Exploring market change in the GB electricity system: the potential impact of Locational Marginal Pricing

Executive Summary

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The authors have worked together on this review of evidence and perspectives on what Locational Marginal Pricing would mean for the British electricity sector. The project has two main outputs – a main report and a record of findings from stakeholder engagement.

This Executive Summary is a standalone copy of that provided in the main report, offering a high-level summary of the main report chapters and a full outline of the key findings and recommendations from the research. For full details, please refer to the main output documents.

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The documents are archived at the following links:

Main Report & Standalone Executive Summary: https://doi.org/10.17868/strath.00083869

Stakeholder Insight Report: https://doi.org/10.17868/strath.00083868

Executive summary

Introduction

Decarbonising the electricity system is a key stepping stone towards net zero greenhouse gas emissions across the economy, and doing so by the middle of the 2030s is both a recommendation of the Climate Change Committee and an ambition of the UK Government. This will require a major change in how electricity is generated and consumed with National Grid ESO's (NGESO) 2022 Future Energy Scenarios (FES) suggesting that up to 80% of electricity will need to come from wind and solar. The need to reliably meet demand for electricity in spite of the variability of renewable resources is stimulating a focus on 'flexibility' in managing the balance between supply and demand.

Questions are being asked by many in and around the electricity supply industry and government about whether existing market arrangements will drive enough investment in the right mix of resources such that a sufficiently reliable supply of low carbon electricity will be delivered to energy users at least cost. The UK Government has set up a Review of Electricity Market Arrangements (REMA) aiming to "identify reforms needed to transition to a decarbonised, cost effective and secure electricity system". This is considering a wide range of options for reform of both the wholesale market for electrical energy and a number of related areas including support schemes for low carbon power, capacity adequacy, operability and ancillary service markets.

One option that has attracted significant interest is that of energy trading based on Locational Marginal Pricing (LMP). LMP markets exist in jurisdictions around the world including several in North America. They operate on the principle that electricity is priced at each individual location on the network and the price there reflects the short run marginal cost of meeting demand at that location.

Several reviews and work programmes, including recent and ongoing work by National Grid ESO (NGESO), Ofgem and the Energy Systems Catapult, are investigating the potential benefits of moving the GB wholesale market from its current arrangements to an LMP market. They argue that a move to LMP and the associated centralised dispatch process would help reduce the increasingly burdensome and costly re-dispatch requirements linked with managing system constraints as well as providing the necessary price signals to drive more investment in, and efficient operation of, sources of generation and flexibility.

To date, these studies have focussed on the high-level principles of LMP and have not described the detail of how these markets operate in practice. Whilst this is a reasonable first step, it is possible that theoretical benefits may not be fully achievable in practice and that the very different context in GB compared with existing LMP systems means that experiences from other countries should be interpreted with caution.

This review explores LMP, how it might be applied in Britain and how the risks faced by different market participants might change were it to be introduced. It describes some key features of existing LMP markets and, through review of existing literature and interviews with industry experts, attempts to draw lessons from them and highlights the challenges of implementing LMP in GB. It also explores the links between LMP and other aspects of a market framework, notably support for low carbon generation delivered through Contracts for Difference (CfDs), and the provision of hedging arrangements for market participants through the sale of Financial Transmission Rights (FTRs). It reveals key details of the design of LMP and FTRs that vary between existing markets and would need to be addressed before any implementation in GB.

A key conclusion is that the design of electricity markets must be matched to the characteristics of the systems in which they are applied. Rigorous assessment of the *interaction* between different mechanisms is crucial.

While some reforms might promise lower direct costs to consumers than others, there is the potential for higher costs to other market participants with the associated risk that one or more of the overall objectives of reform are missed.

We highlight the significant increase in risk that a GB LMP implementation could place on market participants, and identify important differences between a decarbonised GB system and existing LMP markets that would drive the need for major innovation in the underlying LMP frameworks in order to operate in GB. It is likely that attempting to implement an 'off-the-shelf' LMP market along the lines of existing systems simply would not work, whilst designing, testing and implementing the changes needed to make LMP suitable for GB would be extremely challenging on the timescales proposed for decarbonising the GB electricity system.

The rest of this Executive Summary provides a synopsis of the key sections of the report together with a detailed list of 15 conclusions and 6 recommendations.

Structure of LMP markets

The high-level tenet that electricity prices should reflect the local short run marginal cost of meeting demand at each location on a network conceals a wider set of principles, assumptions and processes that make up a real-world LMP market. Figure ES1 shows the elements of a typical LMP framework. This is based around *two* separate LMP markets: a day ahead and a real-time market. Together these markets constitute a centralised dispatch of all supply and demand for electricity. However, they sit within a much wider framework typically designed to ensure security of supply, provide hedging opportunities for market participants and ensure markets run in a fair and competitive way. The main part of this report provides a description of each of the elements shown in the Figure ES1 and a discussion of its relevance for GB market design.

