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Summary of Phase 4 Net Zero Market Reform Workshops

ESO's Net Zero Market Reform (NZMR) programme hosted two workshops in November 2022:

1) Thursday 24th November with 74 external stakeholders
2) Tuesday 29th November with 70 external stakeholders

The purpose of these workshops was to gather views on Baringa's independent assessment of market design and policy packages; this stakeholder feedback will feed into Baringa's assessment, which in turn will inform ESO's own assessment to be published in 2023.

The recording of Baringa's presentation, the presentation slide pack and pre-read slide pack are available on our NZMR website.

Introduction

ESO launched the Net Zero Market Reform (NZMR) programme in early 2021 to holistically examine the changes to GB electricity market design that would be required to achieve net zero. In May 2022, we published the third phase report, with support from FTI consulting, relating to the elements of market design that address operational issues. The key conclusion was that the absence of dynamic locational signals in the GB market is leading to inefficient outcomes, reflected in rising congestion costs, slow distributed energy resource (DER) uptake, and increased redispatch. We found that, in a context of weather-dependent generation, distributed resources, high battery storage, and interconnector capacity, the combination of locational energy pricing and centralised dispatch presents the optimal route to coordinating an increasingly complex system in operational timescales.

We are now undertaking the fourth phase of the NZMR programme, developing holistic market design and policy packages that combine investment and operational elements to effectively deliver the Review of Electricity Market Arrangement (REMA) objectives. We have commissioned Baringa to conduct an independent assessment of a wide range of market design options; Baringa have then used results from this option assessment to design packages and have assessed these packages against the status quo using our ten assessment criteria that include the REMA objectives.

At ESO's Autumn Markets Forum in September 2022, we tested Baringa's assessment methodology and package design approach with over 100 external stakeholders in deep-dive sessions. At the same event, we also presented our updated case for change with focus on investment. Taking learnings from stakeholder feedback, Baringa then finalised their assessment methodology and completed their first draft of the full assessment. Full detail of the methodology can be found in Baringa's pre-read for the workshops, but the assessment sequencing can be summarised as follows:

1) Assess a long list of market design options against ESO's set of ten assessment criteria as used for the Phase 3 assessment by FTI, but enhanced for the purposes of Phase 4 (i.e. sub-criteria have been developed; tailoring to investment)
2) Combine options to design coherent packages for national, zonal and nodal wholesale market pricing models:
    a. 3 x 'baseline' packages: minimal deviation from status quo to address our case for change and REMA objectives to some extent with swift implementation
    b. 3 x 'build' packages: cohesive set of designs and policies to increase confidence of addressing case for change and achieving REMA objectives
3) Assess packages against the same set of enhanced assessment criteria

The purpose of the November workshops was for Baringa to present their initial package assessment results and to gather views from stakeholders. The 'workshop structure' section of this document, explains the aims and format of these workshops further. The stakeholder feedback gathered at the workshops is then set out in the 'workshop output' section. This is followed by a section on our next steps.

Workshop Structure

Table 1 illustrates what was in and out of scope of stakeholder engagement completed with support from Baringa over the fourth phase of the NZMR programme to date. As set out in the introduction, our engagement with Baringa began with the Markets Forum in September 2022 where we discussed with stakeholders the assessment criteria, approach to building packages and proposed baseline packages (but not build packages). Baringa then completed their initial assessment of market design options and packages, which was followed by the two workshops in November to gather views and opinions from stakeholders. The same workshop was run twice, limited to one representative per organisation, to ensure as many stakeholders as possible could attend.

Table 1 – ESO coordinated stakeholder engagement completed with Baringa support. Regarding Baringa's assessment, the visuals represent what was in scope (✔), out of scope (✘) or in the pre-read (📖) of the respective engagement activity.

Baringa Assessment	Markets Forum (28/09/22)	External Workshop (24/11 & 27/11)	Workshop Feedback Form
Development of assessment sub-criteria	✔	📖	✔
Assessment of market design options	✘	📖	✔
Approach to packages (baseline and build)	✔	✔	✔
Composition of baseline packages	✔	✔	✔
Composition of build packages	✘	✔	✔
Assessment of packages (equal weighting)	✘	✔	✔
Implementation of packages	✘	✘	✘
Weighted assessment criteria for packages	✘	✘	✘

The focus of the external workshops, as illustrated in Table 1, was on approach, composition, and assessment of Baringa's market design packages. Given the limited time available, the implementation and weighted assessment of packages was not included in the workshops but will be included in Baringa's final report.

