Markets Forum – ESO responses to Menti questions

Enabling Britain's Clean Energy Future: Markets Forum FAQ's

Net Zero Market Reform

Q1. Will consumers in the north i.e., Scotland be charged more under your proposed nodal pricing? What is the Scottish Government's view assuming that they have engaged with this process?

A. Under nodal pricing, areas where supply is greater than demand would in the long run tend to have lower nodal prices. Given Scotland's substantial wind resource and relatively low demand, nodal wholesale prices in Scotland would likely be substantially lower compared to other parts of the UK. It is then a question for policymakers as to whether or to what extent consumers would be exposed to these nodal prices.

Q2. The benefits you outline depend on "accurate" price signals for demand. Isn't the extent to which these signals are passed on to consumers integral to the proposal rather than just a "design choice"?

A. Even with consumers partly or not exposed to nodal prices, nodal pricing could still generate significant benefits due to improved dispatch, reduced congestion, and improved asset siting, among others. We agree, however, that the full benefits of nodal pricing materialise when consumers are exposed to nodal prices. Should policymakers wish to manage distributional impacts, there are various options for doing this as outlined in the presentation.

Q3. If consumers can participate in the market and access the £££s for flexibility in their location, why should they not also face the counterfactual £££s costs that arises from their location?

A. The extent of consumers' exposure to nodal prices, immediately following implementation and over time as the market matures, would be decided by policymakers. It would also be necessary to consider the cost-reflectivity of other price signals that consumers are exposed to or not, and the coherence of the price signal package.

Q4. The energy market is already complex enough for the average consumer. Is moving to nodal pricing signals adding another layer of complexity and how can it be sold as a benefit to the bill payer

A. Over time, nodal pricing could significantly reduce total system costs and the benefits should flow through to consumers' bills, though we acknowledge there may be distributional impacts that would need to be carefully managed. Average consumers would not be directly exposed to nodal prices; it is suppliers that are directly exposed. Suppliers could pass through the price signals to consumers in the form of smart tariffs or service-based contracts, reflecting consumers' preferences and service requirements in terms of the flexibility that can be provided, the simplicity or complexity of tariff they are comfortable to adopt, and the degree of asset management/control they are willing to entrust to the supplier or third party.

Q5. If distribution and consumers are not part of LMP then what is the point?

A. In the first instance, nodal pricing would be applied down to a voltage level that is practical in terms of ensuring, for example, sufficient liquidity, minimising the risk of abuse of market power. Below a node, resources would be exposed to the same energy price but locational price signals in operational timeframes within the nodal market could come from forward looking distribution network charges (DUoS) or market signals produced by local energy markets. In time, however, nodal pricing could be applied to lower voltages as the energy market matures, particularly with growth in distributed energy resources, and with improvements at the distribution level in relation to network monitoring, digitalisation and availability of data and ICT.

Q6. How do you politically expect the role of Scotland to change on the back of today? E.g., Scottish consumers access to cheap energy due to LMP, but Scottish generators becoming less commercially viable.

A. Nodal pricing would give rise to distributional impacts for both producers and consumers. However, there are various options to manage these over a transitional period, enabling market participants to adapt with time and as the market matures.

Q7. Simply put: will this make Scottish Generators commercially unviable?

A. The efficient dispatch and investment signals provided by nodal pricing would better align investor decisions with the optimal geographical distribution of generation and demand throughout the country, considering the aggregate costs of generation, network infrastructure and congestion. Nodal pricing would impact the business case for energy resources across the geography of the GB market, including Scottish generators. The need for investment in low carbon resources for Net Zero is immense, and to date driven by low carbon support policy, particularly CfDs. Existing CfD generators are likely to be protected. Looking forward, low carbon support policy will continue to play a critical role in driving investment and how this evolves is a major part of the focus of our next phase of assessment.

Q8. What will happen to TNUoS when moving to LMP?

LMP with current network charging would double-count locational signal. Does ESO have a vision of new network charging world, e.g., postal stamp?