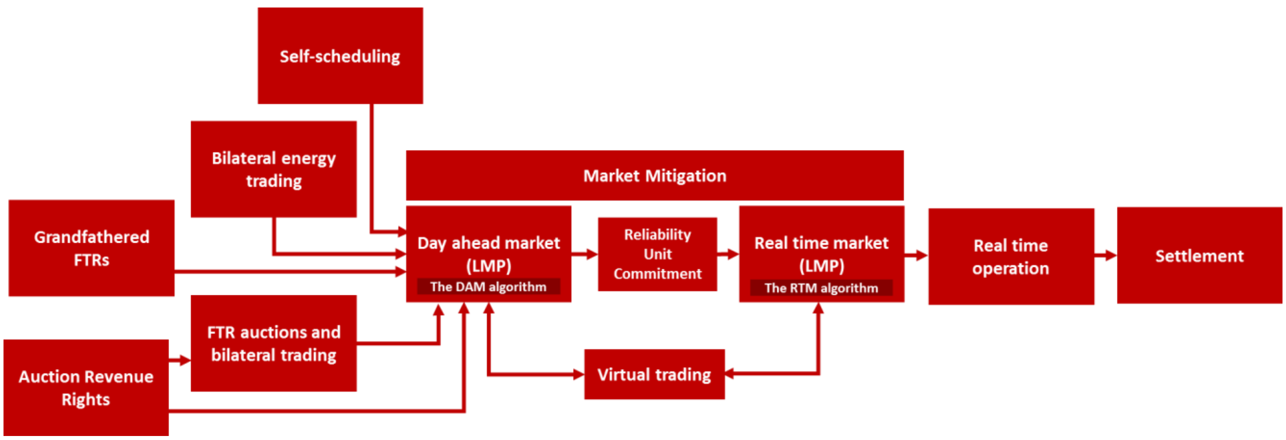

Figure ES1: Key elements of a typical LMP market

The individual elements laid out in Figure ES1 are underpinned by a number of principles or market design choices several of which would represent a significant a departure from existing GB arrangements. These are:

- **Dispatch of resources to meet demand is done centrally:** LMP markets operate using centrally managed optimisation tools to determine 'cost optimal' (within the limits of the algorithms used and data fed into them) dispatch of generator outputs and settings of flexible demand and storage based on bids and offers submitted by all market participants.
- **There is a requirement to participate in central dispatch:** although there are options to opt-out of economic bidding and 'self-schedule', it is mandatory for all participants above a certain size to participate in the central dispatch and to receive or pay the LMP clearing price for their energy. Bilateral trading arrangements are used in LMP markets but must work around this requirement.
- **System access rights are non-firm:** unlike current GB arrangements, generators and flexibility providers in LMP-based markets do not receive firm rights to access the system. Rather, the right to inject or withdraw power is granted temporarily only when participants are dispatched 'on' by the central algorithm either in the day-ahead or real time market.
- **Day ahead dispatch is financially firm:** if dispatched 'on' in the day-ahead market the financial commitment is firm. However, participants can buy their way out of that obligation in the real-time market which typically closes around one hour before delivery.
- **Congestion rent accrues to the System Operator (SO) and needs to be redistributed:** when networks are congested in an LMP market, demand pays more to the SO, than the SO pays out to generation. The residual is known as congestion rent. LMP markets generally specify mechanisms to return that rent to consumers.

- **Market designs should normally incorporate financial tools for hedging risk within the centralised structure:** in most LMP-based markets these include FTRs which pay out the difference in price between two nodes if there is congestion between them, and virtual trading which provides a route to hedge differences in price between the day ahead and real time markets.
- **LMP markets can dispatch reserve as well as energy:** in addition to prices for the generation or consumption of energy, market participants can submit bids and offers to provide reserve services together with the technical parameters to describe their capabilities. The LMP algorithm can then solve to optimise dispatch of reserve as well as energy. Other ancillary services such as voltage support and black start provision remain as separate markets.

One aspect of design of an LMP-based market that is likely to be important for the GB debate is the use of Financial Transmission Rights (FTRs). These can play multiple roles in an LMP market. They can be used: to return excess revenue accrued by the SO to consumers; to provide a means for market participants to hedge their locational risk; as compensation to market participants who lose rights or revenue streams when an LMP market is implemented; and for speculation.

It is important to differentiate each of these roles when discussing FTRs.

A key finding of this report is that FTRs, in the form used in many existing markets, are unlikely to be suitable for use in a GB system dominated by variable renewables and experiencing extensive network congestion.

