The Brattle Group

BSC Modification 229:

Potential interactions with options for changes to transmission charging

Date: 23 May 2011

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Prepared for Ofgem

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1 Introduction and Executive Summary

1. In 2010 The Brattle Group assisted Ofgem in reviewing the cost-benefit analysis carried out by London Economics and Ventyx (LE/Ventyx) for Balancing and Settlement Code (BSC) Modifications P229 and P229 Alternative, which propose the introduction of seasonal zonal losses. Ofgem published our reports in March 2011, as well as the report of Redpoint Energy Ltd. (Redpoint), another consultant Ofgem retained to carry out additional modelling work for the assessment of these modifications.[1]

2. Since these modifications were proposed, Ofgem has initiated Project TransmiT, an independent review of the transmission charging, and associated connection, arrangements for gas and electricity transmission networks.[2] The range of options emerging under Project TransmiT includes potential changes which, if implemented could potentially affect the costs and benefits of P229 and its Alternative. Accordingly, Ofgem has asked The Brattle Group to undertake a short review to investigate how the emerging Project TransmiT options, if implemented, might affect the impact of P229.

3. In this report we first describe briefly the effects of P229 under the existing charging arrangements. We then go onto describe some of the options for changes to Transmission Network Use of System (TNUoS) charges emerging under Project TransmiT, and then consider how these changes could affect the costs and benefits identified for P229. It is not within the scope of this document to discuss the merits of the alternative transmission charging arrangements.

1.1 *Conclusions*

4. Project TransmiT is, amongst other things, a review of the approach to the charges levied for using the gas and electricity networks. It will look at how transmission costs incurred should be allocated. This could be in form of changes to the annual capacity charges or the short-run (variable costs) of using the transmission system or both. Changes to the annual capacity charges as a result of Project Transmit are unlikely to affect short-term operational decisions but could influence long term new build and retirement decisions. Other proposals could affect both long-term and short-term decisions for generators. None of the proposals will affect the costs of P229.

5. A range of options for potential changes are emerging from the academic reports commissioned by Ofgem and in industry responses. These include the following potential options:

[1] www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=104&refer=Licensing/ElecCodes/BSCode/BSC

[2] www.ofgem.gov.uk/Networks/Trans/Project TransmiT/Pages/ProjectTransmiT.aspx

- Flat (socialised) capacity-based TNUoS charges: all generators pay the same charge. A variant of this would be to set TNUoS charges to zero for generators i.e. all transmission costs would be recovered from the demand side;
- Flat commoditised charges: instead of paying on a locationally varying £/kW basis, all generators would pay the same £/MWh charge;
- The introduction of discount to reflect the cost savings associated with generators' "sharing" of transmission capacity; and
- Zonal or nodal energy prices.

6. Two of the possible changes to TNUoS charges – flat TNUoS charges and commoditised TNUoS charges – would eliminate the current locational signals in transmission charges. This means that, in the longer run, compared to the current system of zonal TNUoS charges more plants are likely to locate in the north of GB or, equivalently, the retirement of some northern plants will be delayed. The main effect of P229 is to reduce losses by increasing despatch from southern plant and decreasing despatch from northern plant. Flat TNUoS charges could increase this effect in the long-run, since there will be more plant in the north to respond to zonal losses. If there are no locational signals in TNUoS charges, then the role of zonal losses in prompting more efficient despatch becomes more significant. But we expect the effect of such changes to be insignificant mainly because, as discussed in the LE/Ventyx work and our previous 'Lot 3' report, the effect of zonal TNUoS charges on siting decisions is relatively small. However, if gas exit charges were also to be socialised then long-term locational signals would be significantly reduced and might lead to some changes in where new gas-fired plants chose to locate.

7. Flat TNUoS charges could in theory delay the retirement of coal-fired plant in the north of GB, which would increase the environmental benefits of P229. But the LE/Ventyx report concluded that transmission charges, and therefore changes in transmission charges, would not affect retirement decisions. These decisions would instead be dominated by factors such as the cost of maintenance and overhaul, supply and demand, and the efficiency of new technology. We broadly agreed with these conclusions, and conclude that flat TNUoS charges would not significantly affect retirement decisions and so would not change the benefits of P229.

