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ASSESSMENT OF RETAIL MARKET ISSUES ARISING FROM THE INTRODUCTION OF LMP

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Contents

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1 Introduction and scope

During 2022 and 2023, there has been a significant increase in interest in the possibility of implementing locational marginal pricing (LMP) in the GB power market. Most significantly:

- DESNZ consulted on LMP as part of its wider Review of Electricity Market Arrangements, and is undertaking further analysis of the idea;
- following its Net Zero Market Reform (NZMR) project, NG ESO is recommending LMP as the wholesale market model best suited to support the transition to Net Zero. NG ESO has published an initial report setting out the rationale for its preference; and
- Ofgem commissioned a study into LMP, the initial results of which indicated a significant benefit to customers.

There has been significant focus to date on what LMP would mean for the wholesale market and transmission network build in GB. However, there has been less analysis of the implications of LMP for the state of the GB retail market. In this context, Centrica has commissioned Frontier Economics to review and assess the consistency of the introduction of LMP in GB with two specific key features of the current GB retail market. The specific key features are that:

- there is currently no practical need for suppliers to be vertically integrated (i.e. it is possible for standalone suppliers to operate successfully in the retail market); and

- there is an absolute price cap that applies to all default tariffs.

Our report is structured as follows:

- first, we consider the nature of wholesale trading under an LMP market, and the routes by which a move to LMP may influence the case for vertical integration in the retail market and the application of an absolute retail price cap;
- second, we consider the likely impact of a move to LMP on the liquidity of relevant traded products; and
- finally, we conclude on the possible implications of LMP for the two retail market features that we have been asked to consider.

2 Wholesale markets under LMP and routes for influence on retail markets

Before considering the impact of LMP on the two aspects of the retail market which are within the scope of this report, we set out some relevant context. Specifically we:

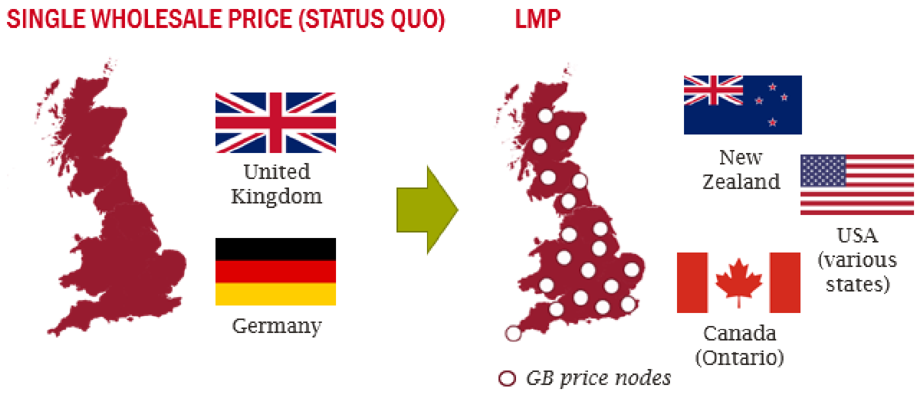
- describe how wholesale trading might occur under an LMP regime;
- summarise the relevance of a move to LMP for:
  - the ability of non-vertically integrated retailers to compete;
  - the absolute default tariff cap; and
- conclude that the impact of LMP on market liquidity is the key route through which LMP may influence these aspects of the GB retail market.

2.1 Wholesale trading under an LMP regime

The current GB wholesale market is a single national price market. This means that suppliers can purchase wholesale energy for delivery to any of their customers in GB by trading energy nationally and without the need for locational hedging.

If the GB electricity system were to move to a system of LMP (also known as nodal pricing) this would imply that instead of there being a single national price there would be different wholesale electricity prices at each node on the GB system.[1]

Figure 1 Illustration of locational price choice in GB



Source: Frontier
Note: [Insert Notes]

[1] There are approximately 900 transmission nodes on the GB system. This gives an indication of how many nodal prices there could be if the GB system moved to nodal pricing. However, in principle the pricing nodes need not be a transmission node and could be at a more or less granular level.