A. We cannot at this stage definitively state how network charging might be reformed to coordinate with a GB nodal wholesale market, as this would have to be agreed in consultation with industry stakeholders. However, in moving locational signals into the wholesale price, we would not expect transmission charging locational differentials to be required to provide long-run locational signals. Transmission charging may therefore logically become a cost-recovery mechanism only, with equal charges across all locations. Whether these should be charged on a commodity (MWh) AKA "postage stamp" or capacity (MW) basis would be decided in consultation with industry. Other jurisdictions with nodal pricing have varying transmission cost allocation methodologies broadly recovered based on usage and load access.

Q9. Does a country with so much offshore wind whose location is defined by seabed lease need locational pricing?

A. For GB to meet its net zero targets will require expansion of flexible assets, firm baseload such as BECCS, CCUS and nuclear in addition to non-dispatchable resources such as wind and solar. Locational marginal pricing would provide both effective long-run signals for where assets can optimally site and accurate short run signals for flexible and demand side assets to optimise against.

Q10. Does anyone believe that TNUoS has ever been an effective locational signal? If not, then why would LMP be any different?

A. Our Phase 3 analysis found that, as an ex-ante capacity-based charge, TNUoS is incapable of resolving the issue of inefficient near real time dispatch. By incorporating locational signals into the wholesale price, LMP can provide effective short and long run signals.

Q11. Is more investment in transmission an option rather that ripping up current market arrangements and introducing nodal pricing?

Why not increase transmission capacity and solve restrictions, instead of fundamentally changing the market?

Agree with Cathy that this seems to be a problem of the failure of connect and manage. Is a much better first step here in reality to increase the t build quickly?

One of the clear Net Zero challenges-efficient transmission investment to ensure generation as located can unabatedly support demand; how do you achieve nodal-clear transmission investment signals?

Would we be having a debate about LMP today if Ofgem had taken a forward-looking view on transmission network upgrades?

Constraint costs are not a result of market failure - simply a case of transmission build not following the renewables build - is it reasonable to depict constraint costs as an unjustified transfer

A. Investment in the electricity transmission network is fundamental to GB meeting net zero. ESO's Network Options Assessment process already determines the optimal network reinforcements, considering constraint costs projections. However, not all upgrades proposed by the ETOs are determined to be optimal, as their cost would exceed the cost of constraints that they would eliminate. Last year's NOA assessment suggested that, even accounting for optimal planned transmission upgrades, constraint costs are likely to rise steeply to 2032 and continue to cost c. £1bn - £2bn pa thereafter. Therefore, nodal pricing that addresses the issue of inefficient dispatch is required in conjunction with expanded transmission build to optimise overall costs.

Q12. Would it not be easier if grid simply stopped accepting grid connections for so much wind behind constraints and not doing the reinforcements

A. Please see answer above for info on ESO's approach to transmission build. It is also important to note that constraints on the transmission network are not always binding, so rejecting a connection application on the basis that it can sometimes cause constraints would in most cases not be an efficient solution.

Q13. Connect & Manage created exponential wind growth Scotland and constraint costs were due to be close to zero today but are currently c.£500m/y. What went wrong & will the Q4.22 Locational Mkt help this?

A. Nodal pricing can mitigate constraint costs by ensuring that the most efficient generation is dispatched to meet demand, accounting for network constraints, and by facilitating more effective, locationally accurate demand response where there is congestion. It is important to note that increased transmission build will also be key to reducing congestion costs alongside more efficient near real time locational signals.

Q14. LMP moves the constraint costs, doesn't eliminate them. Network investment is needed to get more low carbon power to consumers. Does LMP reduce spillage of renewable power?

A. Nodal pricing would reduce constraint costs by removing the need for constrained-off payments and ensuring that the most efficient generation is dispatched for each settlement period, accounting for network constraints. We are confident the Ofgem technical assessment will support our finding that nodal pricing can offer substantial cost reduction in a GB context. The need for an efficient dynamic locational signal in wholesale markets is in addition to the need for new transmission build. We believe nodal pricing could effectively mitigate renewables curtailment by providing strong incentives for flexible assets, correctly located, to consume when there is surplus generation

Q15. LMP benefits for investment in net zero technologies are not fully investigated, but we still think LMP is a good idea? Why?

