Dena Barasi
Electricity Transmission Policy
Ofgem
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Dear Dena

Impact Assessment on RWE proposal P229 - seasonal zonal transmission losses scheme

EDF Energy is one of the UK's largest energy companies. We provide 50% of the UK's low carbon generation. Our interests include nuclear, coal, gas-fired and renewable electricity generation, combined heat and power plants, and energy supply to end users. We have over 5 million electricity and gas customers in the UK, including both residential and business users.

We welcome the opportunity to respond to this consultation.

In summary, we do not support the P229 proposal or its alternative, and we consider that neither better meets the applicable BSC objectives compared to the baseline. The key points of our response are:

- Theoretical analysis indicates potential national benefits that are relatively small and uncertain compared with the total volume of losses, and with the total value of energy traded. Achievement of these benefits requires idealised perfectly competitive behaviour of participants, with generators operating solely according to short-run marginal costs dominated by prevailing fuel prices. It also relies on zonal loss factors derived from historic flows remaining appropriate to the potentially quite different real outturn national and local flow situations to which those factors are applied.
- If these assumptions are not met, the scheme could result in the theoretical benefits not materialising or even, in some circumstances, costs increasing, for example if wholesale prices were to increase, or renewable generators (which the impact assessment shows would be worse off by 1.5% as a class were P229 to be implemented) were to require additional subsidy to overcome additional costs.
- The significant redistribution of loss energy between participants, and the short and long term uncertainty in allocation of loss energy, which is largely unmanageable by individual participants or customers, is disproportionate to such small and uncertain benefits.

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- The current scheme can be considered to represent a de-facto long term risk management arrangement, bearing in mind that, over electricity investment timescales, theoretical loss factors in many locations could swing in either direction.
- EDF Energy has a reasonably balanced locational portfolio of generating plant, but its customers are concentrated in the South. Many of our customers would face increased prices under a P229 scheme, and other than move would be able to do little to avoid this cost.
- A large amount of complex quantitative and qualitative analysis has been performed on this proposal, under both the BSC Modification assessment and Ofgem's Impact Assessment, spanning diverse interacting aspects of the wholesale GB electricity arrangements.
- In our view, this analysis demonstrates that national generation cost benefits should in theory be achievable from such a scheme, including consequential benefits such as reductions in emissions. However, in practice there are many uncertainties and other potential consequences, some of which might not be considered desirable.
- In the context of the GB electricity market as a whole, the theoretical benefits would be relatively modest, with estimates for the change in national generation costs ranging from approximately £0m to £10m/year excluding consequential effects on NOx and SOx, and –£2m to £28m/year including NOx and SOx (Impact Assessment table 4.1). These amounts are small compared with the total cost of transmission losses, suggested as £225m/year (in executive summary), other transmission and distribution costs measured in thousands of millions per year, and the net cost of traded wholesale energy, perhaps £15billion/year.
- Regardless of whether cost benefits would be achieved by changes in activity at the margin, or whether prices for customers as a whole would be reduced, both of which have much uncertainty, there is an absolutely certainty that significant amounts of energy attributed to losses would be redistributed between all participants and customers according to location (£31m between generators, and £37m between suppliers in the first year, according to Table 4.2 of the impact assessment).
- The analysis indicates that if P229 were implemented, costs would increase for transmission and distribution connected generation in Scotland and the North, where significant amounts of renewable generation and a Carbon Capture and Storage generator are expecting to locate. The embedded benefits currently available to most existing distribution connected generation would also be reduced if P229 were implemented.
- We acknowledge that locational loss factors either side of congestion created by the Connect and Manage connection arrangements might provide some small mitigation of constraint costs. However, we consider the potential benefit to be subject to significant uncertainties.

- We note that Project Transmit options include potential fundamental changes to transmission charging. In comparison, the relatively small and uncertain national benefits from P229 seem rather insignificant.
- We note that some of the Electricity Market Reform (EMR) options would be complicated by the implementation of P229, with little apparent benefit. For example, Feed-In Tariffs and/or Contracts for Differences and/or capacity contracts might need to consider the relevant zone of a qualifying generator. We note that the Brattle analysis suggests renewables obligation certificates and renewables obligation volumes should theoretically include losses adjustments in future, even under a uniform allocation scheme (page 5 of Brattle Lot 3 commentary).

We attach as an appendix to this response our earlier comments to the BSC Panel in respect of the P229 Report Consultation as our views on the detail and assessment of this proposal remain unchanged.