8. Proponents of flat transmission charges argue that they could increase the number of wind farms, by reducing the transmission costs for marginally profitable sites in the north of GB. However, Redpoint has already modelled scenarios with substantially more wind capacity than LE/Ventyx assumed, and concluded that the benefits of zonal losses did not vary much with higher wind capacity. It seems that even if flat TNUoS charges did encourage more wind capacity, the benefits of zonal losses would remain broadly the same.

9. In common with flat TNUoS charges, any proposal to 'commoditise' TNUoS charges without locational variation could potentially shift more capacity to the

north of GB in the longer term. Unlike the introduction of flat capacity-based TNUoS charges, a proposal to ‘commoditise’ TNUoS charges on a uniform basis throughout GB would increase all generators’ variable costs by the same amount. This should have no effect on the merit order relative to a situation with the current TNUoS charges. Therefore in the short-term we would expect such a proposal to have very little effect on the costs and benefits of P229. If there is an effect it would be a slight increase in the benefits because the removal of the locational signal could encourage more plants to locate in the north of GB, and so there would be a greater cost-saving from the introduction of zonal losses.

10. The ability of intermittent generators – mainly wind farms – to share their access to the grid with conventional plants would reduce the TNUoS charges for wind farms, and these lower TNUoS charges could lead to increased levels of wind-power generation. But as discussed above, Redpoint found that this had little effect on the costs and benefits of zonal losses. Any proposal to share access could reduce the benefits of zonal losses, if it meant that the output of conventional plants in the north of GB, who shared their access with wind farms, was reduced. However, the intention of this option is that it would only be peak or low mid-merit plants that would share their access with intermittent plants and, hence, that there would be little impact on the conventional generators’ running patterns. Therefore, while this potential change could reduce the benefits of zonal losses, we expect the overall effect would be rather small.

11. Two further potential options that are emerging – zonal and nodal energy pricing – are both related to the introduction of locationally varying energy prices. For nodal or zonal options which include losses in the price setting algorithm, as most do, a separate zonal losses calculation would be redundant. For nodal or zonal options which do not account for losses, it seems likely that the locational pricing signals delivered by zonal/nodal prices would be similar to those associated with zonal losses and hence that the benefits of introducing zonal losses would be reduced.

12. We note that P229 (and its Alternative) have very short payback times. Under all of the scenarios they considered, LE/Ventyx found that the payback period was at most two years from P229’s implementation. We understand that it is unlikely that zonal or nodal prices would be introduced in such short timescales and, hence, even if these options were to be implemented in the medium term, it would still be cost-effective to introduce zonal losses.

13. We have also considered the effect of the ‘connect & manage’ policy that was adopted as the enduring regime in July 2010. We conclude that the benefits of zonal losses may increase against a background of connect and manage, since with connect and manage there will likely be more non-renewable plant in the north of GB that can respond to the zonal losses than was envisaged when the LE/Ventyx cost-benefit analysis was carried out. As a result north to south flows, and therefore losses, will be higher, and this will increase the marginal benefit of a reduction in output by northern plants from introducing zonal losses.

14. **Table 1** below summarises the potential effects of changes to transmission charging arrangements on the benefits of P229. Two of the potential changes might slightly increase the benefits, while two of the potential changes might reduce them. However, we stress that in all cases we expect the effects to be minor.

Table 1: Summary of possible impacts

Possible change	Possible effect on P229 benefits*	Comment
Flat capacity-based TNUoS charges	+	Could shift more plant to the north of GB
Flat commodity-based TNUoS charges	+	Could shift more plant to the north of GB
Discounts for intermittent generation/connection sharing	-	Less production in the north of GB to respond to P229
Zonal/LMP pricing	-	Some or all benefits of zonal losses already captured

*(+ represents a possible increase in benefits, - is a possible decrease, 0 is no change)

2 The effects of zonal losses under the current TNUoS charging arrangements

15. In the short-term, the main effect of introducing zonal losses is to alter the marginal costs of generators. If generators price the cost of their specific loss factors into their offers, this will change the merit order, or supply curve, relative to the current situation. LE/Ventyx undertook modelling to estimate these effects, and published the results in their October 2009 report.

