A REVIEW OF LE/VENTYX'S COST-BENEFIT ANALYSIS OF MODIFICATION P229

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1 Executive Summary

The Brattle Group has been asked by Ofgem to review the cost-benefit analysis commissioned by Elexon on behalf of the Balancing and Settlement Code (BSC) Modifications Group and carried out by London Economics and Ventyx (LE/Ventyx). The main purposes of this review are to provide a view on the robustness of the analysis and conclusions presented by LE/Ventyx and to identify whether and, if so, what additional quantitative analysis might be required for the Ofgem assessment.

The analysis carried out by LE/Ventyx examined the likely implications for the GB electricity market from the adoption of the BSC Modification P229 "Introduction of a seasonal Zonal Transmission Losses scheme". The LE/Ventyx analysis was set out in a report (hereafter referred to as the 'LE/Ventyx report')[1] and submitted to the Authority as part of the Final Modification Report (FMR) on the proposals.

Our overall conclusion is that the conclusions presented by LE/Ventyx are robust and based on an appropriate methodology. Whilst there are inevitably some areas where the analysis could have been improved, we do not consider that these shortcomings will have a material effect on LE/Ventyx's finding that the introduction of P229 would lead to a net benefit under most plausible scenarios.

Wider context for this report

This report forms part of a broader Ofgem project to assess P229 against the Applicable BSC objectives and its wider statutory duties. Ofgem has commissioned three studies:

- Lot 1: CBA review and assessment (this report);
- Lot 2: Additional Scenario Analysis; and
- Lot 3: Further assessment of impacts.

As noted above, one of the objectives of this work stream is to identify whether there any gaps or deficiencies in the LE/Ventyx report that could be addressed by additional modelling. Gaps may, for example, have emerged as the result of policy decisions reached after the LE/Ventyx study was completed. We have identified two additional scenarios that we consider it would be helpful to analyse[2] and this additional modelling will form the basis of the Lot 2 analysis to be undertaken by Redpoint Energy. The third work stream – which The Brattle Group will also undertake – pulls together the results from the LE/Ventyx report and the additional analysis described above, to produce both qualitative and quantitative assessments of the impacts of zonal losses on customers, renewables, security of supply, cost of capital and embedded generation. This work will feed in to Ofgem's own assessment of the merits of P229.

As part of our terms of reference, Ofgem asked us to consider:

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[1] 'Cost Benefit Analysis of Modification P229: Changing to Zonal-Seasonal Transmission Loss Factors, Report Version 1.0 A report for Elexon by London Economics and Ventyx'.

[2] These scenarios are described at the end of the executive summary.

- Were the terms of reference appropriate and were these were fulfilled, paying attention to those aspects that addressed criticism to previous analysis[3]?

- Was the methodology used appropriate and how robust are the results?

- Are there any gaps that should have been covered in the analysis?

- How appropriate were any assumptions made?

- Are the conclusions drawn appropriate?

We also considered criticisms of LE/Ventyx's analysis raised by third-parties. Note that we were not asked to consider the merits of the proposed Modification either in isolation or in relation to the Applicable BSC Objectives – this task is to some extent, however, picked up under the third work stream.

We were able to put written questions to LE/Ventyx via Ofgem and Elexon and also participated in a conference call with them. To reduce the burden on both Ofgem and LE/Ventyx, we did not put questions to LE/Ventyx on issues that did not seem to have a material effect on the outcome of the study.

LE/Ventyx's terms of reference

We consider that the terms of reference issued by the BSC Modification Group were reasonable. We also recognise that both the P229 Modification Group and the BSC Panel concluded that the LE/Ventyx analysis was fit for purpose.

We agree that LE/Ventyx have fulfilled all the most important aspects of the terms of reference that it was set. There are a number of minor areas where LE/Ventyx's analysis appears only partially to fulfil the terms of reference.[4] However, none of these omissions is significant in terms of the overall conclusions.

LE/Ventyx's methodology

LE/Ventyx have considered the impact of zonal losses over the ten-year period 2010/11 to 2020/21. They have calculated what the difference in total generation costs would be with and without seasonal zonal losses, calculated using both the Proposed and Alternative P229 Modifications.[5] This has been achieved by means of load flow modelling to determine how zonal losses might develop over this period. LE/Ventyx have separately investigated the potential impact on demand by considering the effect that the change in prices due to zonal losses would have on the level of demand in different regions. For the longer term, LE/Ventyx have considered the extent to which zonal losses might affect: (a) new plants (where and how many are built); and (b) to some extent, the transmission system.

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[3] Specifically, our critique of the Oxera cost-benefit study in relation to P198, P200, P203 and P204, see http://www.ofgem.gov.uk/Licensing/ElecCodes/BSCode/Ias/Documents1/20081002_Brattle_losses_report.pdf

[4] For example, there is no analysis of the impact of zonal losses broken down by fuel type or generator size.

[5] Although for the Alternative methodology, they only looked at one scenario.

LE/Ventyx have also estimated the total implementation and operating costs for BSC Parties and the central systems of adopting zonal loss factors.

LE/Ventyx's main findings

LE/Ventyx found that the introduction of P229 would result in a number of benefits being realised by the system overall, specifically through short-term redespatch benefits and a demand response. LE/Ventyx generally found that both the types of seasonal zonal losses proposed under P229 would, to varying extents, reduce the total generation costs associated with meeting a given level of demand. There was only one scenario where total generation costs increased and, even then, the increase was transitory – it occurred only in 2012/13 and 2016/17 in the low gas scenario. Moreover, because LE/Ventyx's estimates of the implementation and operating costs associated with zonal loss factors were relatively low, LE/Ventyx found that all the cases it studied led to a positive present value for the net benefits of introducing zonal losses.

LE/Ventyx also concluded that zonal losses were unlikely to result in large efficiency gains with respect to generator siting decisions and reduced costs of the transmission network. Zonal losses simply strengthen the existing locational signals in the existing (zonal) Transmission Network Use of System (TNUoS) charges, and they are unlikely to introduce any additional efficiency effects with respect to plant location. LE/Ventyx also concluded that zonal losses would have no discernable impact on renewables.

As regards distributional effects, LE/Ventyx concluded that zonal loss charging would result in significant transfers between market participants in 2011/12, the year that they assumed that zonal losses would be introduced. This is the only year for which LE/Ventyx explicitly investigated distributional effects but it is the year where the actual distributional effects compared to the previous year will be greatest. Generators in the north and suppliers in the south would face increased loss payments whilst, conversely, generators in the south and suppliers in the north would pay less for losses.

Modelling methodology

We have concluded that LE/Ventyx's modelling methodology is a generally appropriate approach and reproduces the main features of P229 and P229 Alternative.

There are two ways in which their methodology differs from that envisaged under P229 and P229 Alternative but neither of these is likely to have any material impact on the results. The first difference relates to the number of periods used in the analysis. LE/Ventyx used 8760 hours whereas the modifications refer to some unspecified set of "Sample Settlement Periods". Clearly, it was not possible to model the sample periods since they have not been defined. The second difference relates to the use of nodal average prices rather than uniform marginal prices to estimate, in conjunction with the change between uniform and zonal loss factors, the (very modest) impact of P229 on demand.

There is a further issue relating to the way that LE/Ventyx have assumed that generators will take account of zonal loss factors in the offers that they make. In order to reduce the modelling requirements to manageable proportions, LE/Ventyx have included the transmission loss factors (TLFs) rather than the transmission loss multipliers (TLMs) in generators' offers. The TLMs are derived by adding a uniform adjustment to the TLFs so that 45% of actual losses are recovered from generators. The TLMs with uniform losses are around 0.6% and the TLFs are zero, so that prices including TLMs are higher than those including TLFs. Conversely, the zonal TLFs are around 0.5% lower than the zonal TLMs. This means that the change in prices between uniform and zonal losses is always higher if TLFs rather than TLMs are taken into account. Since it is the TLMs that determine the volumes with which a generator is credited and hence its revenues, it is these, rather than the TLFs, that theoretically should be included in generators offers. However, this would have involved modelling each hour of each year in an iterative fashion, which would not have been practical. It is also true that generators would have to estimate TLMs for each period since these are only determined ex post but this should be reasonably straightforward since they will receive hourly data on the TLMs allocated to them, which should provide a good basis for making forecasts.

For most purposes, the inclusion of TLFs rather than TLMs is likely to have only a negligible impact on the outcomes (we estimate around 1%) but this is not true with regard to wholesale prices. LE/Ventyx found that zonal losses led to price increases in all years and scenarios. However, our analysis suggests that had TLMs be included instead then prices might have instead decreased or, at any rate, stayed broadly constant. This finding is of considerable importance when it comes to assessing the impact of P229 on consumers and also means that LE/Ventyx are likely to have over-estimated the distributional effects of zonal losses (since these also depend on wholesale price changes).

LE/Ventyx's inputs

Over a year has passed since LE/Ventyx were commissioned to produce a report and so it is not surprising that some of the assumptions LE/Ventyx adopted when they were beginning their analysis, which we assume was in April/May 2009, are now somewhat out of date. For example, the government's transmission access review has been completed with the conclusion that a "connect and manage" approach is the best way forward. The continued use of such a scheme is likely to bring forward the connection of some renewable generation, increasing flows on the transmission system from what they would otherwise have been and this may, in turn, affect transmission losses. However, we conclude that the range of assumptions assessed by LE/Ventyx is generally sufficient to provide confidence in the robustness of the results, particularly once our recommended additional analysis is completed.

It might have been helpful to have carried out a sensitivity on demand levels. In general, discrepancies in demand forecasts per se are not important, provided that overall generation capacity is adjusted to maintain a reasonable capacity margin. However, in analysing the evolution of loss factors the fact that higher demand requires higher levels of new capacity could have an impact on the results in later years since the loss factors for these years will depend on where these new plants are assumed to be located. Nonetheless, we accept that it is highly unlikely that a demand sensitivity would have resulted in a change in overall conclusions and, hence, that its omission is not a significant issue.

More importantly, LE/Ventyx have adopted very conservative assumptions regarding the development of offshore wind farms. By 2020/21, LE/Ventyx assume that only 5.3 GW of offshore wind would be on-line under their reference case, and this only rises to 6.3 GW under their "aggressive offshore wind" scenario. This is under 50% of the offshore capacity included in NGET's April 2010 Transmission Networks Quarterly Connections Update (TNQCU). It is also inconsistent with the assumptions adopted by the Department of Energy and Climate Change (DECC) in the analysis underlying the conclusions of its transmission access review, which assumed that over 13 GW of offshore wind would have been constructed by 2020. Whilst we accept that the outcome of the round 3 tenders was not known at the time that LE/Ventyx undertook their analysis, we still consider that the lack of a scenario with higher offshore wind capacities constitutes a gap in the analysis that should have been apparent at the time of the analysis. This view is reinforced by concerns expressed by the Modification Group on this topic. [6]

Finally, we note that there has been considerable criticism of the discount rate used by LE/Ventyx[7] – 4.42% real after tax, with sensitivities at 3.5% and 2.5%. Perhaps the most important point to note is that the precise choice of discount rate has little impact on LE/Ventyx's finding that the introduction of zonal losses would generate net benefits. Even under the scenario with by far the lowest net benefit (the "low gas" scenario) the discount rate would have to exceed 38% before the net benefits would disappear. More generally, we consider that the range of discount rates explored by LE/Ventyx is probably broadly appropriate because of two offsetting effects. The main benefits associated with the introduction of zonal losses relate to their impact on generators. The weighted average cost of capital (WACC) for generators is typically higher than for transmission companies, on which LE/Ventyx base their discount rate, suggesting that the discount rate might be too low if it was intended to approximate to a generator's WACC. However, we consider that it would be inappropriate to use a WACC to discount production costs because the WACC represents the appropriate discount rate for cash flows to equity and debt holders, which depend on the difference between revenues and costs. The difference between revenues and costs is inherently more volatile than either revenues or costs, hence a lower discount rate than the WACC should be used to discount production costs.

Critique of LE/Ventyx's main findings

P229 produces a benefit because a system of zonal losses better reflects the losses each plant causes. With zonal losses, more efficient despatch is possible, since the rational outcome is for despatch to be based on costs *including* the cost of losses. In other words, generators should include the changed cost of losses in their offers and this may affect how they are despatched. On the demand side, to the extent that consumers are sensitive to changing prices, then they will also respond appropriately to zonal loss signals. Consequently, the more TLFs approximate the actual losses caused by a plant or a consumer, and are taken into account in their production or consumption, the more efficient the system will be and the greater will be the benefits relative to a system of uniform losses.

LE/Ventyx concluded that zonal losses are unlikely to have any significant impact on generators' siting decisions. We agree with this conclusion. As regards the potential impact of zonal loss factors on renewables, we agree with LE/Ventyx that losses are unlikely to be the dominant determinants of renewables growth. However, we cannot rule out the possibility that

[6] See, for example, page 50 of the P229 Assessment Report.

[7] See, for example, page 45 of the P229 Assessment Report. The Modification Group assessed the impact of adopting a 7.2% discount rate and found that it reduced the NPV of the reference scenario (excluding NOx and SOx benefits) by £6.4 million or around 13%.

zonal loss factors might deter some projects in the north of GB that were only marginally profitable with uniform loss charging. Nonetheless, LE/Ventyx's finding that the introduction of zonal losses would only have a marginal impact on renewables seems reasonable.

Overall, therefore, we believe that LE/Ventyx's conclusions on the benefits of P229 Original and Alternative are robust. However, there are two areas where we believe further investigation may be required as part of Ofgem's assessment of the proposals:

- **Offshore wind capacities:** a sensitivity should be run to investigate the impact of adding additional offshore wind capacity so that the 2020 capacity is consistent with the offshore wind tenders that have taken place (rounds 1-3) and backing off an equivalent volume of conventional generation, so that the effective capacity margin is maintained. We suggest that 15 GW of offshore wind should be included by 2020 (approximately 10 GW more than included in the LE/Ventyx reference scenario), spread around GB in line with the Round 3 capacity allocations.

- **Accelerated renewables** Since LE/Ventyx undertook their analysis, the government has announced that it is intending to implement an approach to transmission access that is likely to result in at least some renewable plants connecting to the transmission system before all the wider reinforcements associated with them are completed. We consider that it would be helpful to run a sensitivity whereby transitory congestion is assumed to occur as a result of this effect to see whether it increases, decreases or leaves unchanged the impact of introducing zonal losses. We suggest that this scenario should be an extension of the offshore wind scenario described above, but with around double the capacity of onshore wind in Scotland assumed by LE/Ventyx.

Following our recommendation to Ofgem that these additional cases should be studied, they have been analysed by Redpoint under the Lot 2 study.

2 Introduction

A BSC modification proposal to introduce locational allocation of variable transmission losses (P229) has been submitted to the Authority. The proposal incorporated both the Original modification and an Alternative developed by the Modification Group. As part of the assessment procedure for these proposals, LE/Ventyx were commissioned by Elexon to undertake a cost benefit analysis. The LE/Ventyx analysis of P229 Original was set out in a report[8,] and, subsequently, an annex was added that provided an analysis of P229 Alternative. Both the report and the annex were submitted to the Authority as part of the Final Modification Report (FMR) on the proposals on 12 March 2010

Some aspects of the LE/Ventyx analysis were criticised by a number of respondents to Elexon's consultations and by members of the P229 Modification Group. The main criticisms concerned the discount factor adopted by LE/Ventyx and the relatively low capacity of offshore wind generation that was assumed to come on line by 2020/21 under all the scenarios considered.

In order to facilitate the Authority's assessment of these modifications, Ofgem has commissioned three studies:

- Lot 1: CBA review and assessment (this report);
- Lot 2: Additional Scenario Analysis; and
- Lot 3: Further assessment of impacts.

The Brattle Group was selected by Ofgem to undertake Lot 1. This report contains our findings. In reviewing LE/Ventyx's report and annex, we have also taken into account the comments made by respondents to the various consultations, the assessment and modification reports (to the extent that they deal with LE/Ventyx's cost benefit analysis) and LE/Ventyx's replies to a number of questions that we raised. All the material on which we have relied is available, or will be available, on either Elexon's or Ofgem's websites.

We have also been selected by Ofgem to undertake Lot 3. A separate report pulls together the results from the LE/Ventyx report and the additional Redpoint analysis, undertaken for Lot 2, to produce both qualitative and quantitative assessments of the impacts of zonal losses on customers, renewables, security of supply, cost of capital and embedded generation.

2.1 Treatment of losses – current and proposed

Transmission losses can be divided into two types:

- *Fixed losses* are those which do not vary significantly with power flow. In transformers, the losses arise from magnetising the iron core. In overhead lines, they include losses dependent on the voltage levels, length of line and climatic conditions.

[8] LE/Ventyx, 'Cost Benefit Analysis of Modification P229: Changing to Zonal-Seasonal Transmission Loss Factors", October 2009.