I hope you find these comments useful, however please contact my colleague Rob Rome (**rob.rome@edfenergy.com**, 01452 653170) if you wish to discuss this response further.

Yours sincerely

Denis Linford
Corporate Policy and Regulation Director

Appendix

EDF Energy response to P229 Report Consultation

Do you agree with the Panel's initial view that the Proposed Modification should be rejected?
We do not think Proposed Modification P229 would better meet any of the BSC objectives.

Key Points

- **There is considerable uncertainty whether BSC Objective (b) would be better met because the theoretical energy cost savings estimated by the cost benefit analysis are relatively very small and might easily be cancelled or outweighed by participants other responses to the imposition of such a scheme.**
- **BSC Objective (c) would not be better met because the impact on competition would be to create short term winners and losers, with potential for large errors in allocation of losses volumes to individual locations.**
- **BSC Objective (d) would not be better met because the costs of implementing and administering the proposal are considerable.**

BSC Objective (b)
We are unconvinced that BSC Objective (b), relating to efficient transmission system operation, here also taken to include efficient overall despatch of generation to meet demand, would be better met, for the following reasons.

A national welfare benefit is theoretically possible if participants are given the correct signals reflecting their individual impact on the shared cost of losses, and they are reasonably able to respond to those signals so the theoretical benefit materialises.

Proposed Modification P229 would allocate an energy volume to every BM Unit which would be uncertain, unavoidable, and beyond the control of its owner, being dependent on the behaviour of other BM Units and the properties of the transmission system, in each half-hour, each season, and in the longer term.

The Cost Benefit Analysis (CBA) performed for P229 shows theoretical net benefits arising from an assumed simple response of marginal generators to the proposed volume adjusters.

However, in the study reference case, the estimated energy cost savings average £7m/year from an £8.4bn/year total "production cost", just 0.08%, equivalent to 0.02 £/MWh reduction in average energy prices. The fraction of total generation costs is lower still, because production cost considered in the CBA is mainly fuel and emissions and does not include the capital cost of generation which investors would also expect to recover. Benefits vary from scenario to scenario, but in all cases the impact on net energy costs is relatively very small, and it is clear that other factors could cancel or outweigh the assumed benefits. For example:

- TLF factors would increase the uncertainty in out-turn energy costs faced by generators. Because this uncertainty is essentially unmanageable, it would be passed through to purchasers in a risk premium on the market price of energy set by marginal generators. We assume any correspondence between beneficial TLF factors and marginal cost generators is transitory and uncertain.
- TLF factors would increase the uncertainty in out-turn energy costs faced by suppliers, both in the short term in individual half-hours, and in the long term where the factors would not be known. This uncertainty would be passed through to customers in a risk premium.
- Both generators and suppliers would need resources to manage the uncertainty and additional complexity associated with a locational transmission losses scheme. We think some parties have underestimated the cost of these resources.
- The effective future capacity of generation investments would become less certain. Over the lifetime of most generation and demand investments, a wide range of loss adjustments is possible. This would increase the investment return required by investors, and hence the price to customers.
- A significant step change in the value of some assets would arise from introduction of Proposed Modification P229. Regulatory imposition of such a change would increase the perception of regulatory risk with potential consequences for future investment relative to other investment activities.
- Approximations in the TLF methodology, for example averaging over zone and season, mean that individual locations could be allocated losses costs which give the wrong signal, and in some cases completely the opposite signal to that which would theoretically give benefits. The P229 Cost Benefit Analysis has allowed for this in estimating generation despatch costs, but we are not convinced the impact on market prices and hence the price actually paid by customers, has been fully considered. Great Britain has a single market price, ultimately dependent on national marginal generation costs, not locational market prices or a weighted locational market price as in the analysis.
- Generators operate with complicated physical constraints on behaviour such as start-up, shutdown, load changing, part-loading, interaction between units, which mean that actual despatch may not match assumptions in theoretical despatch.

- Generators may operate with commercial constraints such as take-or-pay fuel contracts which may cause actual operation to differ from theoretical despatch.
- There is no indication that the introduction of P229 would significantly affect locational siting decisions to the national benefit, since losses are a relatively minor factor in such decisions compared with transmission access costs (which are related to losses), planning, fuel source, social and other factors. The reduction in the net value of losses under P229, as estimated by Cost Benefit Analysis, is due to short term despatch effects and is relatively small and uncertain compared to the value of losses itself and relative to the potentially inaccurate redistribution of losses between BM Units in different zones (see other comments below).
- It is possible that in some circumstances those benefiting from the proposal might retain the benefits rather than passing them on to customers in reduced prices. For example, existing marginal generators might have no incentive to pass on benefits, nor suppliers with customers on long term or default contracts.
- Changes in gas transport costs associated with marginal despatch of gas generation could reduce any theoretical benefit of reduced North to South electricity transport. Gas transport costs were ignored in the CBA. For example, the theoretical marginal benefit for electricity transmission losses of moving gas-fired electricity generation south could be reduced, cancelled or negated by marginal increases in gas transport costs for moving gas from North to South. Gas Shrinkage appears to have similar magnitude to electricity losses, and to be correlated with flows at St.Fergus in the north of Scotland.