Whether the demand side (and hence suppliers) would face a fully granular set of prices under a GB implementation of LMP is uncertain. In many LMP electricity systems, the demand side of the market is settled based on zonal average prices or even national prices whilst generation still faces fully nodal prices.[2] There are a number of ways in which such a market could be designed – for example:

- suppliers' retail load, irrespective of location, could be settled at a price based on a weighted average of all nodes (as calculated by the settlement system), such that the funds collected would be equivalent to those which would be collected had demand been settled at nodal prices;
- since all suppliers would then have a strong interest in this average price, it could form the basis of hub trading (e.g. generators and suppliers could trade CfDs[3] against this virtual hub price, allowing them to hedge average price level risk over time); and
- provided they were made available as part of the market design, generators could then hedge locational risk using Financial Transmission Rights[4] paying out the difference between individual nodal prices and this weighted average hub price.

Under such a design, since forward retail contracting would be more similar (though still not identical) to retail contracting today, there would be fewer issues to address from a retail perspective.

For the purposes of this report we assume that demand would face nodal locational signals in an LMP market. This is the underlying assumption behind the recent modelling of LMP applied to the GB market, with some of the expected benefits being dependent on the active management of electric vehicles (Vehicle to Grid – V2G) and heating demand.[5]

Under nodal pricing, day-ahead trading is typically conducted via a central counterparty (usually the System Operator or Market Operator). Generators are paid for their production by the central counterparty based on their nodal prices and suppliers are charged by the central counterparty for electricity based on the nodal prices of their customers. If there is congestion on the network, there will be a flow of power from lower priced export constrained nodes to higher priced import constrained nodes.[6] As a result of this transfer, the central

2 If LMP is implemented with zonal average prices for demand then generators will receive nodal prices for their output whilst demand within a zone will pay the same average price at all nodes within that zone. The average price that demand would face would be calculated such that total demand revenues (using a single price) are sufficient to fund total generation payments (with each generator paid its nodal price). In this sense, demand faces a weighted average price.

3 We note that in centrally dispatched LMP markets, forward trading of electricity is typically done in the form of CfDs that are settled against the relevant system price that is determined by the dispatch algorithm. It is these CfDs that we refer to here and which should not be confused with renewable investment support CfDs.

4 We explain FTRs further below.

5 https://www.fticonsulting.com/uk/-/media/files/insights/video-podcast/2023/oct/assessment-locational-wholesale-electricity-market-design-options.pdf See ¶ 5.41 and Table 5-3

6 A zone is said to be import or export constrained if, absent physical transmission limits, the wholesale market outcome would result in more power flowing into, or out of the zone.

counterparty typically accrues a positive revenue which is a function of the price spread and the volume of power transported.

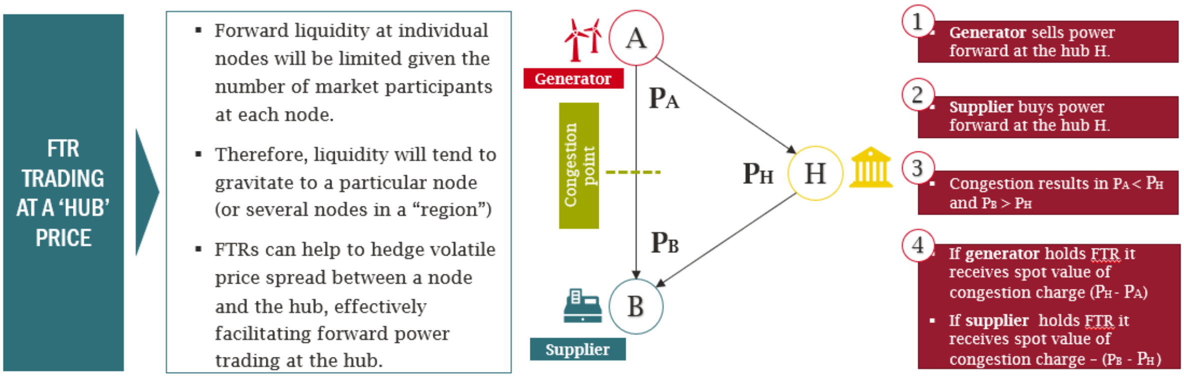
In such a market, if a supplier purchases electricity at one location, and has a customer at another location, the retailer - unless it simply directly passes through the nodal price to the customer - is exposed to a price spread developing between the two locations.

Suppliers could try manage these risks by purchasing energy at the exact location of their customers. However, at any individual node there are likely to be fewer parties to trade with than in today's national market (generators would also face similar challenges).