Merchant investment in renewables looks very challenging under nodal pricing. Flexibility participants still rely on investment in large assets to have something to play with.

A. The current market design, with inefficient locational network signals, is leading to increased cost and operational challenges which are likely to worsen as GB accelerates its low carbon generation build out. We have not seen evidence that nodal pricing has an adverse impact on investment in low carbon technologies and believe that it would bring clear benefits for demand side flexibility, dispatch efficiency and asset siting among other things that are all important aspects of achieving an affordable energy system transition. While nodal pricing provides investment signals, there are many other factors that investors consider such as low carbon subsidies.

Q16. Have you assessed the increased cost of capital required to compensate for the additional price risk in Ercot etc? This will be significant in the absence of a long-term hedge for the life of project.

A. In the jurisdictions with nodal pricing we considered, we found that investor confidence and risk exposure is managed through a variety of mechanisms (such as financial transmission rights) that could be usefully deployed in a GB context to lower the cost of capital. When considering the net impact of nodal pricing it is important to note that no hedge exists for the locational risk in the current market design in the form of volatile TNUoS tariffs, which are also subject to significant ongoing regulatory risk. Our assessment of nodal pricing in a broader context continues, with focus on investment.

Q17. How would the real time nodal pricing give developers the long-term data to build their business models?

A. A core concept of nodal pricing is that market-led locational investment decisions will be based on relatively persistent and predictable differences between average nodal prices over time.

Q18. LMP is based solving short-run marginal cost issues. Whereas investors in renewables assets look to invest on a long-run marginal cost basis. How would LMP incorporate the need for long-term signals?

As Cathy says investment costs are key. Would future investment signals akin to the CfD undermine the "benefits" of LMP. How would long-term certainty be provided in a short-run marginal cost market?

A. We consider that the market design must be optimised to help participants manage risk rather than uncertainty per se. Our analysis of jurisdictions with nodal pricing found that hedging tools such as Financial Transmission Rights are successfully used to help market participants manage risk and that these would be an improvement on the long-term signals currently provided in the GB market via network charges which are subject to continuous regulatory risk where the outcomes can be vulnerable to lobbying by vested interests.

Q19. Have investors been consulted about LMP as part of this process? They are the true audience for this, without their confidence we won't see the capital to invest.

A. Throughout the project we've proactively engaged with a wide range of different stakeholder groups and feel we have had good representation from across the industry including developers, asset owners, suppliers, consumers and many more. In total we've engaged with over 1000 stakeholders across our engagement events which have included bilateral meetings, webinars, and workshops.

Investors, which include financial institutions and developers, are a critical group of stakeholders for net zero market reform and investor confidence is one of the key criteria we have assessed as part of our Phase 3 work. We will publish this detailed assessment with our publication in April. In terms of investor-specific engagement we presented and answered questions in a panel at Cornwall's Net Zero Financing Forum in January. We also have investor representation on our recently formed Markets Advisory Council.

Q20. How much transmission build can be avoided under LMP?

A. Alongside the implementation of nodal pricing, continued transmission network reinforcements will be crucial for the future net zero electricity system as we see greater renewables penetration and significant increases in demand with electrification. A nodal market incentivises supply to be built closer to demand and vice-versa, which would lead to reduced transmission build compared to a national market. We expect a full cost benefit analysis for the implementation of nodal pricing in GB, including transmission build savings, to be included in Ofgem's forthcoming technical assessment on locational options.

Q21. Will the change to nodal pricing create any foreseen challenges with the trade-off between generation being located close to demand centres versus being located where there is land available?

A. As is currently the case with TNUoS, nodal pricing would be one influencing factor in investor's decisions around where to site an asset alongside many other market signals and practical requirements.