BSC Objective (c)
We do not think Proposed Modification P229 would better meet BSC Objective (c) relating to competition, for the following reasons.

The proposal would create windfall winners and losers at implementation, who would be largely unable to mitigate or hedge the costs and risks created by the proposals. The impact assessment shows that existing renewable generators as a class would be worse off by 1.5% as a class were P229 to be implemented. New renewable generators are still showing a bias towards northerly and Scottish locations, and marine renewables are expected to exhibit a particularly strong (almost complete) bias towards Scottish locations; the proposal would represent an adverse factor, and risk, for developers, make it even harder for Britain to meet her renewables 2020 targets.

A benefit to competition is theoretically possible if participants are allocated costs ex-ante representing their contribution to the cost of losses. However, on a shared system the costs theoretically attributable to a particular user at a particular location may be strongly dependent on the actions of other users, and could vary considerably, in either direction, over time. New users change the allocation for existing users, and in turn become existing users themselves. For example, a generator might initially connect at a location and sell long term energy on the basis of the prevailing loss allocation, only for another user to connect and significantly increase the loss factor. This uncertainty represents a risk, which carries a cost, which users would reasonably be expected to seek to manage perhaps via some form of risk premium. One method is simply to pool the costs as at present. Another would be to seek firm losses allocations over extended periods of time, with residual losses perhaps targeted by locational loss factors, or perhaps shared, by non-firm users. The existing arrangement provides a natural locational loss uncertainty risk sharing to all users for the lifetime of an installation. If Proposed Modification P229 were implemented at a point in time without any associated hedging mechanism, there would be no incentive to create or join such a scheme for those who stand to gain from the step change. For example, those users with limited life investments who stand to gain for a period of a few years from introduction of the proposed locational scheme (windfall winners).

Currently, no locational signal for losses is given. If the simple theoretical argument for a locational loss allocation is accepted, the maximum error currently is the difference between zero and the theoretical locational allocation. In a scheme such as Proposed Modification P229 where the zonal seasonal average allocation can be quite different, even in the opposite direction to the theoretical allocation at a particular location within that zone, the potential error for individual locations is doubled. For example, a location with a theoretical loss factor of +0.02 and a current factor 0.00 could be considered to be losing a positive allocation of 0.02, while under Proposed Modification P229 it could be allocated a seasonal zonal factor of -0.02, and be considered to be losing 0.04, twice as much as at present. The results of the load flow analysis performed for P229 show there are many locations where the nodal TLFs are distributed widely around the average and where this could be an issue for individual locations (see results of PTI-Siemens Task 3, report figures 29-32). Although the averaged factors might theoretically on average give the welfare benefits suggested by the Cost Benefit Analysis (noting our doubts given above), they could introduce significant errors for individual locations, which would have a detrimental effect on competition.

Overall, BSC objective (c) relating to competition would not be better met, and this consideration outweighs any potential but uncertain benefit under BSC Objective (b) relating to efficient system operation.

BSC Objective (d)

We think it self-evident that BSC Objective (d) relating to efficient administration of the balancing and settlement arrangements would not be better met, due to the considerable implementation and ongoing operational administration cost of a zonal losses scheme.

Do you agree with the Panel's initial view that the Alternative Modification should be rejected?

Seeking to limit transmission loss adjustments to be positive amounts only (i.e. a charge rather than a credit) is likely to be more widely understood by participants and customers. It reflects the fact that taken in isolation, any individual flow can only cause losses, and real losses cannot be negative.

Compared with the current baseline, the Alternative Modification creates a differential exposure to losses between different zones proportional to the impact of flows in that zone to total variable losses, and assessment modelling indicates it has potential to theoretically reduce energy costs. It mitigates the exposure of individual locations and parties to potential misallocations in the Proposed Modification P229 arising from differences between seasonally zonally averaged TLFs based on historic flows and theoretical outturn nodal values, reduces uncertainties in future loss adjustments, and reduces the unpopular transfer of value between zones which would occur under the proposal.