The structure of LMP markets is discussed further in Section 2 of the main report.

Learning from the LMP experience around the world

The concept of LMPs has been used in major market designs since the mid-1990s in New Zealand and across an increasingly large part of the US since the turn of the century. There is evidence that many of these markets have operated successfully over many years in a way that is largely competitive. However, there have been challenges, particularly with the use in the US of so called 'long term' FTRs (that is, up to three years ahead).

Although successful in fossil fuel dominated systems and in some systems that have partially decarbonised, no existing LMP market approaches the level of penetration of variable renewable generators that is expected in GB in the mid-2030s. Whilst California and Texas have significant capacity of wind and solar – 27% and 29% of total generation capacity respectively, levels that are similar to GB today – none are currently embarking on the scale or speed of decarbonisation proposed for GB. Successful use of LMP in systems where the majority of electricity is generated from schedulable, fuel-based power stations, does not, by itself, provide proof it would be equally successful in systems with very different characteristics.

The key markets reviewed here are PJM in the North Western US, CAISO in California, ERCOT in Texas, New Zealand, Ontario and the SEM in Eastern Australia.

PJM (North West US): the first US LMP market has operated for over 20 years but has a low penetration of variable renewables. It has experienced issues with its FTR markets, with a major scandal in recent years that cost consumers $179 million and, separately, a recommendation made by its independent market monitor that 'long term' FTRs are removed from its market structure.

CAISO (California): the introduction of LMP in California came in 2009. Solar and wind capacity have grown considerably over the past decade and, in recent years, battery capacity has also grown quickly. However, California has experienced summer blackouts with insufficient capacity available to meet early-evening peaks once solar stops generating. The implication is that the combination of the wholesale energy market and capacity adequacy mechanisms has not worked together to ensure sufficient firm capacity is available when needed.

ERCOT (Texas): Texas is often cited as an LMP system which has seen significant development of wind generation with its introduction in 2009 being followed by a period of strong growth in wind capacity. Proponents of LMP have argued, firstly, that LMP did not act as a blocker to the development of wind and, secondly, that LMP provided important signals to the siting of new developments. However, the connection of wind to the network was chiefly enabled by strategically planned, state-funded development of new transmission corridors to the areas with the greatest wind resource coinciding with the move to LMP. Investment has since come in waves based on the availability of transmission capacity to resource rich areas with little evidence that LMP has driven siting decisions for wind in Texas.

New Zealand: the first country in the world to operate under an LMP system, New Zealand is unusual in that for more than a decade it operated without FTRs and exposed the demand side to nodal pricing rather than applying a zonal or system-wide average price to demand. Prior to the introduction of FTRs the New Zealand electricity market was structured around vertically integrated utilities largely generating and supplying at the same node in order to avoid locational risk. More recently, FTRs have enabled greater financial hedging. Although New Zealand operates a highly decarbonised system the vast majority of renewable generation comes from hydro rather than variable, weather dependent sources.

Ontario: is in the process of moving from a centralised pool market with no locational elements to an LMP system. There was widespread acceptance that the legacy system was not fit for purpose and failed to dispatch the existing fleet – mainly fossil fuel generators – effectively.

NEM (Eastern Australia): The Eastern part of Australia currently operates a zonal market but has considered moving to a fully nodal LMP market in recent years. Conversion to a full US-style LMP market was recently rejected, and market participants remain nervous about LMP-like options. Some of the challenges facing Australia mirror issues in GB, particularly around multiple renewable generators being caught behind the same network constraint. Options being considered for managing these challenges may be highly relevant to GB.

The learning from international LMP case studies is discussed further in Section 3 of the main report.

Challenges of introducing LMP in GB

Looking ahead to the 2030s the GB context is one where electricity production will be dominated by variable, Zero Marginal Cost (ZMC) renewable generators: wind and solar. It is also one where transmission constraints will remain a major feature of the system – although the optimal amount of transmission will have some constraints, the new network capacity necessary to reach that optimal level will struggle to catch up with the development of renewable generation that is needed. No matter what wholesale market solution is implemented, the need to build new transmission capacity at speed to increase the ability to transfer electricity from areas with greatest potential for low carbon generation to areas with highest demand will be critical to decarbonising the electricity system.

There are a number of theoretical advantages to a market based on LMP. However, our exploration has identified the following challenges for a GB market based on LMP.

The level of variable renewable penetration required is unprecedented in any LMP-based market: this will create challenges for any market design and will drive wholesale market prices to zero or below for large parts of the year making investment in any form of generation capacity challenging. This would be exacerbated by a move to LMP where areas such as Scotland, with significant growth potential for renewable generation but a lack of transmission capacity, could see zero or negative prices the majority of the time.