Therefore, what is observed in many LMP markets is the development of regional or national trading hubs with some liquidity for forward prices. This helps deal with the issue to some extent. But even if such hubs exist, suppliers will still be exposed to any differences between prices at the hub and those at the nodes of their customers.

If the market design provides for it, suppliers and generators can purchase Financial Transmission Rights (FTRs) that allow them to hedge the risk of price differentials arising between the hub and their supply nodes by transferring this risk to another party. Figure 2~~Figure 2Figure 2Figure 2~~ below shows how an FTR market could operate.

Figure 2 An example of how FTRs could work in practice



Source: Frontier Economics

Where FTRs are used, they are typically allocated by the central counterparty. The central counterparty in the wholesale market is uniquely hedged against the exposure that selling FTRs creates. This is because it collects the congestion revenue price spreads which is positively correlated to locational price spreads which can be used to back the FTRs which hedge participants against differences between their nodal price and the hub price.[7]

Where FTRs are used, they are typically allocated through competitive allocation processes (e.g. auctions) on a defined timescale (set out by regulation). Loose analogues to this process

7 As part of the market design decisions a regulator may choose to impose an obligation on the central party to sell FTRs.

exist today: in the electricity market in relation to interconnector access rights and in the gas market in relation to entry capacity rights.

However, it is important to note that there may be more participants with a commercial interest in trading capacity on an interconnector or at an entry terminal than in relation to an FTR at an individual node on the electricity transmission system. At a given node (assuming prices at the node are weakly correlated with those at the hub), it may only be parties with a physical position at that node who have a commercial interest in trading the relevant FTR. In other words, trading may be limited to those with generation, storage, load or DSR connected there. At some nodes this may imply very few interested parties indeed.[8]

This may result in concerns in relation to market power in FTR auctions, and may result in very limited secondary market liquidity for some FTRs.

2.2 The relevance LMP for vertical integration of retailers

Vertical integration refers to the concurrent participation of firms in upstream and downstream activities. In the context of retail electricity supply, this would mean retailers also having an economic interest in generation assets.[9] These generation assets can be used to self-supply the retail business or can be used to sell electricity into the wholesale market. In either case, vertical integration can offer a retailer a natural hedge against wholesale price volatility because the vertically integrated entity both buys and sells power.

Vertical integration by suppliers can be an attractive business model when there are low levels of wholesale market liquidity. This is because owning upstream assets physically secures access to power across timescales, reducing the risk of having to secure power in potentially expensive and inflexible traded wholesale markets.

While wholesale liquidity in the GB market may not be described as perfect, it has facilitated a decline in the market share of vertically integrated retailers such that, as of the end of 2022, between 59% and 80% of GB domestic electricity customers are served by non-VI firms.[10]

Under an LMP regime, if there were complete and liquid wholesale markets (including at the hub and in relation to FTRs, where relevant) vertical integration should not be any more

8 On the generation side of the market, there will be nodes with few or potentially even single parties interested. For suppliers, there are more likely to be multiple entities with a physical position, although even then it appears reasonably likely that there will be individual nodes with many fewer suppliers with a position than are active in trading today's national product.

9 This can either be through ownership of physical assets or through contractual ownership of rights over the output from generation assets without owning the assets themselves.

10 Based on market share data from https://www.ofgem.gov.uk/energy-data-and-research/data-portal/retail-market-indicators. 59% figure is based on market share excluding Scottish Power, EDF, and British Gas. 80% figure is based on market share data excluding Scottish Power and EDF only. Whilst Centrica still retains a 20% stake in existing GB nuclear capacity, its generation output (8.7TWh) is far smaller than its supply base (28.8TWh) and therefore, it is partially, but not fully vertically integrated. https://www.centrica.com/media/6021/ofgem-consolidated-segmental-statement-2022.pdf

necessary than it is today (because the same risk management results should be achievable through trading in the relevant markets). However, if the introduction LMP were to lead to lower levels of liquidity than exist today, it could lead to greater pressure to vertically integrate to manage risk.

The introduction of LMP will also mean that liquidity needs to be considered by location. For example, if liquidity in some regions is low (e.g. in peripheral nodes and with imperfect FTR markets) then vertical integration may be the only practical answer to manage risk for retailers supplying customers in those areas.

