14th February 2024

FAO: Angus Brandon MacNeil MP
chair, Energy Security and Net Zero Select Committee

CC: ESNZ Select Committee Members
Gwen Edmunds, specialist ESNZ select committee
Rachel Carey, head of policy, REMA, DESNZ
Rob Hewitt, deputy director, electricity market reform, DESNZ
Akshay Kaul, director general infrastructure, Ofgem

Dear Angus,

Thank you again for the opportunity to speak with the ESNZ select committee at last week's inquiry hearing on 'A flexible grid for the future'. As you acknowledged it was a slightly lopsided panel and, with such a contentious topic, difficult at times to respond to each question in detail. I have, therefore, taken the opportunity to submit this supplementary statement to cover some of the specific points raised during the hearing and to add further evidence to the responses that I gave. I have also highlighted several recommendations that we would invite the committee to consider.

Overall, I thought the session was useful in revealing to the committee that there are conflicting views about the merits of Locational Marginal Pricing (LMP) and that the benefit case presented as part of Ofgem's locational pricing assessment has been repeatedly challenged by the industry, independent consultants and several eminent academics. My understanding, based on discussions within REMA working groups, industry surveys and DESNZ's analysis of initial REMA responses, is that the weight of feeling across the sector is against LMP, with the majority favouring a more progressive reform agenda.[1]

In my opening statement, I stated that the implementation of LMP would be a long, complex and high-risk process, especially at a time of energy transition. I said that the implementation of LMP would take a minimum of seven years – in fact, most organisations with experience of LMP markets have said that it could take longer. This important point about the scale of change LMP would bring did not come up in subsequent member questions, and instead we were told that LMP is "tried and tested". Given time, I would have re-emphasised that a LMP market design would be very different to our current market arrangements and would require the unpicking and redesign of almost all of the mechanisms currently used to trade energy, as well as support schemes, like the CfD and RAB models, interconnectors and the retail market.

Such a redesign would, of course, impact renewables, but also energy storage, flexibility, interconnectors, nuclear and low-carbon dispatchable technologies. It would require the creation of a multi-billion financial hedging market to trade in Financial Transmission Rights. Every energy business – from generators, supply companies, traders, and corporations who buy energy – would

[1] See REMA Consultation Response, Strathclyde University, Cornwall Insight's industry survey.

have to adapt their systems, processes, contracts and business models. Experience from those operating in other LMP markets shows that the complexity of operating in such a market would likely increase the costs paid to consultants and intermediaries and could lead to further market concentration, as only those companies that have the scale, risk appetite and capability to adapt to the new regime can effectively compete and see a gain in their market share.

It would delay investment and increase ongoing investment and commercial risk.

The level of upheaval cannot be overstated. One experienced energy expert has compared radical market reform to an F1 driver coming into the pits, mid-race, expecting a quick tyre change, only to be told by the team managers that they are going to attempt to rebuild the car.[2]

The LMP benefit case is complex and has a number of counterintuitive elements. A committee hearing was probably not the best forum to try and unpick where the benefits are coming from and to whom they have been allocated.

We have raised our concerns regarding the benefit case to Ofgem and DESNZ.[3] We highlighted that data and scenarios have been selectively chosen and that numbers have been presented as a forecast rather than as they are, i.e. the hypothetical outcome of modelling assumptions. This has also been identified by several consultant reports and academic reviews, which we have signposted to your research team.[4] [5]

If the committee decides to explore LMP further then I would suggest asking an independent academic or analyst to provide a briefing on the difference between LMP and our current trading market, and a breakdown of where the modelled benefits are coming from, how realistic they are and how they might be distributed between competing claimants. Given that the allocation of value will be a series of policy (and perhaps legal) decisions, it would be beneficial for the committee to understand the trade-offs and compromise that will need to be determined. A broad assumption that nearly all captured value would default to consumers is highly misleading and unrealistic.

Second REMA Consultation

Our main concern right now is that progress towards electricity market reform may be further delayed by a return to a fruitless discussion about radical market options such as nodal LMP. Ofgem's locational pricing assessment report was important because, although it found that LMP could bring benefits against a 'do nothing' scenario, it also acknowledged the need for a counterfactual of reform within existing national market arrangements. We are calling this the 'agenda for progressive market reform'.

The second REMA consultation has been delayed since last summer. We are concerned that, if this is not published soon, there will be insufficient time to complete the process before a general election. We have not seen a draft of the REMA consultation, but along with others in the industry we have been briefed of its minded-to position to drop the options of 'splitting the market' and

---

[2] See Gareth Miller, CEO Cornwall Insight's blog post.
[3] Letter to DESNZ REMA Team September 2023
[4] See, for example, studies by Frontier Economics, Afry, Auora, Cornwall Insight and LMP assessment academic reviews by Strathclyde and University of Cambridge (Pollitt) – references in the Appendix.
[5] See academic reviews commissioned by Ofgem.

nodal LMP. We understand a zonal market option will continue to be explored because there may be a need for zonal 'bidding zones' (or elements of zonal pricing) for the purpose of interconnectors.[6] We expect the second consultation, and work of the REMA team, to focus on the development of a progressive market reform options plus interconnector issues.

We would recommend that the committee speaks with DESNZ and Ofgem to understand the options analysis they have undertaken. If the committee determines that it wishes to recommend a further evaluation of LMP, our concern is that this will, once again, delay the REMA programme.

Progressive market reform – ambition and delivery

A progressive market reform agenda does not mean maintaining the status quo or a business-as-usual approach. The reforms that have already been identified in the areas of constraint management, network charging, flexibility markets, the balancing mechanism, dispatch and operations, digitalisation, the CfD, capacity market and interconnectors would constitute a very significant reform package. This is especially true when put alongside other reform initiatives in connections, network planning and investment, regional and spatial strategic planning, support mechanisms for storage, hydrogen and CCUS, retail market reform and the creation of the NESO.

We presented constraint management reforms to the committee on the 17th of January.[7] In this area alone there is plenty to be getting on with. Rather than lacking ambition, there is already a full reform agenda that is approaching the limit of that which industry stakeholders and policy makers can deliver. The good news, however, is that many of these reform objectives are already well advanced and are now in progress. The priority now is to maintain momentum.

Therefore, our overall recommendation is that the committee lend its support to the immediate publication of the second REMA consultation and, specifically, to support the development of a progressive market reform agenda. Within this, we believe that there are key areas which the committee may wish to highlight to deliver solutions. This might include:

a) Interconnectors – as discussed, the current interconnector process is misaligned and needs to be reformed. There are several priorities here, including the 'recoupling' of GB and EU markets and processes, providing the SO with the means to manage interconnector flows and/or capacities, and the need for better GB and interregional interconnector and grid planning/coordination.

b) Constraint costs and constraint management – we should not accept that constraint costs must rise as we transition to net zero. This is now a very active area of reform that has previously had less focus. In the presentation mentioned above, we identified at least ten reform initiatives, including the tightening of regulations and monitoring to prevent generators making profits from network constraints, which could reduce both the occurrence and cost of constraints. Committee oversight of this area would help galvanise the reform initiatives and set targets for reform objectives.

---

[6] We do not believe that a zonal model will be necessary to solve the issues of interconnectors, but we are in any case obliged to consider this option for as long as 'bidding zones' remain on the table for our EU partners.

[7] A copy of the presentation given to the committee on the 17th of January can be found here.

c) **Local energy supply, community benefit, local ownership and levelling up** – it was clear from our discussion that several members identified the potential for energy to create local benefits as a key objective. I don't believe that LMP will deliver this, and certainly not in a coherent and sustainable way. But there are ways to support local energy supply models, community benefits and ownership and energy clusters within a regional industrial/levelling-up/just transition strategy. This aspect of energy policy does not sit well within the market reform agenda. We think it needs more focus and would be happy to present these ideas to the committee.

d) **Low-carbon dispatchable generation.** Next to grid infrastructure this is probably the most at-risk area to achieve a clean power system. We will need a form of low-carbon dispatchable generation – alongside storage and flex – to break the dependency on unabated fossil generators. This could be CCUS, bioenergy or hydrogen generation – maybe even SMRs – but at present these are either unsustainable (biomass) or have made pitifully slow progress. A question for the committee is whether we are doing enough to incentivise the adoption and conversion of these technologies. Are we challenging industry to move quickly enough?

We would be happy to meet with the committee again. Appearing before the committee is a daunting experience, but a good one nonetheless. Thanks also to specialists Gwen and Anna for their support.

The remainder of this document sets out more detailed responses to the questions raised at the committee hearing.

Kind regards,

Johnny Gowdy

Review of Electricity Market Arrangements (REMA)

ESNZ Select Committee Inquiry: A flexible grid for the future

Supplementary Evidence : Why LMP is not the right answer, and why there are far better progressive market reform options

Johnny Gowdy

February 2024

1 Supplementary written response to the select committee enquiry (7th Feb 2024)

1.1 Q319 Role of Regen

I was asked about Regen's interplay with generators and how we have become a "voice for them". Other panellists were not asked about their potential interest in LMP after making their opening statement. As I stated to the committee, Regen is ***"absolutely not a voice for generators"***.