Very high levels of network congestion and need for network investment: interviewees with experience of existing LMP markets suggest that these markets work most effectively where transmission capacity is close to optimal with some, but not too much, congestion. The level of network constraints in some parts of the GB system is a major challenge in itself. Introducing an LMP market would not change the fundamental nature of this issue. There is currently a need for significant levels of investment in additional GB network capacity, a need that a switch to LMP is unlikely to reduce in the short to medium term even if, in principle, LMP would reduce need in the longer term.

Operation of an LMP market in the face of excessive congestion would, on its own, likely lead to reduced investment in generation behind constraints. It may, however, fail to deliver increased generation investment elsewhere as limits imposed by planning, space and resource levels (wind and solar) are likely to restrict increased development in all but the very long term.

LMPs can provide a mechanism, at least in theory, to support flexibility in relieving network constraints including by incentivising location specific investment in storage and new forms of flexible demand like hydrogen electrolysis. In practice, there may be limitations on how flexible the location of such demand can be, depending, for example, on the market for hydrogen that develops and the need for infrastructure to transport or store it. Further, if levels of congestion remain high it may well limit the ability of some flexibility providers, particularly energy storage, to benefit from locational price signals and make a significant contribution to constraint management.

Dispatch risk: the loss of firm network access creates a new and significant form of risk for individual market participants. 'Dispatch risk' is where generators face the risk of failing to be dispatched by the LMP algorithm and are unable to access the electricity market during that settlement period. The LMP market design concentrates risk onto individual generators in ways that are challenging to manage or mitigate.

An example is seen where multiple ZMC generators are caught behind a single constraint. In this situation dispatch would become relatively arbitrary, set either by very small differences in minor variable operating costs, by small variations in overall system losses, or by bidding incentivised by support mechanisms. There is risk of a '*winner takes all*' outcome with generators falling into a largely fixed and arbitrary merit order. Where within that merit order a generator sits would be hard to predict in advance and would have significant impact on its revenue.

The consequences could include a higher cost of capital, or worse, a significant hiatus in investment caused by increased and poorly understood risks.

Financial transmission rights may fail to match market needs: existing FTR products tend to be of significantly shorter duration than investments in generation capacity and experience from the US suggests potential issues with the competitiveness of FTRs more than one year ahead. In addition, fixed-profile FTRs, whilst suitable for baseload and other schedulable generation with relatively predictable operating cycles, do not match the variable, uncertain characteristics of wind and solar.

Coordination with renewable support schemes: GB's existing CfD support scheme has been successful in supporting investment in low carbon generation. However, it is closely integrated into the wholesale market using market prices as a reference to pay or draw back support. Introducing an LMP market opens up myriad potential arrangements relating to how auctions are cleared, what constitutes the reference price, how 'negative pricing rules' should be designed, and the interaction with FTR arrangements. We show, for a small number of examples, how each combination of choices leads to a unique set of incentives on generators. The lesson is that this is a highly complex area; as it is central to getting investment in low carbon generators, it must not be ignored. The need for wholesale market arrangements to be well-aligned with support for low carbon generation applies whether current CfD arrangements are continued in broadly the same way as today or if alternative approaches to supporting low carbon generation are considered.

Removal of access rights for legacy market participants: moving to LMP would remove existing market participants' firm access rights to the system. In order to avoid any potential legal challenge, there would be a need to think carefully about how to compensate generators and to integrate the LMP market with existing support arrangements including the Renewables Obligation and existing CfD contracts. This would have implications for how these participants bid and offer into the LMP markets.

Implications for consumers: although the focus of the work reported here is on generation and flexibility, it is essential for any market review to consider the impact on consumers. LMP removes some costs and risks, such as those associated with congestion, from consumers (at least directly) and places them on generators. Depending on the precise form of LMP, consumers in some locations may benefit through lower electricity prices in comparison to others. Overall, it is not yet clear how changes in allocation of system costs and overall risks would flow back through to consumers.

The challenges of introduction of LMP into the GB system are discussed further in Section 4 of the main report.

Stakeholder views on LMP

As part of this review we undertook semi-structured interviews with ten electricity market experts. This included specialists with experience in regulation and market design in the US and Australia as well as a number of key participants in the GB debate. The cohort included a mix of views on the value of LMPs for GB. Some of the key themes that emerged from these discussions were as follows.