16. Specifically, LE/Ventyx assumed that generators in the north of GB, where the loss factors under P229 would be higher than currently, will increase the price of their offers, and generators in the south of GB will reduce their offer prices, relative to the current charging system. As a result, less generation would be despatched in the north, and more generation would be despatched in the south. North-to-south transmission flows would reduce, and therefore losses would also decrease, since losses are proportional to the power flowing and the distance the power is transmitted.

17. The north of GB has a higher proportion of coal-fired plants than the south. Since coal-fired plants emit more carbon, sulphur and nitrogen oxides per kWh generated

than gas-fired plants, LE/Ventyx found that reducing despatch from plants in the north of GB would also reduce carbon emissions and other pollutants.

18. The introduction of zonal losses would also affect the prices paid by consumers and, more generally, consumer welfare. First, zonal losses will change wholesale electricity prices, and these wholesale price changes will likely be passed onto consumers. Second, to serve a given demand at the point of use (e.g. a house or business), suppliers may have to buy more (or less) electricity under zonal losses than they currently do. Suppliers would pass on the cost of the change in the gross electricity volumes they need to buy to their customers. In our 'Lot 3' March 2011 report, we found that the effect of zonal losses on consumer benefits was highly sensitive to the predicted change in wholesale electricity prices, and that there was some uncertainty regarding exactly how generators would react to zonal losses in their price offers. In the most likely case, we estimated that zonal losses created an increase in consumer surplus in aggregate.

19. All the effects above stem from the effect that zonal losses have on plants' marginal or variable costs. LE/Ventyx also considered whether zonal losses might have long-term effects, by influencing plant siting decisions. Would they encourage more new plant to locate in the south of GB, and accelerate the retirement of other plants in the north of GB?

20. LE/Ventyx concluded that such long-term effects seemed unlikely to be very material. In our review of their work we broadly agreed with LE/Ventyx's conclusions. Accordingly, the main effect of zonal losses is to influence short-run despatch decisions, rather than long-term siting decisions.

3 Payback period for P229 and P229 Alternative

21. Implementing P229 or P229 Alternative will have both costs, mainly in the form of changes to software systems to deal with zonal losses, and benefits as described above. Consequently, to the extent that Project Transmit might render these modifications unnecessary, it is necessary to consider the period of time over which the modifications would need to be in place to generate a positive net present value. It would not be worth implementing either modification unless it would be in place for long enough for the benefits to re-pay any costs incurred. For example, if the 'payback' period was five years, then it would only be worth implementing zonal losses if it was unlikely that there would be changes to the electricity market within 5 years that would obviate the need, or undermine the rationale, for these modifications.

22. In practice, the most likely payback period for P229 and P229 Alternative appears to be less than one year. In their October 2009 report LE/Ventyx estimated one-off

implementation costs of £3.85 million, with ongoing annual costs of £0.16 million.[3] However, in their base case LE/Ventyx estimated the benefits of P229 in the first year alone were £6.87 million, meaning that at the end of the first year there was already a net benefit of about £3.5 million. Under all of the scenarios they considered, LE/Ventyx found that the payback period for P229/P229 Alternative was at most two years from its implementation. In other words, the sum of the (discounted) production cost savings associated with P229 outweighed the implementation costs and the sum of the (discounted) on-going costs within two years of its introduction. Indeed, under most of the cases studied, the payback period was only one year (the exceptions were the low gas case[4] and the base case for P229 Alternative).

23. In our report on LE/Ventyx's October 2009 analysis, we noted that, if anything they had likely over-estimated the implementation costs.[5] We also noted that while LE/Ventyx should have assumed the implementation costs to occur one or two years before the modification came into effect, in practice this adjustment made very little difference to the pay-back period.

24. In sum, P229 and its Alternative have a very short payback time, so that it would still be cost-effective to implement the modification even if it were for only to remain in place for a few years.