About Regen
The committee can find out more about Regen's recent work here [Regen Annual Report 2022/23] Regen is an independent, not for profit, centre of energy expertise. We were established twenty years ago to support the development and deployment of low-carbon technologies in the south west of England, with a mission to increase low-carbon energy and secure economic benefits for the region. Since the abolition of the RDAs in 2010, we have become a national organisation with people based across the UK, including in Scotland. We are fiercely independent, providing evidence-based analysis and advice with an overall mission to accelerate the net zero transition. Our board and trustees are made up of people from across the energy sector and its stakeholders. This independent position has allowed Regen to support the industry and policy makers by acting as a facilitator and convenor between different stakeholders and interests, and to deal with contentious issues. For example, Regen's CEO, Merlin Hyman OBE, was asked by the ESO to chair the GB Connections Reform Steering Group. We are not a trade body and do not speak on behalf of any industry sector. We do have a membership but this provides less than 10% of our income and renewable generators are a minority of our membership group. We also run collaborative networks, including since 2018 providing secretarial support for the Electricity Storage Network (established in 2008) and setting up REWIRE – Regen's Entrepreneurial Women in Renewable Energy network Our revenue comes from a range of sources, including advisory work across the energy sector, grant funding and public innovation funding. Our largest areas of advisory work are for energy networks (including the detailed analysis of network load forecasts, local energy studies and community engagement), and for local authorities, city/regions and devolved governments. We have completed a number of projects for DESNZ including a recent study on the role of long duration storage. We are actively involved in issues around community benefits, economic growth, energy devolution, planning, local energy supply and the just transition.

1.2 Investment, market and net zero delivery risks

We believe that a shift to LMP would significantly increase investment risk in the GB energy sector. There would be winners and losers but the overall investment and ongoing commercial risk for market participants (generation, flexibility, energy supply and consumers) will increase, and will ultimately increase consumer costs either directly or through risk mitigation measures.

Specific risks would include:

a) Constraint or volume risk – loss of firm grid connection coupled with uncertain network capacity and uncertain network delivery, plus loss of constraint compensation payments.

b) Market price risk – forecast risk – LMP price volatility.

c) Project development risk – loss of firm access rights and increased revenue uncertainty – higher capital cost.

d) Dispatch risk – the risk of being in price merit but still not being dispatched with a move to centralised dispatch and algorithm led dispatch.

e) Balancing risk – participants would still face a balancing risk that would be increased by the increased price volatility at locations.

f) Implementation and policy risk.

The impact for the consumer would be:

a) An increase in the cost of investment – cost of capital – as investors require a higher return on investment and therefore higher profits for a given level of investment. FTI has modelled a 0.5% increase in the cost of capital for some technologies as a sensitivity which produced a significant decrease in benefits. A 1% or 2% increase or more would erode the benefits claimed for LMP. A 1-2% increase is entirely plausible.

b) Delays or cancellation of investment – especially in low-carbon technologies – which would jeopardise the delivery of net zero, and increase consumer costs and dependence on fossil fuels and gas prices.

c) The need for greater risk mitigation policies and interventions – e.g. higher price CfDs, Cap and Floor models, grandfathering of existing grid access rights and constraint payments, allocation of congestion rents and funding of Financial Transmission Rights (FTRs) for generators, which may only be partially effective and would quickly erode the benefits claimed for LMP.

d) An increase in market costs as participants mitigate risk via hedging and the expense in software, consultant fees and transactional costs to forecast marginal prices and constraint and manage an increased balancing risk. Balancing risks would ultimately be transferred to consumer in an uneven way – those with the ability to harness flexibility may get better deals, while those without would face increased cost.

e) Increased market concentration, and therefore less competition, in generation, flex and energy supply markets, as smaller participants are unable to manage these risks compared to larger, vertically integrated companies with larger portfolios and financial backing.

Evidence of investment and ongoing commercial risk

Proponents of LMP have claimed that the is "little evidence" of increased investment risk. We believe that these risks need to be better understood and examined but that there is ample evidence that both investment and ongoing commercial risks will increase under an LMP market.

A market that is relatively stable, with marginal levels of change, low levels of current and forecasted constraint and a history of building network capacity on time would have a lower level of risk associated with LMP. The GB market, going through a rapid energy transition, a massive net zero investment programme with significant grid infrastructure requirements and current constraints, is not in that position.

Evidence of increased risk:

a) Feedback from developers, market participants and investors. There has been extensive feedback that LMP will increase market risks. See for evidence the DESNZ REMA consultation response analysis, Strathclyde university analysis of LMP[8] and recent Cornwall Insight Industry survey.[9]

b) The importance of revenue security is already evidenced in the GB market – hence generators are willing to forego significant upside profits to obtain a long term CfD or PPA contract.

c) The importance of a firm grid connection is already evidenced in the GB market – hence a grid connection is paramount to a project developer and hence the increase in connection application and queues.

d) Feedback from participants in US LMP markets is that they go to significant expense to manage LMP price forecast and balancing risks.

e) The existence of multi-billion FTR hedging markets – which are a significant cost to participants and the system – is proof that there are increased LMP market risks.

"Nodal pricing in the US induces risk-related costs. The mere fact of the need to introduce financial transmission rights (FTRs) in nodal market in the US is evidence of this" Michael Pollitt

1.3 Q318 Overstated LMP Benefits

I said to the committee that we believe the benefits presented by FTI to be overstated. This is not just Regen's view but has also been identified by a number of separate consultant reports and academic reviews, which we have signposted to your research team.[10]

We have raised our concerns regarding the benefit case, and more specifically the way the numbers have been presented as a prediction rather than a hypothetical outcome of modelling assumptions. It has not helped the case for LMP that both the studies commissioned by the ESO and Ofgem have used the same consultants (FTI) who have presented essentially the same model using the same scenario assumptions. It is inevitable that scenarios are going to be used for this type of analysis, but the way they have been selected, and then 'sliced and diced', to produce a positive LMP outcome, has frustrated many in the industry who would have preferred to see a more critical analysis.

---

[8] Strathclyde University Exploring market change in the GB electricity system: the potential impact of Locational Marginal Pricing Simon Gill, Callum MacIver and Keith Bell. Highlights investment risk.

[9] Cornwall Insight – Industry Survey "LMP is not the answer".

[10] See, for example, studies by Frontier Economics, Afry, Auora, Cornwall Insight and LMP assessment academic reviews by Strathclyde and University of Cambridge (Pollitt) – references in the Appendix.

1.4 Q318 Choice of scenarios and how sensitivities have been applied

The main driver in the generation of LMP benefits is the modelled locational and temporal mismatch between the deployment of generation capacity and the investment in network infrastructure. If we assume that renewables will be deployed according to Plan X but network investment according to Plan Y, then there will be an increase in network constraints and other system costs.

The first point of contention is the choice of future energy scenario (FES) and network investment plan for the LMP base case. The LMP base case which produces the largest benefit case is based on the ESO's 2021 Future Energy Scenario, Leading the Way and the Network Options Assessment 7 investment plan (known as scenario **FES LTW 21 Plus NOA7**).

This scenario produces the contested figure of **£24 billion in socio-economic benefits** (i.e. net benefit across the system) and a **£26.8 billion value transfer to consumers,** which (assuming nearly all value goes to consumers) would create a nominal 'consumer benefit' **of £50.8 billion.**[11]

The **FES LTW 21 Plus NOA7** scenario presents the most rapid deployment of renewable energy with the lowest network investment – hence the obvious misalignment between generation and grid capacity. We do not believe this scenario should be used as a base case.

- **Future Energy Scenario 2021 Leading the Way scenario**, produced by the ESO, has accelerated renewable energy deployment to achieve net zero by 2045. Critically, within this scenario, the regional distribution[12] of generation assets is **based mainly on a simple extrapolation of historic build** and does not represent a realistic forward view of the geographic distribution the market would produce with current locational signals, or indeed the outcome of a Leading the Way scenario.
- The **Network Options Assessment 7 (NOA 7)** has already been acknowledged as being inadequate – hence the significant additional investment which has been planned as part of the **Holistic Network Design (HND)**, which itself only runs to 2030.

We would argue that the **LTW 21 Plus NOA7** scenario should not have been used as a base case, but as the most extreme outcome.

Even within the limitations of the modelling assumptions of the FTI model, changing the FES scenario to System Transformation, or the network investment to include the newer HND, has a very significant impact on the benefit case. Individually both of these changes result in a 40-45% reduction in benefits, according to the FTI analysis. It is not known what the impact of changing both sensitivities together would be – this has not been modelled – but one would expect an even more significant drop from a System Transformation plus HND scenario.

FTI have stated elsewhere that the use of NOA 7 as a base for network investment is more realistic because they do not believe that GB can deploy grid capacity as quickly as it is now planned under

[11] Note: these benefits are over a 16-year period from 2025 to 2040.

[12] The regional views produced by the ESO FES go down to the Grid Supply Point (GSP) and have been the least well developed part of the FES programme. They have improved since FES 21 but still primarily exist for illustrative purposes only. They are generally not used for network planning, which is partly why Ofgem is looking to create a new Regional Energy Strategic Planner (RESP).

HND and the Accelerated Strategic Transmission Investment (ASTI) framework. That may or may not be true, but if that is the assumption, then we will certainly not achieve a decarbonised power system by 2035. Therefore, it would be more appropriate to choose a slower net zero scenario like FES Steady progression, with a slower renewable energy deployment, as the base case.