Q22. How will companies be able to hedge locational prices, and will this undermine the benefits you hope it to deliver?

A. Markets with nodal pricing hedge locational prices through tools called Financial Transmission Rights. We consider that these could be successfully deployed in a GB context and would give market participants more control over locational risk than is currently the case with TNUoS.

Q23. What would be the role of DSOs in forming nodal prices and in central dispatch?

A. The introduction of a nodal market can be expected to provide more accurate signals for DSO/DNO to optimise their network and efficiently procure flexible services. DNO/DSO currently do not have upfront visibility of the market conditions that impact their local networks and therefore are often not in a position to optimise their network fully.

Q24. What about conflicting locational signals in the market. Wind is blowing in Scotland, low price in Scotland. Thoughts on how we get to net zero.

A. The overarching objective of net zero market reform is to achieve net zero at the lowest possible cost for consumers. Wind capacity investments already involve an economic trade-off between capturing higher load factors in some locations and benefiting from lower TNUoS charges in southern areas, which reflect the lower cost that these projects impose on the transmission system. Under a nodal market, that same trade-off decision may still exist, except that the locational signal within the wholesale price will more accurately reflect the wider system impact.

Q25. How will the move to nodal pricing affect competition for and strike prices of CfDs?

A. One of our next steps is to consider the complimentary market reforms for nodal pricing and self-dispatch. One element we will be consider in due course is the degree of low carbon central planning which could work alongside the suggested operational reforms. Nodal pricing should help provide much clearer signals for low carbon investment and we would expect any competition for CfDs to reflect the true locational costs.

Q26. Is the regulatory risk of re-zoning in a zonal system any worse than the price risk in a nodal system? How do investors hedge locational risk?

A. The price risk in a nodal system has been shown to be manageable via financial transmission rights and other hedging instruments. We consider these instruments to provide qualitatively improved certainty and forecast ability for market participants compared against the regulatory risk of a rezoning process.

Q27. Would LMP be against Net Zero? Places with high renewable will have lower prices and lower incentives for generators to run. Places with high demand might see an increase of diesel generation.

Nodal pricing. Distraction from fixing huge intermittency challenge associated with Net Zero.

A. Implementation of nodal pricing with central dispatch creates an enduring foundation upon which to build a holistic market design for net zero. Without these in place the wholesale market price is missing a key component: near real-time, dynamic, locational signals. This missing component will lead to both generation and demand side assets responding to inaccurate price signals, resulting in inefficient dispatch and an accelerating rise in costs; all of which will impede decarbonisation. Getting these signals right is a critical first step before for then determining residual intervention requirements addressed in the investment market design elements which will drive an efficient capacity mix to get us to net zero

Q28. BETTA merged GB markets but wasn't BETTER. Would market splitting alleviate the £500m/y constraints and provide better investment signals in the interest of consumers?

A. Our analysis found that market splitting (zonal markets) could temporarily alleviate some constraints and provide improved market signals from the status quo; however, intra zonal congestion costs would remain, and as generation evolves and new transmission comes online, it is inevitable that rezoning would be required to retain these new efficiencies. This would open up the market to continued regulatory risk and its associated costs.

Q29. Is there a risk that we are shaping a very large market to address issues that benefit a small portion of the market - is this a flex providers vs NG ESO BM issue?

A. We do not believe this only benefits a small part of the market. On the contrary, we set out in our slides there are benefits across the whole market. Instead, we believe nodal pricing with central dispatch will deliver significant benefits to consumers, via more efficient dispatch and reduced balancing costs, correct signals to interconnectors and storage, and the accurate dispatch and signals needed to realise demand side value. These benefits are only going to increase as we move to a world with more renewable energy and decentralised users.

Q30. There was no mention of any assessment on impact/cost of transition to nodal pricing. What cost impact do you expect from transition, including possible compensation and who should pay?

Has anyone considered implementation costs for participants?

