I can confirm that the snapshot period weighting used for each season of the seasonal scenario was the same as in the annual scenarios (i.e. Peak 10.4%, Mid 73.8% and Trough 14.8%).

Appendix 3 – Impact of proposals on emissions

Basis of analysis

1.1. The following three tables set out the DTI calorific values and typical conversion efficiencies used to derive both greenhouse emission factors and air quality emission factors. Those factors are used to calculate the changes in carbon emissions, sulphur dioxide (SO2), and nitrogen oxide (NOx) emissions which are reflected in the analysis in chapter 4.

Table 1: Conversion factor for grid electricity

Fuel Type	Units	Kg CO2 per unit	Kg C per unit
Grid electricity	kWh	0.43	0.12

Source: DEFRA, Guidelines for Company Reporting on Greenhouse Gas Emissions July 2005

Table 2: Greenhouse emission factors for electricity generation

	Natural Gas (CCGT)	Natural Gas (OGCT)	Oil	Coal	Unit
CO2	14000	14000	19000	24000	g/GJ
Assumed conversion efficiency	51	22	29	33	%
Emission Factor	0.36	0.84	0.86	0.96	tCO2/MWh

Source: CO2 figures are from the Digest of UK Energy Statistics – Annex B. DTI 2000. Assumed conversion efficiencies are based on Ofgem estimates.

Table 3: Air quality emission factors for electricity generation

	Natural Gas (CCGT)	Natural Gas (OGCT)	Oil	Coal	Unit
SO2	1	1	400	480	g/Gj
Assumed conversion efficiency	51	22	29	33	%
Emission Factor	0.01	0.02	4.97	9.16	kg SO2/MWh
NOx	55	55	100	230	g/Gj
Assumed conversion efficiency	0.36	0.84	0.86	0.96	%
Emission Factor	0.39	0.90	1.24	2.51	kg NOx/MWh

Source: CO2 figures are from the Digest of UK Energy Statistics – Annex B. DTI 2000. Assumed conversion efficiencies are based on Ofgem estimates.

1.2. There will be variations in sulphur content of the fuel, different combustion characteristics and the presence of pollution control equipment will affect the figures. For pumped storage we are assuming a zero emissions factor as emissions would have already been taken into account. Under other generation the change in losses is very small and an accurate emissions factor would be difficult to attribute without more detail of the generation included under this category.

Comparison of OXERA scenarios

1.3. The following section sets out tables highlighting the breakdown of changes in emissions by year and scenario. These are discussed below.

Table 4: P198 - Emission changes by fuel type as a result of zonal loss charging 2006-2011[21]

	2006[22]	2007	2008	2009	2010	2011
Annual Changes in Losses (GWh)	-90	-235	-107	-420	-73	-163
CO2 changes (Mt CO2)	0.14	-0.25	-0.01	-0.31	-1.19	-0.29
Carbon changes (MtC)	0.04	-0.07	0.00	-0.08	-0.32	-0.08
Value of changes @ £35 / tC. (£m)	£1.3	-£2.4	-£0.1	-£2.9	-£11.3	-£2.8
Value of changes @ £70 / tC. (£m)	£2.6	-£4.8	-£0.1	-£5.8	-£22.6	-£5.5
Value of changes @ £140 /tC. (£m)	£5.2	-£9.6	-£0.3	-£11.7	-£45.3	-£11.1
SO2 change (Kt)	2.54	-2.53	0.49	-2.36	-20.64	-2.90
NOx change (Kt)	0.55	-0.68	0.07	-0.71	-4.83	-0.74

[21] Based on July report, central scenario

[22] In 2006 under P198 there is an overall decrease in losses, however this is from a 364 GWh saving in CCGT and 6GWh from pumped storage, but an increase of 274 GWh from coal generation and 6 GWh from oil. As coal generation has a higher emissions factor for carbon, SO_2 and NOx overall the emissions of these will increase.

