BSC Modification Assessments P198, 200, 203 and 204
Comments by Immingham CHP LLP

Introduction

Immingham CHP LLP strongly opposes the change proposals related to P198, 200. 203 and 204, and together with a large majority of the industry we believe that they do not better facilitate achievement of the applicable BSC objectives. We believe there are significant flaws in Ofgem's regulatory impact assessment and the analysis it draws on.

The British electricity market design already incorporates locational signals through NGC's transmission network use of system (TNUoS) charges, which are generally considered within European markets to be comparatively sharp. The instability in the TNUoS charging signal separately warrants consideration, as does the distorting effect of existing transmission constraints, and they both have important interactions with the current change proposal. The considerable upheaval which would result from the modification proposals heavily exceeds the modest potential gains identified in the impact assessment (RIA), many of which we feel are over-stated, and we consider there is great scope for unintended consequences and detriments not identified.

We have addressed the specific questions raised by Ofgem in the appendix to this letter. This covering letter makes some additional general points that we feel are lost in the RIA and need to be addressed before a final decision is made. They include:

- the scope for competitive impacts and detriments especially to smaller players in the market arising from the distributional impact of the proposals
- because of their remote location, an adverse impact on a number of more environmentally benign technologies creating an overall loss in welfare
- the factors that mean that behavioural response is unlikely
- the significant gaps in the RIA
- the tendency to overstate benefits of the proposals and understate costs
- other mechanisms for loss mitigation outside of the BSC have not been explored, and could deliver greater benefits at lesser cost, and
- the inability to address countervailing benefits arising from the phasing and mitigation schemes included in the proposals.

Competitive detriments

Our opposition to the proposals arises not solely from the fact that Immingham CHP, as a northern generator, will be adversely impacted by all of the proposals in front of the Authority, but the profound effects that the proposals would have if implemented on risk and competition in the market-place. Put simply, a ***future*** sharpening of locational signals could be considered as desirable for future siting decisions on dynamic efficiency grounds ***provided*** that the benefits are clearly demonstrated to outweigh the costs. That said, in our view, these effects could be sufficiently material as to lead to cancellation of some committed schemes and discourage significant new investment of a type that the government is keen to incentivise through its low carbon agenda, and it is doubtful whether a robust enough case could be made.

However extrapolating these proposed arrangements to existing installations and participants already committed to investment creates a random redistribution of wealth, which will impact disproportionately on non-integrated and smaller players. Portfolio players will be able to rebalance their output (where they need to) and will enjoy a diversity benefit. Smaller players will simply see a random change in their costs. There seems to be no acknowledgement of these issues and discriminatory impacts in the RIA. Further imposing locational risk on a market where there will be skewed ability to respond will lead to market inefficiency through artificially increasing some participants' costs, especially where very large capital investment has already been spent on facilities designed to last 30 years. In turn such change could materially distort competition.

Environmental disbenefits

There could also be a detrimental environmental impact as the plant assumed to displace output may well be less environmentally desirable. Economic signals can only work if market participants are able to respond to them. However many participants, e.g. existing generation, CHP (located to suit demand needs on existing industrial sites) and wind power (located where the wind blows), cannot respond to new locational costs in the market, and given these tend to be remotely situated they will simply see a new cost which can be likened to a tax.

As a CHP operator we think these impacts have been totally glossed over. CHP plant location is largely tied to the industrial site it is associated with, and it would therefore not be responsive to the cost signals these proposals seek to introduce. In terms of capacity, the regions of Scotland, Yorkshire/Humber, the North West and the North East of England - which would be impacted most adversely by the modification proposals - account for well over 2/3rds of currently installed CHP capacity. The proposed changes would thus result in less competitive generation from most of the CHP sector undermining its ability to compete fairly and further undermining its targeted growth, at a time when there is already widespread and increasing scepticism about the ability of government to meet its targets. It is highly undesirable, given the vast sums of sunk investment, to create such incentives, especially given the beneficial environmental impact of such installations.

As an active developer, we are concerned not only for our operation and consented assets but also for new developments we are assessing, which are all CHP or renewables. All these developments are in areas that would be worse off under other proposed methodologies, and could be put at risk. Renewable generators, who have very limited discretion over development areas, plainly would not relocate to less windy locations in response to more favourable costs arising from transmission losses. It is naïve to assume, as the RIA does repeatedly, that future developments of these technologies have significant choice over the areas in which they can be located. The timing of the proposed change is particularly inauspicious given the significant amount of new build in the pipeline.