A. A full cost benefit analysis for the implementation of nodal pricing in a GB context, including the cost impact for market participants, will form part of Ofgem's forthcoming technical assessment. Our analysis shows that a nodal pricing market with central dispatch could deliver significant net consumer benefits, with evidence from other jurisdictions that have implemented nodal pricing suggesting that the cost of implementation is typically an order of magnitude lower than the benefits.

There have been some studies in Ontario and Texas looking at implementation costs for participants of moving to nodal pricing. These indicate that market participants without experience of nodal markets took on greater cost at nodal implementation versus participants with experience of trading in nodal markets, as could be expected. Ensuring any transition to nodal pricing would mitigate implementation cost and complexity for participants would be a key priority for policymakers.

Q31. How far does the 4–8-year implementation period take us beyond the peak in constraint costs this decade? Do the economics still stack up once those costs fall back at the end of the decade?

A. This question will be considered in detail by Ofgem in their technical assessment of LMP. We are confident that nodal pricing can be an enduring foundation for GB's net zero market design and that it could help realise substantial benefits in reduced constraint costs in the late 2020s, (i.e., even when major transmission projects between Scotland and England have been completed). We agree, however, that implementing nodal pricing as quickly as possible would help realise even greater benefits in the mid-2020s.

Q32. In US markets, a full nodal market is provided to market participants to predict/forecast LMP. This is complex, how will this not be a hurdle for new entrant's vs status quo?

A. Ensuring that market participants have the necessary data and information during a transition phase to be able to model nodal prices would be key. In other markets this has been facilitated by publishing 'shadow' nodal prices before full implementation for participants to view and begin to model. We additionally consider that nodal pricing with central dispatch can help create a level playing field for new entrants since key market data is published and participants can trade with a central counterparty rather than needing to establish a bilateral contract.

Q33. How deep should nodal pricing go? Into the distribution network?

A. How granular a GB nodal market should be (or how many nodes would exist) is a design implementation choice that would need to be made. As part of our work, we have not conducted a full cost benefit analysis for the implementation of nodal pricing in GB and therefore would not be able to comment on the most optimal design. We would expect this to form part of Ofgem's technical assessment.

Q34. Would LMP extend to non- MW aspects- buy the MW with the flexibility, the stability, the voltage support etc?

One of the key benefits attributed to LMP in US is that the algorithms co-optimise energy, reserves, and ancillary services simultaneously at the node. Are the ESO looking at such a large redesign?

A. The ability to co-optimise energy, reserve and ancillary services is one of the key benefits of central dispatch identified in our analysis. However, the extent to which the dispatch algorithm co-optimises with non-MW aspects is a design choice which will have to be considered further, along with the wider impacts on ancillary services procurement.

Q35. How does the move to nodal pricing interact with the development of services we heard about this morning?

A. The Markets Roadmap presentation specifically focused on services owned and operated by the ESO. The net zero market reform work is a broader, more holistic look at all energy markets, so considers wider market reform than the framework discussed in the morning.

Q36. You mention LMP would form part of a broader set of holistic market reforms. Is this something the ESO is anticipating overseeing or is that something you believe others will look at?

A. We will be continuing our assessment of complementary wider market reforms, including the appropriate extent of central planning to secure investment for low-carbon, capacity adequacy and flexibility and how this is best achieved in a world of nodal pricing and central dispatch. Subscribe to our mailing list on our website to get regular updates on our progress.

Q37. How many nodes (versus zones) is assumed in conducting the assessment between the models? And can you say more about what "self-commitment" means in the context of Central Dispatch?

A. ESO's Phase 3 qualitative assessment did not require an assumption on the number of nodes that would exist in a GB nodal market. This is something that will be considered as part of Ofgem's technical assessment of nodal pricing.

Q38. "generators have a locational signal" - interconnectors don't - is an easy first step to give interconnectors a locational signal?

A. Nodal pricing would significantly improve locational price signals in operational timescales for both generation and interconnectors. For interconnectors, nodal prices - which would vary every half hour under current settlement timeframes - would ensure more efficient import and export flows.