- *Variable losses* arise through the heat caused by current flowing through transformers and lines. Variable losses increase with the current (and associated power flow) and the length of line in which it flows.

Transmission losses are allocated to BSC Parties ('Parties') as part of their Trading Charges, by adjusting individual BM Unit Metered Volumes in Settlement through a Transmission Loss Multiplier (TLM). Under the current BSC provisions, both fixed and variable transmission losses in each Settlement Period are allocated to Parties on a 'uniform' (non-locational) basis in proportion to each Party's metered energy. In reality, generators further away from large load centres will create larger variable losses than generators close to load. Therefore, the current uniform allocation of transmission losses does not take account of the extent to which individual Parties are responsible for such losses. In simplified form, the TLMs can be represented by the following equation:

$$TLM = 1 + TLF + TLMO$$

The transmission loss factors (TLF) are currently set to zero but are included in the BSC so as to provide the possibility of including unit specific loss factors. The Transmission Losses Adjustments (TLMO) are calculated separately for suppliers ($TLMO^-$) and for generators ($TLMO^+$). The $TLMO^+$ is the same for all generators and the $TLMO^-$ is the same for all suppliers. They are set so as to ensure that generators are allocated 45% of actual losses and suppliers are allocated the remaining 55%.

The modification, and its alternative, proposes allocating the costs of variable transmission losses on a zonal basis so that all the generators (or suppliers) within a zone are allocated the same TLM but the TLMs vary between zones. The grid supply point (GSP) groups that are used to levy demand Transmission Network Use of System Charges (TNUoS) would define the losses zones. The zonal loss factors would be set ex-ante, based on data from the previous year, and would vary by season. P229 alternative involves scaling the loss factors to ensure that no generator is credited with producing more electricity than it has actually generated, as can be the case if negative TLFs are allowed.

2.2 Structure of the report

The rest of this report is structured as follows. Section 3 discusses the terms of reference set for the LE/Ventyx study by the BSC Modification Group for P229. It considers whether the terms of reference were appropriate and the extent to which LE/Ventyx fulfilled them. The next section, Section 4 describes the methodology that LE/Ventyx adopted for their cost-benefit analysis including the scenarios it studied. We also discuss to what extent LE/Ventyx's methodology was appropriate. Section 5 deals with LE/Ventyx's input assumptions: were they reasonable at the time the studies were undertaken and are they still appropriate? This naturally leads on to a discussion of the results that LE/Ventyx presented, which is covered in Section 6. We discuss the concerns regarding LE/Ventyx's analysis that have been raised by interested parties (Section 7). Finally, in Section 8, we consider to what extent LE/Ventyx's conclusions are robust and whether there are any gaps in their analysis.

3 Elexon's terms of reference

3.1 Summary of terms of reference

3.1.1 Process by which LE/Ventyx was retained

Before describing the terms of reference given to LE/Ventyx, we briefly summarise the process by which LE/Ventyx were retained to perform the work.

Modification proposal P229 was submitted on 28 November 2008 by RWE npower to the BSC Panel. The initial written assessment of P229 was published on 13 December 2008 and agreed the expenditure required for an external consultant to help estimate the costs and benefits of the proposal. Subsequently, the BSC Panel submitted the proposal to an Assessment Procedure to be conducted by the P229 Modification Group. The Modification Group agreed that modelling of the likely cost-benefit impact on allocation of Transmission Losses under P229 should be performed to support its development and assessment of P229.

In January 2009 the terms of reference for the cost-benefit analysis were finalised by the Modification Group for P229 and published by Elexon as "Cost-Benefit Analysis Requirements Specification for Modification Proposal P229". This document was the basis for a competitive tender process for the performance of the cost-benefit analysis. LE/Ventyx were awarded the work at the conclusion of this process.

The terms of reference focused on the original P229 Modification, and this was the focus of the main LE/Ventyx report. In the course of developing options for P229 Alternative the Modification Group subsequently asked LE/Ventyx to extend their analysis to include a case using scaling to eliminate negative TLFs. P229 Alternative was covered in an annex to the LE/Ventyx report, which was issued at the same time as the main report on 3 November 2009. Both the P229 Modification Group and the BSC Panel concluded that LE/Ventyx's analysis met its terms of reference.

3.1.2 Terms of reference

The terms of reference required the consultant to perform a transparent, credible and robust analysis to quantify the net benefit of implementing P229 to the GB electricity market over the ten year period April 2011 to March 2021. This analysis was to be based on the calculation of seasonal zonal TLFs for each year so as to enable the market response to these TLFs to be quantified and the effect of this response on the volume and costs of losses to be assessed. As discussed above, the scope of work was later extended to include analysis of the impact of seasonal zonal loss factors.

The consultant was required to consider the impact on generation (by location, fuel type, and size) and on demand (by location, type – domestic/non-domestic, and level) and on the environment.[9] However, the consultant was required to quantify the effect of zonal TLFs on the

[9] Note that, consideration of the impact of P229 on consumers was explicitly excluded from the terms of reference. See section 2.1 of Elexon's "Cost-Benefit Analysis Requirements Specification".

transmission system in terms of their impact on transmission constraints and the limits that transmission constraints might place on the ability of generation and demand to respond to locational signals.

In analysing the impact of zonal losses on generation, the consultant was required to quantify its impact on:

- The operation and despatch of existing plants (e.g. through increased/decreased production, and decisions to mothball or close plants);
- The growth of future generation (e.g. fuel mix, siting and investment decisions for new plant, and decisions to run previously mothballed plant) and the level of plant margin available to the System Operator;
- Imports and exports via interconnectors;
- Generators connected to 132 kV compared to the impact on geographically proximate generators connected to 275kV and 400kV;
- Wholesale electricity prices; and
- The cost of carbon emissions to generators.

The consultant was required to quantify the costs and benefits over the first five years in detail but was allowed to use extrapolation for later years providing the approach taken in doing so was clearly described. The consultant was not obliged to use its own load flow model to estimate the annual zonal TLFs but if it chose to do so it had to demonstrate that the zonal TLFs for 2008/09 produced by the model were consistent with those provided by Elexon. The consultant was also required to demonstrate that the methodology it adopted for calculating annual zonal TLFs was consistent with the approach that would be adopted if P229 was implemented.

The terms of reference required the consultant to develop a "base case", under which P229 was not implemented, and a "change case", under which P229 is implemented. Apart from the treatment of transmission losses, the two cases were otherwise to be based on the same assumptions regarding market conditions over the ten-year study period (i.e. same fuel prices, fuel transportation costs, generation despatch, profile and growth, carbon prices, demand profile and growth, interconnector trade, and the transmission network) taking into account government policy on energy and the environment. The consultant was also asked to consider the following when deciding what assumptions to use:

a) Existing government energy and environmental policies;

b) Ofgem's System Operator Incentive Scheme;

c) National Grid's Seven Year Statement;

d) National Grid's Transmission Network Use of System charging methodology;

e) Information publicly available on offshore transmission developments or on new interconnector schemes; and

f) Perceptions of risk and the cost of capital in new investment decisions.

The consultant was required to perform sensitivity testing of the key assumptions to which it believed the analysis results were least robust and to provide the rationale for the sensitivities and full details on them.

The terms of reference also required the consultant to quantify the implementation costs of P229 to BSC Parties as a whole and to provide details of the methodology and assumptions involved. (Elexon would provide estimated implementation and operational cost estimates for various market participants - BSC Parties that had provided non-confidential data during the P229 impact assessment, BSC agents, National Grid and Elexon itself).

The consultant was also required to provide an assessment of the distributional impact of P229 throughout the analysis, including the magnitude and locational pattern of the distributional effects.

3.2 Were the terms of reference for LE/Ventyx's analysis appropriate?

The terms of reference given to LE/Ventyx were issued by the Modification Group and, as such, were presumably intended to provide analysis that would assist the BSC Panel and other Parties in reaching a decision as to whether or not to recommend the implementation of P229 Original or Alternative. We have assessed whether the terms of reference were likely to provide economic data applicable to an assessment of whether P229 would better facilitate the achievement of the Applicable BSC Objectives, which are:

a) The efficient discharge by the Transmission Company of the obligations imposed under the Transmission License;

b) The efficient, economic and co-coordinated operation of the GB transmission system;

c) The promotion of 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;

d) The promotion of efficiency in the implementation and administration of the balancing and settlement arrangements.

The terms of reference specifically excluded an analysis of the effect on consumers. In other words the Modification Group did not interpret the Applicable BSC Objectives to include the interests of consumers. Whether or not this is correct seem to be a legal issue on which we are not qualified to opine or comment.

Despite the fact that Applicable BSC Objective (c) relates to the promotion of competition, there was no explicit requirement to consider the effect of zonal losses on competition in generation in the terms of reference. This seems to us reasonable because the analysis required under the terms of reference e.g. the distributional analysis, naturally provides insights into the effect of zonal losses on various aspects of competition. Furthermore, we considered whether there would have been merit in requiring an analysis of the effects of zonal losses on the shape of the merit order. For example, if the introduction of zonal losses flattened the merit order this would increase the number of generators offering power at a similar price and, hence, foster competition. However, we concluded that, for a given geographic spread of generators of different fuel types, the effect of zonal losses on the merit order was very uncertain and highly dependent on fuel prices. Even relatively minor changes in coal and gas prices could have a larger effect on the merit order than the introduction of zonal losses. Hence, any effect of zonal losses on competition in generation is likely to be unstable and difficult to quantify with any certainty. Accordingly, it seems reasonable that such an analysis was left out of the terms of reference.

In a previous report for Ofgem critiquing the cost-benefit analysis carried out by a consultant for an earlier set of modifications proposing the introduction of zonal losses, we commented that it might have been appropriate for Elexon to ask the consultant undertaking the load flow modelling to analyse whether it was likely that locational signals would be over-stated through the combined effects of TNUoS charges and zonal losses. This analysis was subsequently undertaken by Ofgem itself, and, whilst it might have been interesting to see if the new analysis changed the conclusions, we accept that the exclusion is not significant.

Consequently, in general terms, we consider that the terms of reference were appropriate.

3.3 Did the LE/Ventyx analysis fulfil their terms of reference?

In Table 1 below we consider each of the requirements set out in LE/Ventyx's terms of reference and describe whether, and to what extent, it has been fulfilled by LE/Ventyx. We also recognise that both the P229 Modification Group and the BSC Panel[10] concluded that the LE/Ventyx analysis was "fit for purpose".

We agree that LE/Ventyx fulfilled all the most important aspects of their terms of reference and this is certainly true in respect of the key quantifications. However, there are number of more minor requirements that LE/Ventyx have only partially fulfilled. We return, in later sections of the report, to consider in more detail certain aspects of LE/Ventyx's analysis, in particular the credibility and robustness of their findings.

[10] Page 13 of the Final Modification Report states that the Modification Group "agreed that the CBA [cost-benefit analysis] fulfilled the Group's specified requirements and endorsed the CBA as robust and fit for purpose". Page 25 of the Final Modification Report states that the BSC Panel "agreed with the [Modification] Group that the P229 CBA was fit for the purpose of assisting in the assessment of P229".

Table 1: Were the Terms of Reference Fulfilled?

Requirement in Terms of Reference	Fulfilled by LE/Ventyx	Commentary	Significance of any omissions to overall assessment
Calculate a set of "evolved" Adjusted Seasonal Zonal TLFs for the period 2011/12 to 2020/21	Yes	The average zonal TLMs and the zonal TLFs were provided for each season of each year and each scenario.	N/A
Establish the sensitivity of the evolved TLFs to different future market conditions	Yes	LE/Ventyx analysed five sensitivities in addition to the "reference" case	N/A
All input data must be objectively derived from public sources	No	Fuel and carbon prices were Ventyx's proprietary forecasts.	None – Ventyx's assumptions were reasonable.
Quantify implementation costs of P229 to Parties as a whole	Yes	Yes	N/A
Quantify the extent to which the introduction of P229 would lead to movement of money between Parties over 2011/12 to 2020/21 and the magnitude and locational pattern of the movement	Partially	LE/Ventyx analysed the impact by zone on generation and demand in 2011/12. They did not consider the impact on specific Parties, nor how the effect might vary over time.	Limited – such an analysis would not change the overall conclusion. Moreover, as regards how the impact might change over time, it is likely that results presented provide a good indication of the effects that would be seen in other years since the loss factors remain relatively stable.
Present data highlighting the number of companies whose transmission losses payments would increase or decrease. The data should include breakdown by company type.	No	LE/Ventyx provided no analysis by company. They pointed out it is unclear what the impact on supply businesses would be: would they pass any effects through to customers or not?	Such analysis would not affect the assessment of the overall impact of introducing zonal losses.

Requirement in Terms of Reference	Fulfilled by LE/Ventyx	Commentary	Significance of any omissions to overall assessment
Take into account the distributional impact of Parties having to make decisions regarding the mothballing of plants	Effectively	LE/Ventyx assumed that zonal losses would have no effect on mothballing decisions.	None – this point is considered in our other report for Ofgem, and we agree that there would be very little or no impact.
Quantify the extent to which P229 would lead to a change in the volume and cost of transmission losses	Partially	LE/Ventyx provided information on the change in the volume of losses but not explicitly the cost impact.	None – it is not necessary to know the change in the cost of losses to assess the merits of the proposal.
Quantify the extent to which generators would alter plant operation and despatch including mothballing decisions	Yes	LE/Ventyx analysed the impact on generation levels in each zone and year.	N/A.
Quantify to what extent the growth of future generation would be impacted	Effectively	LE/Ventyx assumed that there would be no impact and provided some indicative calculations for 2009/10 to back this up.	Small – since LE/Ventyx's assumptions regarding the impact on P229 on investment decisions seems reasonable.
Quantify the impact on generation by location, fuel type and size of plant	Partially	LE/Ventyx provided data on the impact on generation by zone but not by fuel type or size of plant. However, LE/Ventyx did provide sufficient data for it to be possible to draw some broad brush conclusions on fuel type and size of plant – these can be derived by calculating capacity-weighted average load factors for different categories of generating plant.	No impact on the conclusions for the GB market as a whole.

Requirement in Terms of Reference	Fulfilled by LE/Ventyx	Commentary	Significance of any omissions to overall assessment
Quantify any impact on interconnectors	Effectively	LE/Ventyx assumed that there would be no impact.	Unlikely to be significant, given that interconnector capacity is a relatively small part of the overall capacity portfolio, and that there are likely to be flows in both directions.
Quantify whether the impact would vary depending on the voltage level at which generation connected	Yes	LE/Ventyx found that the largest flow changes occurred at high voltages, suggesting that, if anything, the impact of P229 would be greater for plants connected at 275 kV and 400 kV than at 132 kV.	N/A.
Quantify the impact on wholesale prices	Yes	LE/Ventyx analysed impact on peak and off-peak prices	N/A.
Quantify the impact on the cost of carbon emissions to generators	Effectively	LE/Ventyx assumed that there would be no impact on carbon *prices* from introducing zonal losses	None – LE/Ventyx's assumption on carbon prices is reasonable and it does quantify the impact on carbon emissions so that it is possible to calculate a cost impact.
Quantify the impact on the level of plant margin	Effectively	Since LE/Ventyx assume there will be no changes to plant closure and build decisions and that P229 would reduce line losses and congestion, it concludes that there would likely be a small positive but insignificant impact on capacity requirements.	Limited – it is not obvious that changing the plant margin would materially affect the findings unless the demand assumptions were changed.

Requirement in Terms of Reference	Fulfilled by LE/Ventyx	Commentary	Significance of any omissions to overall assessment
Quantify the impact on the location, type and level of demand	Partially	LE/Ventyx provide data on the present value benefit to demand as a whole and by location for 2011/12. Moreover, not clear that data necessary for such an analysis is available.	Very limited – given that effect on overall demand is small.
Complete a year's sensitivity (2011/12) on what impact demand side effects have on generation	No	Given the demand elasticity assumed by LE/Ventyx (-0.25) and the low impact it had overall it seems unlikely that such a sensitivity would have produced materially different outcomes.	Small – given the demand elasticity assumed by LE/Ventyx (-0.25) and the low impact it had overall it seems unlikely that such a sensitivity would have produced materially different outcomes.
Quantify impact on transmission constraints	Yes	LE/Ventyx analyse the impact in terms of the number of hours of constraints	N/A.
Quantify impact of constraints on costs and benefits of P229 and to what extent response to its signals is limited by physical capacity of the system	Partially	LE/Ventyx produced data on the change in the number of hours with congestion resulting from P229.	Absence of cost quantification is likely to have under-estimated the benefits of zonal losses since LE/Ventyx generally found that congestion decreased.
Quantify impact on the cost of carbon due to transmissions losses from a stated current baseline	Partially	LE/Ventyx provide data on the change in carbon emissions due to P229 and the cost of carbon, so the cost impact can be calculated	None – as explained, the requested information can be calculated from what is provided.
Quantify impact on carbon emissions and other air pollutants, including estimate of carbon output and cost per year by plant type	Partially	LE/Ventyx provide data on the change in CO_2, NO_x and SO_x emissions but not on output and cost by fuel type	None – the relevant perspective for the assessment of the modification is its overall impact on emissions.