FTI Modelled Results for Nodal LMP				
FES Scenario		**Consumer Benefit** – assuming full transfer of all congestion rent value to the consumer. Billions	**Socio Economic Benefit** - system value creation. Billions	**% Socio Economic Reduction to base**
Leading the Way 2021 Plus NOA 7	LTW 21 NOA7	£50.8	£24.0	Base
Leading the Way 2021 Plus HND	LTW 21 HND	£34.2	£14.4	40%
System Transformation 21 Plus NOA7	ST 21 NOA7	£28.0	£13.1	45%
System Transformation 21 Plus HND	ST 21 HND	Not Modelled but would be significantly less than base case		??
Consumer Transformation 21 Plus HND	ST 21 HND	Not Modelled but likely to be less than base because more generation is connected to the distribution network		??
Steady Progression 21 Plus HND	ST 21 HND	Not Modelled but would be significantly less		??

Figure 2: Table showing the scenarios modelled and not modelled. Source: FTI assessment report

Regen's view, shared by many in the industry, is that the choice of scenarios, and the failure to combine generation scenarios with a compatible network build, has significantly inflated the benefit case provided by the modelling. We would add further limitations that:

- None of the FES scenarios represent a preferred or optimised pathway to net zero or current policy or the current market. They are all 'envelope' scenarios to illustrate the range of credible pathways available and should not be treated as forecasts. FES is now changing towards more of a central pathway approach which will, we expect, be aligned with the new Central Strategic Network Plan and the Strategic Spatial Energy Plan.

- The regional geographic distribution of generation assets in FES 21 is not based on a bottom-up analysis of where assets are likely to locate in response to current market-based locational signals. They are primarily based on an extrapolation of historic deployment, which will tend to exaggerate the clustering of generation into previous hotspots and therefore increase grid constraints. The FES team is working on more meaningful regional projections.

- The FTI modelling is still using FES 2021 scenarios which have since been updated twice. This means we have seen the same scenario numbers used for both the ESO and Ofgem LMP studies.

- The FTI modelling is based on the current national market having a single marginal clearing price. This is not a true representation of the current market and may have inflated the occurrence of infra-marginal profits as it ignores the value transfer potential of long-term

PPA contracts. It has been estimated that around 24% of renewable energy is sold under PPA terms.[13]

- The nodal LMP modelling ignores distribution network constraints, presenting only a partial picture as a result. Benefits claimed for siting, operational efficiency and consumer flexibility would be frustrated by constraints on the distribution network.

As I said to the committee, what the modelling shows is not the benefit of LMP but the great importance of aligning future network capacity with net zero delivery with a joined-up strategic plan.

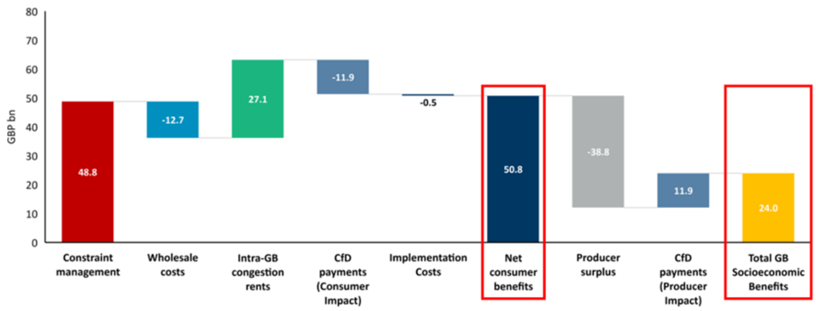
1.5 Response to Q335 Dr Poulter – reference £12 billion figure for initial wholesale price impacts

At the enquiry hearing I was challenged on a statement I made that *"the initial wholesale price impact is, on average, an increase in consumer prices. In your [FTI] estimate, it is about £12 billion over the period that was modelled."*[14] A number that Mr Mann said he did not recognise.[15]

To be clear, I was not claiming this was the full impact. I stated that this was the initial wholesale price impact, and that the consumer benefits claimed by FTI then relied on the redistribution of constraint payments and other revenue taken from producers. (see the transcript Q333).

The "about £12 billion" figure is in the FTI benefit case at £12.7 billion. The number can be found on Figure ES-7 on page 16 of the FTI LMP assessment report[16] with a supporting commentary: *"Under the LtW (NOA7) scenario, the reduction in the wholesale price in the north of GB is more than offset by an increase in the wholesale costs paid by consumers in the south – resulting in a net increase of c.£13bn across the generality of consumers (represented by the light blue column in Figure ES-7".*

Figure ES-7: Overall Cost Benefit Assessment for a nodal market design relative to a national market design (2025-2040) – LtW (NOA7)



Source: FTI analysis

The key point here is not that LMP leads to higher wholesale prices, but that an LMP model will usually produce a higher average wholesale price compared to a single national clearing price model. The purpose of raising this point was to clarify for the members that the claimed LMP benefit case for consumers relies on the redistribution of: *"first, savings on constraint payments to*

---

[13] A single national clearing price is not how our current GB market works in practice but is itself a modelling simplification that will tend to overstate LMP benefits because it ignores the value transfer delivered by long-term contracts and PPAs. It is estimated that around 24% of renewable energy is sold under PPA terms, the second highest in Europe after Spain.

[14] Meeting Transcript.

[15] Mr Mann's response Q334.

[16] FTI report for Ofgem Assessment of Locational Wholesale Electricity Market Design Options in GB; page 16 and 7.

producers, and, secondly, squeezing out the inframarginal rents or the surplus on producers. The assumption is that, that value is then distributed among consumers, which is how we get to the overall net reduction in consumer bills. That is a massive assumption, because there will be other claims on that pot of money."

1.6 Costs not included in the LMP benefit case

A second point of contention is that some obvious costs have not been included in the LMP benefit case or have only been partially included. This point has been highlighted by the academic referees who reviewed the LMP assessment and by those who have experience operating in an LMP market.

Additional LMP costs would likely include:

a) Market power effects. A strong likelihood that, by breaking up the market into smaller units or zones, generators who are in an advantageous market position will be able to exploit their competitive advantage to secure prices above their marginal costs (achieving scarcity rents).

   Prof Michael Pollitt has neatly described this as *"…Microeconomics 101 that reducing the number of firms in the relevant market increases the Lerner Index (and hence market power). 750 years of economics (since St Thomas Acquinas) teaches us the benefits of wide area markets. Either nodal pricing increases local market power or it involves a new form of regulation to prevent an increase in local market power."*

b) Higher costs associated with the operation of an LMP market including the commercial and transactional costs associated with risk management, balancing, price forecasting and participation in Financial Transmission Rights markets. As I said to the committee, participants in US markets, like Texas, have highlighted the additional costs and commercial risk of operating in an LMP environment. Costs include the cost and fees paid to software, data and consultants to provide the far more complex forecasting and pricing analysis associated with LMP.

   Significant value is also extracted from an LMP market by intermediaries and traders in connection with FTRs and other hedging products.

   These costs would be significant, and would be exacerbated by the sheer number of GB market participants. The market would favour larger entities with a mixed portfolio of assets, and larger energy supply companies with the scale to invest in significant IT capability. This could in turn lead to a concentration in both the generation and energy supply market, reducing competition and increasing consumer costs.

   Extracts from Prof Michael Pollitt's Assessment of LMP benefit modelling:

   Nodal pricing in the US induces risk related costs. The mere fact of the need to introduce financial transmission rights (FTRs) in nodal market in the US is evidence of this (Pollitt, 2023). While risk can be hedged – hedging is expensive and its costs should be considered as a core part of any cost benefit analysis of a move to nodal pricing. The FTI Report argues that there is no reason to be believe that nodal pricing increases risk (Para 8.64-65).

The FTR market is inefficient and costly to consumers. The evidence on this is overwhelming and is not mentioned by FTI (see Pollitt, 2023 for a review). Based on FTI's modelling (at Para 7.75) of the congestion rent in a GB nodal pricing system would be that a US style FTR market would cost GB consumers up to £9bn in the LTW(NOA7) scenario (33% of £27bn). There would also be some part of this £9bn that would need to be subtracted from the net benefit. How much this would be is subtracted from net benefit depends on the perspective taken. [4]

c) Compensation to existing market participants and network access rights holders. The modelling assumes that existing generators, demand customers and storage providers (with the partial exception of CfD holders[17]) would not be compensated for their loss of revenue or constraint payments.

In the benefit case, compensation, or grandfathering, of existing participants is considered a policy decision rather than an LMP cost, and we have been told in previous workshops that much of the value transfer to consumers is anticipated to come from existing generators. In part this would be a political decision but it would also be open to legal challenge. Generators currently hold connection contracts with network companies which can be firm or non-firm, which could be used as a legal challenge. More importantly, any decision to impose losses on existing rights holders would send a very negative investment signal.

In REMA discussions about transitional arrangement for LMP and other potential REMA reforms, it has been accepted that some level of grandfathering would be required, although this has never been worked into the LMP benefit case.

Other costs including the costs associated with investment risk already described. FTI has run a basic sensitivity analysis with a 0.5 percentage point increase in the cost of capital applied to some but not all generators. This produced a fall in benefits of £7.5 billion under the FES 21 LTW NOA7 scenario. Industry participants and other consultants have argued that the cost of capital impacts of LMP could be much greater. See for example Frontier Economics.

1.7 Summary comments on the LMP benefit case

It is likely that, if the benefit model was re-run with a System Transformation Scenario, HND investment plan plus costs to recognise above marginal cost pricing (or increased regulation), additional risk and FTR costs, operational and commercial costs, higher implementation cost, grandfathering of existing rights holders and the increased cost of capital, it would substantially reduce the benefit case to near zero or a negative figure.