In a national wholesale electricity market, owning upstream assets (with a generation profile which matches a party's downstream load profile) anywhere in the country provides a natural hedge against wholesale price movements. However, in an LMP market, while a generation asset may provide a good hedge for demand that is in the same location, it only provides a partial hedge for demand at other locations. This is because the nodal price that a generation asset in one location receives may diverge from the nodal price for demand in another location. Vertical integration, within an LMP market, may therefore imply a need for ownership of a geographically diverse level of generation capacity.[11]

2.3 The relevance of LMP for the absolute retail price cap

For the purpose of this report, we consider the implications of LMP for the existing default tariff cap (DTC) as this is well defined.

The most relevant element of the DTC is its treatment of wholesale costs. The DTC includes a wholesale cost allowance based on an assumed hedging strategy. The same hedging strategy is assumed to apply for all default customers in all regions and the same national wholesale price index is used to calculate the wholesale allowance for all customers. The current assumed DTC hedging strategy relies on there being a robust reference price for quarterly products more than a year in advance and the level of market liquidity in different products has been a factor in Ofgem's choice of assumed hedging strategy.

There are regional variations in the allowed wholesale cost allowance today. However, these are based on factors that are fixed *ex ante*. Specifically generation and load in different regions are assumed to induce different levels of electrical losses on the network. Higher line loss factors in some areas mean that suppliers must buy more energy in the wholesale market to cover a given volume of energy delivered to a retail customer. There is a slightly higher wholesale allowance in the DTC for those regions with higher loss factors.

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11 We note that while ownership of capacity can imply ownership of physical assets, it can also be achieved by ownership of rights over the output from generation capacity. This second approach to vertical integration may facilitate broader geographical integration.

Under LMP, assuming there are material deviations between nodal prices, a wholesale cost allowance would need to be defined per node. For every demand node Ofgem would have to specify:

- the relevant trading hub for purchasing power (noting that there may be more than one trading hub for GB power);
- a wholesale energy purchasing strategy for purchasing power at the hub, which could in principle be similar to that used today provided the relevant contracts remain sufficiently liquid to allow a robust reference price to be calculated; and
- an FTR purchasing strategy which, as with the wholesale energy purchasing strategy, would need to use a robust reference price from a sufficiently liquid market that suppliers could reliably achieve. If secondary market liquidity is limited then this may need to be based on primary FTR auctions. As we note above, if there are few participants in the primary auction for some FTRs, suppliers may be able to influence the FTR reference price.

Only if liquidity at the electricity trading hub and in FTR markets is sufficient will it be possible to replicate the current approach to defining a relevant wholesale cost allowance. Even if this is the case, specifying the DTC would become a significantly more burdensome exercise. If liquidity is insufficient, the current approach may result in the specification of wholesale cost allowances which are less reliable. This will in turn either reduce the headroom in the cap (weakening competition at the relevant locations) or increase the headroom (weakening the protection offered to the relevant customers) and may also increase the risk of ex post adjustments to correct for material deviations between allowed and achievable costs.

2.4 Conclusions on the impact of LMP

Based on the above analysis, it is clear that the effect of LMP on liquidity (both in traded energy markets and in FTR products where relevant) would be a key route by which LMP impacts the GB retail market. It is therefore to a consideration of the impact of LMP on market liquidity which we now turn.

3 Possible implications of LMP for liquidity

As noted in the previous section, the level of wholesale market liquidity (across energy and FTR products where relevant) is a key factor in both the incentives for vertical integration and in the reliability of the wholesale cost allowance in an absolute price cap. If LMP were to reduce relevant market liquidity then this would strengthen the case for vertical integration and reduce the reliability of the wholesale cost allowance in an absolute price cap.

In a nationally priced regime, the relevant market for liquidity is the electricity market, as this is the only market in which participants need to trade to hedge their exposure. However, in an LMP market, the relevant markets are the hub market(s) for electricity and the market for FTRs.

The ultimate impact of LMP on liquidity is uncertain. However, there are reasons to believe that a move to LMP may lead to a reduction in liquidity in forward trading for electricity products and that FTR liquidity may be a challenge. Below we:

- consider briefly the relevance of evidence on liquidity in US LMP markets;
- set out conceptually why it is likely that liquidity at hubs may be lower under LMP than liquidity in an equivalent national market; and
- explain why liquidity in FTR products may be limited.

