Appendix 5.2: Locational pricing in the electricity market in Great Britain

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Introduction

1. This appendix describes the effects on competition of the absence of locational variation in the electricity wholesale spot price under current market arrangements despite locational variation in costs.

2. This appendix also describes current components of wholesale costs and the degree to which they vary by location. We outline the history of attempts to bring more locational elements into wholesale prices. We then briefly describe the rationale for geographical variation in spot prices due to losses and network congestion. Finally, we review existing work that attempts to quantify the benefits to competition of introducing more locational spot pricing.

Locational components in wholesale prices under current market rules

3. Table 1 provides a breakdown of the components of electricity wholesale costs and summarises whether they currently contain locational elements.[1]

Table 1: Geography in GB electricity wholesale prices

Cost	*Locational elements in current arrangements*
Generation	Yes
Transmission congestion	No
Transmission losses	No
Transmission network investment	Yes
Transmission connection	Yes
Distribution network	Yes
Distribution losses	Yes

Source: CMA research.

[1] Summaries of current arrangements for cost elements are presented in Annex A to this appendix.

4. **Generation costs** – approximately 40%[2] of total spending on electricity by end users – contain locational elements to the extent that fuels incur costs in being transported to power stations and that other costs are location-specific. For gas power stations, the locational element comes mainly through the pricing of the gas transport network.

5. **Transmission congestion costs** – arise from the fact that, when transmission lines represent a bottleneck, it is not possible to generate electricity from the cheapest sources.[3] The biggest source of these bottlenecks in the GB wholesale electricity market is network capacity between Scotland and England, with there being more opportunity for cheap generation in Scotland than the ability to transport electricity south. This bottleneck is worsening due to the increase in zero incremental cost wind generation in Scotland, which increases the price disparity between Scotland and England and Wales, thus increasing the opportunities for profitable flow of electricity southwards that will sometimes be frustrated by transmission constraints. However, such transmission constraints are expected to abate following the implementation of plans for transmission capacity expansion between England and Scotland. SSE goes so far as to argue that 'existing and planned network upgrades (*e.g.*, Beauly-Denny and the West Coast Bootstrap) will make, or have already made, much of the Working Paper's discussion of constraints in the GB market redundant'.

6. Congestion costs are currently incurred by National Grid through the balancing mechanism (BM) and are averaged over all producers and consumers on a pro rata per MWh basis and included in Balancing Services Use of System (BSUoS) charges. There is no locational element to this cost. However, because transmission investment lags behind congestion under "connect and manage" arrangements,[4] there is scope for competition and efficiency to be enhanced if there were a locational element.

7. **Transmission losses** – about 2%[5] of total spending on electricity – arise because energy is lost in transport at high transmission voltages. For example, a given demand in London needs more generation from Scotland to satisfy it than from the Isle of Grain. Losses are currently recovered by

[2] CMA calculation based on National Grid 2014/15 estimates of system costs.
[3] Imagine a shop that usually buys its milk from an efficient farm with low production costs and passes that through into low prices to consumers; however, when the road to the farm is congested it has to buy the milk from another farm that is more expensive. The cost of the congestion in this instance is the price difference between the expensive and the cheap milk. We do not have an estimate of the proportion of costs attributable to transmission congestion because it is not simple to separate these costs from other balancing costs that National Grid incurs.
[4] 'Connect and manage' refers to the policy by which renewable capacity can connect paying only direct connection costs and National Grid is then to 'manage' any knock-on congestion.
[5] *National Grid Electricity Ten Year Statement 2014*.

adjustments to Balancing and Settlement Code (BSC) parties' metered volumes, which encourages generators to produce approximately 1% more than they are contracted for and suppliers to contract for approximately 1% more than their customers' demand. This adjustment accounts for losses in transmission and is not varied by location.

8. **Transmission network investment costs** – about 7% of total spending on electricity[6] – are levied in order to allow the grid owners[7] to recover investment costs. These charges have locational elements and are regulated by Ofgem. The locational elements of charging provide some locational signals for the siting of generation and demand. Charges vary on a zonal basis to reflect network investment costs (in simple terms, the length of transmission wires). Generators in regions further from demand centres (eg North Scotland or Cornwall) pay more, while consumers pay less. Charges can be negative – for example there is a subsidy to site generation close to London from other site generation investments.

9. **Transmission connection costs** – about 0.6%[8] of total spending on electricity – are designed to enable National Grid to recover the immediate costs that it incurs in connecting generators to the grid. These charges are essentially locational and are regulated by Ofgem.

10. **Distribution network costs** – about 8%[9] of total spending on electricity – are analogous to transmission network costs[10] but occur at the distribution level.

11. **Distribution losses** – arise from the fact that a supplier is charged for the full amount consumed as reconciled through end-point meter readings. This therefore contains losses in the distribution network, which vary by location There is a levy applied on all suppliers for 'Assistance for Areas with High Electricity Distribution Costs', which currently benefits the North of Scotland.[11]

12. The revenues which licensees can earn from running the transmission and distribution networks are regulated by Ofgem. We have not considered in the context of our investigation whether network access charges are set at efficient or competitive levels.

[6] *National Grid Electricity Ten Year Statement 2014.*
[7] These are National Grid Electricity Transmission, Scottish Power Transmission, Scottish Hydro Transmission and various offshore transmission owners.
[8] CMA calculation.
[9] CMA calculation.
[10] These are network investments costs and connection costs.
[11] See National Grid, *Assistance for Areas with High Electricity Distribution Costs*.

A brief history of attempted reforms to locational charging

13. In 1990, at the time of privatisation, it was decided that the market would be liberalised without regard to transmission losses but that this would be fixed soon afterwards. In 1994, the body in charge of governing the Pool started work on the issue. After three years' consideration and two appeals to the regulator, an industry-wide agreement was concluded whereby losses would be factored into wholesale prices gradually over five years. Legal action to obtain a judicial review was launched by some of those opposed to this decision. However, with the launch of the New Electricity Trading Arrangements process in 1998, the legal challenge was put aside.[12]

14. During the major redesign of the GB wholesale electricity market between 1998 and 2001, it was decided that decisions on the future treatment of losses would be left to the modification procedures of the BSC. This process began in 2002 with three BSC modification proposals: P75, P82 and P105.[13] P82 was approved by Ofgem. However, it was successfully challenged by way of judicial review on the basis that the decision was procedurally flawed. Between December 2005 and July 2006 four modification proposals were raised: P198 (by RWE), P200 (by Teesside Power Limited), P203 (by RWE) and P204 (by British Energy). Ofgem was minded to approve P203 and reject the other proposals.[14] It then delayed its final decision as, having considered the responses to its consultation, it wished further analysis to be carried out to inform its final decision.[15] The decision to delay the process was successfully challenged by way of judicial review by (among others) Teesside Power Limited and British Energy.[16] Ofgem published a letter on 17 July 2008 informing that it had decided not to appeal the court's order[17] and was therefore not in a position to reach a decision on the modification proposals.[18]