4 Possible changes to TNUoS charges

25. There are a range of options for potential change emerging from the academic reports commissioned by Ofgem and in industry responses to Ofgem's consultations on Project TransmiT. We focus on the first three potential options below as these are the options that could potentially be introduced in the short to medium term. Note that inclusion of the options below in our assessment does not mean that Ofgem has endorsed any of these options:

- **Flat (socialised) capacity-based TNUoS charges** - The TNUoS charges would no longer vary by location or zone, but there would be a single charge levied on all generators throughout GB. This option would also cover the situation where all

[3] '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'. Table 5-2. p.80.

[4] Under the low gas case, there are also a further three years when the net present value of P229 is negative.

[5] 'A review of LE/Ventyx's cost-benefit analysis of Modification P229', Serena Hesmondhalgh, Dan Harris (The Brattle Group), September 2010.

transmission costs are recovered from the demand side i.e. the generator charge is zero.[6] This arrangement is common in other EU Member States.

- **Flat Commoditised TNUoS charges** - under this option TNUoS charges would be levied on a per MWh basis, rather than the current system where charges are applied per MW of reserved entry capacity. In practice, this potential change would increase TNUoS charges for high load factor generators such as nuclear plant, and reduce TNUoS charges for low-load factor sources of generation such as wind farms.

- **Discounts for sharing access rights** - under this option, intermittent and conventional generators would pay reduced TNUoS charges, if they agreed to share access rights. The idea is that it is not practical or sensible to build the transmission network to accommodate the full capacity of intermittent generation. Instead, capacity could be shared with peak or low mid-merit plants, which are likely to be required to generate precisely when intermittent generation is not running. In this way, although the output of the thermal plant may be scaled back or turned off to accommodate increased output from intermittent generators, the effect is likely to be small. The arrangement would be voluntary, allowing participants to weigh up the benefits of the reduced TNUoS charges against the cost of interruptions.

- **Zonal or nodal energy pricing** - under current arrangements, there is a single GB electricity price. Both these options would replace this with locational varying energy prices, which might or might not be calculated taking into account locational variations in losses. While this approach does not have any explicit implications for TNUoS charges, the assumption appears to be that, since prices would provide the main locational signal for generators and load, TNUoS charges could be made uniform.

5 The effect of TNUoS changes on the benefits of P229

5.1 *Flat capacity-based TNUoS charges*

26. With flat TNUoS charges, there would be no locational signal from transmission charges. This means that, in the longer run, compared to the current system of zonal TNUoS charges more plants are likely to locate in the north of GB or, equivalently, the retirement of some northern plants will be delayed.

27. One could argue that the removal of one locational signal (locational TNUoS charges) could, at least to some extent, be counterbalanced by a new locational signal in the form of zonal losses. However, as Table 2 below shows, zonal losses provide a weaker locational signal than the current zonal TNUoS charges.

[6] Currently generators pay for 27% of the costs of the transmission system and load pays for the remaining 73%.

Therefore the net effect of introducing a flat TNUoS charge and zonal losses is still a reduction in the overall strength of the locational signal for generators.

28. Hence, flat TNUoS charges would, if anything, increase the operational effect of zonal losses in the long-run, since there might be more plant in the north to respond to zonal losses. The exact effect depends on how many plants ‘move’ to the north, relative to plans in the current Seven Year Statement (SYS).

29. However, we expect the effect of flat TNUoS charges to be very small for several reasons. First, as already discussed in Section 2, it is highly uncertain what effect zonal TNUoS charges actually have on plant siting decisions. Table 2 illustrates the sum of regional charges for the gas network (the National Transmission System or NTS), TNUoS charges and zonal losses. The calculation is based on 2010/11 charges, and we approximate the effect of flat TNUoS charges by taking a simple median of the zonal charges in the table. The table demonstrates that while flat TNUoS charges would clearly alter each regional charge, applying a flat TNUoS charge in isolation does not have much impact on the relative costs of the different zones. With flat TNUoS charges, it is still cheaper for a generator to be in the south than in the north of GB (although flat TNUoS charges have reduced the differences between regional costs). It is not clear that flat TNUoS charges really would lead more generators to locate in the north of GB. To really equalise regional charges, the locational NTS charges would also need to be ‘flattened’. Even then, we note that this simple analysis does not take account of other relevant regional cost 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.