The reduction in uncertainty of outturn loss adjustments in the Alternative Proposal would reduce the impact of the factors described in response to question 1 which might prevent the theoretical net energy cost savings indicated by cost benefit analysis from materialising. However, we still consider there is great uncertainty whether benefits would actually be delivered, and therefore whether BSC Objective (b) would be better met.

The reduction in uncertainty and in potential error in relation to individual locations in the Alternative Proposal reduces the detrimental impacts on BSC Objective (c) relating to competition, compared with the Proposed Modification.

In particular, the large transfer of loss allocation between zones, far exceeding the value of any net energy savings, is much reduced. For example, the CBA suggests a transfer of £31m from generators in some zones to those in other zones in 2011 in the proposal reference case (Table 5-6) compared with £13m in the alternative (Table A1-4). Tables 5-7 and A1-5 suggest higher values in subsequent years.

The potential error at particular locations is also reduced according to the scaling factor used. In the hypothetical example described in comments on question 1, a potential error of 0.04 in "true TLF" would be reduced to less than 0.02, similar to the theoretical difference between "true TLF" and current baseline.

However, we still consider the likely impact on competition to be negative.

The impact on BSC objective (d) would be negative, as for the original proposal.

Given these considerations, our net view is that the Alternative Modification would not better meet BSC objectives overall than the current baseline.

Do you agree with the Panel's initial view that, while both are inferior to the baseline, P229 Alternative is superior to P229 Proposed?

As described in response to Assessment Consultation:

The reduction in uncertainty of outturn loss adjustments in the Alternative Proposal would reduce the impact of the factors described in response to question 1 which might prevent the theoretical net energy cost savings indicated by cost benefit analysis from materialising, so making better achievement of BSC Objective (b) more likely than the Proposed Modification. However, we still consider there is great uncertainty whether benefits would actually be delivered.

The reduction in uncertainty and in potential error in relation to individual locations in the Alternative Proposal reduces the detrimental impacts on BSC Objective (c) relating to competition, compared with the Proposed Modification. In particular the large transfer of loss allocation between participants, far exceeding the value of any net energy savings, is much reduced. However, we still consider the likely impact on competition to be negative.

The impact on BSC objective (d) would be negative, as for the original proposal.

Given these considerations, our view is that the Alternative Modification would meet BSC objectives better than the Proposed Modification, though neither are better than the current baseline.

Do you agree with the Panel's suggested Implementation Dates for P229 Proposed and P229 Alternative?

An Ofgem decision one month in advance of the key dates suggested in the assessment report would allow appropriate adjustments to be made to contracts of 1 year or more duration which are being finalised and extend into the potential losses regime, and/or avoid administrative inefficiency of revising such contracts. Notice 3 months in advance of the proposed key dates would allow more leeway to revise the process for such contracts efficiently.

Do you agree that the legal text for P229 Proposed and P229 Alternative delivers the intent of the Proposed and Alternative?

Yes subject to minor corrections/clarifications described below.

We think it would improve readability if defined terms in the legal text were distinguished wherever used. The usual convention in the BSC is capitalisation of such terms, but emboldening as in the Grid Code and CUSC or use of italics could be applied. For example, "network mapping statement", "reference network mapping statement" and "prevailing network mapping statement" have particular meaning when used in Annex T-2 8.6 (proposed)/8.8 (alternative).

The legal text should provide indication of the snapshot date of applicability of the Transmission and Distribution network data. For example, should it be historic to match the historic flow data; or forward looking to match the network during the year of applicability of TLF's to be calculated; at the discretion of the BSC Panel, or something else?

In the legal text for the alternative, punctuation "," is missing compared with Proposal text, at Annex T-2 6.2 after "operates"; at 7.3 after "Year"; at 8.3 after "Period"; at 8.4 after "Year"; at Annex V-1 Table 9 Distribution Network Data after "specified in" and in Transmission Network Data after "specified in".

Alternative text Annex T-2 at 8.8(d) simply refers to the revision of the network mapping statement, while equivalent Proposal text at 8.6(d) refers specifically, and probably incorrectly, to the reference network mapping statement.

Alternative text Annex V-1 Table 9 should include annual reporting to any party (on request) of zonal delivery and offtake data provided by BSCCo to the TLFA under Annex T-2 section 8.2(d)(ii). This could be achieved by adding a specific item, or by modifying reporting of Metered Volume to include data provided by BSCCo to TLFA as well as data provided to BSCCo by CDCA.