Benefits have been overstated

Redispatch benefits are greatly overstated because scale players will internalise many of the cost changes, and operational decisions on base-load plant will be driven by other factors. Constraint costs on the system may also distort more rational redispatch. Benefits arising from longer-term locational signalling are recognised to be negligible. The environmental benefits are heavily dependent on the redispatch effect, and they too are consequently overstated, and the RIA chooses to disregard the increase in losses projected for the back-end of the assessment window. We also consider that the costs associated with implementation of the proposals have been under-estimated.

We believe there is clear evidence demonstrating that the benefits of these proposals have been overstated. The feel of the document is that Ofgem has been looking to accentuate the positives (even where they cannot be quantified) and to play down the negatives. Overall the benefits do not outweigh the costs and do not justify the implementation of any of the proposals.

Demand cannot respond

Demand will also be unresponsive. For the most part, with the limited exception of certain large industrial loads, demand is price inelastic. In the 2006 Seven Year Statement, National Grid estimates demand response to peak pricing to be less than 1GW out of 60GW. The purchase of electricity is not the core activity of demand sites and locational decisions would be much more likely to be influenced by, for example, planning permission, proximity to market, local skills pool, regional policy and availability of key primary resources. None of these factors, of course, will be affected by the current change proposals.

The RIA, by quantifying efficiency gains through estimating demand elasticity, totally misses the point. In the short term demand cannot respond to the signal being created, as there is no alternative, and long-term siting decisions will not be impacted by the introduction of locational losses. Again the impact will be a one-off redistribution of costs between participants.

Even if we were to suppose that longer-term siting decisions for demand-side industry might be impacted by locational losses, this would tend to exacerbate the problem for CHP rather than help. By their nature the locational signals for demand are the opposite of those for supply so the tendency would be for energy intensive industry to locate where locational losses would be greatest for supply. Whilst this does not impact most forms of supply, CHP has to be located adjacent to its host and thus would be disincentivised from sizing to export electricity and thus disincentivised from maximising carbon savings. This important factor does not appear to have been addressed in the Impact Assessment and impacts the UK's ability to meet its CHP target and environmental targets.

Gaps in the RIA

We consider that implementation of the current modifications would have the following detrimental impacts that have not been adequately taken into account in the RIA:

- prices for some consumers will rise:

  The proposals create new direct costs for many participants and increase market risk and indirect costs for the market as a whole. These costs cannot be hedged. Any increased cost will be passed on, while incumbents will retain any reductions. In net terms consumer prices will increase.

- risk in the market will be harder to manage, and new unmanageable risks will be created:

  Understanding, forecasting and managing the variation in locational transmission loss factors (TLFs) will be difficult and impose further transactional costs on the market, which is already overly complex. These effects are such that they could impact on sectoral financing costs and could be regarded as creating a further barrier to entry. Locational effects are also dependent on other parties' behaviour, especially under a zonally-based system. An operator located next to peaking plant could be very adversely affected by something it can neither predict nor control. There are also random effects caused by plant retirement.

  The cost and complexity of the change proposals are significant and on the basis of the Oxera analysis reflected in the RIA, understated. Understanding, forecasting and managing the variation in locational TLFs will be difficult and impose further transactional costs on the market, and these costs increase disproportionately the smaller the player.

- contract disputes will arise:

  It will be necessary to redefine standard terms for contracts (GTMA, etc) that identify the point of sale by location (or any similar basis). Liability for the new allocation of losses may also be unclear in some contracts (e.g. whether it is an energy cost or a transmission cost). This situation could give rise to significant administrative, legal and dispute resolution costs, which have not been identified in the RIA.

- proposed changes will significantly increase market complexity:

  There are already widespread concerns in the electricity market that central trading arrangements are too complex and benefit large integrated players with considerable resource to deal with the implications. Implementation of the losses proposals would constitute a further change and introduce more complexity, and we consider they will increase barriers to market entry. We categorically disagree with Ofgem's assertion that market risk will reduce because of the ability of the governance process to assimilate major change. More generally the issue of impacts on market entry are not addressed.

- impacts on most local generation are not considered.