15. Four months later, on 28 November 2008, RWE raised a new modification proposal, P229, proposing a zonal basis for charging for transmission losses.[19] Ofgem decided to reject the modification. Its reasons were that it

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[12] Much of this early history is summarised in R Green (1997), Transmission pricing in England and Wales, *Utilities Policy* (6)3. Ofgem has published a history of zonal pricing from 1989 to 2006.
[13] All of these modifications had the intent of making the charging for transmission losses more cost-reflective.
[14] Ofgem, (2007), *Zonal transmission losses – the Authority's 'minded-to' decisions*, document reference 153/07.
[15] Ofgem (2007), open letter *Zonal transmission losses proposals*.
[16] Teesside Power et al v Gas and Electricity Markets Authority, CO/11010/2007: Defendant's detailed grounds of resistance.
[17] Ofgem (2008), open letter *Balancing and Settlement Code (BSC) modification proposals on zonal transmission losses*.
[18] At the time, the BSC modification process did not contemplate the possibility for Ofgem to 'send back' a modification proposal to the code panel with a request to carry out further analysis in order to assist Ofgem's decision making. This has now been introduced in the BSC as a result of Ofgem's code governance review (see Appendix16.2: Codes governance).
[19] Modification P229 – Introduction of a seasonal Zonal Transmission Losses scheme.

could not satisfy itself that approval was consistent with its statutory duties and principal objective. Specifically, Ofgem raised questions concerning the large distributional consequences of the proposal, the 'relatively modest scale and uncertainty of expected efficiency benefits'[20], and the fact that locational pricing might be required at a European level as early as 2015.

16. Currently the European electricity market is divided into bidding zones, which should be defined in a manner to ensure efficient congestion management and overall market efficiency. GB currently constitutes one bidding zone for this purpose. The European Commission has adopted a network code (which entered into force in August 2015), the Capacity Allocation and Congestion Management (CACM) regulation, which sets out rules facilitating allocation and congestion management between bidding zones. Under the CACM, the Agency for the Cooperation of Energy Regulators (ACER) is required to assess the efficiency of current bidding zone configuration every three years.[21] If the technical or market report published as a result of this assessment[22] reveals inefficiencies in the configuration of zones in a national electricity market, ACER may request the Transmission System Operators (TSOs) for that market (ie for GB National Grid, SSE and Sottish Power Transmission) to launch a review of an existing bidding zone configuration.[23] The CACM provides minimum criteria[24] for TSOs to review bidding zone configurations (relating to network security, overall market efficiency and the stability and robustness of bidding zones). Independently of the ACER's triennial obligatory assessment, a review of bidding zones may also be launched at any time (and following the same criteria and process) by subjects named in the CACM,[25] including, for GB, ACER, Ofgem following a recommendation from ACER, the three TSOs together or any of them with Ofgem's agreement. The CACM includes a preferred European model for congestion charging, where needed, by zonal splitting. Impact on competition of wholesale spot prices varying by location.

17. It is generally accepted that in a well-functioning market, prices should reflect the cost of alternative uses to which resources could be put. This means that the closer prices are to incremental costs of supply, the better those prices will be at allocating resources between competing uses.

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[20] Ofgem (2011), *Balancing and Settlement Code (BSC) P229: Introduction of a seasonal Zonal Transmission Losses Scheme (P229).* It is not clear why the expected benefits under P299 were considered 'modest' when essentially similar benefits under P203 had previously been thought to merit action by Ofgem.
[21] Article 33(1) of the CACM.
[22] Pursuant to Article 34(1) of the CACM.
[23] Article 34.7 CACM.
[24] Articles 32 and 33 of the CACM.
[25] Article 32(1) of the CACM.

Possible harm from the absence of locational pricing for transmission losses

18. We can expect the absence of locational pricing for transmission losses to create a system of cross subsidisation that distorts competition between generators and is likely to have both short- and long-run effects on generation and demand:

- in the short run, costs will be higher than would otherwise be the case, because cross subsidisation will lead to some plants generating when it would be less costly for them not to generate, and other plants, which it would be more efficient to use, not generating.[26] Similarly, cross subsidies will result in consumption failing to reflect fully the costs of providing the electricity; and
- in the long run, the lack of locational pricing may lead to inefficient investment in generation, including inefficient decisions over the extension or closure of plant. There could also be inefficiency in the location of demand, particularly high-consumption industrial demand.

Possible harm from the absence of locational pricing for congestion

19. The absence of locational pricing for congestion is expected to lead to a short-run effect on competition:

(a) There will be an effect through demand response. Wholesale prices in export-constrained regions will be higher in the absence of congestion charging than they otherwise would be, leading to an under-consumption of electricity relative to other goods and a distortion of competition in favour of other goods; for example, households in Scotland would on average buy more electricity if prices varied locationally in a manner that reflected congestion. In the same way, wholesale prices in importing regions will be lower than they otherwise would be, thus encouraging over-consumption relative to costs. This effect depends on the responsiveness of consumption to prices. This is relatively low in the short run in electricity markets – elasticities are of the order of –0.1 (meaning that a 10% fall in the price of electricity induces a 1% increase in consumption).[27] However, two factors tend to make these price distortions an important concern despite low levels of price responsiveness: (i) low

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[26] This arises because a generator whose location entails lower losses than a competitor will produce less frequently - and overall system losses and costs will be higher - without locational charging than with it.
[27] Elasticities in the very short run are even lower – there is essentially no responsiveness to real-time price in large parts of the electricity market in GB. See, for example, A Serletis, G Timilsina and O Vasetsky (2011) International evidence on aggregate short-run and long-run interfuel substitution?, Energy Economics 33, pp209–216.

price responsiveness over large volumes can add up to large absolute effects; and (ii) price responsiveness is expected to rise with the introduction of smart meters.[28]

(b) The introduction of congestion charging would have longer-run investment impacts. Generators in importing regions, where prices are high, would receive higher energy payments than generators in export-constrained regions (where prices would be lower in constrained periods). This should make investment in generation in importing regions relatively more profitable under congestion charging than in its absence. In the same way, large consumers would face lower energy costs in export-constrained regions and would therefore be incentivised to locate or expand in those regions.[29] As noted in paragraph 8, locational choices are also influenced by the network charging methodology and indeed by planned changes to network capacity in specific locations. Congestion charging would have an impact on location beyond this: it is a signal based on energy production or use, rather than capacity use.[30] The absence of congestion pricing could therefore lead to some degree of inefficiency in the locational choices of investments. However, we recognise that the locational decisions of investments can be significantly influenced by the wider network charging methodology.