Q39. How do you react to this market signal once your asset is built? Or is it fixed once you are built?

A. Under nodal pricing, areas where supply is greater than demand would in the long run tend to have lower nodal prices. But the nodal price would also provide a near real time signal that reflects both the time and locational value of energy for that node. So, the price signal is accurate both at point of asset build and during its operation.

Q40. What attempts have you made to test if the international experience maps across to GB?

A. Our analysis looked carefully at markets that have high renewables penetration since we felt this to be more analogous to GB over the next decade. We also factored into our assessment where jurisdictions' international experience was interesting but not directly comparable. For example, Ontario provides the most recent case study of moving to nodal pricing but has large amounts of hydro in its generation mix rather than intermittent renewables. Clearly, however, no international experience will map directly to GB and its transition to 2035, hence why the Ofgem technical assessment of LMP will be a key piece of evidence for this topic going forward.

Q41. CfDs only cover 15 years, so what wholesale electricity price should renewable generators factor into the upcoming CfD auction for the tail years beyond the CfD? National or nodal?

A. The conclusions presented are the ESO's view of the Operational market reform required to achieve net zero at lowest cost. As we noted we are not the final decision maker in this process, and any changes to the market design will ultimately need to be decided by Government. Investment decisions are for each organisation to make.

Markets Roadmap (Response & Reserve)

Q1. Markets for services and network charges (especially where location is a factor) are becoming increasingly connected. How does the ESO take that into account when designing, purchasing, and utilising?

A. We recognise that the services that we procure are becoming increasingly interlinked, and we are working to understand these interactions in detail. Designing markets in a way that maximises the synergies between requirements and minimises the conflicts will help us to deliver efficiencies in investment and dispatch alongside value for consumers.

For example, we are exploring the opportunity to launch a day ahead market for stability services, and we know that there are interactions between stability, frequency response and reactive power services. We intend to explore these interactions in more detail and understand if there are benefits to be gained from co-optimisation across these markets.

Finally, the network charging methodologies are governed by Ofgem. We work closely with the regulator to understand how any changes to the methodologies could affect our balancing services markets. This is mostly relevant for our long-term markets which explicitly target new investment.

Q2. Have you spoken with any providers happy to deliver a 30 sec ramp and 2 min minimum run on GR? Sounds a battery specific product and will exclude equipment with moving parts

A. The design of quick reserve is still fluid, and we will be engaging with the industry before parameters are finalised.

Q3. Will ODFM be procured in the summer of 2022?

A. No, we have not identified the need for ODFM in 2022.

Q4. When is the next opportunity for providers to engage on reserve reform?

A. We will be sending out invites for the 'show & listen' sessions shortly, along with a consultation on slow reserve.

Q5. Do you have a view on the timescale now for quick and slow reserve?

A. Yes, but it is dependent on the timescales of other strategic deliverables such as Enduring Auction Capability, as well as timings of bundled releases of new IT functionality. We will ensure that we give the market plenty of notice when we have firmer dates.

Q6. Will ODFM be coming back to cover for the delays?

A. No, ODFM was a last resort tool to cover extremely low demand conditions, it was not created to cover pre- and post-fault energy imbalances.

Q7. All of this sounds great. How will you roll out the new services and unroll the existing without it ending up like a soup of services?

A. There will be transition periods where legacy and new services will be procured at the same for, for example, dynamic FFR and DM/DR. We report our volume requirements and plans for phasing out services in our monthly Market Information Report.

We are working closely across response and reserve to form a cohesive delivery plan; information on this will be shared on our Future of Balancing Services webpage.

Q8. Is it not discriminatory to retire FFR before mandatory?

A. We have reviewed the market for dynamic FFR, and we are directing existing providers to connect to the BM via Wider Access, thus ensuring the mandatory market is accessible to all FFR units. More information can be found here.

Q9. Talk about standardisation of products - ESO slow to game - that does not work if ESO does not also apply standard terms & conditions for ALL - no variations, especially of technical requirements.