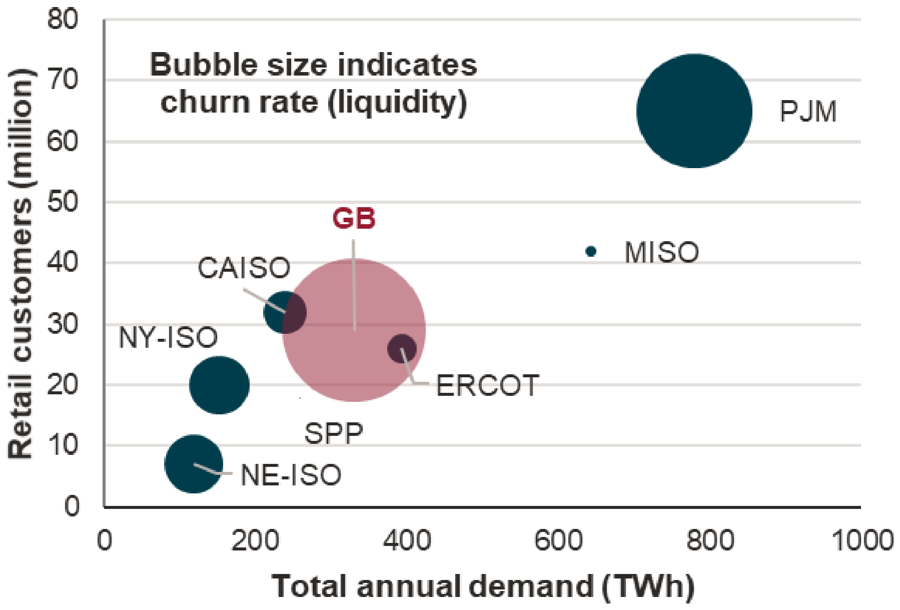
3.1 Evidence of liquidity at hubs in US LMP markets

As part of the industry debate on the introduction of LMP in the GB market, the PJM market has been quoted as an example of a market with LMP that achieves good levels of liquidity.

As we have noted elsewhere,[12] the physical size of PJM relative to GB market makes it less likely to be an appropriate comparator. Smaller US LMP markets, that are more comparable in scale to the GB market, such as ERCOT and CAISO achieve lower levels of liquidity than those in GB. This is shown in Figure 3 below.

12 https://www.frontier-economics.com/media/ekemhlz3/an-assessment-framework-for-a-move-to-lmp-in-the-gb-electricity-market.pdf

Figure 3 Comparing liquidity of US markets and GB market



Source: Frontier Economics, based on Ofgem (Wholesale Market Indicators https://www.ofgem.gov.uk/wholesale-market-indicators) and LEI ("Review of PJM's Auction Revenue Rights and Financial Transmission Rights" report, page 100, https://www.pjm.com/-/media/committees-groups/task-forces/afmtf/postings/lei-review-of-pjm-arrs-and-ftrs-report.ashx)

Note: Larger bubble indicates higher churn rate and therefore higher liquidity. Churn rate measured in 2019

Any evidence from other jurisdictions needs to be considered carefully, as there will be many relevant differences which should be taken into account (including market structure, specific market design, other relevant regulatory arrangements etc.) However, to the extent that such a comparison is informative, this suggests that if the GB wholesale electricity market were to move to LMP, liquidity may decline.

3.2 Reasons why LMP may reduce wholesale market liquidity at hubs

While there may be dangers in drawing conclusions from such comparative evidence in isolation, there are a number of logical reasons to expect that forward trading liquidity at a future hub under an LMP market may be lower than that seen in today's national market. These include that:

- the **cost of trading** may change, as participants at nodes whose prices are not well correlated with those at the hub(s) may need to trade both electricity and FTRs to achieve a hedged position;
- **generators behind network constraints** can currently trade volumes in the wholesale market reflecting their full generating capacity (ignoring network limitations) because they are not exposed to volume risk associated with transmission constraints.[13] However,

[13] They can sell volumes equal to their generating capacity with confidence that if the transmission constraint binds, then they will be compensated for being curtailed by being bid off by ESO in the balancing mechanism.

under LMP, generators are exposed to this volume risk, and therefore generators behind network constraints will not wish to sell volumes at the hub in excess of their expected output;

- **correlations between electricity prices and other commodities** may be different today to those between those commodities and future hub products and nodal prices under a LMP market. This may impact the number of parties with a commercial interest in trading hub or FTR products; and
- the development of **multiple trading hubs may split liquidity** between them, reducing overall liquidity.