20. We do not think there will be a large effect from better technical efficiency of electricity production, equivalent to the effect described for losses in Section 5. The reason for this is that National Grid currently uses a competitive mechanism to buy balancing services through Balancing Mechanism bids and has an incentive to minimise congestion costs. This system has been open to criticism of inefficiency in the past due to the exercise of time-bound locational market power. However, the introduction of the Transmission Constraint Licence Condition, which will be in force until 15 July 2017, into the generation standard licence conditions, has made the abuse of market power arising from the location of the generator a breach of licence. This has made it very risky for generators to manipulate Balancing Mechanism bids for profit, further

[28] We consider the potential impact of smart meters on consumption in Appendix 8.6: Gas and electricity settlement and metering. As a very rough indicator of the magnitude of the price-responsiveness effect, we subtract from the £73 million estimate of net benefit attributable to incorporating losses and congestion from Green (Nodal pricing of electricity: how much does it cost to get it wrong?, *Journal of Regulatory Economics,* Vol: 31, Pages: 125-149, 2007) the £15 million benefit attributable to losses only in Green (1994) to get a value of £58 million. We emphasise that this is an extremely rough way of estimating the magnitude of the effect.
[29] There are a large number of ways in which location decisions for generation and large demand can be influenced by policy. An approach based on connection costs and transmission investment recovery rules are one such way.
[30] So, for example, an energy user who could take advantage of the existence of low-price intermittent wind output in Scotland would be rewarded under locational pricing but not necessarily under a capacity-based network charging regime.

reducing the chance of technical inefficiency. In addition, regulations such as the EU's Regulations on Energy Market Integrity and Transparency[31] have been designed to identify abuse of market power and capacity withholding.[32] Penalties under these regulations provide a further disincentive for parties to engage in unilateral market power strategies. Overall, we believe that the current system of congestion charging is likely to create near-efficient technical efficiency and that a move to more congestion charging would not impact that significantly.

Estimates of the costs of the absence of locational pricing

Transmission losses

21. The benefits of locational pricing of transmission losses, which could be expected in a well-functioning market for the reasons set out in paragraph 18 above, have been widely and recently analysed. We examine the benefits that studies associate to locational pricing of transmission losses in order to gain an estimate of the harm arising from their current absence.

22. The impact of charging cost-reflectively for transmission losses in GB has been thoroughly investigated as recently as 2011 in the context of the RWE-sponsored modification proposal P229.[33] The cost benefit analyses undertaken in relation to P229 were conducted by LE/Ventyx (for Elexon) and Redpoint (for Ofgem), while a third group of experts, Brattle, reviewed the LE/Ventyx work for Ofgem. These report a ten-year net present value (NPV) benefit from the introduction of locational pricing of losses of between £160 million (Redpoint) and £275 million (LE/Ventyx).[34] These values are based on forward-looking modelling of the sort commonly conducted in energy sector impact analyses and the studies appear to us to be credible and to have been conducted with due rigour and expertise.

23. The methodology was similar in both the LE/Ventryx and Redpoint analyses, and involved full electricity market simulations that compared system costs with and without zonal losses. Future scenarios on the location of new investment were imposed and did not vary by scenario, implying that no benefit was attributed to the (long run) possible investment impacts of charging for losses. In this sense, the estimates of the (short run) benefits are

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[31] Regulation (EU) No 1227/2011 of the European Parliament and of the Council on wholesale energy market integrity and transparency (REMIT), adopted on 8 December 2011 and entered into force on 28 December 2011.
[32] Similarly, such behaviour could amount to an abuse of dominant position prohibited under competition law.
[33] Ofgem (2011), *Impact Assessment on RWE proposal P229 – seasonal zonal transmission losses scheme*.
[34] A substantial proportion of the savings relate to environmental benefits from sulphur dioxide and nitrogen oxide reductions, arising from the fact that less coal and gas would need to be consumed in order to satisfy demand under a locational loss-charging scheme.

an underestimate. The benefits accrue from the energy saved from more frequently generating electricity closer to its point of consumption.

24. In all these cost-benefit analyses, the transitional costs of implementation of zonal charging are assumed to be negligible. The reason for this is that the systems are already in place for losses to be included in the settlement process. The introduction of locational pricing of losses would involve changing, in Elexon 's settlement systems, a parameter that is currently zero to a value that varies by generator depending on the location of its plants. The implementation cost is not in actual fact zero, in that a process needs to be put in place to calculate and agree the actual variable loss adjustment factors to be used.[35]

25. Within the context of the proposed modification P229 in 2011, Ofgem concluded that overall P229 would contribute to the BSC objective of 'promoting effective competition in the generation and supply of electricity, and […] promoting such competition in the sale and purchase of electricity'. Ofgem also found that the complexity and implementation cost of introducing charges for losses is likely to be low. Ofgem concluded that 'on balance P229 […] better facilitates the Applicable BSC Objectives'.

26. We have reviewed the quantitative assessments and we agree with Ofgem's conclusion relating to the impact of locational pricing of losses on the BSC objectives. We do not believe that there have been changes to the electricity system since 2011 that would significantly alter this conclusion. Our own updated modelling, described in Appendix 6.1, confirms the order of magnitude of net benefits from the introduction of a locationally sensitive charging regime..

27. However, despite its above-mentioned conclusion that 'on balance P229 […] better facilitates the Applicable BSC Objectives', Ofgem ruled against the proposal on the following grounds:

    (a) It would have a large distributional impact.

    (b) The impact on wholesale prices and therefore on consumers was very uncertain.

    (c) Locational pricing in general might be looked at in the context of market splitting under the EU's CACM mechanism.

[35] In principle and in the IT systems that currently handle settlement, the adjustment factor could be specific to each plant. It could also be averaged over zones. We have not considered which of these would be best.

28. Ofgem's explanation for rejecting the modification proposal P229 was that the immediate benefits of the reform were low and uncertain, the context for decision-making might change in the medium term, and therefore, Ofgem could not satisfy itself that the proposals would operate in the interest of existing and future consumers.[36]

29. We consider below the detailed components in the argument and provisionally find that Ofgem's quantitative modelling does not support Ofgem's decision to rule against P229.