A. We are actively working with the Open Networks project to create a standard contract approach for all products across ESO and DNOs. This will be the basis for contracts for the new reserve products.

Q10. When is DA STOR likely to end been procured by NGESO?

A. We will transition the DA STOR market to the new positive slow reserve product once the appropriate systems and processes are in place. We will ensure that existing STOR providers have plenty of notice of this, not only through the A18 consultation process but also through our new regular engagement sessions.

Q11. How will you consider the carbon intensity of the technology providing the frequency or reserve services? In a net zero works do technology neutral approaches still make sense.

A. As the ESO, we must ensure that our markets are fair and competitive. As part of this, we have licence obligations that prohibits us from discriminating against balancing service providers based on their technology type and require us to minimise the cost to consumers of our procurement actions. Whilst we support the drive to net-zero in the energy industry, the prevention of energy wastage in delivering flexibility is a wider policy issue for BEIS and Ofgem.

Q12. You mentioned the new reserve products replacing STOR and fast reserve. Will this also replace the bilateral spinning reserve contracts that are in place?

A. Our goal is to move all products into open and transparent markets, this includes spin gen and spin pump services.

Q13. Adam mentioned the benefits of smaller windows for reserve. Is there any consideration of smaller widows for markets in general, or are we stuck with half hourly steps and ramps long term?

A. There are no plans to move to sub-settlement period availability windows at present. The question of whether settlement periods should be reduced to less than 30 minutes is something that Ofgem are keeping under open review.

Q14. Do you anticipate changes to your Frequency response services & design based in stability market outcomes?

A. We expect to see changes to the response products in the future, based on feedback from industry stakeholders and from ESO colleagues. We might change our volume requirements or even our service design requirements; this is where our agile delivery approach is beneficial enabling us to adapt to changing environments.

We recognise that there are interactions between stability, frequency response and voltage products. We will be exploring the different options for ancillary services markets with interactions and the potential benefits of co-optimisation of requirement setting and procurement across stability, frequency and reactive products throughout 2022/23.

Our market design principles will help us to make sure our market design decisions, whether for adjustments to frequency response markets or other ESO balancing services markets, are achieving our objectives of efficiency in investment and dispatch as well as delivering value for consumers.

Q15. Is spin gen under the same review?

A. We will continue to use spin gen until we have a functioning market to replace it

Q16. Faye, you mentioned that automating DC market clearing was a big step. What were the major challenges and lessons learnt for other products?

A. A key challenge for us in developing DM and DR was time allocation and planning around regulatory deadlines. We had a small window to respond to consultation comments and on reflection we would have appreciated more time to review the content. We are going to be allocating more time to plan and to review feedback for future consultations – both for response and for reserve.

Q17. You note the connection between ramping & market uncertainty and reserve- do you expect ramp rate/ flexibility markets to be developed to reduce the wrong fast behaviours & incentivise the right ones?

A. We are not considering the creation of markets or products to manage ramping at present; however, we are keeping the issue of interconnector ramping arrangements under review via GC0154: Incorporation of interconnector ramping requirements into the Grid Code as per SOGL Article 119.

Q18. Will MFR procurement levels be impacted by the new response products?

A. MFR volumes won't be offset by the new DM and DR products, although we do expect DC/DM/DR to be eventually procured intraday, and that move to real-time procurement would replace MFR. More information on this can be found in the Markets Roadmap.

Q19. Is there a broad outline for when the four new reserve products might be ready to come to market, both in terms of design and go-live?

A. Yes, but it is dependent on the timescales of other strategic deliverables such as Enduring Auction Capability, as well as timings of bundled releases of new IT functionality. We will ensure that we give the market plenty of notice when we have firmer dates.

Q20. For frequency products when will ESO be applying the legal minimum technical requirements for FCR/FRR/RR (as per SOGL articles 154/158/161) to DM/DC/DR products to ensure compliance and competition?

A. National Grid ESO already meets the minimum technical requirements for balancing products. This is managed through the EBR Article 18 process specifically through Article 18.5.f.