Requirement in Terms of Reference	**Fulfilled by LE/Ventyx**	**Commentary**	**Significance of any omissions to overall assessment**
Impact on renewable generation	Effectively	LE/Ventyx assume there will be no impact and this seems reasonable.	Very limited – we agree that P229 would only have an impact on investment decisions that were already marginal.
Impact of additional fuel transportation for plants moving location	Effectively	Since LE/Ventyx assume that plants will not move location, there is no impact.	None, since this assumption is supported by their analysis of locational inputs to new entry decisions

3.4 Conclusions on the terms of reference

We conclude that LE/Ventyx have fulfilled all the most important aspects of their terms of reference that it was set. There are a number of minor areas where LE/Ventyx's analysis appears only partially to fulfil the terms of reference. For example, there is no analysis of the impact of zonal losses broken down by generator fuel type or size. However, none of these omissions are significant in terms of the overall conclusions.

4 LE/Ventyx's Methodology

4.1 Overview of LE/Ventyx's Methodology

LE/Ventyx used detailed load flow modelling to analyse the impact of zonal losses throughout the analysis period (2011/12 to 2020/21). It then, separately, analysed the impact that zonal losses would have on demand.

4.1.1 Load flow modelling

For each year, the load flow modelling involved 3 separate model runs:

1) running LE/Ventyx's load flow model without optimising losses to derive results for uniform losses for each year (the "base case");

2) separately running LE/Ventyx's load flow model optimising losses for the previous year to derive hourly nodal TLFs which are then averaged to derive the seasonal zonal TLFs;

3) running LE/Ventyx's load flow model without optimising losses but including the seasonal zonal TLFs to derive results under P229 for each year (the "change case");

The calculation of the impact of the Modification on demand is carried out separately from the analysis of the impact on generation. Whilst it is not wholly clear from their description precisely what LE/Ventyx have done, we assume that it has carried out the following analysis. First, it estimates the change in consumption due to zonal losses. LE/Ventyx estimate a price elasticity for demand as a whole and uses this to determine the consumption impact from:

- the volume effect: the volume of electricity for which consumers have to pay changes as a result of the introduction of zonal losses. Since they are billed on a loss-adjusted basis, this equates to a price change; and

- the wholesale prices effect: wholesale prices change because generators respond to zonal loss signals.

LE/Ventyx then estimate the value of consumption under the base and change cases, using the relevant wholesale prices in each case. The impact of zonal losses is then simply the change in the value of consumption.

4.1.2 Implementation costs

LE/Ventyx estimate the implementation and ongoing costs of zonal losses based on data provided by Elexon (for the costs of the transmission owner, BSC Agents, Elexon and some BSC Parties) plus their own estimate of the costs for BSC Parties who had not provided data to Elexon (or whose data was confidential). In making their estimates for these Parties, LE/Ventyx relied upon an average £/kW value derived from data provided by Parties on man-days of effort required. For on-going operating costs for BSC Parties and Agents, LE/Ventyx assumed an annual cost of £160,000.

4.1.3 Comparing costs and benefits of zonal losses

LE/Ventyx calculate the annual benefits of zonal losses as the difference in production costs (including losses) between the base case and the change case plus the benefits from demand responding to the zonal loss charging. LE/Ventyx separately estimated the costs of avoided NOx and SOx emissions, on the basis of estimated marginal abatement costs and presents net present benefits both including and excluding these avoided costs. From these net benefits, LE/Ventyx subtract implementation costs in the first year that zonal losses are introduced and on-going costs for each subsequent year.

4.1.4 Longer term impacts

In terms of longer term impacts, LE/Ventyx considered the potential impact of zonal losses on:

- New investment decisions for both renewable and conventional technologies;
- Transmission capacity requirements; and
- Security of supply.

The potential impacts were generally assessed in a qualitative way, although the impact on investment decisions was backed-up by an analysis of the existing regional signals for new generation and how these would change with zonal losses.

LE/Ventyx concluded that there would be little impact on any of these longer term indicators and that any impact that did occur would likely be positive. For example, LE/Ventyx found that congestion and line flows were reduced with zonal losses, which suggests that transmission capacity requirements might, if anything, be reduced. Similarly, LE/Ventyx concluded that zonal losses would be "*akin to having additional generation and additional capacity available at certain times*" thus leading it to "*predict a likely small and positive but somewhat insignificant impact on capacity requirements*".[11] In other words, zonal losses would, if anything, improve security of supply.

LE/Ventyx were also of the opinion that zonal losses would "*have no discernable or estimable impact on the price of carbon*"[12] which, coupled with a fall in carbon emissions as a result of zonal losses, led it to conclude that the cost of carbon to generators would fall.

4.1.5 Distributional effects

To determine the distributional effects of P229, LE/Ventyx looked at the transfers between regions in 2011/12 without ascribing the effects to any particular players. Thus, for example, it looked at the changes in loss payments made by generators and suppliers in a particular zone and the net changes (generation plus demand) in that zone.

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[11] Page 203, LE/Ventyx report.

[12] Page 204, LE/Ventyx report.

4.2 Scenarios studied by LE/Ventyx

In addition to the reference scenario under P229 Original, which represents LE/Ventyx's view of the most likely outcome, six additional scenarios were analysed to test the robustness of the analysis to changes in assumptions. These scenarios explored the impact of:

- Higher gas prices – prices 30% higher than in the reference case;
- Lower gas prices – prices 30% lower than in the reference case;
- Volatile fuel prices – in any given year, all fuel prices were randomly higher (in 4 years), lower (in 3 years) or equal (in 3 years) to the reference case;
- Aggressive offshore wind – capacities were 20-25% higher than in the reference case;
- Alternative nuclear – higher new nuclear capacities: 5 new nuclear plant on line by 2020/21 compared to two[13] in the reference case; and
- P229 Alternative – the reference case but with the alternative approach to scaling incorporated i.e. all generators face positive loss factors.

Figure 1 and Figure 2 below illustrate the average change in generation and demand TLMs from the reference case for each scenario from 2011/12 to 2020/21. They show that the low gas and P229 Alternative scenarios have the greatest impact on TLMs and that this impact is predominantly in southern (London, South, S-East, S-Wales, S-West) or Scottish locations. In addition, the high gas scenario has a significant impact on TLMs in Scotland. For all zones, the impact on the sensitivities is higher for demand than generation.

[13] In the text describing the alternative nuclear scenario on page 104, it states that "one new nuclear generator was commissioned in 2017" under the reference case. However, in Table 4-8, another new nuclear plant is shown coming on-line in 2020.

Figure 1: Impact of sensitivities on generation TLMs

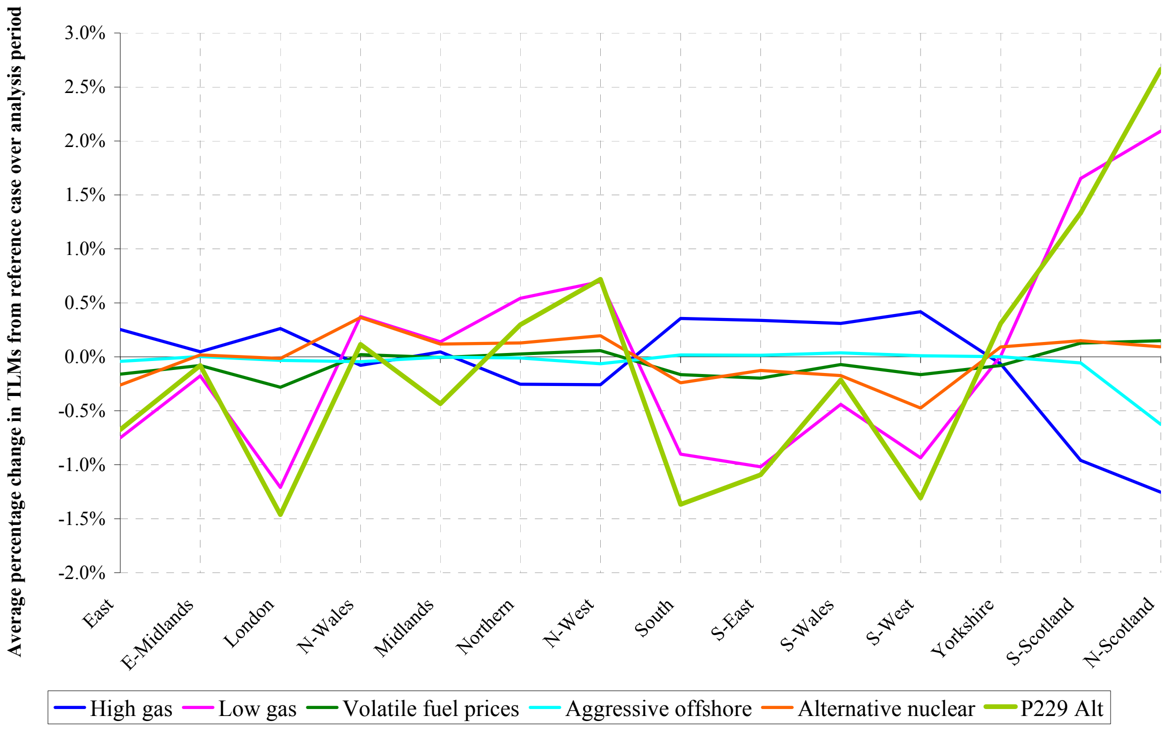
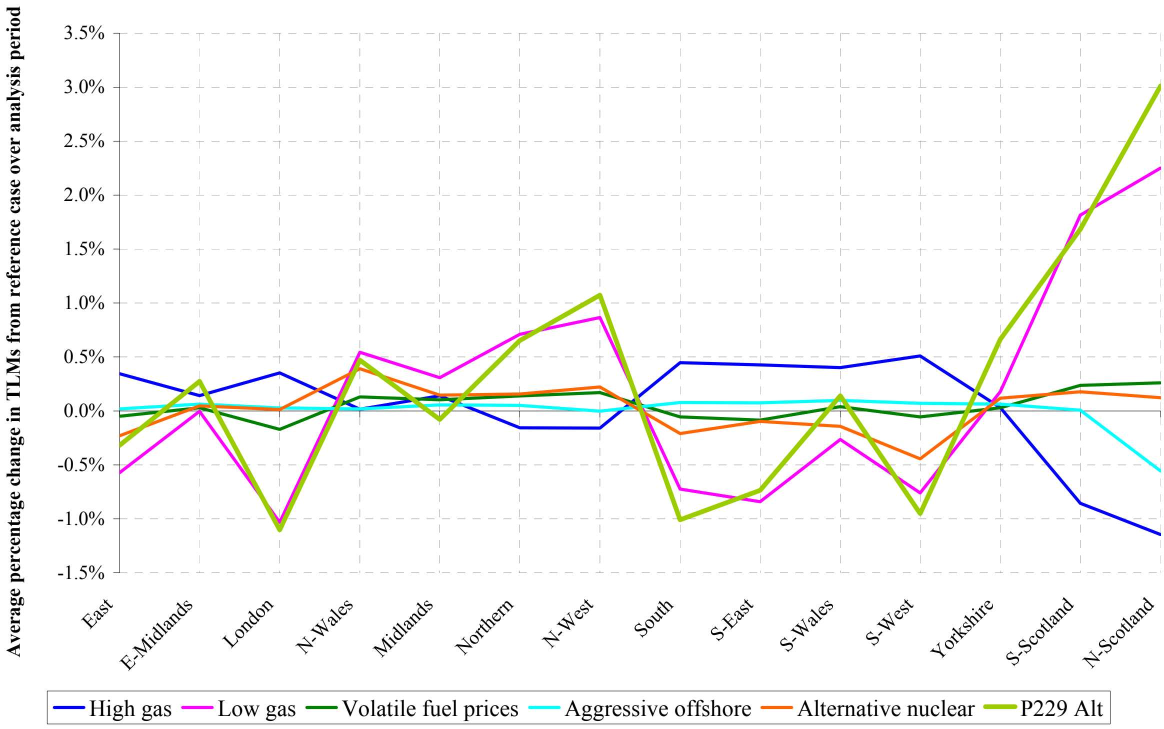


Figure 2: Impact of sensitivities on demand TLMs



4.3 Was LE/Ventyx's methodology appropriate?

We consider that LE/Ventyx's general approach to the analysis was appropriate. In particular, it mimicked what would occur if either P229 Original or Alternative were implemented and was consistent with the suggested approach in LE/Ventyx's terms of reference. However, we consider that there are a number of areas where the methodology could have been improved.

4.3.1 Load flow modelling

There are two ways in which the LE/Ventyx methodology differs from that envisaged under P229. However, we do not consider that either difference is likely to have had a material impact on the results presented.

The first issue is that the seasonal TLFs calculated by LE/Ventyx are based on an analysis of all 8760 hours in each year. By contrast, P229 envisages that "Sample Settlement Periods" will be used to derive the TLFs, although how many sample periods will be used to set the TLFs is not defined. Given the volatility of hourly loss factors (which the Siemens analysis demonstrated), it is unlikely that averaging over all hours will yield identical results to averaging over a sample of periods. On the basis of the available data it is not possible to predict how large an effect this is likely to be nor what impact it would have on the results reported by LE/Ventyx. However, it is likely to be very significantly less than the effect of other uncertain variables such as fuel prices and plant retirement and build decisions.

The second issue is that LE/Ventyx's modelling produces prices that differ by node, as a result of including the impact of both transmission constraints and loss factors. In fact, there is effectively a single GB wholesale price[14], which does not take account of transmission constraints and only reflects loss factors to the extent that they are internalised in the offers made by generators[15]. LE/Ventyx's approach effectively combines the wholesale market with the actions taken by the system operator to manage congestion. This approach should provide good estimates of transmission flows, final generator output and production costs, assuming that the market is perfectly competitive. In other words, in terms of these outputs it should not matter whether a generator initially schedules its output on the basis of contracts struck ignoring balancing requirements and then, subsequently, is contracted by the System Operator to adjust its output or whether the generator's schedule incorporates both elements from the beginning.

However, the wholesale price projections (used to determine demand effects) produced by this methodology are likely to differ to some extent from those that would have been obtained from an unconstrained schedule. Whilst the marginal price from an unconstrained schedule will always be lower than (or equal to) the marginal price from a constrained schedule, it is not necessarily the case that LE/Ventyx have over-estimated prices. This is because LE/Ventyx calculate an average constrained price rather than a marginal constrained price. It is not clear which of these two effects is likely to dominate and hence it is unclear whether LE/Ventyx have over- or under-estimated prices.

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[14] We say "effectively" because the GB wholesale market does not have a centralised mandatory auction but rather largely relies on bilateral trading. However, if the market is efficient, the price in bilateral trades should converge towards a single price and so the different mechanisms should yield approximately equivalent results, at least over the medium term.

[15] Of course, the commodity prices faced by consumers may vary by location if their suppliers pass through the effects of zonal losses but this will still yield a different outcome to that modelled by LE/Ventyx.

4.3.2 *Wholesale prices*

LE/Ventyx have assumed that generators take account of loss factors they face in the offers that they make. We agree that this is a reasonable approach since their imbalance position is measured on a loss-adjusted basis and hence it is rational to contract on this basis. This means that the effective price that generators receive is loss-adjusted.

In order to reduce the modelling requirements to manageable proportions, LE/Ventyx have included TLFs rather than TLMs in generators' offers. The TLMs are derived by adding a uniform adjustment to the TLFs so that 45% of actual losses are recovered from generators. The TLMs with uniform losses are around 0.6% and the TLFs are zero, so that prices including TLMs are higher than those including TLFs. Conversely, the zonal TLFs are around 0.5% lower than the zonal TLMs. This means that the change in prices between uniform and zonal losses is always higher if TLFs rather than TLMs are taken into account. Since it is the TLMs that determine the volumes with which a generator is credited and hence its revenues, it is these, rather than the TLFs, that theoretically should be included in generators offers. However, this would have involved modelling each hour of each year iteratively, which would not have been practical. It is also true that generators would have to estimate TLMs for each period since these are only determined ex post but this should be reasonably straightforward since they will receive hourly data on the TLMs allocated to them, which should provide a good basis for making forecasts.

For most purposes, the inclusion of TLFs rather than TLMs is likely to have only a negligible effect on the outcome. Using the simple model that we developed previously when critiquing Oxera's analysis of the impact of P198, P200, P203 and P204, we find that the impact is generally around 1%, as shown for the reference scenario in Table 2 below. Consequently, it is very unlikely that the use of TLFs rather than TLMs has had any significant impact on the NPV analysis presented by LE/Ventyx.