How might a move to LMP affect siting and investment? There was significant disagreement on the extent to which LMP would improve siting decisions. Stakeholders with experience of existing LMP markets were unconvinced that locational signals from wholesale energy prices significantly changed siting decisions and highlighted that non-price factors such as the availability of resource and the ability to obtain permissions and consents to get a project built were likely to be more important. This appeared to many to be a greater concern for GB than in the US due to more limited space and the restriction of favourable planning policy to particular areas of the country. Whilst some interviewees highlighted the potential for more offshore wind in the southern part of GB including some delivered through floating projects, this is likely to be, at best, a long-term solution due to a lack of an existing pipeline of surveyed and consented sites.

In terms of resources offering particular flexibility services, whilst LMP would in principle incentivise efficient siting of storage, electrolysis and other forms of flexibility, interviewees were aware of very little evidence to show whether it would deliver flexible capacity in practice. An important implication of this is the need for more detailed in-depth studies of the likely operation of flexibility, any dependencies on other infrastructure (such as for hydrogen) and the relative importance of wholesale energy markets, ancillary services and other flexibility revenue streams for different forms of flexibility in LMP and other market designs.

Impact on cost of capital: interviewees highlighted a number of pieces of evidence on the potential impact of LMP on cost of capital, some anecdotal and some more formalised. This evidence suggests that increases in the range of two to three percentage points are credible and arise from the significant increase in risk faced by individual market participants, and the limited opportunities for mitigating that risk. Other interviewees emphasised the interaction between LMPs and CfDs or alternative low carbon support mechanisms and noted that the cost of capital would ultimately depend on the overall risk associated with the combination of market structure and support mechanisms. This is an important point and highlights the need to explore in detail the interaction between each element of a market framework. Overall, our conclusions from the interviews are that there is an urgent need for more quantitative evidence on this point, and that there is the real potential for cost of capital increases to offset any operational cost savings that LMP may deliver.

Consumer savings: a key argument for LMP is that it would lead to lower prices for consumers overall. Interviewees were aware that LMP markets can transfer the burden of costs away from consumers and onto other market participants. However, they also highlighted the importance of understanding how those costs and risks would end up being recycled. Whilst some may be directly absorbed by generators through reduced profit, interviewees also highlighted the potential that they are passed to consumers through higher CfD strike prices or PPA contracts struck alongside the LMP market.

A more detailed discussion of Stakeholder views forms Section 5 of the main report.

Conclusions

Our review has led us to reach the following conclusions.

1. **Moving to LMP could increase the risk of failing to deliver decarbonised power by 2035.**
   Introducing an LMP market would create significant short-term disruption, increase the allocation of costs and risks to individual generators and require significant innovation to adapt the existing LMP standard model to suit a GB system. This risks turning GB's wholesale electricity market into a national experiment at a time when certainty is needed to deliver significant investment in the sector. One result could be a delay in our ability to deliver a decarbonised electricity system due to a hiatus in investment.

   There will be risk associated with any significant change in market arrangements. Some of that risk stems from the fact of change itself and the uncertainty that it creates, and some will be down to the nature of the particular set of changes. Any implementation of LMP should be part of an appropriate and complementary package of reforms spanning ancillary services, capacity markets and low carbon support mechanisms. These elements interact and combine to impact the potential profitability of different investments. There is little time to carry out the necessary analysis, design, consultation and implementation at the pace required to impact on how the electricity system looks and is operated in the mid-2030s.

   The difficulty of solving this challenge should not be underestimated and exploring at least some of the complexities involved needs to be a central part of the evidence base used to make decisions on future wholesale market arrangements.

2. **LMP could significantly increase the cost of capital for generators, but that depends on the interaction between the wholesale energy market framework and the wider package of market reform including mechanisms to support investment in new low carbon generation.**
   In addition to the risk of delaying a decarbonised electricity system, there is a risk that market reform will result in a more costly system than expected. A key part of that risk comes from the cost of capital. There is anecdotal evidence that markets that price energy on a nodal basis increase the cost of capital for merchant investment relative to those that do not, but there is limited published analysis of the effect. Our review suggests that, relative to today and dependent on the implementation of a wider package of reforms, LMP would place additional revenue risk on GB investors and create a situation where risk is hard to forecast and difficult to control for individual market participants (e.g. the risk to a generator of a competing generator connecting at the same node or of a major demand customer closing).

   Participants in an LMP market face both price and dispatch (or volume) risk. For ZMC renewables, in particular, it is important that these risks can be quantified and managed in advance for a significant fraction of a project's operating life. Mechanisms do exist in LMP markets to manage price risk. These include FTRs and bilateral PPAs. However, evidence from existing markets suggests that these mechanisms are likely to be limited to a timespan of no more than a few years, much shorter than the typical lifespans of generation assets. Dispatch risk relates to the lack of firm access rights in a conventional LMP market and uncertainty over whether a market participant will be scheduled by the LMP algorithm which mean, without dispatch by the algorithm, a participant cannot participate in the market. In contrast to price risk, there are limited mechanisms in place in existing LMP markets to mitigate dispatch risk. In principle, generators might self-schedule but they will then be exposed to the energy price at their connection node which, in a wind dominated area under windy conditions, could turn negative leading to them losing money.