If you'd like to discuss your question further, please contact the team and we'd be happy to help.

Q21. Can you comment on the development of response services closer to real time vs. managing constraints?

A. Enhanced network visibility is something that is being explored across a range of areas. Our current priorities are launching the new set of services and refining them with Day 2 requirements. Constraint management will be a consideration of any move closer to real time in combination with all the other factors that are part of service design.

Q22. With more and more granular procurement of frequency response in EFA block slots, what is the ESO doing to enable providers to switch between services like FFR and DC?

A. The legacy dynamic FFR services are procured at month ahead, and this is not in line with our strategy to move procurement closer to real time. We will be phasing out the procurement of dynamic FFR and we are currently working closely with providers with their onboarding and testing activities for the new services. If there is more that we could be doing to support response providers, please get in touch and we will be happy to discuss

Q23. What is ESO proactively doing to ensure small scale flex can compete on an equal basis with traditional large scale flexible assets?

A. There is a lot of work being undertaken to ensure that all providers are treated equitably, from improving systems and processes to engaging with small scale flex providers to understand and address specific barriers.

Q24. Have you got any concerns about overall impact on costs for consumers if there's a move of day-ahead liquidity into STOR and STOR-like products?

A. We are always conscious of the impact of our decisions on costs; however, we do not anticipate a significant shift of liquidity out of the BM into new reserve products. BM parties can already participate in STOR so there should be little impact from introducing positive slow reserve; negative slow reserve is more likely to appeal to renewables which are either embedded and therefore do not participate in the BM or participate in the BM but with high BOAs. In addition to this, the volumes procured in reserve markets are significantly lower than volumes instructed through the BM.

FSO

Q1. How will you retain individuals experience and expertise during the change? Those who don't remember history...

A. The success of the ESO lies in our people, and so it is vital that the journey to a future system operator should consider their needs.

Over the summer, we commissioned an independent agency to conduct a colleague sentiment survey, colleague interviews and workshops. Our people care deeply about the future direction of our organisation, with more than three quarters responding to the survey. Our colleagues have told us that they are strongly motivated to work in an organisation focussed on delivering net zero, and that they want to work in a nimble, flexible organisation unencumbered by unnecessary and inappropriate bureaucracy that can stifle ideas and slow decision making.

At the same time, we know uncertainty can be concerning, with some of our people worried about the potential changes to an unknown future state. To ensure we can retain, nurture, and develop the talent in our organisation, the approach to the transition should minimise uncertainty in both timelines and outcomes, giving timely assurances on organisational model and roles, along with impacts for individuals around issues such as pay, terms and job security.

Q2. How are you going to manage the risk of becoming a single point of failure for net zero delivery when you end up holding so many critical aspects that will facilitate the transition to net zero

A. The future system operator will have a central role, but it will not carry the sole responsibility to deliver net zero and will act in collaboration with the industry.

As the ESO, we already carry out critical roles to facilitate the energy transition. We are confident as a future system operator we would be able to further enhance the delivery of net zero. We will continue to engage with the industry to ensure that we are not becoming a blocker at any point. As part of a successful transition plan, clear accountabilities for activities will need to be identified across industry and this was a key theme of our consultation response in September 2021.

Q3. The FSO capabilities include ones you have rightly identified as needing to grow – equally many of these skills exist within industry already – are you considering technical advisory forums in these?

A. As these roles develop, we will ensure that the industry is engaged in an appropriate way to enable the successful delivery of net zero. For some of these roles this may take the form of technical advisory forums.

Q4. Does the FSO also need to be an ISO as in entirely separated from National Grid

A. Achieving net zero will require those across the energy industry to work in completely new ways. Due to the proposed new and enhanced roles the future system operator may be asked to undertake, we agree it is the right time to consider the appropriate organisational model, with independence being an important factor.

Q5. With your net zero market design work, have you already pushed on with FSO work?

A. As a prudent ESO we are continuing to advance the energy industry within our remit and ensuring that the industry can provide in the future.