In addition, the design of the FTR regime (which will need to be defined by regulation) is likely to be an important determinant of forward liquidity at any hub, particularly if there are relatively few nodes on the system whose prices are well correlated with hub prices.[14] In particular:

- if low volumes of longer term (e.g. multi-year) FTRs are sold, this may limit trading at hubs in longer dated forward energy products (because until FTRs are available, suppliers and generators will not be able to construct a complete hedge for the exposure resulting from long term trades in energy at the hub);
- if FTRs are auctioned infrequently (e.g. once a year), trading of forward energy products at hubs may be concentrated around the dates of those auctions, relate to energy products which match the profile of the FTR products sold (e.g. baseload, peak, off peak), and reflect the volumes sold at those auctions;
- even if different FTR products are auctioned at various points in time (e.g. annually, quarterly, monthly, daily) there may be a tendency for longer dated sales volumes to be conservative.[15] As noted in relation to multi-year FTRs, low volumes of longer dated products will tend to reduce hub liquidity in the associated energy products; and
- if primary auctions of FTRs involve volume profiles (e.g. daily and seasonal load profiles) which do not match well to participants' (nodal) net positions, there may be additional time or cost associated with acquiring a portfolio of FTRs whose volume does match these positions, which may in turn impact trading in forward energy products.

3.3 Reasons why liquidity in FTR products may be limited

As we noted above, the importance of FTRs will in part depend on the pattern of prices observed at the hub and at individual nodes. If price differentials are low, and/or if nodal prices are correlated with hub prices, trading in FTRs may be less critical to managing supplier risk. However, it is difficult to predict whether this will be the case in the GB system with any

[14] If the prices of different nodes are well correlated then the risk that trading parties take on by trading at the hub without also trading FTRs is smaller.

[15] This is because the volume of FTRs sold is typically driven by the volume of power flow feasible between network locations. This is difficult to forecast with high degrees of certainty at the year ahead stage (as it will be influenced both by network availability and by the overall dispersion of generation and load in a given settlement period). This tends to result in lower levels of longer term sales, complemented by release of further volumes closer to real time if network conditions allow.

reliability, and even if it is the case for a period of time, evolution of both the pattern of generation and load, connected technologies, and the transmission network itself mean that such conditions cannot be relied upon to persist.

Assuming these conditions do not hold, the points which we have discussed above suggest that participants may face barriers in securing FTRs:

- the number of parties with a commercial interest in any individual FTR product may be limited, particularly on the generation (and storage) side, which implies that direct secondary market liquidity in individual FTRs may be limited. This would in turn mean that primary auctions of FTRs would be the main route by which parties acquire the hedges, and the main source of any reference price;
- the design of these auction arrangements will need to be defined by regulation. As such, any firm view as to the ability of participants to acquire FTRs in advance of clarity as to their design is speculative. However, as we noted above, there are reasons to believe that:
  - there may be limited sales of multi-year FTRs;
  - FTRs may be auctioned gradually up the point of delivery, limiting sales of annual FTRs;
  - there may be a tendency for conservative sale of even annual volumes; and
  - it may be difficult or time-consuming to acquire a profiled portfolio of FTRs.

Therefore, in addition to issues relating to liquidity of forward energy products at hubs, there may be difficulties for participants seeking to hedge locational risk over time through FTRs, and a limited set of markets to use as a reference price for locational hedging instruments.

4 Conclusion

Introducing an LMP market design in GB in combination with a retail market that accommodated independent retailers and that maintained a form of absolute price regulation would raise significant challenges. There are good reasons to expect that a move to an LMP market would result in lower levels of liquidity and increased barriers to securing hedging instruments in relevant markets compared to the situation today.

While the route by which the retail market will be affected will depend on the precise design of a GB LMP system, which is yet to be specified, our high level analysis suggests that a move to LMP would:

- reduce the sustainability of a standalone business model because managing risk through traded wholesale products may not be as feasible;
- likely make vertical integration of some form more attractive, although suppliers would still need to consider how they manage locational risks by vertically integrating (i.e. they may want economic interests generation assets in specific locations [either through physical ownership or long term economic rights]); and
- make any absolute price cap harder to set in an accurate and robust manner due to lower liquidity and consequently less robust reference prices.

In addition, in relation to the absolute tariff cap, we note that if Ofgem were to set an absolute price cap in a market with around 900 pricing nodes, it would add significantly to the complexity of administering a cap and of communicating cap levels.