30. Ofgem stated that 'Analysis by our economic consultants, Redpoint, suggests that wholesale prices might rise, although the analysis is highly sensitive to assumptions.'[37] Redpoint actually said that its most accurate simulation of price changes showed that 'The average TLM-adjusted[38] P229 price change is negligible, at around 0.04 £/MWh.' In the early years, Redpoint considered that prices would fall. One would expect a more accurate incorporation of transport costs in the retail price for electricity to lead to a fall in the total cost of energy generation through the effect of more efficient generation choices. Eventually, such falls in total cost should be reflected in lower average prices, although this can be slow in electricity systems, and therefore a fall in the average retail price of electricity. We would not expect the sort of modelling conducted by Redpoint to provide accurate estimates of the total long run impact of this kind of policy change on prices.

31. Ofgem requested Brattle, another consultancy, to review the modelling work done for P229 by LE/Ventryx for Elexon. Brattle, in its report to Ofgem, explicitly emphasised the same methodological point on prices:

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[36] Ofgem, (2011), 'Balancing and Settlement code (BSC) P229 Introduction of a seasonal Zonal Transmission Losses scheme'.
[37] Ibid.
[38] Redpoint usefully summarises the current methodology for incorporating losses as follows:
Transmission losses are allocated in the BSC by applying Transmission Loss Multipliers (TLMs) to scale up or down metered volumes for demand and generation. TLMs are calculated for each settlement period for demand and generation according to the following formula:
TLM = TLF + 1+ TLMO+/-
where TLMO+ = - (0.45 x total losses volume) / (total generation output volume); and
TLMO - = (0.55 x total losses volume) / (total demand volume).
The Transmission Losses Adjustment (TLMO+/-) uniformly adjusts metered volumes such that 45% of total losses in the period are allocated to 'delivering Units' (eg generators) and 55% are allocated to 'offtaking Units' (eg customer demand). The Transmission Loss Factor (TLF) is Unit specific, thereby enabling losses to be allocated on a locational basis in principle. TLFs are currently set to zero for all Units and have no practical effect.
The modelling that we commissioned from NERA considered two alternative policies for losses charging. In the first, TLM = 0.45 MLF + 1 + TLMO+/- (referred to as the 45/55 scenario) and in the second, TLM = MLF + 1 + TLMO+/- (where MLF is the marginal loss factor: the incremental losses expected from a small change in injections or withdrawals at each node.). This is explained in further detail in para 5.71-5.73 of chapter 5.

LE/Ventyx found that zonal losses led to price increases in all years and scenarios. However, our analysis suggests that had TLMs been included instead then prices might have instead decreased or, at any rate, stayed broadly constant.[39] This finding is of considerable importance when it comes to assessing the impact of P229 on consumers and also means that LE/Ventyx are likely to have over-estimated the distributional effects of zonal losses (since these also depend on wholesale price changes).[40]

32. Together, the Redpoint and Brattle analyses imply that little evidential weight should be put on the prospect of a significant price rise.[41]

33. Having noted the possible scale of price increases and redistribution from customers to generators, Ofgem went on to argue that 'However, if either of the P229 proposals were only implemented for a short time, it is not clear that the resultant redistribution of wealth from consumers to generators is in customers' interests, even if there is an overall NPV benefit because the long-term market efficiencies would not have taken place'.[42]

34. The first point to note with this component of the argument is that it relies on there being a significant redistribution from consumers to generators – in other words a price rise. We have seen that this is contested by the consultants Ofgem employed to investigate the question. The argument further claims that if the benefits only last a few years, then they will be small. This is of course true but not surprising or unique to this particular modification proposal (annual "small" impacts may have a much larger cumulative impact over time). Moreover, the scale of the benefits assessed did not include long-term effects arising from changes to investment location.

35. However, the argument does not provide any reason to believe that the modification would be incompatible with the market splitting changes that Ofgem is evaluating or that the benefits of the modification proposal would not continue to accrue. If the CACM process were to lead to a market splitting between Scotland and England and Wales, the two markets would be treated like any two European markets. Prices would be determined within a market

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[39] LE/Ventrix, for modelling convenience, compared results of modelling TLM = 0 with TLM = TLF, where TLF was determined zonally. A more accurate approximation would have been TLM = 1+ TLMO (the current method) with TLM = 0.5*TLF+TLMO, (0.5 because P229 proposes semi-marginal variable loss factors). On average, the second comparison is zero, whereas on average, the first is equal to half average TLFs. This made a minor difference to NPVs but a material difference to an estimate of price changes.
[40] Brattle (2010), *A review of LE/Ventyx's cost-benefit analysis of Modification P229*.
[41] SSE, in its response to the working paper, suggested that 'locational pricing of losses and constraints could lead to increased wholesale costs should there be a high incidence of marginal generation located in high cost areas of the network'.
[42]Ofgem (2011), 'Balancing and Settlement code (BSC) P229 Introduction of a seasonal Zonal Transmission Losses scheme'.

and the markets would be “coupled” through day-ahead auctions and the trading of transmission capacity rights. The question of losses would continue to be material: how should generation output metered at the interconnection point be assessed in its contribution to demand? Even if market splitting might require a change to the identity of the supplying unit (no longer a specific plant, but instead an interconnection point), it would still require an adjustment for transmission losses.

36. National Grid has submitted to us an outline of a mechanism that would solve both the constraint charging problem, the losses charging issue and would also be consistent with the European Target Model.[43] It involves market splitting the existing GB bidding zone at a finer grain than, for example, England/Scotland. We comment on this model in Section 6. We believe that it is attractive and may be a sensible option for the future. However, it is a big and complex modification which we do not believe would lead to a timely solution to the problem we have identified.

37. The argument that the early years of a reform do not themselves amount to a compelling case for reform would seem to be the opposite of good regulatory practice: they ensure that only the shortest-term benefits materialise.

38. We believe that Ofgem was right to conclude that there would be net benefits to competition of introducing more locational charging of losses. We instructed NERA to perform updated simulations of the impact of locationally-sensitive loss charging. The model and results are described in detail in Appendix 6.2. These confirm the orders of magnitude of the previous studies.

Parties’ Comments

39. In this section, we report parties’ comments and objections to our modelling of the costs of the AEC and the benefits of our proposed remedy. We also respond to specific arguments.

General comments

40. Intergen[44] agreed that locational adjustment to the Transmission Losses factor will help incentivise future investment decisions but it considered that in the short-term these changes could be interpreted as a windfall gain/tax on existing generating assets with some winners and losers.

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[43] National Grid response to Notice regarding assessment methodology for losses proposed remedy – consultation on methodology and scenarios.
[44] Intergen response to PDR, page 2.