However, this is not true with regard to wholesale prices. In line with LE/Ventyx's results, our simple model suggests that zonal losses lead to price increases when TLFs are incorporated in generators' offers. By contrast, our analysis suggests that had TLMs be included instead then prices might have instead decreased as a result of zonal losses or, at any rate, stayed broadly constant. This difference is very significant when it comes to assessing the impact of P229 (and its alternative) on consumers. It also means that LE/Ventyx is likely to have over-estimated the distributional impact of zonal losses since this analysis depends in part on the change in wholesale prices.

Table 2: Estimated impact of incorporating TLFs rather than TLMs under the reference scenario

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Change in prices (£/MWh)										
TLFs	0.24	0.35	0.38	0.35	0.40	0.36	0.36	0.34	0.32	0.30
TLMs	-0.19	-0.06	-0.02	-0.04	0.00	-0.03	-0.03	-0.08	-0.13	-0.16
% change	-225%	-730%	-2577%	-1102%	-9100%	-1441%	-1178%	-519%	-346%	-291%
Change in CO2 (Mt)										
TLFs	-43.43	-38.25	-33.97	-34.64	-36.32	-34.46	-32.52	-28.63	-28.23	-23.75
TLMs	-43.14	-37.97	-33.73	-34.41	-36.14	-34.30	-32.24	-28.61	-28.02	-23.58
% change	1%	1%	1%	1%	1%	0%	1%	0%	1%	1%
Change in production costs (£ billion)										
TLFs	-12.78	-18.30	-11.15	-11.40	-10.47	-9.85	-10.32	-8.79	-9.46	-6.77
TLMs	-12.65	-17.98	-11.01	-11.24	-10.38	-9.84	-10.31	-8.65	-9.20	-6.73
% change	1%	2%	1%	1%	1%	0%	0%	2%	3%	1%
Change in despatch from coal-fired plants (TWh)										
TLFs	-5.07	-7.13	-3.34	-4.26	-1.98	-3.36	-3.61	-2.70	-2.17	-1.47
TLMs	-5.12	-7.23	-3.15	-4.33	-2.20	-3.43	-3.65	-2.74	-2.21	-1.53
% change	-1%	-1%	6%	-2%	-10%	-2%	-1%	-1%	-2%	-4%

4.3.3 Implementation and on-going costs

We acknowledge that estimating implementation costs is very difficult, giving the scarcity of data provided by Parties and the very wide divergence in cost estimates. LE/Ventyx used the limited data provided by Parties to estimate a cost per MW of generation and then used this to calculate an overall cost for Parties, based on the total installed GB capacity at the start of the analysis period. To this they added, the costs estimates provided for central BSC systems and processes.

We have checked that using more up-to-date information on capacities does not materially affect the outcome, see Table 3 below. Given the relatively low overall costs involved, we agree that a stylised approach to estimating costs is appropriate. However, there are two areas where we consider that the analysis could have been improved although neither would have a significant impact on the results.

Table 3: Check on LE/Ventyx's implementation cost calculation

			Consultation responses				Estimated costs			
			Implementation period [1]	Costs (£) Min [2]	Max [3]	Average [4] ([2]+[3])/2	Weeks effort [5] From [1]	Costs per person (£) [6] [5]x[A]	Number staff [7] [4]/[6]	Total costs (£) [8] [5]x[B]x[A]
Weekly salary (£)	[A]		701							
International Power Mitsui			10 Days	n/a	n/a	n/a	2	1,402		14,120
Total Gas & Power			6-9 Months	n/a	n/a	n/a	30	21,030		211,806
ScottishPower			8 Months	n/a	n/a	200,000	32	22,432	9	200,000
E.ON UK			9 Months	n/a	n/a	n/a	36	25,236		254,167
EDF ENERGY			12 Months	300,000	600,000	450,000	48	33,648	13	450,000
Western Power Distribution			Minimal	-			n/a			
GDF Suez Energy UK			6-9 Months	n/a	n/a	150,000	30	21,030		150,000
RWE Trading GmbH			Minimal	-			n/a			
Drax Power Limited			12 Months	n/a	n/a	n/a	48	33,648		338,889
British Energy Trading & Sales Ltd			9 Months	100,000	300,000	200,000	36	25,236	8	200,000
Centrica			Minimal	-	10,000	5,000	n/a			5,000
Average number people working	[B]								10	
Total labour costs (£)	[C]									1,823,981
Total capacity for the above companies in 2009(MW)	[D]		40,383							
Unit cost (£/MW)	[E]	[8][C]/[D]	45.17							
Total generating capacity 2009 (MW)	[F]		83,562							
Total cost (£)	[G]	[E]x[F]	3,774,250							

Notes:
[A]: Weekly salary is the gross weekly pay in 2008 for the employees in the electricity, gas, steam and air conditioning supply sector
[E] & [G]: NGET 2009 Seven Year Statement - Table 3.5 (no updates included)

First, it is not obvious that implementation costs will vary with installed capacity. The major implementation costs involve systems upgrades to allow for varying loss factors. Consequently, the costs are likely to depend on the systems that have to be upgraded rather than the number of power stations to which the upgrade has to be applied. Of course, it is possible that companies with many power stations will have more complex systems that cost more to upgrade but it is by no means obvious that this will be the case. A further disadvantage of this approach is that it assumes the costs to suppliers are zero. Whilst we accept that the large suppliers are part of vertically integrated companies, whose costs will be captured, there are smaller suppliers whose costs will not have been captured.

On the other hand, we acknowledge that this approach may be conservative in the sense that it produces higher implementation costs that were estimated previously. Since we would have expected many Parties to have taken substantial implementation work when it seemed likely that one of the earlier zonal losses proposals would be implemented, we would have expected implementation costs this time round to be lower rather than higher.

Second, we consider that it is wrong to include all the implementation costs in the first year that the zonal scheme is introduced. All affected entities will need to have implemented the necessary systems *before* zonal loss factors are introduced. Precisely how much of the implementation costs would be incurred in the BSC year preceding the implementation of P229, would depend on when the modification proposal was implemented. We have investigated the impact of taking the most conservative approach possible – namely assuming that all the implementation costs are incurred in the preceding year. At a 4.42% discount rate, the impact of correcting this assumption is small – the net present benefit falls by only £0.16 million.

4.3.4 Comparing the costs and benefits of zonal losses

To determine whether LE/Ventyx's methodology is appropriate, we have first considered what impact the introduction of zonal losses will have. In general terms, zonal losses will affect:

1. Consumers –the price of electricity and the volume of losses for which consumers must pay will change. This change is known as the change in consumer surplus – in other words a change in the benefits consumers get from using electricity;
2. Generators – generators will be affected for the same reasons as consumers. The change they face is simply the change in their profits;
3. The total costs of generating electricity to meet a given level of demand – both the plant used to generate the electricity and the gross volume of electricity that has to be generated i.e. the volume generated at the station gate before losses are taken into account, will change.

Mathematically, the sum of 1 (change in consumer surplus) and 2 (change in generators' profits) above equals 3 (the change in the cost of generating electricity).[16] It is the third measure of the effects of losses that LE/Ventyx have calculated. In other words, LE/Ventyx ask: what is the cost of the inputs (essentially fuel) required to deliver a given amount of electricity (net of losses) with and without a zonal losses proposal?

In an example in Appendix I, we illustrate that (in aggregate) changes in generators' profits can differ from the calculated changes in costs. However, whether generators' profits are higher or lower than the changes in costs will depend on the actual TLM's applied in each year, and the effect that the TLMs have on prices. Hence it is not clear if LE/Ventyx's published net benefits (which are based on costs) have under or over-estimated the actual effect of the proposals on generators' profits. LE/Ventyx's approach instead estimates the net effect on consumers and generators (i.e. the overall societal effect) of introducing zonal losses by looking at changes in costs. This is a common approach to performing cost-benefit analyses when one is interested in the effect on all parties in society and one that seems appropriate in the context of Ofgem's assessment of P229.

4.3.5 Distributional effects

LE/Ventyx's analysis of distributional effects is limited in two respects. First, LE/Ventyx only looked at 2011/12. The problem with looking at a single year is that it may not be representative of what would happen more generally – a point we discuss further in Section 6.2. On the other hand, the cash flow changes for generators will be largest in the first year that zonal losses are introduced and they will have the largest present value impact so that it makes sense to concentrate on this year. In addition, as discussed further in Section 6.2, we would expect the distributional effects to diminish somewhat over time.

Second, LE/Ventyx only looked at distributional effects in general terms by looking at what happens at a zonal level. We accept that there would have been difficulties in presenting data for specific companies but it would have been helpful to present sufficient data for Parties directly to

[16] This is true in a 'closed' system without interconnectors. However, since the GB interconnector capacity is small relative to total demand, GB approximates to a closed system. Moreover, LE/Ventyx effectively assumed that the system was closed since interconnector flows did not vary between the base and change cases.

be able to make assessments of the impact of P229 on their businesses.[17] This would have required LE/Ventyx to provide data on output by fuel type and zone and also on wholesale prices under both the change and reference cases. However, from the perspective of an overall assessment of P229 we do not consider that this omission is material, since it seems unlikely that P229 would have a material impact on competition in generation. (This point is discussed further in our Lot 3 report).

Finally, as discussed in Section 4.3.2 above, the fact that LE/Ventyx's modelling methodology meant that TLFs rather than TLMs are reflected in wholesale prices will have over-estimated the increase in wholesale prices that is likely to result from the introduction of zonal losses. Since LE/Ventyx's estimate of distributional effects depends in part on the change in wholesale prices, they are likely to have over-estimated these effects.

4.3.6 Interconnector modelling

LE/Ventyx's approach to modelling interconnectors was to assume (a) that the flows across them would not change as a result of zonal losses and (b) that the flows were fixed for all years and scenarios. For existing interconnectors (IFA, Moyle), the fixed flows were based on historic actual flows whilst for new interconnectors (Britned, and the two GB-Ireland interconnectors) the flows were based on previous Ventyx analysis. It seems rather simplistic to assume that the introduction of zonal losses would have no impact on interconnector flows

We accept that proper accounting of the impact of zonal losses on cable flows would have required the detailed modelling of interactions between the Irish, Dutch, French and GB markets, which did not form part of LE/Ventyx's terms of reference. We further accept that there are particular difficulties in modelling flows to and from the Irish market. However, since interconnectors account for a relatively small proportion of the capacity available to meet GB demand, we do not consider that the absence of more detailed modelling is likely to have had a significant impact on the results.

4.4 Conclusions on LE/Ventyx's methodology and the robustness of the results

LE/Ventyx's general conclusion is that the introduction of zonal losses would introduce net benefits from generation redespatch and demand side adjustments and we consider that their analysis supports this conclusion. Whilst the shortcomings we have identified with LE/Ventyx's methodology suggest that the precise values of the net benefits found by LE/Ventyx may be debatable, they are not sufficient to suggest that the results cannot be trusted to provide a reliable indication of the likely impact of P229

In addition, we consider that LE/Ventyx's approach to estimating longer term impacts – concentrating on the likely impact of zonal losses on siting decisions and renewables build – is appropriate. Finally, given their terms of reference, LE/Ventyx's approach to measuring distributional effects appears generally reasonable.

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[17] Parties can, of course, use the TLMs published by Elexon to estimate the impact of P229 on their businesses but they will have to make their own assessments of the impact that it would have, for example, on the output of each of their plants. This introduces the risk that the parties assessments will be different to those modelled by LE/Ventyx and hence that the analysis will contain inconsistencies.

5 Input assumptions

Ofgem have asked us to comment on whether LE/Ventyx's input assumptions were appropriate. In considering this issue, we have taken into account information that would have been available at the time the study was begun (April/May 2009) and that is available now (May 2010).

5.1 Discount rates

LE/Ventyx applied a discount rate based on the estimated real, after tax Weighted Average Cost of Capital (WACC) for electricity transmission, using parameters from Ofgem's December 2006 price control. This resulted in a base-case discount rate of 4.42%. LE/Ventyx also carried out sensitivities at discount rates of 3.5% and 5.2%, and found that the benefits were still strongly positive in both these cases. LE/Ventyx argued that an after tax WACC should be used, because the system losses are not taxable. We also note that the Modifications Group raised some concerns that the base case discount was too low.

LE/Ventyx's conclusions regarding the net benefits of P229 are insensitive to the exact choice of discount rate. For example, even with a discount rate of 100%, there would be a net benefit of around £4 million under the base case. Nevertheless, we have a number of detailed comments on the discount-rate issue which we will make for the sake of completeness.

First, we note that the main benefits of P229 – which are reduced transmission losses – depend on the volume of avoided losses and the electricity price. Therefore these losses are approximately as risky as generators' revenues streams, which also depend on the volume of electricity produced and the electricity price.

Second, financial theory dictates that the WACC should be used to discount a stream of cash flows to equity and debt holders. It is not generally correct to use the WACC to discount a revenue stream. We do not go into detail here, but it is a generally accepted fact in financial analysis that the discount rate for the revenue stream would be *lower* than the WACC.[18] Intuitively, this is because the WACC is used to discount the difference between revenues and costs. The difference between costs and revenues is inherently more volatile than either costs or revenues – hence the discount rate for both costs and revenues will be lower than the WACC.

We also note that, based on previous analysis we have carried out[19], the WACC for generation firms is higher than that for electricity transmission owners. This is because the measured beta for electricity generation firms – which represents the non-diversifiable risk – is higher for generation than for transmission.

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[18] For example, the concept of using different discount rates according to the operating leverage of the stream of cash flows is discussed in Chapter 10 of "Principles of Corporate Finance", by Brealey and Myers – the most widely used corporate finance text book. By definition, revenues are cash flows with zero operating leverage.

[19] This issue is discussed in our report on "The Cost of Capital for the NorNed Cable" (June 2004), prepared for the Dutch energy regulator (DTe), available at http://www.dte.nl/nederlands/elektriciteit/transport/openbaar_dossier_aanvraag_norned_kabel.asp

In sum, the LE/Ventyx report uses a discount rate based on electricity transmission rather than generation, which tends to underestimate the discount rate, but the appropriate discount rate for benefits will be lower than the WACC. To an extent these two factors should compensate one another, and it is likely that the 'correct' discount rate falls within the range of discount rates investigated by LE/Ventyx. Moreover, the impact of adopting a higher discount rate was investigated by the P229 Modification Group. They found, for example, that using a discount rate of 7.2% reduced the NPV under the reference case from £47.86 million (excluding SOx and NOx benefits) to £41.45 million[20] – a decline of around 13%.

There is also an issue as regards the use of an after tax WACC. The LE/Ventyx report argues that an after tax WACC is appropriate because system losses are not taxable. However, we note that the losses are a cost, which would affect the generators' taxable income. In other words, if (in aggregate) generators experience a reduction in costs due to a reduction in the cost of losses, they will experience an increase in taxes. From an industry point of view, the most consistent analysis would be to estimate the after tax benefits, which are the reduction in costs multiplied by (1 – tax rate). The after tax costs could then be discounted at an after tax rate. However, since the implementation costs would also be considered on an after tax basis, considering after tax costs and benefits would make no difference to the balance of costs and benefits, since both sides of the equation are multiplied by (1 – tax rate).[21] Hence we conclude that the after tax rate seems appropriate, though we do not fully agree with the justification put forward in the LE/Ventyx report.

5.2 Gas prices

As we explain below, the gas prices used by LE/Ventyx were below the forward prices existing at the time the study was prepared but are now within 10% of market expectations as of May 2010.

Table 4 compares the gas prices used in the LE/Ventyx study with the price forecasts that were available at the time that the study was undertaken (April/May 2009) and now. So as to compare forward prices (which are always quoted in 'money-of-the-day' or 'nominal' terms) with LE/Ventyx's real (2009) prices, we have converted them into real terms, using forecast inflation rates that were available at the relevant times. We have only examined LE/Ventyx's fuel price assumptions over the period 2010 to 2012, since this is the range for which gas forward prices are available. The table shows that the reference case gas prices were high compared to the forward curves in April and May 2009 for 2011 (17% and 16% high respectively). Thus, at least for one year, gas prices were higher than the market expected at the time that the study was undertaken but they are now more in line with the forward curve.

[20] See page 47 of the P229 Assessment Report.