Table 2: 2010/11 regional charges for a 400 MW CCGT with and without a flat capacity-based TNUoS charge (£ million)

Location	NTS exit charges	TNUoS charges	Zonal losses	Total regional charges	
				Zonal TNUoS	Flat TNUoS
Central London	0.84	-2.49	-0.25	-1.91	2.45
Penninsula	1.31	-2.28	0.16	-0.81	3.33
South East	0.99	0.31	0.21	1.52	3.07
North East England	0.13	3.42	1.74	5.29	3.74
South Scotland	0.01	4.85	2.57	7.43	4.44
North Scotland	0.01	7.80	2.92	10.73	4.79
Range	1.30	10.29	3.17	12.63	2.34
Median	0.48	1.86	0.98		

30. Second, for flat TNUoS charges to have an effect on the benefits of zonal losses, there would have to be plant planned for the south of GB that could move north. We assume that only plant planned to come into service in 2015/16 or later would be in a position to respond to any changes in transmission charges by re-siting to

the north of GB. The East Midlands zone and all the zones below that in Table 3 have 2010/11 TNUoS charges which are below the median TNUoS charge. So potentially new plants planned for these zones could move to a more northerly zone with flat TNUoS charges. Table 3 illustrates that LE/Ventyx assumed that 9.5 GW of capacity would fall into this category, and might move to a more northern zone with flat TNUoS charges, and this could increase the short-term benefits of zonal losses. However, we find this rather unlikely since, for the reasons given above, the effect of flat TNUoS charges is probably not enough to induce developers to re-locate their planned plants. It is also worth noting that any assumption that plant would move seems inconsistent with the original P229 analysis, since LE/Ventyx did not assume that planned plant re-locate to the south of GB as a result of P229.

Table 3: 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

31. We also note that, since most new plants will likely be gas-fired, even if some new plants do move from the south to the north the reduction in emissions estimated as a result of zonal losses will not change much from the original estimates. The significant change with respect to emissions involves swapping coal-fired output for gas-fired output and flat TNUoS charges would not make any difference to this. Flat TNUoS charge could perhaps delay the retirement of coal-fired plant in the north of GB, which would increase the environmental benefits of zonal losses. But the LE/Ventyx report concluded that P229 would not affect retirement decisions, which would instead be dominated by factors such as the cost of maintenance and overhaul, supply and demand, and the efficiency of new technology.[7] We broadly agreed with these conclusions, and it therefore seems unlikely that flat TNUoS charges will have much effect on retirement decisions.

32. One effect of flat charges could, however, be to increase the deployment of offshore wind. A report commissioned by Scottish Power estimated that flat transmission charges could increase the capacity of offshore wind by around 4-8%,

[7] LE/Ventyx report §3.6.3 pp.46-47.

or up to 4 TWh, due to the exploitation of marginally economic sites.[8] However, we note that Redpoint modelled a scenario with 15 GW of offshore wind, substantially more than the capacity LE/Ventyx assumed, as well as a 'RES-E Target' scenario under which sufficient renewable generation capacity was included to meet the UK's 2020 renewable energy targets. Redpoint concluded that the benefits of zonal loses did not vary much with higher wind capacity, relative to the assumptions in LE/Ventyx's base case. Accordingly, it seems that even if flat TNUoS charges did encourage more wind capacity, the effects of zonal losses would be largely the same.

33. Allocating all of the transmission costs to load and setting a zero TNUoS charge for generators is really just a special case of the flat transmission charges discussed above, with the flat charge set to zero. As Table 4 below demonstrates a zero TNUoS charge would not make any significant changes to the relative costs of the regions – southern zones would still be cheaper and northern zones would be more expensive. Therefore we expect the effect of zero generator charges on the benefits of P229 to be the same as the effect of a flat TNUoS charge.

