Appendix 2.3: Market splitting and losses proposal from National Grid

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Date: 28th January 2016

Dear Tony

Energy Market Investigation: Market splitting and losses proposal

Following from the CMA's provisional findings regarding the absence of locational signals for losses (and constraints), we have been considering how a GB market mechanism might be designed to account for locational losses whilst remaining compatible with the potential changes that might emerge from arrangements resulting from the EU Capacity Allocation Congestion Management (CACM) code.

The attached paper is a thought-piece elaborating how such an industry model might be designed. We attempt to demonstrate this further in the attached spreadsheet (which uses exaggerated figures for the purpose of illustration). We are offering this material as an alternative approach for industry consideration. It is not intended to be taken as a recommendation or proposal for industry change.

Yours sincerely

Mark Ripley

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Energy Market AEC 1: Absence of locational prices for transmission losses and constraints

Thought piece by National Grid

In our response[1] to your provisional findings and notice of possible remedies we suggested that if it is desirable to introduce locational signals for losses then it would be beneficial to do it in a way that will be compatible with arrangements under the EU Capacity Allocation and Congestion Management (CACM) code which may be used to manage transmission constraints. In this submission we set out an example of what such a compatible arrangement might look like. We hope these thoughts will be helpful in the context of the further analysis being undertaken by NERA and the CMA.

This paper outlines an approach to introducing locational signals for losses and constraints for consideration in relation to AEC 1 that has been identified in the CMA's energy market investigation. The paper is intended to be a thought piece and does not explore all of the details or practical implications that would need to be determined in order to implement the model in GB. As such whilst this does not constitute a recommendation or proposal for industry change, it seeks to offer thoughts on designing a remedy to AEC 1 that would be compatible with the direction of the EU Target Model.

What does CACM require?

The CACM code has been approved under the EU comitology process and thereby will be implemented in the GB market. It specifies a target model for managing material and enduring congestion (i.e. network constraints that cannot be economically managed by counter-trading by system operators or economically eliminated by investing in reinforcements). This model can signal network congestion in locational energy prices by adjusting, where appropriate, market bidding zones (the market price areas). The target model will be implemented for capacity allocation and congestion management on interconnectors between national markets. It can also be applied to manage internal congestion in a market area, providing short-run locational price signals to market parties and thereby encouraging appropriate self-dispatch, by splitting the existing market into areas in which different prices will arise if inter-area transmission constraints are active. The target model market coupling algorithms ensure area prices will converge when inter-area capacity is sufficient for market determined inter area power transfers. These algorithms have facilities for determining the extent that inter area power transfers should occur given their impact on associated transmission losses. The exact nature of its implementation in GB is still to be determined and any change in market bidding zones will be the subject of a merits assessment and will be subject to approval by Ofgem.

Why is this relevant to efficiently signalling the effects of transmission losses?

As noted in the CMA's provisional findings, previous GB market rule change proposals which have sought to signal the impact on transmission losses of producing or consuming at different locations have all proposed scaling wholesale market parties' metered volumes (the so-called BMU volumes). The proposals were for locational loss factors to be determined in advance of delivery and so seek to

[1] https://assets.digital.cabinet-office.gov.uk/media/55e6bd68e5274a558000001a/National_Grid_resp_to_PFs.pdf

reflect the expected impact on GB transmission losses from production or consumption at a particular location over some future period. These ex ante loss factors would be used to scale metered volumes such that a pre-determined proportion of actual half-hourly losses would be allocated to production and consumption accounts. An aim of using ex ante loss factors was that it would provide market parties with some opportunity to determine how much more or less than their physical positions they would need to contract in order to maintain balance. However, as transmission losses are proportional to the square of circuit power flow, and power flows and actual losses will depend on many uncertain factors, there is a risk that the scaling factors actually applied ex post might not achieve the anticipated level of predictability or accuracy, resulting in some parties being unduly penalised or rewarded. Concerns about these sensitivities and potentially inefficient outcomes are likely to have been the main reasons for the industry's preference for scaling factors that were reduced (by a factor of 50%) from those that would reflect the full marginal effect of a users' activity on system losses.