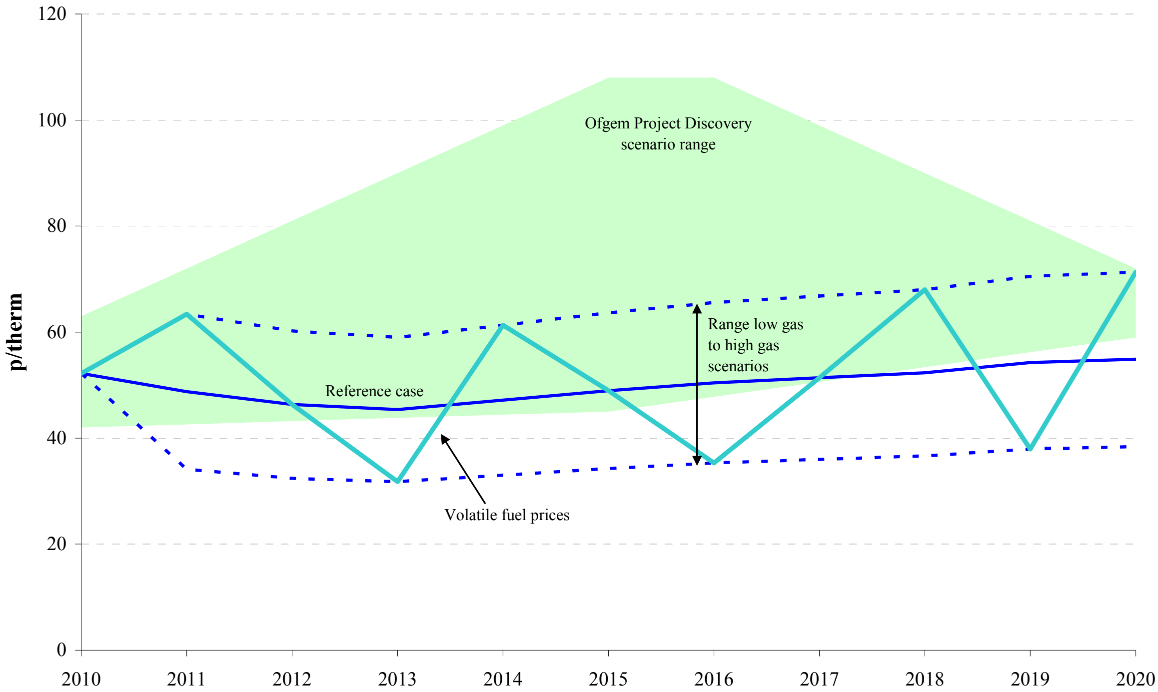
[21] Of course, this reasoning is only correct if the tax rate remains constant over the period considered.

Table 4: Difference between LE/Ventyx gas prices and forward curves

Period	Forward curves		
	May-10	Apr-09	Mar-09
2010		0%	-6%
2011	-6%	17%	16%
2012	8%		

Looking over the longer term, we have also compared the various LE/Ventyx gas prices projections to the range of gas prices adopted by Ofgem in its Project Discovery scenarios, see Figure 3. The figure suggests that LE/Ventyx's long run gas prices may be somewhat on the low side, although there is obviously significant uncertainty regarding likely price levels eight or more years into the future.

Figure 3: Comparison of LE/Ventyx gas prices to Project Discovery gas prices



Whilst the gas prices appear to be on the low side, we note that the high gas scenario led to significantly higher net benefits than the reference scenario (£101 million compared to £47.86 million excluding NOx/SOx benefits). Consequently, from this perspective, the reference case appears conservative in that it may under-estimate the potential benefits. More generally, we conclude that changing LE/Ventyx's gas price assumptions would be unlikely to result in any fundamental changes to the conclusions that can be drawn from their analysis.

5.3 Coal prices

As Figure 4 shows, we have also compared the coal prices LE/Ventyx used with forward prices from April/May 2009 and May 2010 and the Ofgem Project Discovery scenarios. As with the gas prices, we have converted all prices to real (2009) terms – in this case using US inflation forecasts. We have also converted the forward prices from US dollars to pounds sterling using the exchange rates published at the same time as the forward prices. For the Project Discovery assumptions, we have used the exchange rate of 1.5 \$/£ adopted by Ofgem.

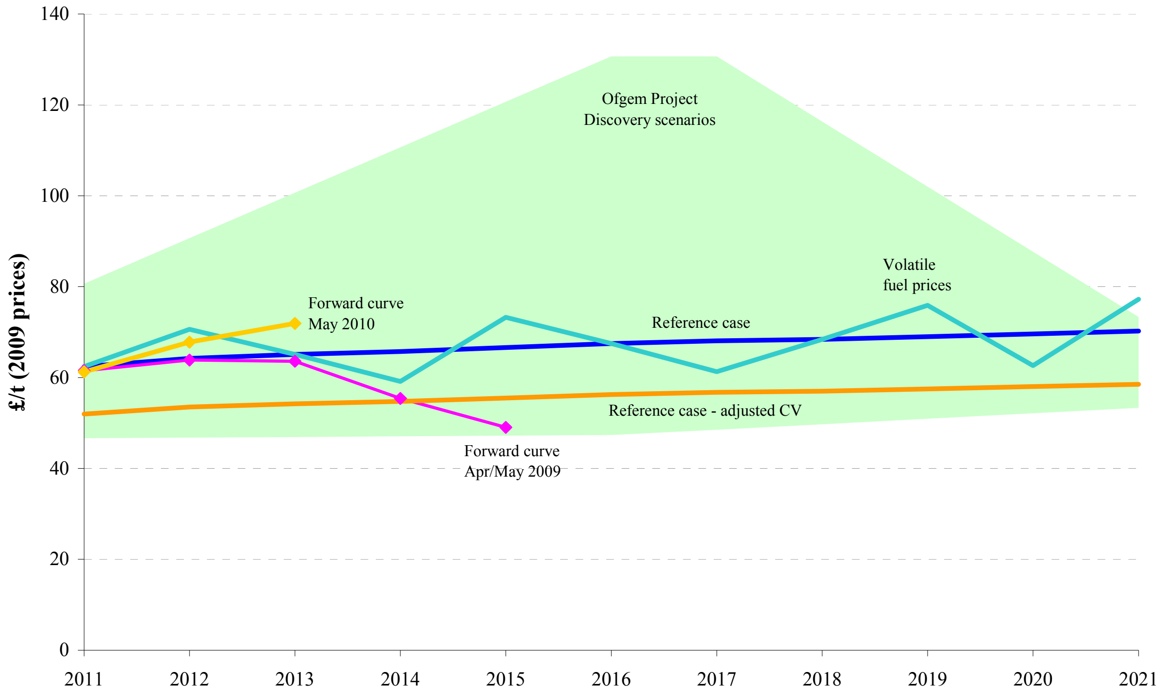
Whilst LE/Ventyx presented coal prices in terms of both £/GJ and £/t, we have concentrated on their £/GJ values. This is because it was these values (rather than the £/t numbers) that determined the marginal costs of coal prices. We have converted the forward curve and Project Discovery coal prices from £/t to £/GJ by assuming a calorific value of 25 GJ/t. The reference case coal prices appear slightly on the low side compared to forward prices, as shown in Table 5. Nonetheless, LE/Ventyx's figures still lie within the range of outcomes covered by the Ofgem Project Discovery scenarios, as can be seen from Figure 4, although they are around 15% below both contemporaneous and current forward prices.

Table 5: Difference between LE/Ventyx coal prices and forward curves

	Forward curves		
Period	Mar-09	Apr-09	May-10
2011	-14%	-15%	-13%
2012	-14%	-16%	-18%
2013	-13%	-15%	-22%
2014	1%	-1%	
2015	16%	13%	

However, the volatile fuel price scenario does not seem fully to capture the range of plausible outcomes that might be seen in the future, since the volatility incorporated in the coal prices is modest (+/- 10% from the reference case prices). The market has seen much larger coal price swings than this over recent years. On the other hand, the high and low gas scenarios give a good indication of the impact that more extreme fuel prices on their own are likely to have so that the limited coal price volatility in this scenario is unlikely to materially affect any assessment of P229.

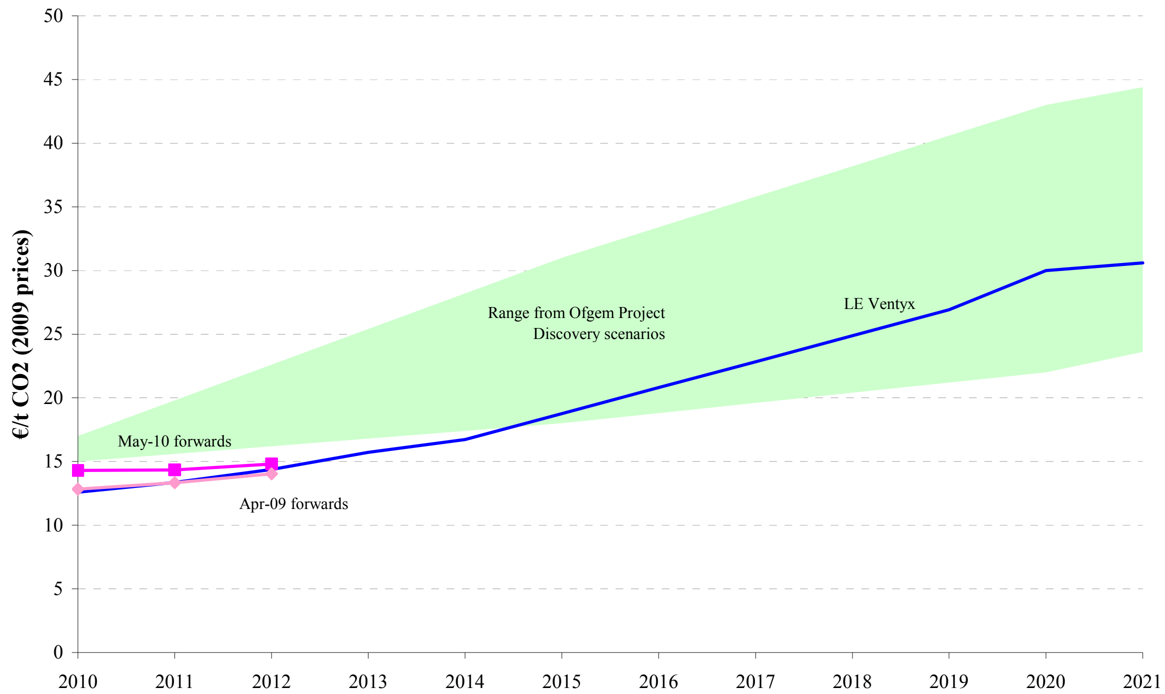
Figure 4: Comparison of LE/Ventyx coal prices with forward prices and Ofgem Project Discovery scenarios



5.4 Carbon prices

The CO2 prices that LE/Ventyx adopted were very close to the forward curve for traded carbon prices (from the European Energy Exchange) at the time the study was undertaken, as can clearly be seen from Figure 5 below. They are slightly below current forward price levels – but these only extend out to the end of Phase II. In the longer term, LE/Ventyx's assumptions lie well within the range of CO2 prices considered by Ofgem in its Project Discovery scenarios. Hence, LE/Ventyx's assumptions with respect to the carbon prices seem reasonable.

Figure 5: Comparison of LE/Ventyx CO2 prices with forward prices and Ofgem Project Discovery scenarios



5.5 Demand growth

LE/Ventyx produced their own demand forecasts rather than relying on those published by NGET in its Seven Year Statement (SYS). This was because they undertook the study before the 2009 SYS was produced and correctly considered that the projections in the 2008 SYS were likely to be too high, at least in the early years, since they were produced before the credit crisis began.

We have compared the LE/Ventyx' assumptions to the projections included in the 2010 SYS and to the projections adopted by Ofgem for its Project Discovery scenarios (which were published in October 2009). As Figure 6 (peak demand) and Figure 7 (annual demand) demonstrate, NGET and Ofgem produced rather different forecasts at least initially, with NGET's views being more pessimistic.

LE/Ventyx's assumptions lie within the range of outcomes covered by the Ofgem Project Discovery scenarios and their peak demand assumptions are below that produced by "Users" in the 2010 SYS. On the other hand, their assumptions are well above even the high forecast produced by NGET itself. For example, LE/Ventyx's peak demand forecast is 9% above NGET's base forecast in 2016/17 and 2% above their high forecast.

Figure 6: Comparison of LE/Ventyx's peak demand assumptions with those from the 2010 SYS and Project Discovery

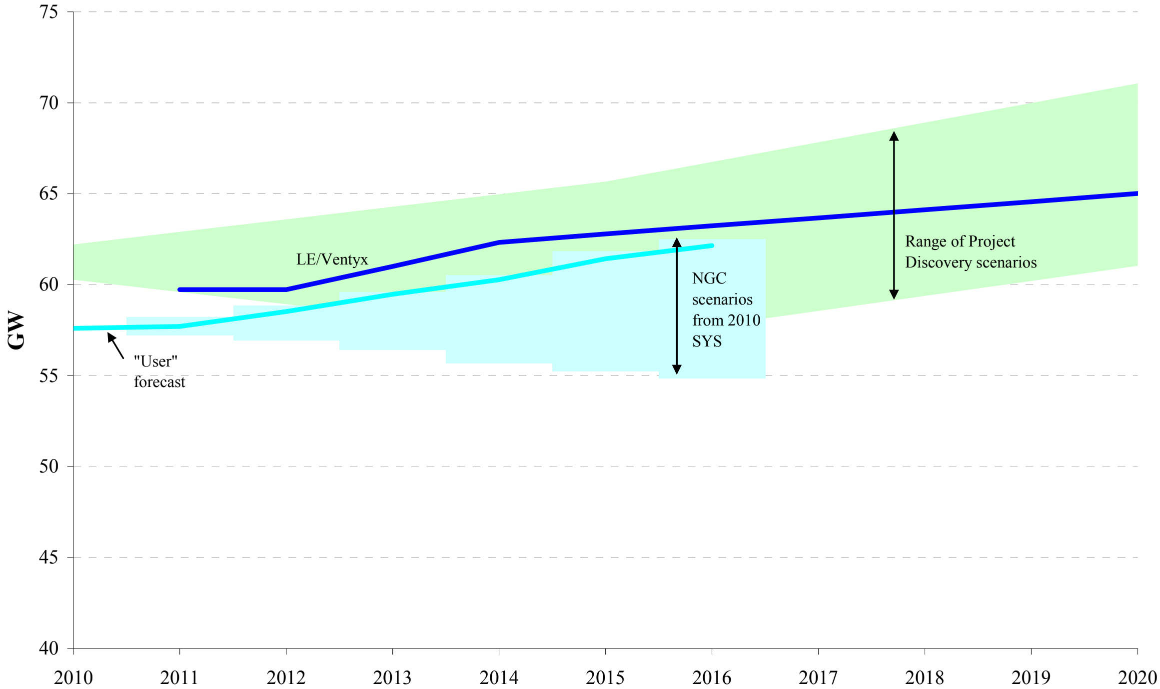
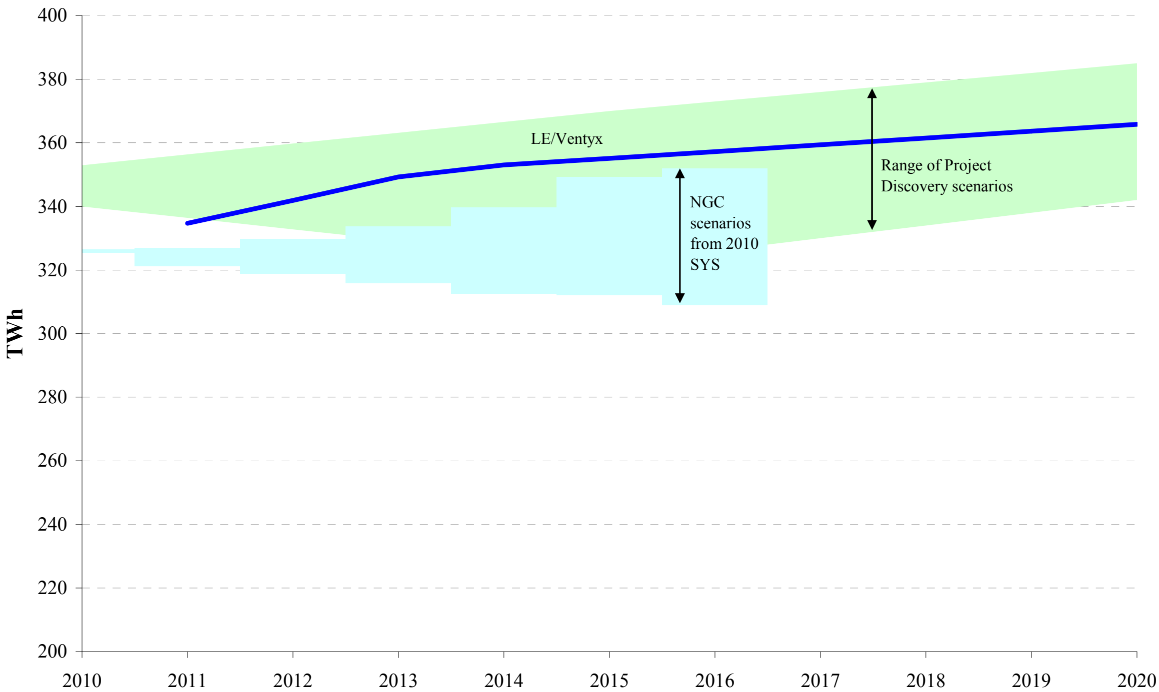


Figure 7: Comparison of LE/Ventyx's annual demand assumptions with those from the 2010 SYS and Project Discovery



One reason that LE/Ventyx may have assumed higher demand levels than NGET is that LE/Ventyx modelled all future renewable generation as if it would be transmission connected, whereas NGET assumes continuing growth of embedded renewable generation, which reduces its demand forecasts.