Do you have any further comments on P229?

We repeat here comments made in our Assessment Consultation, and have provided comments and suggestions on the draft Modification Report separately.

Comments from Assessment Consultation Response

It seems surprising that the large loadflow differences between peak and offpeak periods and/or working day and non-working days do not merit separate consideration in the same way as seasons. We would have expected consideration of these factors in the assessment process, although such a refinement would be unlikely to change our overall view.

Losses arise on real networks from circulating currents due to reactive power effects not modelled by DC loadflow models. Previous studies have shown these can make significant contributions to variable losses and can affect transmission loss factors, but they are particularly sensitive to the prevailing configuration of the network and reactive power control in effect. Although it is arguable whether users should be allocated locational losses costs dependent on the System Operator’s prevailing network operation, we would have expected more consideration of the potential materiality in the assessment, although it is unlikely any resulting refinement would change our overall view.

The “aggressive wind” scenario with 6.9 GW of offshore wind by 2021 compared with 5.8 GW in the reference case does not seem particularly aggressive compared with latest government aspirations, and the aggressive renewables scenario in work conducted by the Electricity Networks Strategy Group (ENSG).

The Cost Benefit modelling has not considered potential HVDC links within the GB transmission system which could considerably change the pattern of flows and resulting losses (independently of any locational losses scheme).

The modelling has been conducted in relative isolation from the many other industry proposals currently on the table. It has not considered the impact of other potential changes affecting the despatch decisions of generators in particular, including potential constraint management methods, possible locational BSUoS, and changes to transmission access and charging. Specifically nuclear life extensions have not been considered. All of which could have far reaching implications for any locational pricing mechanism.

We note the analysis of impacts on CO2, SOx and NOx. The price attributed to theoretically avoided SOx and NOx emissions far exceeds that which we believe appropriate for GB large power station emissions, and their materiality therefore seems hugely exaggerated. We note that the SOx/NOx environmental benefits apparently arise because more polluting generators appear coincidentally to be currently concentrated in locations with disadvantageous transmission loss factors. This suggests a one off short term benefit rather than a long term sustainable environmental benefit. We note the SOx/NOx disbenefits in the high gas price scenario.

P229 would create gross cash/energy flows from some locations and from some parties to others. These seek to imitate the flows which would be expected to occur in an idealised market situation where a party should be willing to pay another party for any benefit created by the action of the other party. However, in reality there is no market for, and no rights to, losses allocations, and imposing such a scheme represents a regulatory charging regime with largely unmanageable risk.

We estimate the impact of the Proposed Modification P229 on EDF Energy supply business would be an increase in energy purchase costs of approximately £10m per year. This cost would unavoidably have to be passed on to our customers.

We note a significant difference in forecast results for the Alternative Proposal between London Economics/Ventyx Cost Benefit Analysis for P229 and analysis undertaken in 2006 by Oxera for proposals P198/203 (similar to the current proposal) and P204 (similar to the current alternative proposal). Oxera results indicated that the value transfer between different zones under P204 were approximately 20% of those under P203, proportional to the scaling factor used in the alternative relative to the proposal, as would be expected. However, the theoretical potential energy cost savings under P204 were about 50% of those under P203. This would be consistent with the range of different potential marginal generator costs being quite small so that small losses adjusters had a similar effect on theoretical despatch changes as much larger adjusters. In the LE/Ventyx analysis for P229, the theoretical energy cost savings for the alternative show a similar proportion as the transfer between zones, approximately 20% of those under the original proposal. This suggests the assumed individual generator costs were more widely and/or smoothly distributed so that the impact of loss adjusters is directly proportional to their size. We asked Elexon for information to confirm this explanation, but none was readily available, so we draw no conclusion on which might be more accurate, but note the significant difference.

The proposed approach for potential HVDC circuits within the GB transmission system under a locational losses scheme is a pragmatic one. However, if a locational losses scheme were to be approved and implemented, the suggestion to exclude losses on these circuits does not seem consistent with the principle of allocating losses to those considered responsible for creating or (in the case of Proposed Modification P229) avoiding them. The fact that the flow on a parallel DC circuit may be independent of small changes in flow of users on either side of it does not mean those users are not affecting the losses on the circuit, and exclusion of losses on such a circuit because a different method of determining an allocation is required seems a practical solution rather than a principled one. If a locational losses scheme were to be approved and implemented, we would expect further BSC Modifications to be raised in respect of losses on any firmly anticipated HVDC circuits.

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