There are ways that wider market design can reduce and reallocate some of the risk on particular market participants through other arrangements, particularly support mechanisms for low carbon generators. Continued use of CfDs could absorb some of the price risks associated with network constraints while adoption of something akin to a 'deemed generation' CfD would be required to mitigate generator dispatch risks, a potentially bigger factor for GB. However, the extent to which such measures are utilised and their detailed design would have direct consequences on the level of consumer welfare benefits that LMP could deliver.

3. **LMP markets are in use in some parts of the world; some of them have a reasonable level of ZMC renewable (wind and solar) penetration but not to the extent that GB expects to have by 2035.**
   LMP markets have existed in their modern form for at least 20 years in parts of the US and elsewhere and are generally considered by those who work within them to be efficient, effective and competitive overall, although there are some important caveats with certain aspects of those markets such as long-term FTRs.

   Other markets also provide evidence that it is possible to operate LMP markets with moderate penetration of variable, zero marginal cost renewables. In 2020 CAISO had a 28% penetration of wind and solar (as a proportion of total electrical energy production) and ERCOT 41%. Investment in renewables continues to be made in those systems although it is unclear whether this investment is made 'because of' or 'in spite of' LMP. However, there is no experience world-wide of introducing LMP into a system that is undergoing the level of change currently being experienced in GB, nor one that has ambitions on such a short time scale to convert fully to decarbonised electricity system, a process that will potentially require an increase in the penetration of variable, zero marginal cost renewables to provide 80% of electricity.

4. **LMP has the potential to improve the efficiency of dispatch of system resources including generation and flexibility.**
   The locational signals delivered through LMP markets on day ahead and operational timescales have the potential to improve the efficiency of dispatch. This includes the dispatch (or not) of ZMC renewables. The benefit comes largely in terms of driving efficient dispatch of interconnectors, storage and fuelled, schedulable generators. This has the potential for operational savings through the burning of less fuel. However, the significance of such savings in a system in which most energy comes from ZMC generation should be assessed. However, the significance of such savings in a system in which most energy comes from ZMC generation should be assessed.

   The design of the algorithm is critical to successful dispatch, and needs to reflect the underlying physical characteristics of the system. For a decarbonised electricity system, the way the algorithm deals with multi-period constraints would be particularly important as this would be central to efficiently dispatching energy storage and demand flexibility.

5. **LMP is likely to be limited in its ability to drive more efficient siting in GB.**
   Evidence from this review suggests that LMP would likely have limited impact on the siting of ZMC renewables. We have come across little evidence of locational price variations affecting the siting of renewables in existing LMP markets and several interviewees highlighted that non-price factors such as availability of resources (wind or sun) and the ability to get planning permission are more likely to drive siting decisions.

   The experience of Texas suggests that renewable investment is likely to come in waves in line with availability of new transmission capacity to areas with the best resource rather than being redirected to other locations which already have more network capacity available. These factors are likely to have a strong impact in GB where space is at a premium, planning and consenting is difficult and time consuming, and resource availability is concentrated in particular parts of the country.

6. **LMP markets do not, on their own, solve the problem of planning, designing, building and operating an efficient and effective transmission network.**
   An LMP market is largely about efficiently managing access to a given quantity of network capacity. There is limited evidence that moving to LMPs leads to less need for transmission network in practice. Comments made by interviewees highlight that LMP markets are most effective where there is a close-to-optimal level of transmission network, with some (but not too much) network congestion.

7. **There are significant concerns in existing LMP markets with 'long term' Financial Transmission Rights for hedging.**
   In US markets FTR products are often available for no more than three years in advance, and market monitors in two systems (CAISO and PJM) have advocated the removal of so called 'long-term FTRs' with terms from one to three years ahead, citing poor consumer value and the potential for manipulation. Long-term FTRs often sell at auction for significantly less than the value they realise suggesting a lack of competition for these products. Despite significant resource given to market monitoring FTR markets have been subject to major scandals. One prominent example in PJM saw costs of US$179 million associated with what FERC ruled as manipulative FTR trading.