  The RIA acknowledges that in some areas new generation will be incentivised to move closer to demand, but it does not consider the effect on embedded benefits for existing operators. It also does not consider impacts on distribution costs and losses of increased investment on distribution networks. It also implies that reduction of loss charges in some areas will lead to more connection activity; the obverse of this is of course that higher charges will encourage parties to embed, potentially resulting in less efficient usage of the grid. These are major oversights.

- the presentation of the analysis is incomplete

  No attempt has been made to summarise the net impacts of the assessment identified by modification group and panel, which is unhelpful. More substantive deficiencies are the failure to address unintended consequences and alternative solutions to address the alleged deficiency.

Reasonable alternatives have not been considered

ICHP is disappointed that an SO- or TO-focussed approach to management of transmission losses has not been considered in parallel with the BSc modifications. While this style of approach does not necessarily address the defect identified by providing a solution within the BSC, it evidently is an option for meeting the intention behind the modification of creating an arrangement that enables optimal management of the cost of transmission losses.

Several markets internationally apply downward pressure on the cost of transmission losses through mechanisms administered by the transmission entity, and this type of approach would be very compatible with the existing style of approach to setting transmission incentives in the UK. Such an approach also has considerable merit in terms of avoiding the increase in market complexity inherent in the current proposals.

In this context we also feel that the properties and effects of various mitigation and phasing options have not been adequately addressed given the positive effect they are likely to have in terms of addressing new risks and unintended consequences, and also as a means of eliminating the distributional detriments of the P198 and P203 original proposals.

Conclusion

In summary the RIA falls well-short of a rounded, balanced assessment. The net impacts are hard to assess because there is no summary. A ten year cost-benefit assessment is inadequate to test a proposal that is likely to have significant longer-term impacts on the distribution of costs within the industry. There are a number of unfounded qualitative judgements in the report that seem designed to bias the assessment (including paras 3.27, 4.25 and 4.26). We believe the document needs considerably greater amplification to correct the analysis before it is submitted to the Authority.

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Appendix

BSC Modification Assessments P198, 200, 203 and 204

Responses to questions by Immingham CHP LLP

Question 2.1: *Do respondents consider we have appropriately summarised the direct impacts of the proposed and alternative modifications?*

No.

The direct impact of the proposed changes on allocation is overstated.

The allocation and therefore any savings is skewed. We consider that behavioural changes to the extent anticipated are over-stated as industry structure will dilute a large element of the expected behavioural response. Self balancing, not central despatch, is the norm, and the cost of losses is just one element relevant to operating an integrated portfolio.

Total redispatch savings are overstated.

Oxera have already put down an important caveat which Ofgem notes at para 2.14 “The level of annual loss savings varies considerably from year to year, which Oxera attribute to approximations in the modelling approach used”. More fundamentally the concept of the merit order is largely redundant in the British market and self-balancing by portfolio asset owners is the norm. Assumptions on re-despatch benefits and reduced total losses in the RIA are speculative at best, and within the wider scheme of things cannot be regarded as significant. As the RIA notes “Changes to the total volumes of losses are likely to be relatively small as a consequence of any of the proposals being implemented” (3.33)

The RIA also acknowledges that “if the signal is inaccurate or not sufficiently material to alter operating decisions, the modifications would not be expected to alter the volume of losses.” If those savings do not materialise or are significantly less than those estimated, then the changes become largely an arbitrary redistribution of costs, which might hinder, not help, competition.

In fact the Oxera analysis showed negative gains in 2014-15 and 2015-16 (that is an increase in losses compared to the current arrangement), a point that is not brought out in the RIA. It is very possible that a 15 year assessment window could have revealed a cancelling out of the losses savings implied in the earlier part of the period.

Implementation and operational cost estimates are prudent.

The costs indicated at page 26 do not seem to reflect trading parties’ submissions to Elexon during assessment. Participants will need to review their settlement and billing systems and, equally important and as we have already noted, renegotiate existing contracts. Taking into account the IT and legal costs, we think participant’s costs will be well in excess of the £1.6mn quoted.

Question 2.2: *Do respondents consider there are additional direct impacts that have not been fully addressed?*

Yes.

The distributional impacts on *types of participant* and on *different technologies* are largely ignored.

This is a major weakness of the document. There appears to be a feeling that all participants are able to hedge their position. This may be true for large integrated generators/suppliers but not for single plant generators.