Table 4: 2010/11 regional charges for a 400 MW CCGT with and without zero G charges (£ million)

Location	NTS exit charges	TNUoS charges	Zonal losses	Total regional charges	
				Zonal TNUoS	Zero TNUoS
Central London	0.84	-2.49	-0.25	-1.91	0.59
Penninsula	1.31	-2.28	0.16	-0.81	1.47
South East	0.99	0.31	0.21	1.52	1.20
North East England	0.13	3.42	1.74	5.29	1.87
South Scotland	0.01	4.85	2.57	7.43	2.58
North Scotland	0.01	7.80	2.92	10.73	2.93
Range	1.30	10.29	3.17	12.63	2.34
Median	0.48	1.86	0.98		

5.2 *Flat commoditised TNUoS charges*

34. This option involves 'commoditising' the TNUoS charges – that is, charging for transmission on a uniform (non-locational) £/MWh rather than a £/MW basis. In common with the flat capacity-based TNUoS charges discussed above, commoditised TNUoS charges would remove the locational signal in the TNUoS charges. Again, we would expect the long-term effects of this to be small for the reasons discussed above, but if there is an effect it will be to slightly increase the

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[8] Oxera, Principles and priorities for transmission charging reform. Report prepared for Scottish Power. 2010.

benefits of P229, because there will likely be more plant in the north that respond to the zonal losses.[9]

35. Assuming that imports would also have to pay the variable TNUoS charge, which seems likely as they currently pay TNUoS capacity charges, then the supply curve or merit order would shift upwards, but would otherwise be unchanged. Prices might increase, as the marginal price would now include the TNUoS charges, but, assuming that demand was relatively insensitive to an increase in prices, this would have no effect on the marginal plant at any point in time, relative to a situation with the current TNUoS charges. Therefore in the short-term we would expect this option to have no effects on the costs and benefits of P229.

5.3 *Discounts for sharing access rights*

36. The ability of intermittent generators – mainly wind farms – to share their access rights with conventional plants would reduce the transmission costs for wind farms. Specifically, National Grid estimates that 2014/15 TNUoS charges for intermittent renewable generation located in Northern Scotland might fall to £11.00/kW compared with the normal charges of £19.18/kW. Conversely, intermittent generation located on the South West peninsular would see a charge of £-0.28/kW compared with a normal charge of £-4.23/kW.[10]

37. The lower TNUoS charges for intermittent generation could lead to increased levels of wind-power generation. However, as we also point out above, there is little difference between the 'RES-E Target' scenario and LE/Ventyx's base case in terms of the costs and benefits of zonal losses.

38. However, this option could reduce the benefits of zonal losses, if it meant that there was less production from conventional plants sharing access rights, which are in effect interrupted by wind powered generation. Since most of the wind is in the north of GB, we would expect the biggest reduction in conventional generation to also be in the north, and the production of the northern conventional generators would be replaced by southern generators. As a result, there would be less northern generation to respond to the zonal loss signals and the benefits of its introduction would reduce. The significance of this effect is hard to estimate, since it will depend on the details of the scheme. However, the intention is that such sharing will take place mostly with peak or low mid-merit conventional plants. The idea being that such conventional generators would benefit from this scheme, as well as the intermittent generators. In other words, the periods when the conventional plants sharing access are most likely to run is precisely when the intermittent plant

[9] As for flat capacity-based TNUoS charges, the assumption is that flat commoditised charges would result in more plants being built in the north and/or delayed retirement of northern plants.

[10] For discussion see Baker P,. et al, Energy Policy Group Exeter University, Academic Review of Transmission Charging Arrangements, First Draft Report, April 4, 2011 pp.14-15.

are not running. Accordingly, it seems that conventional plants sharing access rights with intermittent plants will not be interrupted very frequently. If this were not the case, it seems likely that it would be more cost effective to build more transmission capacity, given the relative costs of generation and transmission. Therefore, while this option could reduce the benefits of P229, we expect the overall effect to be rather small.

5.4 *Zonal and nodal energy pricing*

39. These options, which are variants of one another, would involve a significant change not only to transmission charging arrangements but also to the way in which electricity commodity prices are set.

40. Whilst, in theory, zonal or nodal pricing would have no explicit effect on TNUoS, our working assumption is that uniform TNUoS charges would be applied if either of these options were introduced.