Recent trends, especially the larger impact of short-term weather and other market conditions including their effect on interconnector flows, increases the concern about the accuracy of scaling factors determined from forecasts of conditions. Such ex ante scaling factors would also not be able to reflect any effect on losses that might result from behavioural responses to the conditions that may occur at different times by flexible parties, exacerbating the risk of undue penalties or rewards to certain parties. These issues will be particularly acute in the event of network constraints because power flow patterns and the impact of different users on losses may change significantly in such conditions.

While loss scaling factors derived in real-time would address accuracy concerns, they would be a source of additional imbalance uncertainty for which there would be only limited opportunities for market parties to hedge. They would also cause operational uncertainties due to parties wishing to adjust their physical positions to maintain balance as scaling factors vary and due to the likelihood that overall system length will also vary with losses. For these reasons, it is useful to examine how transmission loss impacts may be signalled via locational energy prices and how interactions with constraints could be addressed by adopting a design consistent with the CACM target model.

How could transmission losses be incorporated in a (split) NETA/BETTA market?

As a result of Ofgem's Electricity Balancing Significant Code Review (EBSCR), which implemented a single energy imbalance price in the BETTA market for long and short positions, there is now an opportunity to incorporate locational signals into the BETTA energy markets via suitable calculation of a (single long/short) energy imbalance price in different GB locations. The proposed approach would require:

1) A single energy imbalance price for long or short positions computed at each market location (network node or zone, as appropriate) which reflects, in a similar manner to current national imbalance price, the energy balancing cost of providing a MWh (or accepting a MWh) at that location in each delivery period.

2) The delivery location of all BETTA bilateral energy contracts to be defined. (Arrangements would need to be determined for the treatment of existing bilateral contracts, one option might be that they are deemed to be fulfilled by

delivery at a specific network node). System operator balancing contracts will continue to require delivery at the specified location.

3) Production (or consumption) at locations other than this contract delivery location would be subject to two energy imbalance cash-out exposures:

   i. A long position at the location of actual production (or contracted consumption).
   ii. A short position at the location of contracted production (or actual consumption).

With these requirements established:

- A generator who produces the contracted volume of energy at the contract delivery location, or a supplier who off-takes the contracted volume of energy at the contract delivery location, would both face no imbalance exposures.
- A generator who has contracted to provide CV MWh at location 1 but produces GV MWh at their connection location 2 would be subject to an imbalance charge of (CV.IP1 - GV.IP2), where IP2 is the imbalance price £/MWh at the generator's connection location.
- Similarly a supplier counterparty (contracted at location 1) who off-takes SV energy at location 3 would face an imbalance charge of (SV.IP3 – CV.IP1). It can be seen that if a generator produces in accordance with their contract (i.e. GV=CV) then they retain an exposure to the difference between the real-time energy prices at their location and the contract location for the volume of the trade. The same applies to the off-taking supplier.
- The contracting generator and supplier can choose who takes the locational price exposure by specifying the contract delivery location but between them they will take exposure for costs resulting from producing and consuming at different locations.

Using the approach described above, accurate marginal locational prices can be signalled to market parties via real-time imbalance prices. The impact of locational imbalances on transmission losses could be derived in a number of ways but a methodology which would ensure consistency with CACM might be as follows:

a) Divide the system into zones such that existing and potential major congestion pinch points, which may be relevant to future market splitting, lie on the links/boundaries between zones and these links also provide a reasonable representation of transmission losses given bulk power flows across the transmission system. The following four zones and 3 boundaries are one example of how key congestion pinch points, interactions with interconnectors, the effect of main North-South bulk flows on losses could be captured in a manner consistent with existing GSP Group supplier metering resolutions. This example is for illustration only and has not been assessed quantitatively against different zoning.

b) Using the existing PAR50 imbalance price calculation, determine the system imbalance price and note the zone in which the marginal energy balancing action resides.

c) In the absence of market splitting, calculate imbalance prices in other zones by using IPs = IPr.(1-TLFsr) where IPs = sending end imbalance price, IPr = receiving end imbalance price and TLFsr is the transmission loss factor for exchanges between the sending and receiving zones. This can be calculated from a full network loadflow, or for simple radial cases, may be derived from TLFsr = 2.fs.r = 2. linkloss/fs (see Appendix B).

d) With market splitting due to congested links between zones, the imbalance prices may be derived from a linear programme optimisation of the dispatch or a modified form of the PAR50 calculation in each of the market split areas.