In view of the wide range of future demand projections produced in 2009/10, we conclude that the assumptions are reasonable. Although we acknowledge that the Modification Group decided that a demand sensitivity was unnecessary, we consider that it might have been helpful had one been undertaken. In general, discrepancies in demand forecasts per se are not important, provided that overall generation capacity is adjusted to maintain a reasonable capacity margin. However, in analysing the evolution of loss factors the fact that higher demand requires higher levels of new capacity could have an impact on the results in later years since the loss factors for these years will depend on where these new plants are assumed to be located. Nonetheless, we accept that it is highly unlikely that a demand sensitivity would have resulted in a change in overall conclusions and, hence, that its omission is not a significant issue.

5.6 Transmission capacity changes

LE/Ventyx have primarily relied upon the transmission line upgrade data contained in the 2008 SYS. However, they did not include all the upgrades included in the SYS for the period corresponding to the start of the analysis period i.e. 2011/12 onwards. Instead it included "*selected upgrades*" to "*address reported congestion in the study results*" in combination with a check to ensure that "*all new generating facilities did not encounter significant local congestion limiting their output*". LE/Ventyx also assessed transmission flows to ensure there was "*no excessive congestion impacting study results*". Beyond the period covered by the 2008 SYS i.e. beyond 2014/15, LE/Ventyx state that it assumed any congestion not anticipated in the SYS would be "*identified, studied and addressed before causing severe despatch limitations*".[22] By this, LE/Ventyx meant that it did not add new transmission lines after 2014/15 but that it relaxed overload constraints if congestion on particular lines was unduly high.

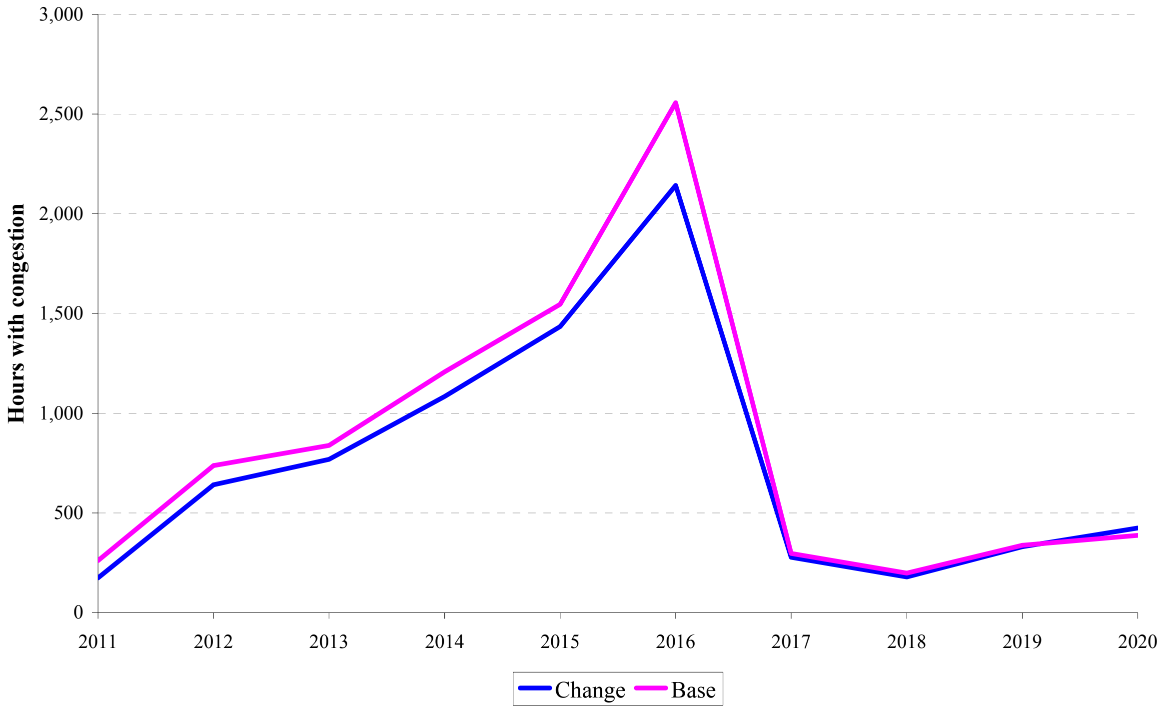
We would expect the results for the final years studied to be somewhat less reliable than the earlier years whatever approach was adopted to dealing with transmission constraints because of the increasing uncertainty associated with power flows and the lack of firm plans for transmission expansions that could affect flows and hence loss factors. However, the approach of relaxing constraints adopted by LE/Ventyx is likely to over-estimate the impact of zonal losses in later years. This is because it does not capture the reduction in system resistance, and hence losses, that results from additional transmission capacity.

We note, for example, that LE/Ventyx have not taken into account the Western HVDC cable between Hunterston and Deeside which is now scheduled for 2015 (although it was only targeted for 2018 when LE/Ventyx undertook their analysis). The impact of this cable is effectively to increase demand in Scotland and increase generation in the north of England and to decrease congestion between Scotland and England. Given the timing of the connection, we do not consider it necessary to run a separate scenario to analyse the influence of this interconnector. To some extent, the type of impact that it might be expected to have will have been explored by the different capacity assumptions included in the various scenarios that LE/Ventyx and Redpoint

[22] All the quotations from the LE/Ventyx report come from Section 4.7 on page 72.

will have analysed. Moreover, LE/Ventyx's relaxation of transmission constraints may also have indirectly captured the impact that the HVDC cable might have. For example, under the reference scenario, congestion levels rise to a peak in 2016 before falling sharply, see Figure 8 below, Whilst LE/Ventyx consider that this pattern is largely driven by plant entry and retirement assumptions, it is possible that it also reflect the impact of relaxing transmission constraints, which is what would be achieved by the HVDC cable.

Figure 8: Congestion levels under the Reference scenario



The approach taken by LE/Ventyx appears broadly reasonable given the time at which the study was undertaken[23]. However, we consider that given more recent market developments, the analysis may not have adequately addressed what impact increased flows might have on the effects of zonal losses. For example, the announcements by the government regarding the introduction of a "connect and manage" approach to transmission access are likely to mean that new wind farms will come on-stream earlier than would otherwise be the case. This is because "connect and manage" will enable such generators to connect to the transmission system before the wider reinforcement works required to accommodate them are necessarily completed. Moreover, Ofgem has recognised the need for significant transmission upgrades to deal with the anticipated growth in renewable generation. Consequently, we consider that it is now appropriate to consider the extent to which zonal loss factors are sensitive to the impact of accelerated renewable entry. (We discuss a further potential problem with the assumptions on transmission capacity in relation to renewables in Section 5.8 below).

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[23] Although we would have thought it more logical to include all the transmission upgrades identified in the SYS.

5.7 Conventional new entry assumptions

As Table 6 shows, LE/Ventyx add nearly 19 GW of new conventional generating projects over the analysis period to maintain a "balanced" system. By a balanced system, LE/Ventyx mean one with (a) a stable long-term reserve margin, (b) sustainable price levels and (c) annual profits for new plants that are sufficient to cover their capital as well as their operating costs.[24]

Regarding the assumption of a "balanced" system, we agree that this makes sense for a reference case. This is because it is unlikely that the system would remain indefinitely in a state of over- or under-capacity. Moreover, it is unclear whether a system with a lower or higher capacity margin would yield different results. Consequently, analysing the impact of a "balanced" system seems sensible. Assuming that LE/Ventyx's starting point was similar to that reported by NGET in the 2009 SYS (a capacity margin[25] of over 46%, or 42% when the impact of the capacity factors of wind are taken into account[26]), LE/Ventyx's new build and closure assumptions mean that the capacity margin would have fallen to just under 37% (21.4% with wind adjustments) by 2020. These seem reasonable assumptions for a balanced system.

Table 6: LE/Ventyx conventional new entry assumptions (MW)

	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Specific												
N-Scotland	0	0	0	0	0	0	0	0	0	0	0	0
S-Scotland	0	0	0	0	0	0	0	0	0	0	0	0
Northern	0	0	0	0	0	0	0	1,020	0	0	925	1,945
N-West	0	0	0	0	0	0	0	0	860	0	0	860
Yorkshire	0	0	0	0	0	0	0	0	0	0	0	0
N-Wales & Mersey	0	0	0	0	0	0	0	1,650	0	0	0	1,650
E-Midlands	850	2,120	0	0	0	1,230	0	0	0	0	840	5,040
Midlands	0	0	0	0	0	0	0	0	0	1,305	1,650	2,955
Eastern	0	0	0	0	0	0	0	0	0	0	1,315	1,315
S-Wales	800	0	0	0	0	0	2,000	0	0	270	435	3,505
S-East	1,200	0	0	0	0	0	0	0	0	0	0	1,200
London	0	0	0	0	0	0	0	0	470	0	0	470
Southern	0	0	0	0	0	0	0	0	0	0	0	0
S-Western	0	0	0	0	0	0	0	0	0	0	0	0
Total	2,850	2,120	0	0	0	1,230	2,000	2,670	1,330	1,575	5,165	18,940

In Table 7 below, we compare the LE/Ventyx assumptions to those contained in the April 2010 Transmission Networks Quarterly Connections Update (TNQCU). This shows that LE/Ventyx include only half of the capacity additions listed in the April TNQCU. It is not surprising that LE/Ventyx assume a lower level of plant build because NGET includes all plants that have requested connections. Some of these plants may not, in fact, be developed and so NGET's numbers tend to over-estimate future new capacity levels. Given the significant difference in total capacities, it is more sensible to compare the geographic spread in entry on a percentage basis – as shown in the right hand half of the table. This suggests that the LE/Ventyx assumptions broadly follow the patterns suggested by the TNQCU with most entry occurring in the midlands and the south.

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[24] See page 58, LE/Ventyx report.

[25] Capacity margin = (Installed capacity – peak demand)/demand.

[26] Based on LE/Ventyx's assumed capacity factors of 27% and 36% for onshore and offshore wind respectively.

Table 7: Comparison LE/Ventyx assumptions to April 2010 TNQCU assumptions (2011/12 to 2020/21)[27]

Zone	Capacities (MW)			% new capacity		
	LE/Ventyx	Apr-10 TNQCU	Difference	LE/Ventyx	Apr-10 TNQCU	Difference
N-Scotland	0	0	0	0%	0%	0%
S-Scotland	0	2,100	-2,100	0%	6%	-6%
Northern	1,945	950	995	10%	3%	8%
N-West	860	4,380	-3,520	5%	12%	-8%
Yorkshire	0	4,585	-4,585	0%	13%	-13%
N-Wales & Mersey	1,650	1,670	-20	9%	5%	4%
E-Midlands	5,040	3,435	1,605	27%	10%	17%
Midlands	2,955	1,600	1,355	16%	5%	11%
Eastern	1,315	6,100	-4,785	7%	17%	-10%
S-Wales	3,505	3,720	-215	19%	11%	8%
S-East	1,200	3,433	-2,233	6%	10%	-3%
London	470	0	470	2%	0%	2%
Southern	0	0	0	0%	0%	0%
S-Western	0	3,340	-3,340	0%	9%	-9%
Total	18,940	35,313	-16,373			

5.8 Renewable new entry assumptions

In response to questions that we asked LE/Ventyx, we have now received data on their assumptions regarding onshore wind and other renewables. As noted above, we have also established that LE/Ventyx have assumed that all new renewable generation will be transmission connected. This means that comparisons with NGET SYS data should be treated with caution since the LE/Ventyx data are likely to contain plants that would be treated as embedded by NGET.[28] On the other hand, to the extent that the LE/Ventyx figures are lower than those produced by NGET, this may suggest that LE/Ventyx have under-estimated likely new additions of renewable plants. (This may not necessarily be the case, particularly for the later years since, as discussed above, NGET's numbers tend to over-estimate future new capacity levels).

Table 8 compares LE/Ventyx's assumptions regarding onshore wind to NGET's April 2010 TNQCU assumptions. (Note that the NGET data for Scotland only extends to 2019/20 so that the last two years show the same data for Scottish zones.) It shows that LE/Ventyx's assumptions are generally lower than those of NGET and that there are also discrepancies in the geographical spread of plants. For example, LE/Ventyx assume that there are currently more onshore wind farms in the north of Scotland than the south, whereas the NGET data indicates the opposite. It is unlikely that this discrepancy has any significant impact on plants not located in Scotland due to the existence of a significant transmission constraint on the southern boundary of the south of

[27] The TNQCU data for Scotland only extends to 2019/20.

[28] We do not consider that this assumption will have had a significant impact on the zonal loss factors estimated by LE/Ventyx. If the renewable generation had been treated as embedded, zonal demand levels would have been lower and hence the flows would have been broadly the same. As regards the position of renewable generators, again any impact is likely to have been small because suppliers are likely to pass through the impact of zonal losses to embedded generators.

Scotland zone. However, the omission of up to 600 MW of onshore wind plants in Wales by 2020 may have a more general, albeit relatively modest, effect.

Table 8: Comparison LE/Ventyx assumptions on onshore wind to April 2010 TNCQU assumptions

Zone	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
April 2010 TNQCU										
N-Wales	0	0	0	0	97	281	281	281	281	281
S-Wales	0	299	299	299	299	299	299	299	299	299
S-Scotland	2,996	3,328	4,116	4,347	4,490	4,490	4,490	4,490	4,601	4,601
N-Scotland	1,351	1,661	1,743	2,348	3,451	3,451	3,465	3,465	4,287	5,370
Total	4,348	5,287	6,157	6,995	8,337	8,521	8,535	8,535	9,467	10,551
LE/Ventyx										
S-Scotland	862	986	1,161	1,349	1,576	1,819	1,998	2,166	2,341	2,523
N-Scotland	2,586	2,712	2,937	3,149	3,402	3,639	3,710	3,742	3,767	3,785
Total	3,448	3,698	4,098	4,498	4,978	5,458	5,708	5,908	6,108	6,308
Difference from TNQCU										
N-Wales	0	0	0	0	-97	-281	-281	-281	-281	-281
S-Wales	0	-299	-299	-299	-299	-299	-299	-299	-299	-299
S-Scotland	-2,134	-2,342	-2,955	-2,998	-2,914	-2,671	-2,492	-2,324	-2,259	-2,077
N-Scotland	1,235	1,051	1,194	800	-50	187	245	277	-520	-1,586
Total	-900	-1,589	-2,059	-2,497	-3,359	-3,063	-2,827	-2,627	-3,359	-4,243

Table 9 compares the LE/Ventyx assumptions on offshore wind to those contained in the April 2010 TNQCU. The table clearly demonstrates that LE/Ventyx's assumptions are very low – both the reference and aggressive offshore cases yield 2020 offshore capacities that around half of that included in the TNQCU. (Again, the 2020 TNQCU number may be an under-estimate because the Scottish data only extend to 2019.)

Table 9: Comparison LE/Ventyx assumptions on offshore wind to April 2010 TNCQU assumptions

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
April 2010 TNQCU	2,379	3,156	4,503	6,094	6,998	7,807	8,807	9,207	10,607	11,007
LE/Ventyx										
Reference	1,340	1,690	2,090	2,490	3,010	3,460	3,910	4,360	4,810	5,260
Aggressive offshore	1,621	2,076	2,596	3,116	3,792	4,332	4,837	5,332	5,827	6,322
Difference from TNQCU										
Reference	-1,039	-1,466	-2,413	-3,604	-3,988	-4,347	-4,897	-4,847	-5,797	-5,747
Aggressive offshore	-758	-1,080	-1,907	-2,978	-3,206	-3,475	-3,970	-3,875	-4,780	-4,685

Moreover, even the TNCQU 2020 value is less than that the value of 13. 1 GW adopted by the Department of Energy and Climate Change (DECC) adopted in the central scenario it used in the analysis undertaken for its transmission access review. Whilst we acknowledge that the results of the round 3 tender for offshore wind had not been published when LE/Ventyx undertook their study, there was sufficient information to indicate that 5 GW was an unduly low assumption and the Modification Group believed that offshore generation developments were significantly underestimated by LE/Ventyx. We concur with the Modification Group's view.