41. Both of these approaches imagine that Locational Marginal Pricing (LMP) would be introduced. Under an LMP system each 'node' in the system has a price which reflects the marginal cost of supply at that point. Normally, this price already reflects transmission constraints and losses. However, under zonal pricing option (market splitting), the locational prices may or may not include zonal losses.

42. With nodal prices derived from LMPs that reflect locational loss differences, a separate zonal losses calculation, such as that incorporated in P229 and P229 Alternative, would be redundant. However, there would likely still be a benefit from introducing P229 (or its Alternative). This is because, as discussed in the preceding section, the payback period for these modifications is at most two years and it is likely that options such as nodal pricing will take longer than this to be implemented.

43. With zonal pricing (market splitting), it seems logical that there would be lower prices in the northern zones, because power flows largely from the north to the south of GB and transmission constraints arise on this route. Therefore we would expect lower zonal prices in Scotland and higher prices in London. In response to these prices, existing plants in the north of GB would run less, and plants in the south would run more. Hence zonal pricing would reduce the benefits of zonal losses, since some or all of the changes in despatch that occur due to the introduction of zonal losses, would occur anyway under a zonal pricing system. In the long-term we would expect to see more plants locating in the south where prices are presumed to be higher, which would again reduce the effect of P229 or its Alternative. However, as in the case of nodal prices, we understand that zonal pricing may not be capable of being implemented in the short term and hence that there would be benefits from introducing P229 (or its Alternative) due to the short payback period for these modifications.

6 The effect of ‘Connect and Manage’

44. In May 2009 Ofgem approved an interim ‘connect & manage’ approach to generation connections, and in July 2010 the Department of Energy and Climate Change (DECC) implemented a permanent ’connect & manage’ regime. Under both connect & manage regimes, generators are allowed to connect to the transmission system before any of the required wider network reinforcements are complete.[11] Any resulting constraints will be managed by National Grid and the costs socialised over all network users.

45. The ‘connect & manage’ policy is not part of Project TransmiT. Nevertheless, since neither the LE/Ventyx analysis nor our 2010 reports explicitly addressed the effect of connect & manage on the benefits of introducing zonal losses, we discuss it briefly here.

46. The previous regime – where generators had to wait for wider works to be completed before they could connect to the transmission system – provided a relatively strong locational signal to generators. In particular, generators in the north of GB, including renewable generators, often faced long delays before they could connect. Indeed, these delays were the main motivation for implementing the ‘connect & manage’ policy. Consequently, the’ connect and mange’ policy removes a relatively strong locational signal.

47. In the preceding discussions, we concluded that the loss of locational signals might motivate some generators who had planned to locate in the south of GB to move north. But in the case of connect & manage, there is already a queue of (mainly renewable) generators waiting to connect in the north; ‘connect & manage’ will simply allow them to connect more quickly. Once they are connected, as we as we concluded in our ‘Lot 3’ March 2011 report, zonal losses will not affect the despatch of most renewable plant, and wind in particular.

48. More generally, however, it is possible that some non-renewable plant may move to the north of GB as a result of ‘connect & manage’, as under the other charging options that would reduce the locational signal. This would increase the benefits of zonal losses. We also note that ‘connect & manage’ will increase flows from north to south at least in the short to medium term, due to earlier connection of northern renewable generation, which will increase losses. Because losses are proportional to the square of the power flow, the higher flow will increase the marginal benefits from any non-renewable plant that do respond to zonal losses. Therefore we expect the ‘connect & manage policy’ to increase the benefits of zonal losses.

49. One other likely effect of ‘connect & manage’ is that non-renewable plants in the north of GB will be constrained off more frequently. In this case, the main effect of zonal losses would be to reduce the costs of congestion. Because zonal losses

[11] DECC, Government Response to the technical consultation on the model for improving grid access URN 10D/723 27 July 2010.

would increase the offer prices of northern generators, the compensation they require for being constrained off would decrease relative to a situation with uniform losses. However, this benefit is simply a re-distribution of welfare from generators to consumers. It is different from the cost savings identified by LE/Ventyx.