Table 5: P203 - Emission changes by fuel type as a result of zonal loss charging 2006-2011[23]

	2006[24]	2007	2008	2009	2010	2011
Annual Changes in Losses (GWh)	-504	-383	-512	-559	-559	-272
CO2 changes (Mt CO2)	0.03	-0.20	-0.25	-0.38	-2.33	-0.23
Carbon changes (MtC)	0.01	-0.05	-0.07	-0.10	-0.64	-0.06
Value of changes @ £35 / tC. (£m)	£0.2	-£1.9	-£2.4	-£3.7	-£22.2	-£2.2
Value of changes @ £70 / tC. (£m)	£0.5	-£3.7	-£4.8	-£7.3	-£44.5	-£4.4
Value of changes @ £140 /tC. (£m)	£1.0	-£7.5	-£9.6	-£14.7	-£89.0	-£8.8
SO2 change (kt)	2.51	-0.65	-0.53	-2.31	-31.38	-0.88
NOx change (kt)	0.39	-0.30	-0.32	-0.75	-7.48	-0.30

Table 6: P204 - Emission changes by fuel type as a result of zonal loss charging 2006-2011[25]

	2006	2007	2008	2009	2010	2011
Annual Changes in Losses (GWh)	-231	-97	-279	-385	-122	-124
CO2 changes (Mt CO2)	-0.09	-0.03	-0.13	-0.17	-0.54	-0.06
Carbon changes (MtC)	-0.03	-0.01	-0.03	-0.05	-0.15	-0.02
Value of changes @ £35 / tC. (£m)	-£0.9	-£0.3	-£1.2	-£1.6	-£5.1	-£0.6
Value of changes @ £70 / tC. (£m)	-£1.8	-£0.5	-£2.4	-£3.2	-£10.3	-£1.2
Value of changes @ £140 /tC. (£m)	-£3.5	-£1.0	-£4.9	-£6.5	-£20.6	-£2.4
SO2 change (Kt)	-0.14	0.12	-0.42	-0.47	-7.54	-0.26
NOx change (Kt)	-0.12	-0.01	-0.20	-0.26	-1.79	-0.11

[23] Based on July report, seasonal scenario
[24] Under P203 in 2006 there is an overall decrease in losses, however this is from a 773 GWh saving in CCGT and a 7 GWh saving from pumped storage, but an increase of 272 GWh from coal generation and 5 GWh from oil
[25] Based on September report, seasonal scenario

1.4. Tables 4 and 5 highlight that for P198 and P203 there is an increase in carbon, SO2 and NOx emissions in the first year, this is caused by an increase in losses from coal generation. The overall savings in the first year are from the reduction in gas generation losses. From 2007 onwards gas is favoured over coal. The reduction in losses from coal generation has a beneficial environmental impact with savings in carbon, SO2 and NOx emissions.

1.5. The fuel impacts are greater under P203 than P198 due to the more focused reallocation of losses during different times of the year. From 2007 onwards there is a larger movement away from coal generation in comparison to the central scenario. This results in a higher annual emissions savings in P203 scenario from 2008.

1.6. Table 6 highlights that for P204 there is also fuel switching from coal to gas, particularly at the end of the time period. The despatch signals under the P204 are weaker than the signals under P198 and P203, resulting in lower loss savings and avoided emissions. In 2006 however there is not an initial growth in emissions because under the P204 losses from coal generation do not initially increase.

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.[26]

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[27].

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[28]; and
- The interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[29]

[26] entitled "Gas Supply" and "Electricity Supply" respectively.
[27] 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.
[28] 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.
[29] The Authority may have regard to other descriptions of consumers.

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:

- Promote efficiency and economy on the part of those licensed[30] 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 Regulation31 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.

[30] Or persons authorised by exemptions to carry on any activity.
[31] 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.

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.

Network Mapping Statement

The document established by Elexon on behalf of the BSC Panel to map power flows on the GB transmission system by node.

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 Adjustments (TLMOs)

TLMOs are a component of the formulae used to calculate TLMs. TLMOs are used to calibrate the TLMs such that 45% of total actual losses are allocated to generators and 55% of total actual losses are allocated to suppliers.

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 Factor Agent (TLFAs)

The TLFA would run the Load Flow Model

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.

Transmission Owners (TO)

Companies which own and operate transmission assets. Currently there are three electricity TOs; NGET, SP Transmission Ltd and Scottish Hydro Electric Transmission Ltd.

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:

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

1.2. Please send your comments to:

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