ELEXON

24 June 2022

By email to: WMReform@ofgem.gov.uk

Dear Wholesale Market Reform team,

Re: Call for Input – Locational Pricing Assessment

Please find below our response to your call for input on locational pricing. We welcome the opportunity to provide input on this topic, and look forward to assisting you over the coming months as you consider the benefits of introducing locational pricing into GB wholesale electricity markets.

Elexon Ltd is the Code Manager for the Balancing and Settlement Code (BSC), which facilitates the effective operation of the current wholesale markets and Balancing Mechanism. We are responsible for managing and delivering the end-to-end services set out in the BSC and accompanying systems that support the BSC. This includes responsibility for the delivery of balancing and imbalance settlement and the provision of assurance services to the BSC Panel and BSC Parties (energy Suppliers, generators, flexibility service providers and network companies). In addition, our expertise is available to support the industry, government and Ofgem in considering future changes to the industry rules, for the benefit of the consumer. Elexon is a not-for-profit company, set up as an arm's-length subsidiary of National Grid ESO (Electricity System Operator).

Our experience in designing and managing the current BSC processes gives us a unique insight into the issues that must be solved to allow all market participants (flexible and inflexible, licensed and exempt, distribution-connected and transmission-connected) to have appropriate access to arrangements for balancing and imbalance. In addition, whilst we are recognised for having in-depth knowledge of the settlement system, the experts we have within our business have, in many instances, worked across various aspects of the energy markets and therefore we would be happy to work with you on the wider aspects of the proposal, if it would be beneficial to have our insight.
We have limited our response to questions and areas where we feel we can add value.

If you would like to discuss any areas of our response, please contact John Lucas, Market Design Manager at john.lucas@elexon.co.uk

Yours sincerely,

Angela Love
Director of Future Markets and Engagement

Elexon's Response to Call for Information

Q1: The key opportunities associated with introducing more granular locational pricing in GB

We recognise that the cost to consumers of balancing the system and managing transmission constraints has risen very dramatically in recent years, and that locational pricing is a promising option for incentivising the innovation and behavioural change needed to address this. But it is important that these benefits are accurately weighed up against the potential risks and dis-benefits, and we therefore welcome Ofgem's decision to undertake rigorous modelling of the options.

There are a lot of change initiatives already underway within the market, including the introduction of the Future System Operator and Distribution System Operators, Market-wide Half Hourly Settlement (MHHS) and Faster Switching, all of which are occupying a lot of time and resource both for market participants and for the bodies who support the arrangements.

In support of these initiatives, Elexon has been investing in new systems and programmes, including Elexon Kinnect, our new digital platform, and the Helix solution (the re-development of the central systems to introduce MHHS). The benefits of these investments will mean that future changes to the arrangements will be delivered more quickly and efficiently. We therefore believe that the current change programmes and investment should be taken into account when considering implementation timescales.

Q2: Key implementation challenges, risks and mitigations

One of the key implementation challenges for locational pricing would be ensuring that the design is robust and its implications for all types of party are fully understood, in order that any risk of unintended consequences can be managed and if possible mitigated. We provide some thoughts below on potential risks, but also how they could be mitigated.

Application of Locational Signals to the Retail Market

We understand that one of the desired outcomes of locational pricing would be to incentivise behavioural change in a wide variety of market participants (generators, storage operators, interconnectors, suppliers and consumers), in order to reduce the cost of managing transmission constraints and balancing the system, for the overall benefit of consumers. But applying locational signals (defined at the level of transmission zone or transmission node) to distribution-connected retail customers is potentially problematic for a number of reasons:

- Some customers will have (or perceive that they have) limited ability to shift their electricity consumption to a different time or a different geographical location. There is a risk that such customers may perceive strong locational signals as unfairly and arbitrarily penalising them for decisions they now cannot easily change (e.g. on where to locate their businesses). Options for mitigating this include Grandfathering (although this would dilute the benefits of locational pricing, and could be administratively burdensome if required for large numbers of customers), or transitional arrangements (discussed further below).

  Another option for avoiding disproportionately punitive impacts on customers with limited or no ability to shift their consumption could be to provide all customers (and their electricity Suppliers) with the choice of:

  - Opting in to fully locational pricing, which would then incentivise them to invest in the technology required to shift their electricity consumption to more appropriate times or places (and being rewarded through the locational pricing mechanism for doing so); or

    - Choosing a less sharply locational charging arrangement, which did not expose them to the full variation in prices (across time and location) seen by more flexible customers. Their charging arrangement could, for example, be based on a price that is averaged across a number of nodes[1] and Settlement Periods (so that it varies less over time and geographical location). This could also mitigate the risk that the benefits of locational pricing go disproportionately to those customers with the resources to invest in flexibility, leaving the less affluent to face higher energy costs. However, it would need to be designed in such a way that customers who could invest in becoming providers of flexibility were still strongly incentivised to do so (in order for the benefits of locational pricing to be realised).