[17] CfD holders are partially compensated for LMP price revenue loss but not constraints payments, so they are protected from a price risk but not the volume constraint risk. We think that FTI has assumed that only 50% of future renewable capacity will be under a CfD – within an LMP market we struggle to see how many projects would be built without a CfD, or equivalent.

1.8 There are better ways to ensure the transfer of value between consumers and generators

The LMP modelling makes a very simplistic and unrealistic assumption that rents and surpluses captured by an LMP market would be passed to the consumer as a consumer gain. Hence the very large "Consumer Benefit". Most LMP schemes have not been implemented with the purpose of transferring value in this way.

In reality, there would be lots of other claimants on any value transfer gained including existing contract holders, higher CfD strike prices, RAB and Cap and Floor models, funding for FTR schemes and higher transactional costs.

LMP would penalise generators in areas of generation constraint by forcing prices down to their marginal cost and removing constraint payments. This is economic theory but marginal cost pricing does not make much sense for a renewable or nuclear generator since the marginal cost is near zero and would not cover variable costs or provide a fair return on their capital investment. So either these projects would not be built, or would have to receive revenue support in some other way – undoing the claimed benefit.

But if the government is, quite rightly, concerned about generators making excess profits, especially during periods of high wholesale prices then there are better means to ensure a fair value exchange:

- By extending the use of Contracts for Difference, RAB and Cap and Floor models – all of which have a consumer value share. CfDs for example made a net contribution to consumers during the energy price crisis.
- Support the use of long term PPA contracts – by energy suppliers, large energy users and public bodies – which can be negotiated on the basis of long term costs.
- Collaborative ('sleeved') PPAs could also be used to support public procurement, local tariffs, levelling up tariffs.
- In extremis – if we faced another price crisis and it was felt that generators were making too much profit another form of Electricity Generation Levy could be retained. However, we would recommend a redesign so that it was more targeted to precisely capture windfall excess profits and not inhibit future investment.

As part of a progressive market reform, many in the industry and consumer groups are calling for a new deal between consumers and generators – lower cost energy in exchange for long term revenue security.

1.9 Q325 and Q328 Ofgem's views on LMP and next steps

Ofgem's position on LMP was referenced with a claim that Ofgem had found in favour of LMP and that it produced significant consumer savings across all scenarios. In fact we would recommend that the committee reads the Ofgem assessment document, and the academic reviewers that Ofgem engaged. It would also be beneficial for the committee to speak directly with the Ofgem team.

The Ofgem assessment is quite nuanced and, we understand, has changed significantly from its initial position of being broadly in favour of LMP. The Ofgem assessment acknowledges the limitations of the modelling and the counter views of the academics. It also highlights the challenges and risk of implementing LMP, its long timescale and that the investment risks need to be better understood.

It does state that LMP would be likely to produce significant consumer benefits but then adds the critical caveat that this was against a 'do nothing' counterfactual, which was unrealistic. The assessment then goes on to state that the focus for Ofgem is to now work with others to develop a proper counterfactual. Regen and others in the industry have welcomed this assessment because of this critical statement, that the next step is to properly look at a progressive counterfactual.

Ofgem Assessment Page 5 – Executive Summary *"We find that locational pricing is likely to produce significant benefits for society compared to current arrangements, i.e. doing nothing to improve locational signals in existing market arrangements. The scale of these benefits will be shaped by several important policy choices.* *Ofgem has already set in train a series of improvements in how network and generation infrastructure is co-ordinated and delivered through centralised system plans and anticipatory network investment.* *Further work is underway to develop a more realistic counterfactual of improving locational signals under current market arrangements. This could be done through a combination of better spatial planning, reforms to Contracts for Difference (CfD) scheme design, network charges, access arrangements and balancing markets. This "reformed national market" should serve as a future counterfactual to locational pricing in determining whether or not the latter would be a desirable policy.* *We intend to continue working with the government to develop this counterfactual, and in the next phase of work, examine the implementation requirements of locational pricing in more detail if this option is taken forward as part of its Review of Electricity Market Arrangements"*

We would suggest that the committee speaks with Ofgem directly to garner their views as these may not have been accurately represented to the committee.

1.10 Harnessing Consumer flexibility – an effectve and fair approach

A lot of the questions raised by the committee were in connection with how we can best harness consumer flexibility in a way that provides system benefits, treats the consumer with respect and also protects, or shields, those consumers who may be less able to benefit from flexibility opportunities (and may in fact be penalised because of their demand needs).

There was broad agreement across the panel that flexibility will be critical and that we need to use this facility to achieve net zero and maintain energy resilience as well as lower overall costs. There was no consensus on whether consumers should be exposed to very volatile price signals driven by network constraints. This reflects previous discussions around LMP, which have mainly focused on how we can shield consumers from its effects.

1.11 Flexibility in a changing energy system

The energy market is changing rapidly. We are already seeing more price volatility in the wholesale market including periods on windy and sunny days when prices have fallen to near zero and even negative, but on other days where we have seen peak wholesale prices regularly well over £400 and sometimes higher. This highlights that the market is already sending strong time-of-use signals and this has supported an increase in agile tariffs etc.

As we deploy more renewable energy, alongside nuclear, we are going to enter a situation where, for significant periods of time, when there is excess energy, electricity prices may drop to near or below zero, while at other periods we will see very high prices driven by the need to bring on back up and standby generation.

Price volatility is an issue but also an opportunity. There are lots of ways we can use this to our advantage – through storage, interconnectors, production of hydrogen etc., as well as by harnessing consumer (domestic and industrial) flexibility.

A key part of demand side flex is get consumers engaged in the system and to respond to an appropriate level of market price signal, but there must be a balance between harnessing consumer flex and putting consumers in a position where they may be disadvantaged, treated unfairly or otherwise disengaged.

A balance between consumer price-risk exposure and protection of those consumers that are unable to respond is important. It is also important that all consumers view the system as being fair without arbitrary advantages and disadvantages, or particular consumer groups who are both gaining from the net zero transition and profiting from it.

As a first point of principle, if price volatility as being driven by the overall supply/demand balance across the market, then there is a good argument that demand and generation should be exposed to that price signal. We are all in the same market, on the same net zero transition and contributing to the investment in new energy systems assets and infrastructure.

Whether that signal is passed on to individual consumers then becomes a matter of the tariffs provided by retail suppliers and consumer choice they offer. Some tariffs may be highly agile, while others may be less variable. Some supply companies may choose to trade in short term markets, while others will opt to buy energy on long term contracts. And we may need to think about how we protect some consumers with social tariffs or subsidised bills.

However, where flexibility is needed to provide system benefits or deal with issues like network constraints, we think flexibility should be harnessed via more targeted flexibility markets and service provision. In other words, we should incentivise those demand consumers that can offer flexibility to do so, without penalising the entire consumer group.

LMP adds a whole additional level of volatility – driven principally by the occurrence of network constraints. It's important to understand this difference – LMP price differentials are constraint driven, not the fact of being located near generation, of whether your view has been obscured by pylons, or if you are in a deprived area targeted for levelling up.

LMP price differentials are the happenstance of network constraints – whether these apply to generation or demand, or both – and this is largely determined by historic network investment. Network constraints will also very likely change over time and change rapidly. The outer Hebrides would be a good example of changing network constraints.

The reason why we don't think transmission constraint price signals should be delivered in the wholesale price is that:

a) Their occurrence would be arbitrary to the consumer, driven by the happenstance of historic and future network investment.

b) LMP constraint pricing would be even more volatile, and locationally specific, than the current wholesale price signals – we don't think that the public would accept this as fair.

c) Many consumers will not be in a position to respond to these price signals – proponents of LMP will say that consumer can be protected from these signals. That may be true, but that implies that someone else (the supply company?) is taking the locational price risk and ultimately that means an increase in bills.

d) LMP signals based on transmission constraints may well run counter to distribution network constraints – so we would potentially be frustrating consumers who want to respond to a transmission LMP signal but are unable to do so.

To summarise, constraint or system service locational signals should be more targeted and offered to consumers on an opt in basis. i.e. through the targeted procurement of flexibility services from those consumers that are able and willing to respond – rather than inflicted on everyone.

We think that this form of flexibility, for what are system services, should be harnessed through other flexibility solutions. For example, an expanded Balancing Mechanism (which is already locational), flexibility markets which are already being developed and local constraint markets (LCMs).[18] There are examples of these markets in place today and lots of potential for them to expand and innovate.

1.12 Q321 – Q324, Q330, Projection of future regional benefits

Several times during our session MPs and panellists talked about consumer benefits in Scotland or in the North or the South of England, as if these were a forecast or firm prediction.

In reality, it would have been more honest to say that we do not know what the impact of LMP would be for any given geography over time, as there are a lot of uncertainties and imponderables.

The claim that consumers in Scotland could benefit is based on the scenarios used, assumptions about network investment, assumptions that consumers would be exposed to the LMP signal, assumptions that generators would continue to build in Scotland and assumptions that subsidies would continue to be paid to generators in Scotland by consumers across GB.

I made the point to the committee that LMP is not about geography or location per se. LMP doesn't favour regions for levelling up or down, it doesn't reward communities that are hosting generation or grid assets, it is primarily an algorithm that determines a marginal price which is driven by the occurrence of network constraints. If we want to target an area for levelling up then there are better, more sustainable, ways to do this.