The distributional effect of reallocation impact on competition is largely ignored.

The RIA notes that: “This might be expected to influence pricing in a competitive market – although the precise form of the response is difficult to predict” (3.34). However there will be a random impact on parties’ costs. The document should explore how these cost changes are likely to impact on different types of participant and different technologies given their location.

We contend that the impact would be disproportionate on smaller players because of larger players' ability to diversify the effect of the changes across their dispersed portfolios. We also believe that certain technologies will be systematically discriminated against. See comments within our covering letter.

Question 2.3: *Do respondents wish to present any additional analysis that they consider would be relevant to assessing the proposals?*

No.

Question 3.1: *Do respondents consider we have appropriately summarised the indirect impacts of the proposed and alternative modifications?*

No.

The accuracy of allocation of losses under the proposals is limited.

The RIA notes a number of simplification techniques applied across the different proposals at pages 30-31, which means that the factors proposed are not cost-reflective. More specifically:

- All are based on ex ante zonal factors. Ex-ante factors as proposed based on prior year performance cannot be properly cost reflective in terms of guiding operational decisions, especially in a system that is subject to significant shifts in power flows from year-to-year.

- A zonal approach is very blunt, potentially creating significant subsidy issues within zones for transmission-connected plant, but conflicting signals for distribution-connected plant. As the RIA notes "Variations within zones could be significant particularly for geographically nodes within a zone." (3.8)

- It also creates asymmetry with generation zones applied for transmission use, raising the prospect of dual and possibly conflicting locational signals. The examples at table 3.1 miss the point: generation zones can and do vary. The purpose of the incentive is different, and while the "pattern of locational loss charging echoes the pattern of TNUoS" this should not and will not necessarily always be the case. The changes proposed are very material; an 85% load factor generator in the SW relative to the NW would see a shift over the status quo relative to P198 of in excess of £11/kW. Even for low load factor plant the change in the losses element of the charge are considerable, rising by almost 200% in the North of Scotland, which is where much of the wind projects in planning is expected to materialise.

  It is also wrong to state that the strength of the locational signal for losses is relatively small when compared with the TNUoS signal. In four of the zones cited the losses charge is about 50% or more of the comparable TNUoS charge for an 85% load factor generator.

The indirect locational benefits have thus been misstated, but still create a material effect and greatly increase the locational signal. It does not follow that a stronger locational signal is better if it does not necessarily reflect costs, especially where one component of the signal is intended to capture operational decisions (and reflects MWh), but the other the impact of future investment (and reflects MW). The proposed zonal approach will create particularly perverse incentives for outliers.

In this context it is also relevant that the one element of the locational signal is inherently volatile. This is best evidenced by the recent decision of national Grid to exclude 3GW of new connections from the charging base for 2007-08 TNUoS. This had the effect of lifting all charges to generators but skewing them especially in certain zones. Year to year changes in zonal generation charges can also be significant.

The confused regulatory policies that have given rise to these conflicting charging approaches requires fundamental re-examination not "pick and mix" rationalisation.

Impact on long-term decisions has not been properly quantified

The starting point for the assessment is not the right one. In a sector where asset lives are typically 20 years or more and where there is the expectation of considerable new development from 2015 onwards, a ten year cost-benefit analysis is inadequate.

Oxera was unable to quantify any additional medium- or longer-term benefits arising from locational losses on siting: “there are already significant locational signals, which are likely to site new plant in advantageous transmission zones during the study period; the long-term impacts will not be realised until beyond 2015,” Oxera says in its report. It also notes an “ambiguous” effect. It also notes a “negligible impact on transmission network operation and development (Oxera, p77).

The RIA refers to annual long-term benefits of £10.6mn under P198 and P203 (p34), though Oxera (p54) considers that a range of £1-20mn would be prudent (noting that the range is “large and very uncertain” and also that the methodology will “systematically tend to overstate the effect on losses”).

The assessment on perceptions of risk is flawed.

We fundamentally dispute the assertions at para 3.27. There is widespread agreement within the industry that the treatment of losses has been mishandled and created considerable uncertainty. It is impossible to quantify the effect but it is not positive.

Consumer prices could increase.

Customers will tend to see the marginal cost of losses across the system because larger players will be able to pass the cost through in their contracts and tariffs, increasing consumer prices. For every 0.1% increase above average cost recovery, prices could increase by between £10-15mn across the system per annum more than offsetting the volume savings claimed.