41. We accept that the change can lead to windfall gains and losses. We discuss this aspect of our remedy in our discussion of distributional effect at paragraph 103.

42. Drax[45] argued that losses make up a very small amount of a customer's overall electricity bill but the change proposed by the CMA would impose a huge cost on industry, which will ultimately be borne by consumers.

43. We believe that in a well-functioning electricity market, incremental costs are borne by final consumers. We also argue that our proposed remedy will reduce the total long run incremental cost of meeting electricity demand (see Section 6).

44. Both EDF[46] and Centrica[47] supported the principle of cost reflective network charging. But EDF[48] considered that the additional modelling analysis undertaken by NERA did not meet the standard of proof required to conclude that there is a certain net benefit and to proceed directly to implementation..

45. We do not believe that additional modelling would change our degree of confidence in the order of magnitude of net benefits. There are many possible additional scenarios that are plausible. However, we have placed weight on the analytical argument that net benefits will exist in all properly defined scenarios. We have used the updated modelling, as well as extensive previous modelling exercises, to establish that it is more likely than not that the substantial net benefits of our remedy will exceed the low costs by a clear order of magnitude. We do not believe that plausible alternative assumptions would change the order of magnitude effects that we have found in the modelling. We elaborate on this position in Section 6.

46. RWE[49] strongly supported the CMA's proposals for the implementation of locational adjustment for transmission losses and considered that the case for the economic efficiency and competitive benefits of zonal losses had been made on a number of occasions during the last few years.

47. In contrast, SSE[50] said that the CMA has not established the existence of an AEC to the required legal standard. In particular it said that to support its position the CMA relied on theoretic assumptions or on evidence that is out-of-date, of highly questionable value and ignores the fact that, under the proposed methodology, customers will not be charged directly for the losses

[45] Drax response to PDR, page 1.
[46] EDF response to PDR, paragraphs 3.2-3.3, pages 17-18.
[47] Centrica response to PDR, paragraph 451, page 88.
[48] EDF response to PDR, paragraph 3.3, page 18.
[49] RWE response to PDR, paragraph 39.1, page 12.
[50] SSE response to PDR, paragraph 8.2.2, page 64.

they are responsible for. SSE considered that the current system is not demonstrably less cost reflective than the proposed remedy.

48. For the reasons described in Section 6, our final decision is to adopt P229 in all its technical details and to require no further technical changes. Therefore, customers will be charged with some cost-reflectivity.

49. In terms of the type of evidence adduced to establish the AEC, we have relied on the analytical observation that technical efficiency is enhanced as prices move closer to reflecting incremental costs. Although SSE has submitted that this is not necessarily the case, we have seen no evidence that it is unlikely to the case over the range we are considering. There may be some exceptional theoretical cases in which an apparent move towards cost-reflectivity does not lead to net benefits. We have no evidence or other reason to believe that this is such a case. We have also relied on a range of modelling studies, although these have been more important in establishing the order of magnitude of any detriment than in establishing the existence of the AEC.

50. SSE[51] also added that engaging NERA to carry out the CMA's cost-benefit analysis entailed a very real risk of apparent bias or confirmation bias (or both) due to NERA's position as a long-standing advisor to RWE. It[52] added that the measures put in place by the CMA to mitigate potential risk of conflict of interest were insufficient and not followed in any case. In particular, SSE[53] submitted that the CMA did not adhere to the transparent and iterative process it had undertaken to follow by failing to publish a working paper with the details of NERA's model and its results.

51. For the reasons set out in our notice of 16 September 2015[54], which include addressing SSE's submissions that existing models at the time of the Provisional Findings were out of date, we believe that it was appropriate to carry out further modelling in order to assess the impacts on electricity markets of the introduction of locational pricing for losses. We published on 20 October 2015 our reasons for appointing NERA[55], highlighting the importance of appointing an expert consultancy to carry out this work within our statutory timeframe. Two parties, including SSE, have raised concerns around potential apparent bias, confirmation bias, or both, arising from the appointment of NERA and the timetable for completing the work. We responded to parties'

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[51] SSE response to PDR, paragraph 8.3.2, page 64.
[52] SSE response to PDR, paragraph 8.3.6, page 65.
[53] SSE response to PDR, paragraph 8.3.7, page 65.
[54] Notice regarding assessment methodology for losses remedy, 16 September 2015.
[55] Notice regarding assessment methodology for losses remedy – appointment of economic consultancy, 20 October 2015.

comments in our notice of 30 October 2015.[56] We published for consultation our methodology and proposed scenarios on 8 December 2015.[57] We invited interested parties to participate in a workshop to discuss NERA's modelling approach and scenarios. Five of the Six Large Energy Firms, National Grid and Ofgem sent representatives in person to our workshop (one person from SSE also attended the workshop by phone). We provided to attendees the materials used by NERA at that workshop for parties to consider in their response to our consultation on methodology and scenarios.

52. We published the results of NERA's modelling and more details of the model as an Appendix to our PDR[58]. In the light of parties' responses, we decided to run three additional scenarios using a 50/50 allocation of losses costs between generators and suppliers.

53. In running this further modelling process we note that:

(a) Parties have had the opportunity to comment on our methodology and scenarios (including on the external advisors appointed to carry out this modelling exercise), both in writing and within the context of the above-noted workshop.

(b) We considered comments made to us about certain of the assumptions. We did not modify our scenarios in light of these comments because we were not presented with any alternatives that were clearly better suited to the specific purpose of this modelling exercise.

(c) Parties have had the opportunity to comment on the results of tour earlier modelling exercise and our interpretation of these results, which does not differ materially as regards the further modelling exercise. Specifically, parties corrected our interpretation of the 45/55 split.

(d) Parties have had the opportunity to conduct their own analyses in full knowledge that the analysis was being conducted in parallel by us and by NERA. EDF, for example, took advantage of this opportunity to present some analysis relating to the impact of intermittent generation on the predictability of loss factors.

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[56] Notice regarding assessment methodology for losses remedy - update on appointment of an economic consultancy, 30 October 2015
[57] Notice regarding assessment methodology for losses remedy – consultation on methodology and scenarios, 8 December 2015.
[58] Appendix 2.2: Modelling the impact of zonal transmission loss multipliers (report prepared by NERA Economic Consulting for the CMA).

(e) In the light of parties' responses we have run additional scenarios that more accurately reflect the reality of the P229-based remedy.

54. For the reasons set out in Section 6, while we acknowledge that additional analysis could be carried out, thus further testing the sensitivity of orders of magnitude to scenario input assumptions, we do not believe that this would provide additional relevant evidence to support or invalidate our AEC findings or the design of our remedy.