- Even where it is appropriate (in principle) to expose customers directly to locational prices, it will not necessarily be straightforward to do so, due to the difficulty in mapping Metering Systems on the Distribution System to nodes or zones on the Transmission System. Because of these difficulties, current locational charging mechanisms (transmission losses and Transmission Network Use of System (TNUoS) Demand charges) are based around the fourteen historical distribution areas, known in this context as "**GSP Groups**". However, this design choice reduces the benefit of these locational charging schemes (because GSP Groups bear little relation to constraint boundaries on the Transmission System). We therefore assume that the introduction of locational pricing will require a new process for mapping Metering Systems to nodes or zones (at least for those customers who choose to provide flexibility services). Appendix 1 to this response explains this in more detail, and we would welcome the opportunity to discuss this further with you.

Potential Need for Transitional Arrangements

Even if the enduring market arrangements allow non-flexible customers (and their electricity Suppliers) to be somewhat shielded from locational prices (as discussed above), introduction of the new arrangements risks disruption to supply businesses through:

- Sudden step changes in the wholesale prices to which they (and their customers) are exposed; and
- Potential teething problems with the complex new systems and processes that they need in order to operate in the new market arrangements.

In the medium term, one would expect supply businesses to manage these risks (e.g. by innovating to make more use of flexibility). However, if the shock to supply businesses is too large and too sudden, there may be a risk that some of them cannot manage in the short term (leading to disorderly market exits). As you know, recent price shocks in the wholesale market have illustrated the risk that each supplier failure places further financial stress on those suppliers left in the market. It would be unfortunate if the introduction of locational pricing caused a cascade of disorderly exits from the supply market. However we can see at least one approach to mitigating this risk and that would be to introduce transitional arrangements (e.g. phasing in locational pricing over a number of years for non-flexible customers).
We note that the impact of any pricing shock on suppliers would potentially be affected by the price cap (if it was still in place when locational pricing was introduced).

Incentives for investment in generation

On 9 June 2022 the BSC Panel discussed locational pricing (following a presentation from NGESO on the findings of their work on Net Zero market reforms). There was some discussion of the risk that

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[1] One option would be for these customers to be exposed to a price that reflects the average locational price in their GSP Group (i.e. historic distribution area). Appendix 1 to this response discusses how this approach could simplify the implementation of locational pricing.

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locational pricing could dis-incentivise large-scale investment in renewables, due to a combination of:

- Lower wholesale prices in those areas of the country which are geographically remote from population centres and other forms of demand (many of which are areas where building wind farms is currently most economically attractive); and
- Increased risk from more complex Contracts for Difference, and having to rely on Financial Transmission Rights (FTRs) that are not necessarily available long-term.

In considering the potential benefits of locational pricing, you may need to take into account this risk of reduced investment (although we anticipate that there could be opportunities to address these risks).

Q3: The proposed approach to modelling zonal and nodal market designs

As discussed above (and in Appendix 1), we believe there are practical limits to the accuracy with which locational signals (defined at the node or zone) can be applied to distribution-connected customers (even if it were deemed desirable to do this for all customers). This means that the theoretical benefits of applying such locational signals are not in fact 100% achievable, and this should be taken into account when modelling the potential benefits.

Appendix 1 – Potential issues in attributing demand (measured at Grid Supply Points) to customers (on the Distribution System)

As discussed above, we assume that achieving the benefit of locational pricing will depend upon exposing at least some distribution-connected customers and generators to the wholesale price applicable to 'their' transmission system node or zone. However, it is not necessarily straightforward for settlement processes to identify which customers are responsible for the demand (or generation) measured at a particular transmission sub-station (Grid Supply Point). This Appendix discusses this in more detail, focusing specifically on:

- Issues with mapping Metering Systems to transmission system Nodes or Zones; and
- Additional issues relating to electrical losses on the Distribution System.

Mapping of Metering Systems to Transmission System Node or Zones

Historically, the electricity industry has shied away from implementing charging schemes that rely on associating individual Boundary Points on the Distribution System with specific nodes (or zones) on the Transmission System. For this reason, current locational charges for distribution-connected customers (and generators) are set on the basis of fourteen "**GSP Groups**" that correspond to historic distribution areas. This is the case for both:

- Transmission Network Use of System (TNUoS) Demand Charges, as defined in Schedule 14.17 of the Connection Use of System Code (CUSC); and
- Transmission Loss Factors, which are used to allocation transmission losses, as defined in Section T of the BSC. In this case the fourteen GSP Group Zones are applied to all parties (transmission-connected as well as demand-connected), in order to achieve a consistent method for allocation of transmission losses.