For the moment, assuming a hypothetical implementation in 2025, modelling would suggest a lower LMP price in Scotland. However, as discussed above, it will take a minimum of seven years to

[18] See for example the ESO's current trial with PICLO. See also S Gill paper on constraints.

implement an LMP-based market system, meaning we cannot know in the early 2030s what the exact supply/demand balance will be in Scotland, or how much network investment will have been made. Yes, it is still likely that Scottish energy will be constrained, but LMP could in fact change that balance; many developers, including offshore wind, could look at the changes being proposed under LMP and decide to delay their projects until they have revenue security and a guarantee that network capacity will be available. That is what has happened in other LMP markets, such as Texas.

There is an important quote from Ofgem which I think the committee should consider:

"Simply put, the more the transmission network is upgraded to reduce network constraints, the lower the net benefits from locational pricing." Ofgem Assessment of LMP 2023

We could even get into the perverse position where Scottish consumers campaign against network investment from Scotland to the rest of GB or Europe because it will reduce their marginal price benefits.

This supports a wider point that LMP would be extremely divisive and, rather than bringing consumers with us on the net zero transition, would undermine its cross-UK support.

Q331 If it is hard to predict the impact of LMP, on average, across Scotland then it is even more difficult in complex energy regions like the North of England and almost impossible in specific locations like the Outer Hebrides.

If you would like to discuss the Outer Hebrides in more detail we would be happy to do so. As it happens, Regen has just completed an energy review for the islands on behalf of SSEN as part of the evidence gathering for their network investment plans. This reveals just how complex the energy balance is and the range of future energy outcomes, plus the added complexity of new Transmission investment alongside a heavily constrained distribution network.

Q331 – the statement that the North of England would have "similar" or the "same" benefits as Scotland is not correct and is not supported by the modelling. The impacts of LMP across the North of England are expected to be more varied and will depend heavily on future network and generation deployment.

1.13 Q322 and Q333 – Would demand shift in response to an LMP price signal?

In a steady market, not going through significant change, we might expect that a stronger locational wholesale price signal would encourage some energy-intensive users to choose a location with lower prices.

In practice, there isn't much evidence of this happening in response to short-term marginal pricing. West Texas[19] was earmarked as a location of wind farms in the US and it was hoped that this would then attract new industry into this previously deprived area. LMP pricing is, however, difficult to predict and will only reflect the current supply/demand balance and level of constraint – all of which may change.

[19] See Regen Paper Wild Texas Wind

Most industries also have other strong locational drivers – access to resources, skills, customers. Data centres for example need strong telecommunication links, and IT skills, and hence have targeted the M4 corridor. Industries that have responded in Texas include crypto-currency mining, but the exception proves the rule – these businesses have very low start-up costs, don't employ many people, don't have a product that needs to be distributed, are very energy intensive and can shut down and move very quickly.

Industries could be attracted to locate close to energy sources but what most really need is a long-term low-cost price, not a volatile marginal price based on the happenstance of current network constraints. In our view there are better ways to support industry including by creating energy hubs, supporting long-term supply agreements, sleeved PPAs, Energy Club models and by looking at long term (10 year) network charges.

1.14 A more direct route to locational signalling for demand consumers – Network Charges

We touched on this briefly but did not discuss the most obvious alternative to LMP to provide a locational signal to demand and generation, and to potentially lower charges for consumers in Scotland, which is the reform of Transmission (TNUoS) and Distribution (DNUoS) network charges.

Historically, GB regulators have tended to flatten out (semi-socialise) consumer network charges across GB so as not to send strong locational signals and to maintain a fairer access to energy. So, for example, transmission network costs charged to demand consumers in Scotland and England do not differ by as much as they would if the full network charge signal was passed to consumers. Generation, however, receives the full transmission locational cost signal. Regen, and others, have highlighted the current inconsistency in the application of TNUoS charges to demand and generation.

If the full impact of TNUoS charges were applied to demand customers across GB, the differential between a customer in the North of Scotland and South of England could be as high as £6-8 per MWh – see Regen and Energy Landscape Insight Paper Improving locational signals in the GB electricity markets.

Whether applying more cost-reflective network charges is the right or appropriate level of locational signal for demand consumers remains a point of contention; it could lead to a significant distributional impacts and would probably not be supported except for commercial and industrial consumers.

The panel was right to highlight that the discussions about more granular and pointed network charges have been ongoing for some time without much change, and that they do raise very significant distributional and fairness issues. The point I would make, however, is that we already have the tools to give very strong locational signals to both demand and generation if that is appropriate and that, because these are forward looking, they are likely to be more effective in terms of investment siting than a short-term marginal price signal. The fact that we have so far struggled to apply these signals should be raising a more general warning flag to the committee that, in reality, UK policy makers are very reluctant to use energy bills to drive consumer behaviours or location and so, by that logic, would not apply extreme LMP price signals either.

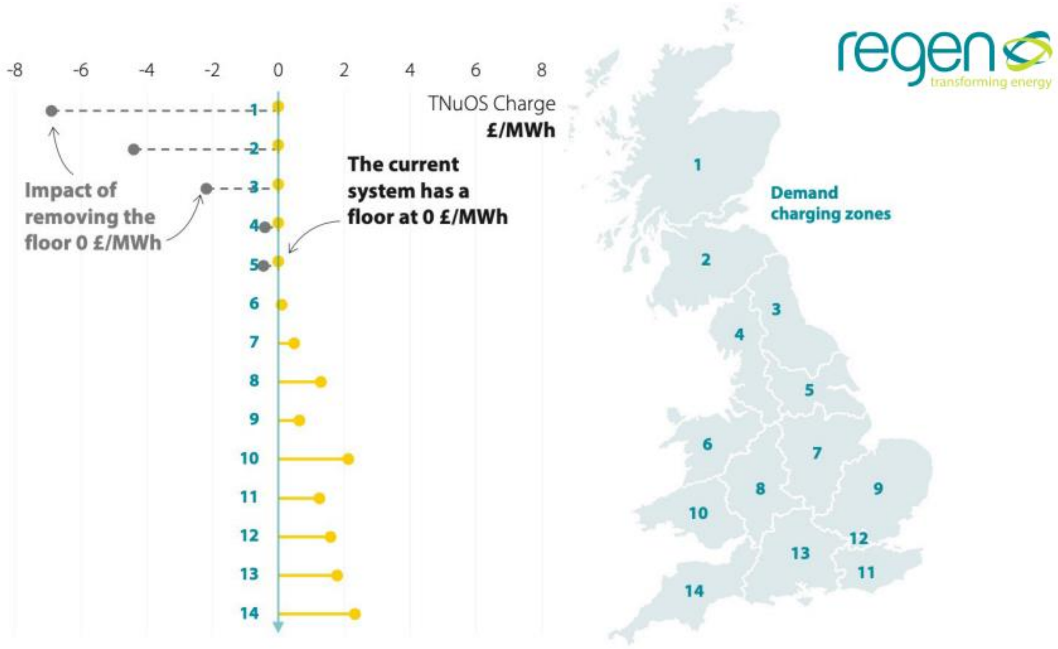


Figure 1 Transmission Network Charges for demand consumers in £/MWh based on a 50% load factor against its Triad demand, showing the current system that includes a floor at zero and the impact of removing that floor. Source: National Grid ESO.

Ofgem is currently looking at transmission network charging (the TNUoS task force) and it is expected that network charging will form a key part of the next round of REMA consultation. We would recommend to the committee that it puts oversight of network charging reforms as a priority for the department.

1.15 Q333 Will generation respond to LMP locational signals?

Members asked whether generation is likely to respond to the LMP price signal by moving location.

The evidence is pretty clear that investors in large scale generation assets are unlikely to positively respond to an LMP price signal. They may, however, choose to either delay or not build projects if there is an increased investment risk within an LMP market.

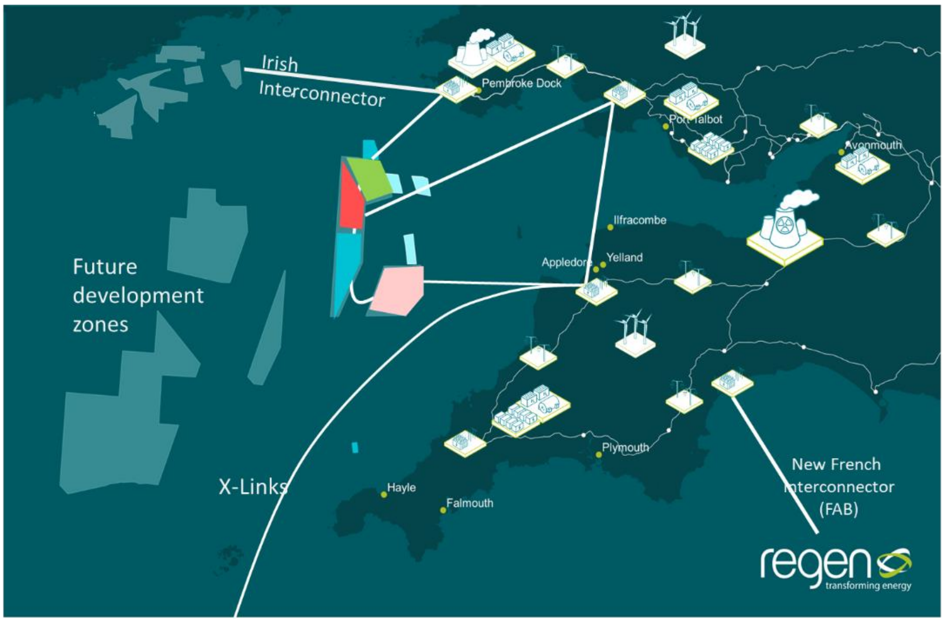
Academics such as Michael Pollitt have suggested that all re-siting benefits should be removed from the LMP benefit case:

"Long run price signals dominate generator siting, there is little evidence that nodal pricing has much impact on location of generators or loads if they are not expected to persist." Prof. M. Pollitt

The obvious problem with LMP locational signals is that the marginal price only reflects the current level of network constraints. It takes at least 7-10 years to build an onshore wind farm, longer for offshore and nuclear. Large projects, wherever they are located, will require network reinforcement, meaning current constraints are not necessarily a useful guide for investment decision making. More important to the developer is the availability of a connection agreement, future network charges and the length of the connection queue. The GB system already gives these locational signals via network constraint heat maps, network charge forecasts, and the connection queue.