55. While the NERA analysis was of course considered, we had reached the conclusion of a provisional AEC without this evidence. The NERA analysis strengthened our belief in the existence of substantial detriment and it assisted in remedy design. However, it was not in itself decisive in reaching the conclusion of an AEC.

56. Modelling assumptions and results

Locational modelling of investment

57. Drax[59] commented on some of the modelling assumptions made by the CMA in each case and we have noted how we have taken such comments into account in our findings:

(a) Transmission charges (TNUoS) were used as the main determinant of plant location decisions. Whilst TNUoS may play a part in new thermal generation investment decisions, there are many other determinants that have an equal or greater influence on build decisions, including available land/access to existing generation sites, planning requirements, access to the network, access to fuel, proximity of workforce, other local infrastructure, etc. These factors are not considered by the analysis.

We do not agree with this comment. NERA's methodology, described in Appendix 6.1, Section 3.3.3, explains that the location of plants has not been based exclusively on TNUoS charges and does take these other factors into account.

(b) The model fails to recalculate TNUoS charges year-on-year, meaning that the accuracy of transmission charging signals is ignored after year one.

We do not agree with this comment. While NERA uses a fixed forecast of TNUoS to 2030, based on the analysis they performed in the course of Project TransmiT, the TNUoS charges within this forecast vary year-on-

[59] Drax response to PDR, pages 1-2.

year reflecting anticipated changes in supply-demand conditions and development of the transmission system over the period to 2030. The TNUoS charges therefore evolve over the period and continue to provide transmission charging signals after year one for the given supply-demand background.

(c) It is clear that locational TNUoS signals do not work effectively today. Despite a requirement for thermal generation in the north of the country (to provide system stability (ancillary services)), transmission charges continue to rise. This is due to the volume of intermittent renewable capacity connecting in the North, which is indifferent to TNUoS (and losses) charging signals due to the structure of the CfD FiT contract.

We believe that this is not the case. Generators will locate where it is most economic for them to do so, and NERA models this choice. CFD-supported wind farms pay TNUoS, and we would expect them to factor their TNUoS costs into their CFD auction offer prices.

(d) National Grid must maintain system stability. If transmission related charges continue to signal the closure of thermal plant located in the North, then National Grid will be forced to enter arrangements to maintain the provision of ancillary services. This does not appear to have been considered in the modelling.

We have not asked NERA to simulate the purchase of ancillary services in its simulations. It is possible that ancillary contracts will give extra economic life to plants in the North that might otherwise have closed under a locational charging regime. We do not consider that this is an argument against locational pricing, and we agree that it is important that ancillary services be purchased competitively. We do not believe that a full modelling of ancillary services will change the order of magnitude of the benefits.

(e) The delivery timescales of new renewable and nuclear capacity are questionable. Given that political support for renewable investment is waning, and the decision on new nuclear deployment has been significantly delayed, it appears that the future of renewables and nuclear new build is uncertain.

The timings for these new generation programmes are indeed uncertain (though we do not accept the premise that “political support” for renewables is changing) . However, if they are delayed compared to the modelling assumptions, we would expect the supply of zero marginal cost plant, which are likely to be least sensitive to locational loss factors, to be lower than we have assumed. Accordingly, there may be more scope to improve the efficiency of the merit order of thermal plants from the application of zonal loss factors, and hence the benefits of adopting locational losses charging should be larger.

(f) The assumed wholesale electricity price curve is questionable. The CMA notes on page 68 that a wholesale electricity price of £70/MWh to £90/MWh is assumed. This seems excessive in comparison to the traded market over winter 2015/16, which has seen the month-ahead baseload price rarely rise above £40/MWh.

We do not agree with this comment. The price is a modelled output not an assumption, which depends primarily on commodity prices. As shown in Appendix 6.1, the modelled price varies from around £40/MWh at the start of the period (2017) to up to £90/MWh by 2035. In practice, the modelled electricity price is largely driven by assumptions on commodity prices, and we have considered a wide range of commodity price scenarios from the sources documented in Appendix 6.1.

(g) There appears to be little consideration of IT system changes outside the BSC. Changing the way in which transmission losses are charged will lead to additional costs to generators (production and trading systems) and suppliers (pricing system changes and quotation production costs).

We do note that in Section 6, we report Ofgem’s finding in relation to P229 that implementation costs would be small, which we have incorporated into our assessment of the AEC and the proportionality of the remedy. We also note that RWE has commented in relation to our own work that implementation costs would be low because the work has already, for the most part, been done.

58. EDF[60] highlighted that the ‘Reference’ scenario taken by NERA appears somewhat out of date given the recent fall in gas prices and that the impact of this assumption is that NERA’s results may be significantly overstating the incremental impact of introducing locational losses on existing coal stations, including on EDF Energy’s portfolio.

59. Moreover, we do not agree with this criticism. Fossil fuel and other commodity prices are volatile. We have considered a relatively wide range of price forecasts, as described in Appendix 6.1, and found that the welfare effects of

[60] EDF response to PRD, paragraph 3.4, page 18.

locational losses are robust to changes in gas prices. Hence, we do not consider this factor would reduce the likely welfare savings from this policy.

60. Scottish Renewables[61] submitted that some input assumptions were subject to significant change and appeared completely inconsistent with the direction of travel for UK energy policy, for example:

(a) the Capacity Market price forecast, which is one of the main drivers of the derived ‘benefit’, appeared much higher than that which any other analysis had previously presented on the subject – with little justification as to what would drive such an outcome;

(b) the projected capacity out to 2035 identified that the majority of new onshore wind capacity would be delivered in England and Wales – failing to account for recent changes to Government policy which were likely to drive future development into areas with highest resource.

61. Renewable UK[62] submitted that the fact that dynamic effect of locational pricing was explicitly not considered within the model -because it was deemed to overcomplicate the modelling significantly- undermined the model’s ability to predict with accuracy both the distributional impact and the long-term benefit to consumers that were the core arguments used to justify this change. SSE[63] considered that the analysis undertaken by NERA places undue reliance on assumptions that are highly questionable or unsubstantiated and the sensitivity of which has not been properly tested.

62. We do not agree with this comment. We have relied on published, independent sources for our assumptions to the maximum extent feasible. We have also run a range of scenarios to assess the robustness of our results. Moreover, we note that parties had multiple opportunities to provide constructive input into the assumptions used. No alternative sets of assumptions for the modelling process were submitted.