8. **An 'off-the-shelf' LMP market solution does not exist for GB – we would need to adapt existing processes and develop new ones.**
   If LMP were chosen for GB there would be a need to significantly adapt the 'standard model' of LMP design in potentially complex ways to reflect both the physical characteristics of the system and wider market structures, particularly CfDs. (See further points below). No existing LMP market operates on a system where ZMC generation is the price setter across much of the network for a significant part of the year. And, whilst the theory of LMP markets can still work in such a system, it is clear that it would raise specific and new challenges. One example of innovation that will be needed is to develop ways of ensuring that the system can always be balanced even with the very high ramp rates of residual demand that can be expected in future. These innovations would take time to develop, test and demonstrate making proposed implementation before the end of the decade challenging. Introducing a period of policy uncertainty risks an investment hiatus that could impact on 2035 targets for decarbonisation of electricity.

9. **A new form of FTR suitable for variable renewables would need to be developed.**
   Whilst FTRs are argued by many to be critical to the effective functioning of an LMP market, we believe there are significant risks associated with relying on them in the context of a decarbonised GB electricity system either to hedge long-term risk or act as compensation for the loss of firm access rights that existing generators would face. FTRs currently in use in US markets involve fixed, pre-defined profiles, and therefore do not match the time-varying nature of wind and solar generation, nor do they have the flexibility to adapt to the uncertainty in future output inherent in weather dependent renewables. A new form of FTR suitable for variable renewables would need to be developed and tested robustly.

10. **Integration of LMP and centralised CfD renewable support would be a world first (with associated risk of trying something new).**
    Whilst existing LMP markets have been run with support for renewables based on fixed or near fixed payments per MWh, they have not been run with arrangements similar to Britain's Contract for Difference

arrangements where the uplift payment depends on the difference between a strike price determined in an auction and a market reference price for each wholesale market settlement period. There would be a number of important choices to be made in co-designing a joint LMP and CfD system for GB such as how to set the reference price, and how to deal with negative wholesale prices.

11. **An LMP market may not efficiently dispatch a large number of generators caught behind the same network constraint.**
All ZMC generators caught behind a constraint would have the same short run marginal cost: zero. Bidding in an LMP market may be influenced by very small differences in variable operation and maintenance costs, small impacts on overall system losses, and arrangements related to support payments.

    Given these small differences, there would be a significant degree of arbitrariness around which ZMC generators are dispatched 'on' and which are not. Even if the relevant locational price is zero, this can lead to significantly different revenue outcomes across the ZMC fleet due to the different forward contracting and low carbon support arrangements that market participants have, the majority of which are likely to depend on dispatch and physical production.

12. **Without additional arrangements, a move to an LMP market might fail to deliver capacity adequacy.**
LMP has the potential to reduce revenue available for some schedulable generators including peaking plant and increase the importance of a robust capacity adequacy mechanism. As with other elements of the overall market package, it is critical to ensure that the energy and capacity adequacy arrangements work effectively together.

    Ensuring a secure low carbon system requires significant capacity of schedulable low carbon energy sources such as hydrogen peaking plant, gas generation combined with CCS, storage, or access to reliable imports. Many market designers, including those in CAISO, PJM (and GB), have made the judgment that a wholesale energy market needs to be combined with some form of capacity adequacy mechanism in order to ensure sufficient capacity to meet peak demand. Others markets such as ERCOT rely on the energy market alone, through scarcity rents, to support capacity adequacy.

    A significant quantity of ZMC renewables is likely to impact on revenues not just for peaking plant but also for 'mid-merit' schedulable generation which will have limited running hours in a system with a high level of variable renewable generation capacity. These generators will almost certainly require a strong capacity market or other non-wholesale market-based revenue streams, and this requirement would likely be stronger in a market with LMP than in one without.

    Evidence from the rolling blackouts experienced in California in recent years suggests that poor coordination between their LMP market, where day-time revenues have been eroded through the growth of solar power, and the Capacity Procurement Mechanism was one factor leading to insufficient generation available in the early evening after the sun had set.

13. **The impact of a move to LMP on the demand side is unclear.**
In principle, LMP would reduce the total cost of dispatch. Depending on the extent to which locational prices are passed through to energy users there is the potential for consumers to benefit in areas where the marginal price is very low. On the other hand, LMP could expose energy users in import constrained areas to higher energy prices. The overall extent of benefits to the demand side depends on negative effects of LMP –

e.g. on cost of capital to investors in new generation and the impact of that on cost of energy – not outweighing the benefits.

At present there appears to be little evidence to help understand the potential real-world impact of LMP on the demand side and little consensus on the extent to which the demand side should be exposed to locational prices. In most US LMP markets, for example, the demand side is only exposed to locational price difference at the zonal rather than nodal level. However, some markets, such as in New Zealand, do apply nodal prices to the demand side.

The prospect of highly variable energy prices for consumers based on location leading to a 'postcode lottery' has the potential to raise significant distributional as well as political concerns. Most energy users in Britain buy their electricity through Suppliers who could be charged for demand on a nodal basis but regulated in the degree to which time and locational variation can be passed through to end consumers.