The choice between using load flow /despatch optimisation software or the existing PAR50 type calculations will depend largely on the desire for transparency and consistency with current imbalance price setting methodologies.

What would be the revenue implications of locational imbalance prices?

As noted above, generators and suppliers may choose to contract bilaterally to hedge against uncertain spot imbalance prices, and may choose how to allocate locational differentials by selecting the delivery location of their bilateral contract. In total, the bilaterally contracting parties would face a charge (perhaps negative) which reflects the impact of the flow from generator to off-take on the costs of total system losses.

Across the total system, and including the balancing contracts the system operator must enter to ensure the reliable delivery of supplies and good frequency quality, the total imbalance charge revenues recovered under unconstrained (non-market split) conditions can be shown to match the total cost of inter-area link losses (we illustrate this in the attached spreadsheet, the results of which are described below). Under constrained (market split) conditions it can be shown that the revenues remaining after funding the cost of losses is sufficient to meet the revenue requirements of a set of financial transmission rights (FTRs) which could be available as hedging instruments to users of the established inter area link capacities.[2]

Spreadsheet Models

The workings on the attached spreadsheet demonstrate, through two simplified models, how zonal losses are resolved by applying (1) zonal imbalance prices and (2) zonal loss factors to scale metered volumes. These models take initial physical positions that are assumed to have been determined by the market. From these physical positions and a minimal set of assumptions, each model calculates the price signals (zonal imbalance prices in (1) and the implied zonal marginal costs in (2)) that must have occurred to give rise to those positions and flows. (In the spreadsheet, network resistances and hence the resulting losses and marginal loss factors have been exaggerated for illustration purposes. Actual network resistances suitable for such boundary calculations may well be smaller by a factor of 4 or more and give proportionately smaller price differentials).

Whilst the zonal imbalance price model begins with identifying the location of the marginal generator and making this the marginal zone, the zonal loss scaling factor model assumes the marginal generator is located in the market at a notional location which gives a 45:55 G:D split of losses. This means that the imbalance price method produces symmetrical signals for demand and generation as opposed to the divergent signals that emerge in the respective marginal costs derived by the zonal loss scaling factor model. The differences in absolute price signals, that can be seen in the results (see example tables below), illustrate the potential for considerable mis-signalling to market players of the impact they have on losses.

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[2] In the USA PJM market, FTRs are allocated by an auction which ensures the resulting FTR allocation is always consistent with the established network capacity (however it is used) and so the FTRs should be revenue adequate. The resulting FTR auction revenues are allocated to network providers and reduce the network charges they would otherwise levy.

The results below assume losses are met by generation in zone 4 at a marginal price of £100/MWh, this gives rise to additional signalling marginal costs for generation and demand that is ~30% above the actual marginal cost. Whilst the relative signals between zones are comparable over the two methods, the discrepancies observed in the absolute marginal costs that come out of the scaling factor method indicates the potential for inaccurate signals for generator dispatch.

£/MWh	**Absolute signals**				**Relative signals between zones**		
	zone 1	**zone 2**	**zone 3**	**zone 4**	**2-1**	**3-2**	**4-3**
Imbalance price method for gen	59	67	83	100	8	16	17
Imbalance price method for dem	59	67	83	100	8	16	17
Meter volume scaling method for gen (marg cost)	77	88	109	131	11	21	23
Meter volume scaling method for dem (marg cost)	75	85	105	128	10	20	22

Assuming losses are met by generation in zone 1 at a marginal price of £120/MWh (with assumptions made for physical positions):

£/MWh	**Absolute signals**				**Relative signals**		
	zone 1	**zone 2**	**zone 3**	**zone 4**	**zones 2-1**	**zones 3-2**	**zones 4-3**
Imbalance price method for gen	120	150	202	261	30	52	59
Imbalance price method for dem	120	150	202	261	30	52	59
Meter volume scaling method for gen (marg cost)	82	102	138	178	20	36	40
Meter volume scaling method for dem (marg cost)	77	96	130	168	19	34	38

Due to these divergences in price signals we consider that there may be benefits in exploring the benefits that may result from zonal prices over zonal scaling factors.