(a) SSE[64] submitted that the additional benefit attributed to the 100:0 split of costs is based on a flawed analysis – if the multipliers for the 45:55 split of costs were cost reflective then moving to the 100% case should not alter dispatch decisions;

We agree with this comment, in part. As explained in paragraph 5.79, the PDR contained a misinterpretation of the 45/55 split. What we in fact

[61] Scottish Renewables response to PDR, page 2.
[62] Renewable UK response to PDR, page 3.
[63] SSE response to PDR, paragraph 8.4.1, page 65.
[64] SSE response to PDR, paragraph 8.4.1 (a), page 65.

modelled and intended to model was a full-marginal versus semi-marginal variable loss adjustment. This clarification has been reflected in our findings. If we had in fact modelled and intended to model the actual mechanism of the 45/55 G/D split, SSE's criticism would be valid. However, it is based on a misunderstanding. We therefore do not accept that this criticism is relevant to the interpretation of the modelling results.

(b) SSE[65] submitted that assumptions relating to capacity market (CM) costs and impacts are given too much weight and distort the results produced – to the extent that the modelling shows a benefit to customers, it is almost entirely accounted for by the apparent benefit relating to CM costs in just two years of the modelled period;

Our modelling shows that price effects in both the capacity and energy market are unpredictable and relatively small. However, the cost saving resulting from the policy is significant and stable, and we consider this is a more appropriate estimate of the change in welfare resulting from the policy. Hence, we have placed only limited weight on "assumptions relating to capacity market costs and impacts".

(c) SSE[66] submitted that the model's results beyond 2026 are dismissed on a basis that is arbitrary and not adequately justified – SSE would expect the model to show South to North flow on the transmission network as a result of the significant reduction in capacity in Scotland in the early years of the modelled period;

We note that we do not entirely dismiss the modelled effects of the later period. There are net welfare benefits shown in both periods. However, the unknowns and unknowables of the later period lead us to place less weight on this evidence in reading our findings.

(d) SSE[67] submitted that the DTIM model is not tested against reality so there is no evidence that the modelled results are in any way realistic – this failure to provide a sound reality check makes the modelled benefits arising from reductions in constraint management costs, for example, extremely doubtful (constraint costs constitute more than 65% of the modelled efficiency gains for all scenarios in the period 2017-2016);

We do not agree with this comment concerning the DTIM model. DTIM

[65] SSE response to PDR, paragraph 8.4.1 (b), page 66.
[66] SSE response to PDR, paragraph 8.4.1 (c), page 66.
[67] SSE response to PDR, paragraph 8.4.1 (d), page 66.

has been used in a number of academic articles and has been subject to academic peer review, for example by a journal of the Institute of Electrical and Electronic Engineers.[68] DTIM has been used by Imperial and NERA extensively in our work for RWE during Ofgem's Project TransmiT. This has been subject to the normal processes of industry review and critique. In the context of another study of the GB grid, National Grid reviewers of DTIM model results concluded "Overall, our view is that these initial DTIM results provide strong and independent support of the conclusions of the ENSG Report".[69]

(e) SSE[70] submitted that sensitivity analysis of the following "key input assumptions" would be necessary in order to interpret the results on a sound basis (e.g., in relation to station location, merit order of generation, dispatch of interconnectors, wind and PV generation profiles, and location and level of demand).

We note that we have conducted some sensitivity analysis on some of these factors (i.e. merit order of generation and dispatch of interconnectors) through our commodity price scenarios. We have noted in relation to the assessment of the proportionality of our remedy (Section 6) that we do not believe that it is reasonable to think that further plausible sensitivity analysis will alter our conclusions about the orders of magnitude of the benefits of the policy. Although sensitivities may be informative in other contexts and for other purposes, we do not believe they would assist with answering the narrow question of the order of magnitude that we are ascertaining from the modelling in this exercise.

63. SSE[71] also said that the claimed long-term efficiency benefits were overstated and would be negligible because the true cost of losses for a specific generator would change sharply and in an unpredictable manner making locational losses a very poor signal for investment.

64. We do not believe that this is a criticism of the modelling or of the remedy. We have not factored any benefits from the improved efficiency of investment into the modelling of welfare benefits of locational losses, so our results are not affected by the extent to which locational losses are, or are not, a poor signal for investment. The simulation modelling has focused on the immediate benefit of reducing the waste of energy involved in not having locationally-sensitive loss charging. We believe that any impact on investment, (it may

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[68] See PowerTech, 2009 IEEE Bucharest, for example.
[69] "Our electricity network. A vision for 2020", Electricity Networks Strategy Group. DTIM user report, Qiong Zhou and Paul Plumptre, National Grid
[70] SSE response to PDR, paragraph 8.4.1 (e), page 66.
[71] SSE response to PDR, paragraph 8.5.3, page 67.

nonetheless in some cases affect particular location decisions), will add to this benefit.

Modelling of Europe

65. DONG Energy[72] submitted that our modelling of Europe exogenously was not satisfactory in light of the impact of our remedy and given the interconnection capacity (4.4GW) assumed by the CMA and the potential for more.

66. We disagree that the technical way in which Europe was modelled was inappropriate NERA proposed to model European markets in a "reduced form", whereby prices in Europe did not vary as UK prices varied in the model. They were taken as an exogenous given, and imports were optimised against these given prices. NERA's reason was that this would make the model tractable and yet would not compromise accuracy to a degree that would affect the order of magnitude of results. We accepted NERA's reasons for the simplification. We do not believe that a more complicated model would impact on the order of magnitude of benefits, because imports remain a relatively modest source of electricity in all plausible scenarios.

Marginal loss factors

67. EDF[73] considered that it was unclear whether the CMA indented (intended) to use marginal loss factors or averaged or scaled loss factors as per previous BSC proposals including P229. It said that if it was the CMA's intention to use marginal loss factors then this would increase the risk of applying inaccurate loss factors to a party at any moment in time. It said that the use of marginal loss factors would risk over recovery of variable losses and would increase distributional impacts between locations.

68. We agree with EDF that there was a lack of clarity in our PDR which arose for the reasons given in footnote 148 of paragraph 5.80 in Section 5. In terms of quantifying the detriment from the absence of locational pricing, we believe that the full-marginal treatment is the more relevant, while the semi-marginal is used to model P229. We do not intend to order the use of full marginal loss factors.

[72] DONG Energy response to PDR, page 3.
[73] EDF response to PDR, paragraphs 3.10-312, page 19.

Use of zones

69. EDF[74] said that the details of the scheme modelled by the CMA do not appear to align to the scheme envisaged for implementation of P229. Specifically it noted that the representation of locational loss adjustment in the modelling performed by NERA is not consistent with the P229 solution. Previous modification proposals, including P229, used zones defined by distributional Grid Supply Point Groups.