The failure to include sufficient offshore wind capacity will have resulted in LE/Ventyx including more conventional plant that is actually likely to be required. For example, based on the assumptions on annual availabilities used in the Project Discovery scenarios, we estimate that the output of the additional 9,740 MW of offshore wind required to reach 15 GW by 2020 under the reference case could be replaced by 4,500 MW of CCGTs or coal plant.[29]

In addition to our concerns regarding LE/Ventyx's wind capacity assumptions, we also note that LE/Ventyx model a single wind output profile for all onshore wind farms and a single wind output profile for all offshore wind farms. Whilst we acknowledge that these profiles have been created by averaging actual historic data for a number of sites, it seems likely that this approach will over-estimate the volatility of wind output which, in turn, will have consequences for the loss factor calculations. However, it is not obvious what effect less volatile wind output would have on loss factors, particularly given the smoothing effect of the zonal and seasonal averaging.

As regards renewables other than wind farms, Table 10 provides a comparison based on data provided to us by LE/Ventyx that has not previously been published. This is probably the area where there are most likely to be differences from the NGET data, due to LE/Ventyx's assumption regarding transmission connection for all new renewables. To some extent, this hypothesis is confirmed by the fact that there are no landfill or sewage gas plants listed by NGET and yet LE/Ventyx assume that there will be between 700 and 900 MW of such plants on the system.[30] We are surprised that there is a discrepancy in the hydro assumptions since the capacity of existing hydro plants has not changed significantly over the course of the past few years but presumably this is due to differing assumptions regarding which plants are connected at the distribution and transmission levels. In any event, given that hydro plants are almost all located in Scotland and flows southward are subject to considerable constraints due to transmission bottlenecks, we think it is unlikely that the differing assumptions will have had a significant impact on LE/Ventyx's findings.

[29] This is based on an annual availability of 38% for offshore wind and 83% for new conventional plants. 6750 ~ 14740 x0.38 / 0.83.

[30] LE/Ventyx assumes a steady decline in landfill gas capacity which is not quite offset by increases in sewage gas capacity.

Table 10 Comparison LE/Ventyx assumptions on other renewables to April 2010 TNQCU assumptions[31]

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
LE/Ventyx										
Landfill & sewage gas	949	931	913	896	878	860	843	806	788	752
Biomass	425	825	875	925	975	1,075	1,175	1,275	1,375	1,475
Hydro	620	625	630	635	640	645	650	655	660	665
Other	37	38	39	74	75	76	111	111	111	136
Total	2,031	2,419	2,457	2,530	2,568	2,656	2,779	2,847	2,934	3,028
April 2010 TNQCU										
Biomass	97	431	946	1,816	1,816	1,816	1,816	1,816	1,816	1,816
Hydro	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,084	1,090
Tidal								410	410	410
Wave								700	723	723
Total	1,175	1,509	2,024	2,894	2,894	2,894	2,894	4,004	4,032	4,038
Difference from TNQCU										
Landfill & sewage gas	949	931	913	896	878	860	843	806	788	752
Biomass	328	394	-71	-891	-841	-741	-641	-541	-441	-341
Hydro	-458	-453	-448	-443	-438	-433	-428	-423	-424	-425
Other (vs tidal/wave)	37	38	39	74	75	76	111	-999	-1,022	-997
Total	857	911	434	-364	-326	-238	-115	-1,157	-1,098	-1,010

We strongly believe that there is a need for additional analysis to investigate what impact increasing the assumed offshore wind capacity would have. We have suggested, and Ofgem has accepted, that new analysis should be undertaken including offshore capacity assumptions broadly consistent with the central "Connect and Manage" scenarios modelled for DECC so that 15 GW of offshore wind are assumed to be in place by 2020. This analysis has been undertaken by Redpoint as part of the Lot 2 analysis.

5.9 Other locational charges

In their analysis of new entry costs, LE/Ventyx rely on TNUoS and gas exit charges from 2009/10 as they would apply to a 400 MW power plant with an efficiency of 55% operating at a load factor of 85%. The range of charges across the locations that LE/Ventyx studied has subsequently increased for gas but decreased for electricity, as shown in Table 11 below. As we discuss further in Section 6.2, the overall effect has been to decrease the strength of the locational signals that already exist so that the impact of zonal losses has increased.

[31] Again, TNQCU data for Scotland only extends to 2019 so some capacity may be missing from last year.

Table 11: Comparison of 2009/10 and 2010/11 TNUoS and gas exit charges (2009 £ million)

Location	NTS exit charges			TNUoS charges		
	Zone	2009/10	2010/11	Zone	2009/10	2010/11
Central London	NT	0.82	0.84	16	-2.79	-2.49
Penninsula	SW	0.51	1.31	20	-2.67	-2.28
South East	SE	0.98	0.99	17	0.10	0.31
North East England	NE	0.13	0.13	10	3.94	3.42
South Scotland	SC exc. SC1	0.01	0.01	7	5.44	4.85
North Scotland	SC1	0.01	0.01	1	8.64	7.80
Range		0.98	1.30		11.43	10.29

5.10 Conclusions on LE/Ventyx's input assumptions

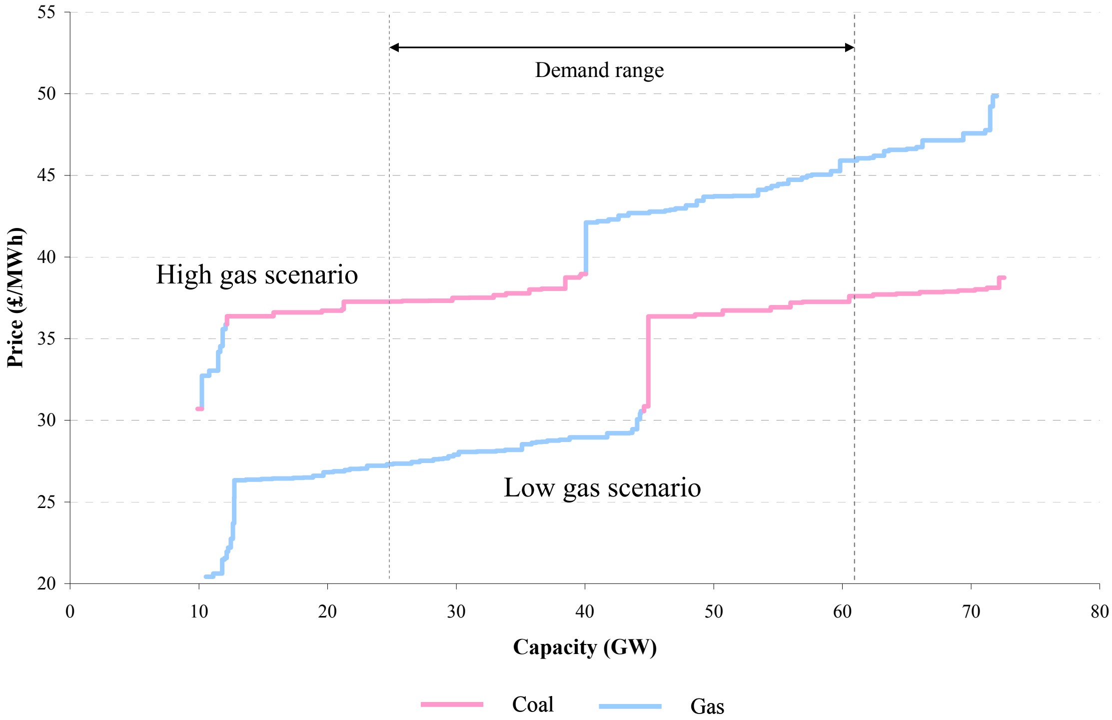
Over a year has passed since LE/Ventyx were commissioned to produce a report and so it is not surprising that the assumptions LE/Ventyx adopted when it was beginning their analysis, which we assume was in April/May 2009, are now somewhat out of date.

The gas prices used, while below the forward prices existing at the time LE/Ventyx prepared their studies, are now within 10% of market expectations as of May 2010. The coal and CO2 prices LE/Ventyx have used are broadly consistent with the contemporaneous forward prices at the time LE/Ventyx prepared their report, the current (May 2010) forward prices and the assumptions adopted in Ofgem's Project Discovery scenarios. Consequently, we conclude that LE/Ventyx's fuel and carbon price assumptions were reasonable and will still generate plausible results today.

Moreover, we have checked whether the range of sensitivities analysed by LE/Ventyx covers a broad enough range of outcomes to provide assurance that the results are not biased by particular input assumptions. In particular, we have checked that a range of different situations with regard to the relative costs of coal and gas plant has been examined. Figure 9 compares our estimates of the coal and gas portions of the winter merit order in 2012/13 including the effects of zonal losses under the two gas price sensitivities. It clearly demonstrates that LE/Ventyx have looked at very different situations. Under the low gas price scenario, the gas plants appear together as a group at the bottom end of the merit order whereas under the high gas price scenario the situation is reversed with most gas plants[32] appearing above the grouped coal plants in the merit order. Whilst this does not represent a complete reversal of the merit order i.e. with all the coal plants being cheaper than any of the gas plants, we estimate that it would be sufficient to radically change the ratio of coal to gas plant output. Under the low gas scenario, we estimate that gas plants would account for around 90% of the combined coal + gas output but this value drops to 42% under the high gas scenario. (The combined coal + gas output remains essentially constant under both scenarios).

[32] We have included some gas-fired CHP plants as "must run" towards the bottom of the merit order.

Figure 9: Estimated merit orders for 2012/13 based on annual average fuel prices



Given the wide range of views on future demand levels that have been produced since the LE/Ventyx report was commissioned, we conclude that the assumptions are reasonable.

More importantly, LE/Ventyx have adopted very conservative assumptions regarding the development of offshore wind farms. By 2020/21, LE/Ventyx assume that only 5.3 GW of offshore wind would be on-line under their reference case, and this only rises to 6.3 GW under their "aggressive offshore wind" scenario. This is under 50% of the offshore capacity included in NGET's April 2010 TNQCU, which in turn is around half that required to meet the government's renewables target.

6 Results

6.1 Redespatch effects

Table 12 below summarises the net benefits for the various cases that LE/Ventyx have analysed. We have adjusted the present value of the production cost savings to take account of the fact that the implementation costs would be incurred before any benefits could accrue. There are positive net benefits under all the cases, but clearly the P229 Alternative approach yields much lower benefits than the P229 Original approach. This is only to be expected as the scaling adopted under the Alternative proposal results in loss factors that do not reflect 'actual' losses i.e. the losses generators in that zone actually create in particular periods, as closely as those generated by P229 Original. It is possible, therefore, that the low gas scenario would yield a net dis-benefit under P229 Alternative, but all the other sensitivities should continue to yield positive benefits, albeit reduced by around 75%.

Table 12: Summary of benefits (2009 £ million)

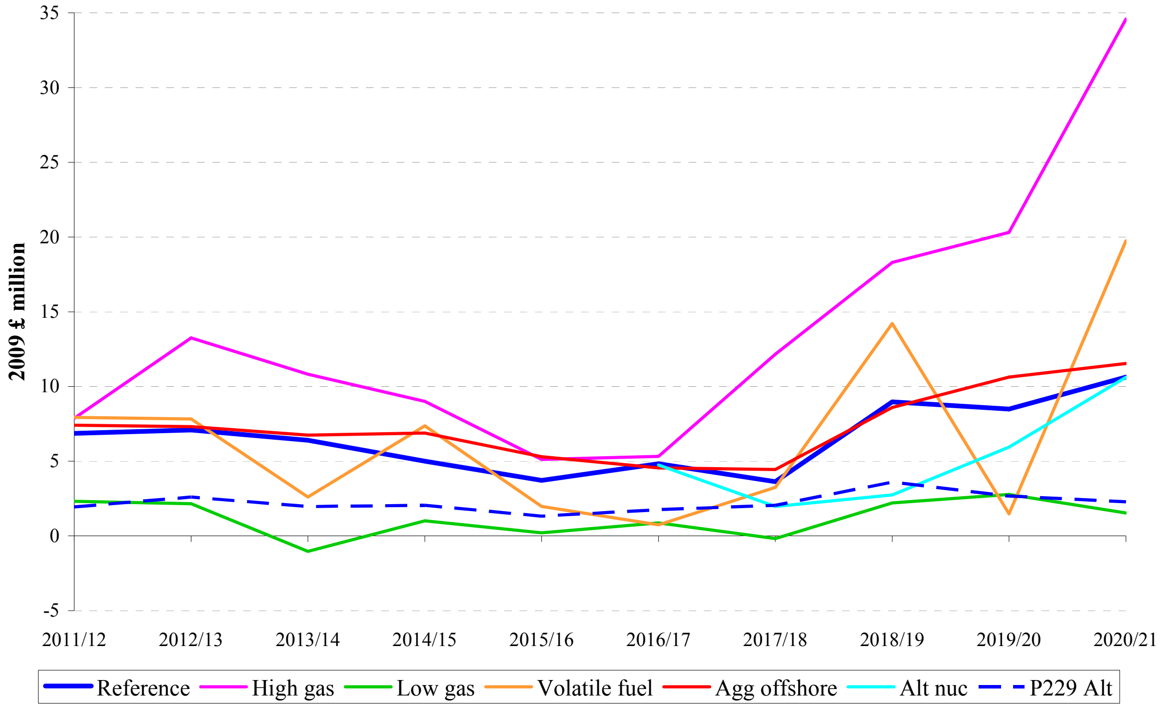
Net benefit	Base	High gas	Low gas	Volatile fuel prices	Aggressive offshore	Alternative nuclear	Base P229 alt
Adjusted production cost savings	45.96	97.61	4.14	46.32	51.97	38.60	12.28
Demand side savings	1.74	3.23	0.36	1.73	1.82	1.59	0.09
Total	47.70	100.84	4.50	48.05	53.79	40.19	12.37
Min. production cost saving							
Value (£ million)	3.63	5.12	-1.03	0.74	4.45	1.97	1.32
Year	2017/18	2015/16	2013/14	2016/17	2017/18	2017/18	2015/16
Max. production cost saving							
Value (£ million)	10.63	34.59	2.77	19.75	11.54	10.62	3.60
Year	2020/21	2020/21	2019/20	2020/21	2020/21	2020/21	2018/19

The table also shows that the maximum production cost savings always occur towards the end of the period analysed - under five of the cases, they occur in the final year (2020/21) and the earliest they occur is only two years earlier (2018/19 under P229 Alternative). The minimum cost savings occur over a wider range of years (2013/14 to 2017/18).

It is difficult to be certain what causes these patterns but we assume that they are probably related, at least in part, to increasing levels of retirement and new build in the later years analysed. This would result in increased mismatches between 'actual' losses that occur in a given year and the TLFs that have been calculated from data taken from the preceding year. An additional cause of the volatility in later years may relate to the fact that LE/Ventyx did not add any transmission capacity after 2014/15 but simply relaxed line constraints.[33]

[33] See Section 5.6 above for a discussion on this point.

Figure 10: Production cost benefits



The changes in net benefits under the high and low gas price scenarios that LE/Ventyx studied seem plausible and are confirmed by our simple modelling. The higher gas prices mean that the marginal costs of gas and coal plants will be closer together so the introduction of zonal losses is likely to give rise to more opportunities for fuel switching to reduce losses. Without zonal losses, high gas prices lead to increased flows southward from northern coal plants than is the case under the reference gas prices where southern gas plants run harder. Zonal losses mean that some of this coal output will be replaced by southern gas output. In addition, the higher electricity prices that result from the higher gas prices increase the likely demand side benefits to some extent.