In any case, a large project would very likely change the supply/demand balance at a location, especially in a nodal market.

As Figure 2 highlights, currently the South West of England would seem like a very good location to build new generation. Transmission network charges are very low reflecting the fact that this region is currently a net importer of energy. If LMP was implemented today it would be sending a positive price signal but would that attract investment?



Scale of change

Generation
Hinkley C
X Links
Offshore Wind
Geothermal
Onshore wind and solar

Demand
Battery manufacturing
Electrification of steel
Hydrogen Electrolysis
Heat – heat pumps
Transport – Evs

Flexibility
Energy storage
Interconnectors – France
Interconnectors Ireland
Link – England - Wales

Figure 2 Level of energy transition change coming to south west England and South Wales

However, a generator considering building a new generation project in the region in 2035 would have to consider all the other projects and demand changes happening in the vicinity, plus network investment and the possibility that grid upgrades may, or may not, be delayed. They would have to consider Hinkley C, X-Links, offshore wind, interconnectors to Ireland and France, a connection to South Wales, significant upgrades to transmission and distribution infrastructure, new battery manufacturing facilities and a host of other energy demand and supply changes.

In the near future the South West could flip to being a net energy exporter – the LMP price signal is therefore very uncertain and unreliable = "unbankable". Any generation or demand developer would want to know that they will have a grid connection, predictable network charges and either the ability to forecast or lock-in future energy costs/revenues.

Smaller (and quicker) generation projects – for example solar PV – may be more amenable to marginal price signals but:

- They are already receiving very strong cost signals via the transmission network charges.
- Most solar is connection to the distribution network. A key point is that LMP would send transmission locational signals but not distribution – it is only a partial signal. So telling solar developers it would be better to locate in one region may be good for transmission, but that same region may be constrained on the distribution network, as well as having higher land prices, planning and land use challenges.

1.16 Q326 & Q329 The re-siting of generation modelled by FTI is dubious and could be misleading

At the enquiry hearing FTI were asked to comment on how generation responded to LMP pricing. The response focused on a claim that offshore wind was more likely to locate in the Celtic Sea.

I expressed scepticism about this response. The reason for this is that offshore wind in the Celtic Sea was not considered when the FES 21 scenarios were being developed, and therefore does not feature in the single-market counterfactual. Celtic Sea offshore wind (lease Round 5) has since been introduced by the Crown Estate and is now a strong possibility. However, this has nothing to do with LMP (wind already has a very strong locational single to develop in the South via network charges) and everything to do with the Crown Estate spatial planning and lease strategy.

As it happens, Celtic Sea offshore wind will require significant grid investment and, once the HND is complete, is more likely to be split between the South West and South Wales. Claiming that strategic projects like offshore wind and nuclear would meaningfully respond to a marginal price signal is, we think, misleading and incorrect.

Other shifts in generation capacity modelled by FTI could also be challenged. We understand from previous presentations given by FTI that the two main shifts are:

- More solar PV in the South of England (less in the North). Our observation is that developers would love to develop more PV in the South – there is better irradiance and lower network costs – and there is already a significant queue of projects that would like to connect. However, they are limited by the lack of capacity on the distribution networks and by other factors such as land price, land use restrictions and planning.

  The gradual shift of projects further north has been driven because of the availability of brownfield sites and grid capacity, and better planning outcomes. LMP may send a marginal signal (although it is likely this would be less than current network charges) but it is only a partial signal that does not consider other factors such as constraints on the distribution network.

- More onshore wind in the North of Scotland (less in South Scotland). A strange and unexpected outcome from the modelling with a dubious business model. The FTI LMP model has suggested that, with nowhere else to go, more onshore wind would concentrate in the North of Scotland because the wind resource is better, despite there being network constraints. This seems strange and is maybe a quirk of the modelling assumptions. A point that has been raised by the industry, and academics at Strathclyde, is that there has been no analysis as to whether new or existing onshore wind farms in North Scotland would be commercially viable under LMP – this is a major omission in the analysis.

1.17 Operational benefits – mainly from the better operation of interconnectors and energy storage

The breakdown of these benefits are not given, but the FTI commentary suggests that the most significant contribution to operational benefits is from Interconnectors and, in particular, interconnectors that could be built into network areas that are constrained. E.g. from Norway into the North of Scotland.

Operational benefits make up over 50% of the socio-economic benefits claimed for LMP. Unfortunately there is little breakdown of where these benefits come from.

There is a potential trade-off between more efficient markets and more efficient system operation, but academics have pointed out that it is difficult to find concrete evidence that LMP does have better operational benefits.

"While the theory behind LMPs is strong, the evidence on their operational impact is much weaker." Prof. Michael Pollitt

System operators have suggested that LMP gives the System Operator (SO) more time, and more control, to better align the use of assets and to co-optimise different system services. For example, a SO is less reliant on a time-critical balancing mechanism to redispatch CCGT plants at above market prices. Critics have suggested that this means that LMP provides the means to better optimise the use of fossil fuels and less likely to use other low-carbon solutions. Whether this operational gain is the result of LMP or the result of moving back to a mandated market[20] and centralised dispatch is open to debate.

The counter argument however is that, with market reforms and enhancements to system operations, the existing market arrangements could be made more operationally efficient and this could be done much more quickly. Constraint management is a very good example where the expansion of the BM, investment in automation and IT system in the control room, use of Local Constraint Markets, better forecasting, capacity optimisation and active network management (plus a bunch of other things) could significantly reduce costs.[21]

Significantly, these progressive reforms would work with the grain of the existing market arrangements and tap into the low-carbon flexibility agenda that is still a cornerstone of energy policy. They would also encourage new forms of flex enabled by IT, digitalisation and system automation.

1.18 Q316, Q356, The importance of interconnector reform

Everyone on the panel agreed that interconnection reform is essential. We think that this needs to be tackled urgently as their inefficiency is currently costing consumers. We would recommend that DESNZ convenes an Interconnector working group to better understand and resolve the issues.

The FTI benefit model for LMP does not go into detail but the commentary suggests that the key source of operation benefits are from interconnectors and, to a lesser extent, from batteries operating more efficiently. We don't have a breakdown of benefits from individual interconnector flows, which would be useful to know.

The FTI model includes an assumption that future interconnectors would flow into parts of the network that are already constrained. The most significant one being from Norway to Scotland. This would clearly add to constraint costs and, we think, is a key source of operational benefit claimed for LMP.

---

[20] A key feature of LMP is that it creates a 'mandated' wholesale market. In other words, market participants must bid into a central day head and intraday market. Any bilateral trading would then be outside the wholesale market and purely financial/paper. This is a very different market arrangement, and would arguably be a step backwards from our current trading arrangements.

[21] For more detail of constraint management reforms see Regen ESNZ Select Committee presentation https://www.regen.co.uk/regen-talks-constraints-with-esnz-select-committee/

A Scotland-Norway interconnector was proposed but has not progressed. There is a question whether Ofgem would/or should approve future interconnectors into parts of the grid that are already constrained unless these are included in the new Central Strategic Network Plan and properly analysed for their grid and system impact. Better strategic planning of interconnectors would be one obvious way to reduce future constraint costs.

Aside of better planning there are a number of interconnector reforms that should be considered, as per the breakout box below. Given the potential of these reforms, we do not think that a zonal LMP market would be necessary. This view is shared by interconnector operators that we have spoken with.

1.19 Interconnectors – there are better more immediate options

There was agreement across the panel that the issue of interconnectors needs to be addressed. The committee should ask the government to look at the operation of interconnectors with some urgency.

Interconnectors are not operating as efficiently as they should, partly because of the '**decoupling**' of GB and EU markets since Brexit.

The first step would be to work towards a '**recoupling**' of interconnectors across markets, but this needs to be done in a way that **supports the GB market, and allows system operators on both sides to better utilise the inherent flexibility** of HVDC interconnectors.

This could mean, for example,

- **Better alignment** of interconnector trading with GB day ahead and intraday balance trading – at the moment we can get contra-price signals.
- **Enabling the SO** to affect flows by countertrading and/or potentially managing forward capacity limits.
- Finding better ways to **allow interconnectors to participate in balancing and flexibility** markets
- Considering the cross-regional aspects of interconnector operation and markets.

We also need to ensure that we are better at strategically planning the rollout and location of interconnectors. They need to be part of any future **Central Strategic Network Plan**, so we don't build interconnectors without considering their wider grid and energy system impacts.