The assessment of demand response shows minimal impact.

Demand-side savings (para 3.35) at less than £0.8mn per annum at most under P203 are based on questionable assumptions of demand elasticity, and are not material. Assuming consumer prices rise overall the effect is possibly understated. As we note in the covering letter, this emphasis misses the point, the key conclusion should be that locational losses will not have an impact on location decisions of customers.

The RIA does not address distributional effects or the impact on small businesses.

These are important omissions specifically provided for in the guidance on the conduct of impact assessments.

Question 3.2: *Do respondents consider that there are any indirect impacts of the proposed and alternative modifications that have not been fully assessed?*

Yes.

There are two important omissions in the assessment of indirect impacts.

The extent of cross-subsidy within zones has not been assessed.

The impact on variable transmission losses on distributed generation has not been examined. There is a mirror image effect relative to the impact on transmission-connected plant from the manner in which embedded benefits work.

Question 3.3: *Do respondents wish to present any additional analysis that they consider would be relevant to assessing the proposals?*

No.

Question 4.1: *Do respondents consider that we have appropriately outlined the key environmental impacts of the different proposals?*

No.

The assessment falsely suggests a significant value of environmental benefits.

This adds a further £20-65mn of benefits over the period to 2011 depending on the modification implemented and assuming a £70/t value for carbon abated, with the greatest impact being under P203. A number of points arise from the estimate:

- the benefits will be scaled back to the degree re-despatch benefits do not materialise;
- why the value is shown as running only to 2011 - we assume this end point is explained by the fact that after that point the annual quantum of reduced losses falls away under the Oxera analysis, implying these benefits are eroded or lost
- if a lower figure were assumed the impact at the lower end of the range would be immaterial
- the estimated increase in losses from 2014-15 will increase carbon and the associated costs
- the same points apply to the alleged SO_2 and NO_x benefits identified.

No account seems to have been taken of fuel switching effects, and the discriminatory impact of the proposals on low carbon renewables and CHP technologies.

Transmission impacts are negligible, although the RIA implies these are positive.

We have already noted Oxera's view that there would be a "negligible impact on transmission network operation and development" (Oxera, p77).

The environmental effects of the proposals arising from changed incentives to distributed generation is not assessed.

The RIA also notes “Oxera concluded that the introduction of zonal loss charging strengthens the locational signals for building power stations closer to demand, however the strength of this signal relative to other changes is uncertain.” (4.18) More realistically it is likely to incentivise developers to embed where feasible in high cost zones. This effect is not considered, and could even lead to increases in total network losses. The environmental impact of this could also be detrimental.

The assessment of the impact on low carbon technologies is not correct.

The RIA takes as its starting point the general conclusion of Oxera that “the introduction of zonal loss charging will have little, if any, impact on renewable new build across the period to 2015-16”. However Oxera qualified its conclusion by reference to other factors such as the design of the RO. It concludes essentially that other factors will drive renewable build decisions. However it does repeat comments from its 2003 report that there would be “a marginal impact on the profitability of renewables projects connected to transmission networks and large distributed generation” and notes distributional impacts, which must impact on development at the margin.

The large majority of new developments are in the North and in remote locations. There are particularly problems with consenting projects in the south. It is wrong to assume that any reduction in the north will be offset by additional projects in the south. We conclude that there will be a net welfare loss to renewables technologies.

We reject the implication at para 4.24 that the locational loss charging will be beneficial for CHP. See our covering letter. There is no analytical basis for such statements and we are concerned that unfounded qualitative comment is intended to bias the assessment.

Question 4.2: *Do respondents consider that there are other environmental impacts that should be assessed?*

Yes.

There are gaps in the environmental analysis.

Again the environmental impact on distributed generation not subject to transmission charges has not been assessed.

Question 4.3: *Do respondents have any additional analysis in relation to environmental impacts that they wish to present?*
No.

Question 5.1: *Do respondents have any views on both the process and timetable that are proposed for taking forward this assessment of the proposed and alternative modifications?*

The consultation on the RIA has been very narrowly defined to focus on the costs and benefits of the proposals. It is essential that there is a further consultation once the Authority has arrived at a “minded to” decision and that there is the opportunity for full consultation at that time.

We believe significant revisions are required to the RIA before it is suitable for submission to the Authority.