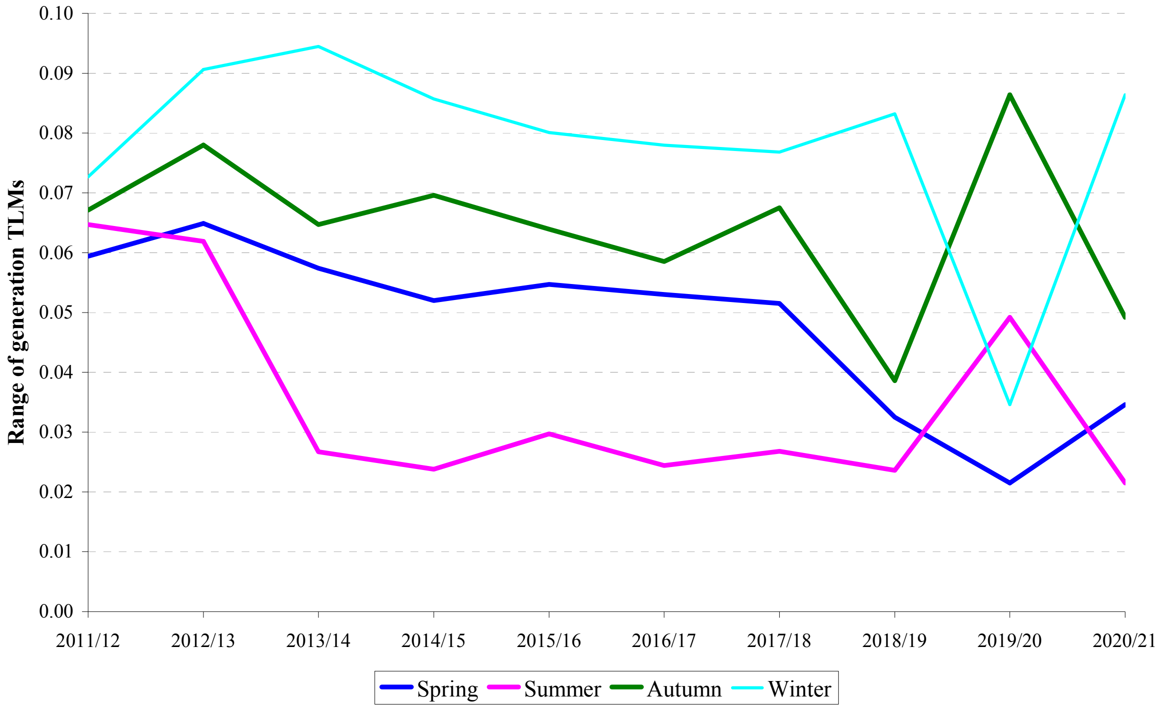
In addition, the fluctuating level of production cost savings under the volatile fuel scenario shows that the scenario is capturing the effect of unforeseen changes in circumstances between one year and the next.

6.2 Distributional effects

LE/Ventyx concluded that zonal loss charging would result in significant transfers between market participants in 2011/12. Generators in the north and suppliers in the south would face increased loss payments whilst, conversely, generators in the south and suppliers in the north would pay less for losses.

These results are, unsurprisingly, consistent with the zonal loss factors that LE/Ventyx estimate for 2011/12. Whether the results are representative of what might happen over the longer term depends on how stable the TLFs are over time. To illustrate why this is so, it is convenient to concentrate upon what happens to generators. Introducing zonal losses has two effects on generators. First, even if generators do not change the outputs of their plants, the loss payments (loss volumes multiplied by annual average baseload electricity price) to which they are exposed will change. Second, this change in loss payments may be modified if the output of particular plants changes as their position in the merit order shifts.

Figure 11: Spread in generation TLMs under the reference case



Considering the first effect, its impact depends on the extent of the geographical spread in the zonal loss factors. Figure 11 shows the spread between the highest and the lowest seasonal TLM in each year under the reference case: for example, the highest TLM in summer 2011/12 was around 0.065 higher than the lowest TLM. It demonstrates that there is some evidence that the geographic spread in loss factors declines over time but the picture is somewhat confused.[34] Nonetheless, distributional effects appear likely to decline over time to some extent even without considering the effects of generators' responding to the price signals from zonal losses.

If generators do respond to the price signals, which would be rational, then this is likely further to reduce the geographical spread in zonal loss factors (because plants with high losses will reduce their output) and hence further erode distributional effects.

It is likely, however, that LE/Ventyx's results exaggerate the distributional effects since they are based on prices derived from generator offers using TLFs rather than TLMs. As we have previously discussed (see Section 4.3.2 above), the change in prices between the change and base cases is always higher on this basis and is likely to over-estimate the price change that might be expected in practice.

[34] It seems likely that the atypical range of generation TLMs in 2019/20 is caused partly by high retirement assumptions (5400 MW) and partly by the modified approach to modelling congestion adopted for later years.

6.3 Longer term effects

LE/Ventyx concluded that zonal losses would strengthen the locational signals that already exist to build power stations close to demand. However, LE/Ventyx also concluded that it was uncertain how significant this effect would be since other non-cost related effects, such as planning permission and land availability, might be more important. Moreover, in the medium term i.e. until 2015/16, LE/Ventyx stated that there was unlikely to be any significant impact since most of the proposed power stations are favourably located with respect to transmission losses. Over the long term, LE/Ventyx estimated that the impact of any changes in siting decisions on net benefits was very uncertain but could lie in the range of £1-20 million per year.

As we noted in Section 5.9 above, the strength of the existing locational signals have decreased since LE/Ventyx undertook their analysis. This means that the incremental effect that zonal losses might have on plant siting has increased since LE/Ventyx's study, as demonstrated in Table 13 below.

Table 13: Regional new entry cost analysis for a 400 MW CCGT using 2009/10 and 2010/11 charges (£m)

Location	Non-loss regional charges		Zonal	Total regional charges	
	2009/10	2010/11	losses	2009/10	2010/11
Central London	-1.97	-1.66	-0.25	-2.217	-1.907
Penninsula	-2.16	-0.97	0.16	-2.001	-0.815
South East	1.09	1.31	0.21	1.295	1.517
North East England	4.07	3.55	1.74	5.811	5.288
South Scotland	5.45	4.86	2.57	8.019	7.428
North Scotland	8.64	7.81	2.92	11.561	10.728
Range	10.80	9.46		13.78	12.63

However, the table also shows that zonal loss factors are unlikely to be a decisive factor in determining where a plant is sited since they generally serve to reinforce the current locational differences by making locations that are already attractive more attractive and vice versa. Moreover, this simple analysis does not take account of other relevant regional differences such as the availability and cost of sites, the costs of connection to the gas and electricity grids, and of the ease with which the necessary permits can be obtained.

We note that a BSC Panel member suggested that zonal losses might serve to dilute the locational signals provided by TNUoS charges for generators in zones where there are negative TNUoS charges. The rationale for this suggestion was that negative TNUoS charges are levied on the basis of loss-adjusted metered volumes during triad periods. However, we cannot see that this is likely to be a problem – indeed the opposite will be the case, as demonstrated in Table 14 below. This calculates the impact in 2011/12 under the reference scenario based on 2010/11 TNUoS charges, under the assumption that a generator would be exporting 1 MWh in each triad period. It demonstrates that generators in the relevant zones (there are only four zones with negative generation charges) would actually be slightly better off as a result of the introduction of zonal loss factors, since these are all greater than one in the relevant TNUoS zones.

Table 14: Impact of zonal losses on generator TNUoS charges in negative charge zones[35]

TNUoS zone	TNUoS charge (£/kW)	Winter loss factor		TNUoS costs (£/MW)		
		Uniform	Zonal	Uniform	Zonal	Change
Central London	-6.414672	0.993	1.016	-6,370	-6,519	-149
Oxon & South Coast	-1.362801	0.993	1.018	-1,353	-1,387	-33
Wessex	-2.635277	0.993	1.018	-2,617	-2,681	-65
Penninsula	-5.871777	0.993	1.017	-5,831	-5,971	-140

LE/Ventyx also concluded that zonal losses would have little, if any, impact on the growth of renewables before 2015/16 since other factors (the design of the Renewables Obligation and non-economic issues) would be a more important limit on renewables building rates. Moreover, LE/Ventyx found that zonal losses only had a marginal impact on the overall profitability of renewable generation, although there were distributional effects with renewable generators in Scotland and the north of England being adversely affected and renewable generators in the south of England receiving some benefits.

LE/Ventyx have not provided details of the cost assumptions for different types of renewables that it has included in their analysis so it is not possible to verify their conclusions directly. However, their conclusions appear reasonable: difficulties in obtaining planning permission are generally cited as a major obstacle restricting the growth of renewables. On the other hand, we would expect that the introduction of zonal loss factors would have negative consequences for some renewable generation projects in the north of GB that were only marginally profitable with uniform loss factors. Consequently, LE/Ventyx's conclusions appear reasonable.

[35] For Oxon & South Coast and Wessex, we have used the Southern GSP Group loss factors and for Penninsula the South-Western GSP Group factors. Whilst this is a simplification, there are no instances in 2011/12 where generator TNUoS zones overlap with GSP groups that have generator TLMs less than one.

7 Concerns raised by interested parties

In their responses to the BSC consultation, interested parties have raised a number of concerns regarding LE/Ventyx's analysis, in addition to the widespread concerns regarding offshore wind capacities and discount rates that we have already addressed. In this section, we consider these concerns and the extent to which they change our critique of the LE/Ventyx analysis.

(a) *The implementation costs are too low at £1.5 million considering that there are 215 Parties to the BSC since this equates to a cost of £7,000 per Party*. We consider that this specific criticism is unfounded because not every Party to the BSC represents a separate company. Since it seems reasonable to assume that implementation costs would be incurred at a company rather than a Party level, the calculation that is presented is unrealistic. This is not to say that we do not have some issues regarding the implementation costs calculated by LE/Ventyx but, as explained in Section 4.3.2 above, we think that, if anything, implementation costs may have been over-estimated.

(b) *SOx and NOx benefits estimated by LE/Ventyx are over-estimated and ignore the data from the NERP cap and trade scheme where prices are effectively zero due to over-supply*. The latter part of the comment suggests that the respondent is considering the matter from the perspective of a generator, whereas LE/Ventyx's approach considers the welfare impacts. In some respects, the treatment of NOx benefits appears conservative in the sense that the government guidelines suggest that N2O (the main NOx gas) should be valued as a greenhouse gas with a pollutant value 310 times that of CO2.

(c) *No account is taken of the impact of zonal losses on balancing costs*. It is correct that no account was taken of the impact of zonal losses on balancing costs but this was not part of the terms of reference. In any event, since LE/Ventyx find that congestion reduces with zonal losses it is likely that their introduction would lead to a reduction in balancing costs.

(d) *LE/Ventyx have not appropriately taken gas transportation cost effects into account.* We are uncertain what the respondent's concerns were – the bulk of gas transportation costs are related to capacity costs, which would not be affected by the introduction of zonal losses since no plants shift their location. There might be some rebalancing of commodity costs but it does not seem likely that these would be significant and, in any event, consideration of gas transportation charges was not included in the ToR.

(e) *LE/Ventyx assume that there will be no new generation in zone 6 between 2015 and 2018 despite the fact that there are significant planned developments.* Whilst the respondent may be aware of planned developments none are included in the April 2010 SYS, irrespective of whether the comment is meant to apply to TNUoS generator zone 6 or GSP Group 6 (Northern).

(f) *No account has been taken of the need for coal plants to fit SCR* (selective catalytic reduction) *by 2016*. This is true and we assume that the respondent was concerned that the effect of the major outages required to fit SCR had not been captured. We think that it was reasonable to ignore this effect because the timing of any outages is difficult to predict and their effect would be transitory and so unlikely to affect the general conclusions.

(g) *Potential HVDC links within the GB system were not considered by LE/Ventyx*. We have addressed this point in Section 5.6 above and concluded that the omission of such a link is unlikely to have lead to significant distortions in the present value calculations.

(h) *Nuclear lifetime extensions were not considered by LE/Ventyx.* This is true but LE/Ventyx have included new build nuclear which will take place on existing nuclear sites and so, to some extent, mimic the effect of nuclear extensions.

(i) *Alterations to the economic life of existing assets not considered but they would likely be detrimental to security of supply.* LE/Ventyx have considered whether the introduction of zonal losses would be likely to alter closure or mothballing decisions and concluded that it would not. We tend to agree that other factors, such as changes in wholesale prices, are likely to be more important determinants of such decisions although we accept that zonal losses could have an impact if a plant is adversely affected by zonal losses and is only marginally profitable with uniform losses.

8 Conclusions

LE/Ventyx found that the introduction of zonal losses would lead to net benefits due to redespatching by generators and demand adjustments by suppliers. In reaching this conclusion, LE/Ventyx took account of implementation costs, which it estimated would only be of the order of £4 million for central systems and BSC Parties together, and on-going costs of around £0.2 million per year. It also concluded that zonal losses were unlikely to have any impact on generator decisions regarding investment and closure or on the growth of renewables.

We believe that these general conclusions are robust, except in respect of the impact of zonal losses on wholesale prices and (to a lesser extent) distributional effect, and conclude that the introduction of zonal losses can be expected to produce some net redespatch benefits for the foreseeable future. We accept that the magnitude of these benefits will change over time, particularly if the distribution of generation plant around GB changes, and there may be occasional years when zonal losses actually result in a dis-benefit due to mismatches between the TLMs and actual losses. Nonetheless, given the low level of implementation and operating costs associated with the Modification, it is difficult to see how the net present value of introducing P229 could be anything other than positive. However, there are two areas where we believe further investigation may be required, which Ofgem has commissioned Redpoint to undertake under the Lot 2 analysis:

- **Offshore wind capacities:** a sensitivity should be run to investigate the impact of adding additional offshore wind capacity so that the 2020 capacity is consistent with the offshore wind tenders that have taken place (rounds 1-3) and backing off an equivalent volume of conventional generation, so that the effective capacity margin is maintained. We suggest that 15 GW of offshore wind should be included by 2020 (approximately 10 GW more than included in the LE/Ventryx reference scenario), spread around GB in line with the Round 3 capacity allocations.
- **Accelerated renewables** Since LE/Ventyx undertook their analysis, the government has announced that it is intending to implement an approach to transmission access that is likely to result in at least some renewable plants connecting to the transmission system before all the wider reinforcements associated with them are completed. We consider that it would be helpful to run a sensitivity whereby transitory congestion is assumed to occur as a result of this effect. We suggest that this scenario should be an extension of the offshore wind scenario described above, but with around double the capacity of onshore wind in Scotland assumed by LE/Ventyx.

In Section 6.1 we provided some commentary on the differences LE/Ventyx found in the benefits for P229 Original and Alternative. We noted that the overall pattern of benefits (the scaling under the Alternative approach leads to lower benefits than that adopted under the Original approach) seemed reasonable. Furthermore, the changes in net benefits under the high and low gas price scenarios that LE/Ventyx studied seem plausible and confirmed by our simple modelling. The higher gas prices mean that the marginal costs of gas and coal plants will be closer together so the introduction of zonal losses is likely to give rise to more opportunities for fuel switching to reduce losses. Absent zonal losses, high gas prices lead large flows southward from northern coal plants. Zonal losses mean that some of this coal output will be replaced by southern gas output. In addition, the higher electricity prices that result from the higher gas prices increase the likely demand side benefits to some extent.

The extent to which the introduction of zonal losses would affect the behaviour of consumers or generators' new entry decisions seems likely to be much less significant. On the demand side, there may be some response but any effect from zonal losses could be swamped by changes in the level of electricity prices. As far as new entry decisions are concerned, not only are there strong locational signals already, from electricity transportation charges, but other factors such as the availability of suitable sites and planning permission may prove to be more decisive in determining where plants are built. We also agree with LE/Ventyx that zonal losses are likely only to have a marginal impact on the growth and overall profitability of renewables. However, we cannot rule out the possibility that zonal loss factors might deter some projects in the north of GB that were only marginally profitable with uniform loss charging.

Finally, LE/Ventyx's analysis of the distributional effects of zonal losses appears may over-estimate their impact, particularly in the longer term. For 2011/12, the over-estimate arises from the over-estimated change in wholesale prices (resulting from factoring TLFs rather than TLMs into prices). In the longer term, the spread in zonal loss factors typically declines to some extent over time and so distributional effects would also diminish.

Appendix I : Measuring changes in costs and profits

As we discussed in Section 4.3.4, there are a number of different ways in which the effects of the despatch impact of zonal losses can be measured. Table 15 below gives a stylised example of the changes in generators' costs and profits from introducing zonal losses. The example illustrates that the change in costs is about £25 of cost savings, but that the increase in generators profits is lower at £6. The sum of changes in generator profits and consumer surplus equals the change in costs – hence in this example consumers experience an increase in welfare of £19 due to the price increase caused by the introduction of zonal losses.

Table 15: Example of changes in costs and generator profits – all costs in £, output in MWh

Plant data

Plant number	MC (no losses)	Uniform LF	Zonal LF
1	15	0.95	0.95
2	23	0.95	0.93
3	25	0.95	1.03

Uniform losses case

Plant despatch

Plant	Gross output	Credited output	Net output	Physical Losses
1	100.0	95.0	95	5
2	59.1	56.2	55	4.1
3	0.0	0.0	0	0.0
Totals	159.1	151.2	150.0	9.1

Cost of generating	2,860
Volume of losses	9.1
Cost of losses	170.2
Marginal price	24.21
Price of losses	221.28
Genco revenue	3,660
Genco profit	800

Zonal losses case

Plant despatch

Plant	Gross output	Credited output	Net output	Losses
1	100	95	95	5
2	0	0	0	0
3	53.4	55	55	-1.6
Totals	153.4	150.0	150.0	3.4

Cost of generating	2,835
Volume of losses	3.4
Cost of losses	35.0
Marginal price	24.3
Price of losses	82.5
Genco revenue	3,641
Genco profit	806

Benefits

Cost benefit	25.3
Change in Genco profits	5.8