This is an area where we definitely need to be working with European partners such as Norway, Ireland, France etc., in addition to the need for a joined up strategy and aligned market arrangements to be part of the **European Offshore Network Development Planning** initiative.

Zonal market solutions may be considered by this review, such a radical change may not be required if we first implement other reform options. As one industry expert has commented interconnectors should be "**part of the flexible grid solution, not the problem.**"

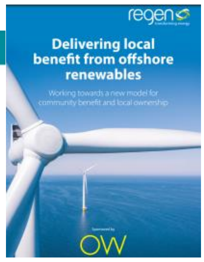
A good contact for the committee would be John Geasley who supports the interconnector industry forum. John@interconnectables.com

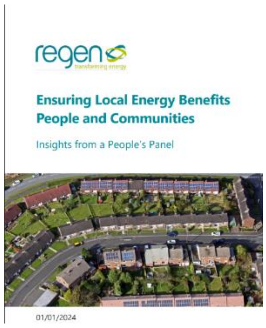
1.20 Q352 Community benefits, local ownership, levelling up, energy hubs and local supply

At several points during the enquiry session, members asked about the benefits of local energy and how energy can benefit local communities.

This is a very interesting and important topic and an area in which Regen has done a significant amount of work. I won't go into detail here, as it is a different area of scope. LMP is sometimes confusingly presented as a means to achieve local energy benefits and levelling-up. I think this is misleading because LMP is rather agnostic to the locality or merits of a consumer group, it is really about the optimisation of energy flows given network capacity, which, as I said to the committee, is driven by the happenstance of network constraints.

If the committee does wish to consider local energy supply options and the use of energy to support levelling up, local ownership or community benefit schemes then we would be happy to attend a future session, or the committee could review some of our recent publications:





The summary is that there are lots of options to supply energy to targeted communities and energy clusters including models based on local supply models, energy clubs, local generation tariffs, sleeved PPAs etc. These are not easy models to implement and the ability to supply energy locally at a discounted price has been an aspiration of the energy community for some time. Some of the challenges relate to regulations, while others are due to the way in which network charges are levied. This has led some schemes to opt for a private wire or independent network arrangement which may not be economically optimal in a whole-system sense. This is definitely an area for future reform and innovation and we would welcome the committee's interest in this area.

1.21 Q339 What's tried and what's tested?

Several times during the committee meeting we heard that LMP has been "tried and tested" in other countries, and that the alternative routes to flexibility have been untested. Given time I would have liked to challenge these assertions directly.

LMP has been implemented in a number of energy markets in the US and elsewhere, and there are older zonal markets in Europe such as Norway. However, as academics such as Keith Bell and Callum MacIver at Strathclyde, have noted, every country context is different. No market has implemented LMP while in the middle of an energy transition and with the level and diversity of renewable energy now seen in the UK. Markets that have shifted to LMP have done so from a zonal or central pool arrangement – as we had in the period between privatisation and the NETA and BETTA reforms in 2001 and 2004 – not from the complex and sophisticated trading market we have today with many more market participants. LMP is also, generally, not implemented for the purpose of exposing consumers to price volatility or recruiting flexibility or enacting a value transfer between producers and consumers. Whether LMP would be effective in harnessing consumer flexibility in a GB context is unproven. Over two years, we have barely moved on from a discussion, which you heard, about whether it would be a good idea to expose consumers to an LMP price signal or shield them from its effects. From experience, this rabbit hole is where we usually end up on this subject.

By contrast, we are now seeing some very exciting and innovative developments in the area of demand-side flexibility, and the use of flexibility more generally. A big debate, which will probably not be fully resolved until we experience life in a net zero energy system, is the degree to which we expose all consumers to flexibility price signals via the wholesale price – sometimes called implicit flexibility – and the degree to which we choose to harness or recruit consumer flexibility with targeted and explicit flexibility services. Examples of the latter, which I believe the committee has already heard evidence on, include; flexibility procured by distribution networks which have been around for several years, the ESO's Demand Flexibility Service which has been very successful, and new Local Constraint Markets such as the current ESO trial with Piclo. It is true that these products are new and innovative but they are not 'untested', and will be available far more quickly that a uncertain rollout of LMP.

The advantage of implicit flexibility delivered via the wholesale price is that it applies to all demand, even if energy suppliers choose to offer tariffs that shield their consumers from its volatility. We think this makes sense when applied to the overall energy system balance on the basis that we are all in this energy system together, we are all contributing to net zero investment and subsidies. We may need to protect vulnerable and disadvantaged customers and we would hope and expect that energy suppliers would then offer a range of tariffs whereby consumers can choose to what degree they actively participate. We also expect that suppliers will themselves hedge against this volatility in forward markets and by buying energy on long-term contracts.

1.22 Should generators be compensated for network constrained lost revenue ?

Several comments were made to the effect that generators should not be compensated for lost revenue due to network constraints or that they were being paid "for doing nothing".

Regen gave a presentation to the committee on the 17th of January which provides some useful background on the subject of constraint management.

The committee could recommend a legal change to generation licence conditions so that they would no longer be paid for network constrained generation. This change would not require LMP, but it would have far-reaching implications.

There are some points that the committee would need to consider:

a) Not all generators are paid for network constraints – some have accepted a 'non-firm' connection[22] agreement but this tends to be the exception, is normally temporary and is not common for large generation projects.

[22] Regen has completed a study where generators did accept a temporary 'non-firm' connection as part of the Dunbar Active Network Management scheme. This study also discusses the use and advantages of non-firm connections.

b) Almost all large projects, which take years to build (wind, nuclear etc), will have secured a firm connection agreement with their network provider very early in the project timeline. At the moment, the wait to get a connection can be 7 or 10 years, or even longer. Most developers will not even begin the development process – e.g. consenting and engineering design for offshore wind – without that connection agreement in place. It is not possible to apply for a CfD without a grid connection agreement. It is one of the first priorities (along with a land/seabed lease) and they would certainly not be able to raise development finance without a firm connection.

c) In theory, the connection lead time allows the networks time to build the necessary network capacity to support generation. However, in the recent past, network capacity has been delayed, partly because of unexpected delays in network build and partly because the networks and Ofgem have taken a conscious decision, backed by a cost-benefit analysis, to delay build and accept some level of constraint.

d) There has now been a shift in the approach of Ofgem and the networks towards more strategic and coordinated investment, and also to bring in greater incentives for network build to be delivered on time. This is reflected in the new Accelerated Strategic Transmission Investment (ASTI) framework. In part this shift in thinking has been prompted by the rise in network costs as a result of the steep increase in gas prices.

e) The claim that generators get paid "for nothing" ignores the commercial and legal position that generators will have paid for their network connection offer and to retain this as an option, they may also have contributed significantly towards the up-front cost of network upgrades (especially if they have connected to the distribution networks). They will also be paying very high network charges.

f) It should be noted that generators are not allowed to claim compensation (which they do via bids into the Balancing Mechanism) for any more than their lost marginal revenue. This is strictly enforced and has led to a number of fines. See [Transmission Constraints Licence Conditions.]

g) It should also be noted that the largest portion of constraint costs is not the payment to generators to turn down, but is in fact the payments made to generators (normally CCGT) to turn up to replace the constrained generation.

h) There has been some evidence of gaming of the Balancing Mechanism – both by generators who have been turned down and turned up. We referenced these in our presentation on the 17th. The committee could ask Ofgem and the ESO for an assessment and action plan to address these.

If, as a result of a change to constraint payments, or the introduction of LMP, generation developers would lose any guarantee that a connection will be available or constraint compensation if it is not, that would be a very major change in the allocation of constraint risk. If the constraint risk was minimal and could be accurately forecasted, it is possible that generators could hedge this through a higher CfD strike price, or through a RAB-type revenue support model.

However, since we are going through a rapid energy transition with many moving parts, predicting constraints will be very difficult, especially since the key organisation with agency over whether there are constraints will be the NESO, Ofgem and the networks. Therefore, on the principle that risk is best placed with those who can manage it, it seems likely that some form of constraint compensation would still be needed and would be the most economically efficient approach.

The good news however is that, under a progressive reform agenda there are lots of ways in which constraint costs can be reduced.