70. We do not agree that this was the purpose to which the model was put. We consider that the degree of regional granularity modelled using the DTIM model is similar to that envisaged under P229, in the sense that there are 14 GSP zones and 16 DTIM nodes. Hence, the degree of zonal averaging built into DTIM is similar to the degree of zonal averaging used when computing TLFs under P229. On this basis, we do not believe using the exact GSP zoning would change our view of the order of magnitude of the benefits.

Congestion

71. There are no comprehensive or recent assessments of the costs and benefits of market splitting in the GB electricity system. The last comprehensive assessment of the costs and benefits of implementing a zonal pricing scheme is by Green, published in 2007 but using data from 1997.[75] This study applied only to England and Wales and considered splitting this area into 12 zones. The combined annual benefit of congestion and losses pricing was estimated to be £73m.

72. The most recent study was a very partial quantification of splitting Scotland from England and Wales by Staffell and Green in 2014.[76] They found that on average domestic consumers in Scotland would benefit by an estimated £64 off their annual energy bills.[77] Generators in Scotland would have lower revenues.[78] Consumers in energy-importing areas (such as south-east England) would face higher prices (an estimated average increase in annual energy bills of up to £14),[79] while generators there would enjoy higher

[74] EDF response to PDR, paragraph 3.16, pages 19-20.
[75] Nodal pricing of electricity: how much does it cost to get it wrong?, *Journal of Regulatory Economics,* Vol: 31, pp125–149, 2007.
[76] I Staffell and R Green (2014) *Electricity markets in Great Britain: better together?*.
[77] I Staffell and R Green (2014) *Electricity markets in Great Britain: better together?*.
[78] This assumes that the market under locational pricing of congestion would be no less competitive. Locational rents are currently controlled to a degree through the Transmission Constraint Licence Condition (TCLC). It would be necessary to make sure that analogous measures were in place to avoid the exploitation of locational rents under split markets.
[79] I Staffell and R Green (2014) *Electricity markets in Great Britain: better together?*. This estimate does not take account of benefits that would be passed back to consumers from the elimination of congestion costs in BSUoS charge. The explanatory note further states that, in order to have regard to Ofgem's statutory duties, aims or objectives of the regulator, the remedy contemplated by the CMA must be consistent with the regulator duties.

revenues. While this study looked at distributional effects it did not try to estimate a net benefit figure.

73. Conceptually, the net benefit calculation this study identified would be composed of:

(a) gains from static efficiency (mainly demand response);

(b) gains from dynamic efficiency (mainly location of new generation and new demand);

(c) costs from increases in transactions costs; EDF Energy argued that 'the introduction of zonal pricing increases the complexity and potential cost of hedging and risk management which could act as a barrier to entry for small players'; SSE raised a similar objection, adding that such a reduction in liquidity could lead to a reduction in competition for end-customers;

(d) costs from reductions in liquidity due fragmentation of the market with possible impacts on entry and therefore dynamic efficiency; Ofgem, EDF Energy, and Scottish Power have pointed to the existence of these costs; and

(e) one-off transitional costs; SSE and Scottish Power have noted that this might be high.

EDF Energy also pointed to the possibility of costs from more effective exercise of market power in the light of small (and therefore more concentrated) areas.

74. An assessment of the likely costs and benefits over time needs to take a view of the expected levels of transmission investment, since this will be a significant determinant of the level of congestion costs. SSE and EDF Energy noted that expected transmission investment was likely to render transmission constraints much less important in the coming years. National Grid has to some degree confirmed this view.

75. We did not receive any responses to our working paper in favour of implementing increased cost-reflectivity of congestion constraints. National Grid provided a response to our Provisional Findings and proposed a model

for the future that would more accurately account for network constraints.[80] We comment on this long run proposal in Chapter 6.

Zonal vs nodal congestion pricing

76. We had suggested in our wholesale electricity market rules working paper[81] that self-dispatch might be incompatible with congestion charging and that one benefit of a return to a centralised pool might be the implementation of nodal pricing.

77. RWE and SSE both commented that self-dispatch was compatible with locational charging. Specifically, with market splitting, it would be possible to calculate different imbalances prices for different zones. Whilst the very granular nodal pricing systems that are seen in some markets in the USA (for example ERCOT in Texas) may not be possible without a mandatory wholesale pool and centralised dispatch, the preferred EU model for congestion charging under the CACM (as described in paragraph 16) does not require a mandatory pool with centralised dispatch. National Grid's model for discussion[82] also makes it clear by example that self-dispatch can be consistent with zonal pricing. This argument is considered further in Appendix 5.1: Wholesale electricity market rules.

78. The CACM process will periodically determine the costs and benefits of different levels of splitting. We can assume that this review process will consider the full cost-benefit of splitting, including such issues as reduced liquidity, increased complexity, and, if relevant, any changes required in the operation of the balancing markets.

[80] National Grid response to Notice regarding assessment methodology for losses proposed remedy – consultation on methodology and scenarios.
[81] Wholesale electricity market rules working paper.
[82] National Grid response to Notice regarding assessment methodology for losses proposed remedy – consultation on methodology and scenarios.

Annex A: A summary of current charging arrangements

Component of electricity costs	**Description**	**How charged for in current arrangements?**
Generation costs	Short- and long-run costs incurred by generators in producing electricity. Variable costs include fuel costs (for thermal generators), carbon allowance costs, variable operational costs. Fixed costs include recovery of generation plant investment (capital) costs, fixed operating costs.	Wholesale electricity price (spot price or forward contracts) plus additional earnings in BM for flexible plant. CfDs for new low-carbon generation from 2014. Capacity payments for existing and new capacity from 2018/19.
Transmission constraint costs (ie congestion costs)	Short-run cost of transporting electricity from one point to another over high-voltage long-distance transmission wires, when there is limited capacity available relative to amount of generation that wishes to dispatch. Equal to the difference in marginal generation cost of meeting demand in export-constrained (lower-cost) zone versus marginal generation cost of meeting demand in import-constrained (higher-cost) zone.	National Grid takes system balancing actions in the BM to resolve transmission constraints. Costs of these actions are socialised across all market participants via BSUoS charges. They are levied on an output basis (£/kWh), split 50% on generation and 50% on demand (load).
Transmission loss costs	Short-run cost associated with the electricity that is lost as heat when being transmitted. Equal to the additional cost of generation that needs to be brought onto the network to make up for the electricity lost.	National Grid takes energy balancing actions in the BM to ensure the balancing of supply and demand, taking account of losses on the wires due to heat. Generators are settled on approximately 1% less power than they are metered to have produced while suppliers are settled against the actual reconciled energy volumes consumed, which include both transmission and distribution losses.