14. **In the US significant attention is paid to Market Monitoring to identify the degree of efficiency and competition in LMP markets and to spot potential breaches of market rules. We should be ready to devote similar levels of attention here.**
The effort placed on market monitoring in US LMP markets is significantly greater than is seen in GB. This provides detailed analysis and insight into the operation and effectiveness of each element of the market structure. Market monitoring is carried out independently of the regulator with monitors given the power to make recommendations to the Market Operator and to the regulator, and to refer potential breaches of market rules for formal review. We see significant value in adopting similar approaches to the GB market regardless of decisions over the form of that market.

15. **While there are major questions to be resolved in the design of LMP and complementary arrangements as part of an overall package, any alternative set of arrangements must address similar issues.**
The final suite of reform options that is brought forward from the ongoing review process should be the package that best addresses the overarching objective of the power system, which this report suggests to be:

Ensure that, by 2035, net production of greenhouse gases on the GB electricity system is negligible while supplying electrical energy with sufficient security and resilience at lowest total cost to energy users over the medium to long term.

In achieving this objective, reform of energy markets should consider their interaction with a wider set of economic, social and environmental policies and how development of the energy system makes the most of opportunities for the whole economy, ensures fair access to and affordability of energy, supports regional development across GB and provides appropriate protection for natural capital and ecosystem services.

This raises significant challenges associated with coordinating the siting and dispatch of resources.

These challenges will grow under any set of market arrangements.

Whilst there are significant risks and challenges associated with moving to an LMP market, many of the fundamental issues will be common to any market system and there are areas where current GB arrangements are poorly aligned with the changing needs of the system. In particular, any form of electricity market arrangements needs to:

- Manage the cost and risk created by ZMC generators connecting where strong non-price locational signals dictate.
- Incentivise flexibility – storage, flexible demand and schedulable sources of energy – to be made available in the right places, at the right times and ensure that it is used efficiently within the constraints of the system.
- Provide signals to interconnectors to connect in the most effective locations in GB and to dispatch them in a way that supports the GB system without exacerbating network constraints.
- Influence the development of the transmission network to better anticipate where market participants will connect, ensuring that there is sufficient transmission capacity in the right parts of the network at the right times.

Recommendations

Based on our review of existing LMP markets and the discussions we have had with interviewees we make a number of recommendations for action related to market reform and informing policy.

1. Further analysis and critical appraisal of market reform options, including LMP, should take clear and detailed account of the package of measures that LMP would be implemented within. This should include, but is not limited to:
    - the likely level of innovation needed in LMP structures and in the coordination between LMP and other GB market arrangements and system objectives;
    - how LMP and CfDs might be co-designed to deliver desired outcomes including appropriate splits of cost and risks between market participants, mitigating risks associated with LMP without undermining the main objectives;
    - the need for new FTR arrangements to support variable ZMC renewables and the limitations of FTRs as long-term hedging mechanisms that have been identified in existing LMP markets;
    - consideration of how an LMP algorithm would dispatch multiple ZMC generators behind the same constraint.
2. Cost Benefit Analysis (CBA) should be carried out for LMP as part of a package for reform (rather than for LMP in isolation) and against counterfactuals reflecting that the appropriate comparison is not just with current GB arrangements but with other options for reform.
3. To inform CBAs, robust quantitative evidence is required on the impact of moving to LMP on the cost of capital for different types of market participant. This needs to be supplemented with significant sensitivity analysis considering the impact of the wider package and context for all market reform options. Sensitivities should include:
    - the risk implications of different forms of CfD or alternative low carbon support mechanisms in combination with LMP;
    - the impact of delays in transmission development and of network outages;
    - constraints on siting for new network users.
4. Undertake a detailed study of the size and allocation of risk under different market proposals. This should review any changes to risk, including the risk of failing to achieve a decarbonised electricity system by 2035 and of insufficiently secure supply. It should consider how risk is allocated across market participants. It is important that those undertaking this work fully understand the nature of risk under an LMP market combined with a fully decarbonised electricity system. This report highlights that dispatch risk would become increasingly important with a scale significantly larger in GB than in existing LMP markets.
5. Develop a longer-term plan for transmission network development beyond the period covered in the ‘holistic network design’ that exists at the time of writing, giving the sector an indication of what transmission capacity across major boundaries could be in 2035 and 2040. This should be assessed for a number of scenarios rather than just a central pathway (much like FES does for generation and demand) and for boundaries expected to experience significant and costly congestion over the coming decades.
6. Review the approach to market monitoring in US LMP markets and consider funding and implementing similar, independent monitoring of GB markets, regardless of the form of those markets.