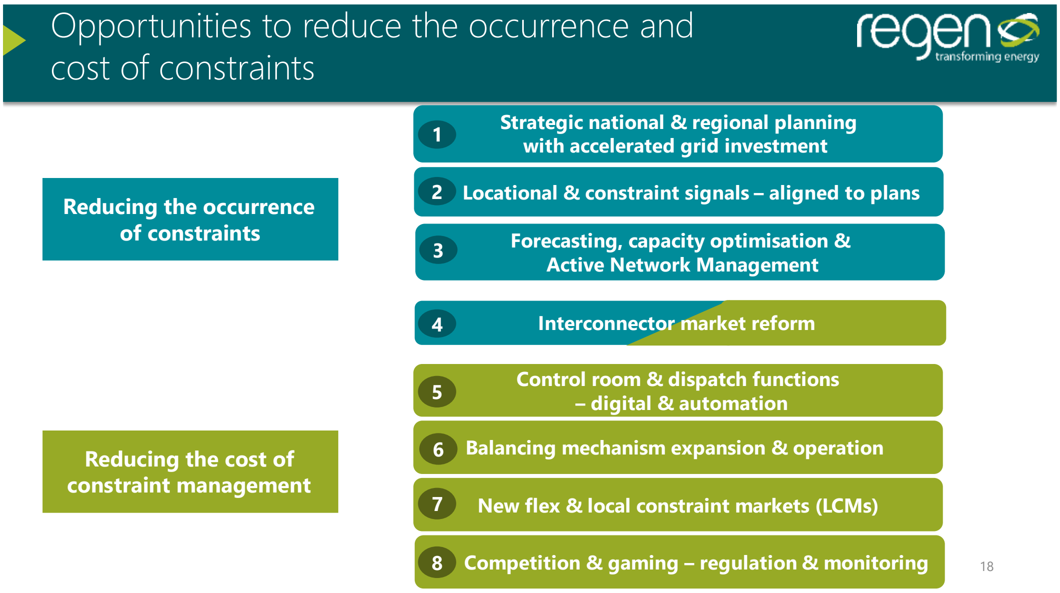


Figure 3 Opportunities to reduce constraints costs – part of presentation given to the select committee on 17th January 2024

2 Core objectives of market reform

The first REMA consultation published in Autumn 2022[23], considered a very wide range of potential market reform options to achieve a number of reform objectives. As the options under consideration have been reduced through the consultation process, the objectives and case for change has also become more clear.

The objectives for REMA have now been distilled down by DESNZ into four main areas that were presented to the REMA forums and stakeholder groups. These four areas, which are expected to form the basis of the second REMA consultation to be published in early 2024, are outlined in Figure 4.

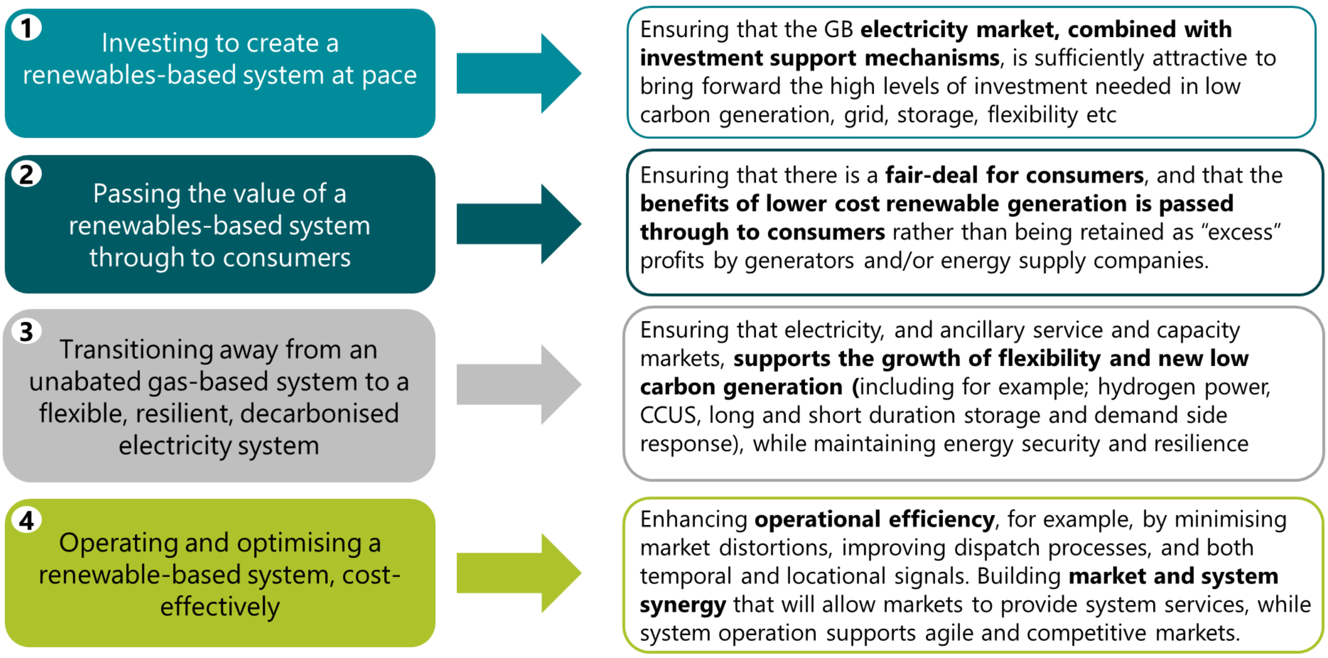


Figure 4 Expected high level REMA objectives for the second consultation. Source: Regen analysis based on presentations by, and discussions with, DESNZ.

[23] DESNZ REMA First Consultation October 2022

3 What is Locational Marginal Pricing (LMP)?

An LMP-based design would radically change the basis of GB electricity market arrangements and would require a significant programme of detailed design, system development and implementation which would potentially last seven to ten years[24] and would have far reaching impacts (and costs) across the entire energy system. LMP would come with a large and complex investment in IT systems, data and dispatch tools, as well as significant changes (and cost) for market participants.

LMP is sometimes misrepresented as 'recognising the value of local energy' or 'representing a true local market price', or 'being cost reflective of energy costs at a locality'. This may sound like it supports more energy localism but LMP is not a route to local energy, local energy supply or local markets.

LMP is actually a return to a mandated central market, centralised dispatch and an algorithm which then calculates the marginal price at each location or node, driven primarily[25] by the occurrence of network constraints. It would be more accurately described as congestion based marginal pricing. In basic terms, a shift to an LMP-based system would feature:

- A mandated electricity market where the market price for consumers and generators at each location (node or zone) is set at the marginal cost of meeting the next unit of demand at that location.
- Price differentials between nodes, nodal hubs or zones that are largely driven by the level of transmission[26] constraint that is present plus other locational costs such as losses. A completely unconstrained system (assuming no losses) would in theory have equal prices at every node.
- Market/grid access that is non-firm, meaning a market participant only has a right to access the market and dispatch when instructed to do so by the market operator. No constraint payments are made.
- Market operation and dispatch that is centralised and is managed by an independent market operator – most probably the ESO. Dispatch decision making is automated using an incremental linear optimisation algorithm that optimises market prices (potentially at five minute intervals) while adhering to network constraints. Note: a degree of self-dispatch may be maintained for generators who are prepared to bid as price takers and this could be a significant proportion of distributed generation.

[24] A benchmark has been given of 5 years from the time that a go/no go decision is taken, which would equate to a seven-year lead time. Other industry stakeholders have however suggested a longer period given the complexity of the current GB market trading arrangements and that the implementation would be against a backdrop of the net zero transition. Establishment of the financial arrangements and systems to support billions of pounds of Financial Transmission Rights would, for example, take years to design and implement.

[25] Other cost factors are included – e.g. losses – but the marginal aspect – i.e. the element that really drives volatility and differences between network nodes, nodal hubs or zones – is the occurrence of network congestion.

[26] In theory LMP nodes could be defined at lower voltage levels to take into consideration Distribution Network constraints, in practice however nodes are normally at transmission GSP level which, for the GB system, would imply around 350 nodes. Some LMP markets feature Nodal Hubs (a group of nodes within an uncongested part of the network) to facilitate trading and liquidity.

- Congestion rents, collected by the System Operator, which accrue because of the difference between the (higher) marginal price paid by consumers at a congested location and the (lower) price paid to generators who are selling electricity into that location.
- Financial Transmission Rights (FTRs), (sometimes called Congestion Revenue Rights) which are financial instruments that allow some (limited) degree of revenue hedging by market participants and traders. FTRs are usually funded as a share of congestion rents and can be sold at auction or awarded to generators to offset revenue losses. The effectiveness of FTRs to fully hedge constraints has been challenged as they are often expensive, lack liquidity and are generally time-limited to a year or less.

Appendix: Suggested further reading for the committee

Table 1 Selected literature review on the subject of LMP

FTI's final modelling report produced for Ofgem, which highlights the potential benefits of LMP in a number of modelled scenarios	Link
Ofgem's Assessment of LMP based on the FTI modelling analysis and other academic review input, which concludes that LMP could provide consumer benefits against a 'do nothing' scenario, but that a more proactive counter factual is needed.	Link
Cambridge University – Michael Pollitt - Comments on the FTI Report on the assessment of locational wholesale electricity market design options in GB August 2023 which concludes that the benefits claimed have been over optimistic Cambridge University – Michael Pollitt Locational Marginal Prices (LMPs) for Electricity in Europe? The Untold Story	Link Link
University of Strathclyde - Keith Bell and Callum MacIver - Review of the report for Ofgem by FTI on the assessment of locational wholesale electricity market design options in GB. Highlights investment risk and overstated benefits	Link
Strathclyde University Exploring market change in the GB electricity system: the potential impact of Locational Marginal Pricing Simon Gill, Callum MacIver and Keith Bell. Highlights investment risk	Link
AFRY study finds a move to locational pricing in UK electricity market would be high risk for little reward AFRY Review of electricity market design in Great Britain	Link Link
Frontier Economics assessment of the benefits of LMP – which gives a much lower assessment of LMP benefits against higher levels of risk	Link
Cornwall Insight – Industry Survey "LMP is not the answer"	Link
Regen's review of the impact of LMP in the Texas (ERCOT) market, which concludes that the growth of wind in West Texas was achieved through strategic network investment not LMP locational signals	Link
Constraint Management – regen presentation to ESNZ select committee	Link
Constraint Management – Dr Simon Gill – Energy Landscape, for Scottish renewables	Link
Regen letter to REMA team	Link