Because the fourteen GSP Groups are not defined in relation to constraints on the Transmission System, using them as the basis for these locational charges inevitably reduces the extent to which parties are incentivised to dispatch demand and generation on the 'right' side of transmission constraints (and hence reduces the overall benefit to consumers of these locational charging schemes). But this approach was taken because of the perceived cost and difficulty of accurately allocating Metering Points to transmission system nodes or zones.

One of the reasons for this cost and difficulty is that, in principle, the node or zone from which a particular Metering Point is supplied may vary across time, depending on power flows within the Distribution System. Therefore, to achieve maximum accuracy, Metering Points would be allocated to nodes or zones after the event, using actual metered data from the Distribution System. However, as well as being potentially complex, this would create significant risk for suppliers, who would have to buy power for their customers without having certain knowledge of the zone or node to which they would be allocated. We therefore suggest that a more pragmatic solution may be to fix the allocations in advance, using either historic or forecast data on power flows across Distribution Systems. For example:

- Each Metering Point could be allocated to the **single** node or zone which (on average, across the period analysed) would be most affected by a marginal increase in demand at that point; or
- Each Metering Point could be allocated to **one or more** nodes or zones, using a percentage allocation reflecting the extent to which (across the period analysed) each node or zone would be affected by a marginal increase in demand at that point.

Of these two options, allocating each Metering Point to a single node or zone would simplify the design of systems operated by Suppliers (and Distributors), but would introduce additional inaccuracies into the treatment of customers who regularly take power from different nodes or zones (depending on power flows across the Distribution System).

We do not currently have data to quantify this issue of mapping Metering Points to nodes or zones (either in terms of the effort required, or the likely accuracy of the resultant mapping), and we suggest that engagement with Licensed Distribution System Operators may be needed to understand the issue better. One option for mitigating the issue would be to apply the process only to those customers (and generators) opting to provide flexibility:

- Such customers would be exposed to a fully locational price (and would therefore need to be mapped to zone or node, as discussed above); but
- Other customers would be exposed to a price that reflected the average locational price across their GSP Group (and would not therefore need to be individually mapped to a node or zone).

Treatment of Distribution Losses

Under current GB arrangements, electricity Suppliers are responsible not just for the electricity directly used by their customers, but also for the electrical losses on the Distribution System which those customers are deemed to have caused. Therefore the design of any locational pricing scheme must consider the application of wholesale prices to distribution losses.

Currently, distribution losses are calculated for each of the fourteen GSP Groups (i.e. historical distribution areas), and allocated to customers and generators through a two-stage process:

- In advance of each BSC Year, Licensed Distribution System Operators are required to calculate Line Loss Factors (LLFs) for customers on their networks, in accordance with "LLF methodology principles" set out in BSC Procedure BSCP128 ('Production, Submission, Audit and Approval of Line Loss Factors'). LLF values are expected to be highly accurate on average (across a BSC Year), but will not accurately reflect the losses in any individual half hour Settlement Period.
- A second factor is calculated after the event, using out-turn metered data, for each Settlement Period. This is referred to as "**GSP Group Correction Factor**" (GSPGCF). We would expect the volumes of energy allocated through this mechanism to become significantly smaller, once the introduction of Market-Wide Half Hourly Settlement (MHHS) makes actual half hourly data available for most/all Metering Points (greatly reducing the volume of profiled estimates entering settlement).

The combined effect of these mechanisms is that there is significant socialisation of distribution losses within each GSP Group. This partly reflects the difficulty of assigning losses to individual customers, but may also reflect a deliberate policy decision to simplify prices for suppliers and customers (for example by allocating losses uniformly across Domestic customers in each GSP Group).

If a decision is made to implement locational pricing, a decision will need to be made between:

- Continuing to use historic distribution areas (GSP Groups) as the regions across which Distribution Losses are socialised; or
- Changing the processes for calculating LLFs and GSPGCFs such that losses are socialised across different regions (e.g. the geographic areas associated with transmission nodes or zones).

In principle, the second option should sharpen the incentives on customers (by ensuring that appropriate wholesale price signals are applied to losses they cause on the Distribution System, as well as the electricity measured at their meter). However, it would require all customers (and generators) to be associated with a node or zone. Given the potential difficulties in doing this (discussed above) it may be more pragmatic to continue socialising distribution losses across the current GSP Groups. This would also avoid the need to invest in additional Settlement Metering within Distribution Systems, to measure flows of electricity from customers associated with one node or zone to customers associated with another (which would be needed in order to calculate the distribution losses within the geographical area associated with each node or zone).

Whichever approach to apportioning distribution losses was ultimately chosen, we are confident that our experience in operating and monitoring the current Settlement processes will allow us to successfully develop and implement the necessary changes to the BSC and its systems and processes.

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