While the potential definition of access rights, their allocation and the potential for creating aligned system operator incentives on congestion management and loss optimisation is beyond the scope of this note, the above illustrates that there is scope for network loss costs to be met by locational imbalance prices without supplemental charges or further loss allocations to network users (for example by scaling meter volumes).

Not directly illustrated in the spreadsheet but an aspect that can be inferred from its workings is the effect of also implementing market splitting to signal and resolve congestion. In the imbalance price approach, market splitting for congestion would result in marginal prices that derive from congestion and these would replace the price differences due to loss considerations. Whereas with meter volume scaling, there is a big risk (unless specific additional measures are instigated) that meter scaling factors would provide an effect that adds to any congestion prices (and hence cause significant overstatement of true marginal costs).

Conclusions

This paper has sought to set out an illustration of how efficient transmission loss signals may be established in a framework that is consistent with the existing GB NETA/BETTA market and is also consistent with the EU capacity allocation and congestion management (CACM) code which might require market splitting to manage enduring GB transmission constraints. It has highlighted how such an approach might avoid certain difficulties and undesirable properties of an approach based on adjusting metered volumes.

We have provided a table in Appendix A that sets out some potential benefits and risks that we have identified with the options for providing locational loss signals. These are not exhaustive but may serve to highlight initial issues for consideration.

Next Steps

We aim to assess the impact of splitting the GB system into separate imbalance pricing zones by developing our public domain tool that we use to assess scenario analysis of the GB electricity system. This will allow an assessment to be made of the impact of introducing zonal pricing on output, generation costs, losses and marginal prices.

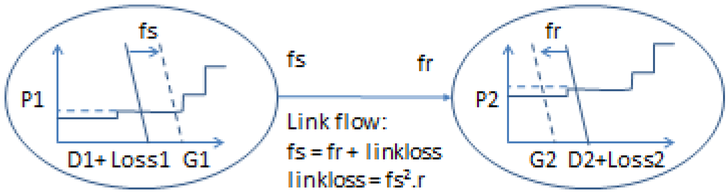
There are many issues, both in terms of the specific details of arrangements and their implementation (including settlement system change costs), that have not been addressed in this paper. If further investigation is considered worthwhile we would be happy to work with industry parties to examine the practical issues and potential costs associated with implementing such an approach.

Appendix A

Approach	Pros	Cons
P229 (BMU meter scaling by ex ante average loss factor)	No system energy/revenue recovery surplus Differentials predictable for parties	**Marginal signal attenuated by 50%** **Greatly approximates actual short-run dispatch conditions** **Absolute marginal cost signal affected by G:D loss allocation** Unclear interaction with future congestion management (& TNUoS)
BMU meter scaling by marginal ex-ante loss factor	Differentials predictable for parties Sharper signal than average loss factor	**As above but sharper signal can amplify impact of short-run approximations and interactions**
Short-run locational energy prices reflect marginal losses	**More efficient signal than average loss factor** **Reflects conditions at dispatch decision points** Avoids meter adjustments Can be compatible with CACM	**Requires clarity on CACM implementation (especially delivery locations for contracts)** There is a risk that a locational energy market may give rise to inefficiencies due to differences in the ability of market parties to access different locations (for example, undue costs or risks of acquiring market products) Produces revenue recovery surplus (but this can be used efficiently) Complex change to current arrangements that will require changes to systems, existing contracts and charges to implement

Appendix B

2 zone energy price example



Zone prices will differ due to either

1. The shadow price of a binding capacity constraint $fs = f_{max}$, or
2. The shadow price associated with not exceeding optimum link flow for losses

The shadow price of the capacity constraint (if active) is just the difference in energy balancing prices in the two zones with full link transfer (less link loss at the receiving end)

Optimum link loss occurs when cost saving of incremental transfer just matches the incremental cost of the losses arising. It can be shown that this occurs when P1 = P2.(1-TLF) where TLF = 2.fs.r = 2. linkloss/fs for small flow increments

NG/LAD 20 January 2016