After each workshop, ESO circulated a feedback form for additional views on all areas of Baringa's assessment, as well as for feedback on the workshop itself. Based on feedback from the first external workshop on 24/11, ESO adjusted the timings in the second workshop (29/11). The Q&A session was reduced, to give more time for the breakout session to allow for more comprehensive discussion. Table 2 shows these adjusted timings.

Table 2 – Agenda for stakeholder workshop on Tuesday 29th November

Item	***Timing***
Introduction and context	13:30-13:40
Baringa presentation: a) Method and approach to package assessment b) Package composition and results from assessment	13:40-14:10
Q&A session: a) Clarification questions on Baringa's assessment b) Questions on technical coherency of packages	14:10-14:35
Breakout: National, zonal **or** nodal package composition a) Discussion in breakout groups b) Playback to plenary	14:35-15:20 *14:35-15:05* *15:05-15:20*
ESO next steps, feedback and close	15:20-15:25

The workshops began with Baringa presenting their assessment and results, followed by a Q&A to clarify the assessment and the technical coherency of the packages. Given the time constraints of the external workshops, it was then only possible to have one breakout session on either national, zonal, or nodal packages. Ahead of the session, stakeholders were able to sign-up to discuss their preferred package in the breakouts; while those who did not sign-up were randomly allocated. The questions discussed were:

1. Have we got the baseline package right – anything you would change and why?
2. Have we got the build package right – anything you would change and why?

Workshop Output

This section summarises the Q&A, the breakout sessions, and any additional feedback received from stakeholders attending the external workshops. All responses have been anonymised and themed where possible. Please note any questions on the theory of the market design options have not been included here, and we would refer stakeholders to BEIS' Review of Electricity Market Arrangements consultation document for more information on the theory of the various options.

Q&A Session

During the workshops Baringa hosted a Q&A session (using Slido) to answer clarification questions on their assessment and on the technical coherency of packages. These have been grouped by theme in the bullets below. These points of clarification were addressed in the workshop and/or have been incorporated into Baringa's final report.

<u>On clarification of assessment details,</u> attendees raised:

- Customer impact needs to be carefully considered in the assessment, given that BEIS highlighted the importance of delivering fair outcomes for consumers in REMA. For example, when financial transmission rights (FTRs) are used in conjunction with more granular locational pricing, it is important that the consumer costs and the reduced locational signals are incorporated into the assessment
- Need to be clear in the assessment on assumptions that have been made about how responsive generation and demand will be to locational signals
- Importance of considering cost of capital impacts associated with the different market design options
- Whether the counterfactual used considers ESO's Holistic Network Design (HND) and/or other improved grid investment (transmission build out)
- That designing policy packages could distract from the need to build transmission capacity, and this is a fundamental concern of the system that needs to be addressed before locational marginal pricing is considered. However, it was also raised that there needs to be a balance of transmission capacity and setting right market signals to ensure efficient and effective net zero delivery
- If possible, explain the rationale behind scoring of packages against sub criteria for transparency and to be challenged, for example why Nodal scores highest on decarbonisation benefits given the potential for investment risk
- Compatibility with EU markets (for example if there are different settlement period lengths) should be considered in the assessment of each market reform option, given interdependencies between neighbouring markets
- On FTRs for hedging, could consider evaluating FTR use in existing locational market pricing markets as basis for scoring
- Whether market liquidity has been factored into the evaluation
- Could be useful to consider planning and consenting timeframes in the investor confidence and implementation scoring
- On market design options, further clarity on:
    - Technologies we are considering as low carbon
    - The rationale behind whether local energy markets are considered in the assessment
    - Why supplier obligation has been ruled out, but decentralised reliability options have not
    - Whether costs of IT system upgrades required for centralised dispatch have been factored into the assessment
    - Terminology used to describe the policy options/packages to avoid confusion
- Whether national, zonal, nodal could be too binary, what about the other reforms that could happen outside the pricing mechanism – these could be more marginal and therefore help with achievability

- Need to make clear what timeframes are related to both baseline and build packages
- Given the biggest decision is likely on wholesale market splitting (need to factor in the different potential designs here) and the pricing model, the rationale in the assessment here needs to be comprehensive – for example, need to justify why split markets are not being taken forward
- On Elective Participation, how similar this is with the green power pool concept
- Need to be clear about difference between baseline and build and the delta between each

On technical coherency of packages, attendees raised:

- Why settlement reform policy options are only implementable with centralised dispatch
- Why the evolution of the contract for difference scheme is not considered as baseline but is considered in build
- That BM reforms appear as part of all the build packages, and the rationale behind this
- Need to be clear on assumptions around interconnectors in nodal/zonal packages, and whether they are operating in energy and/or capacity markets
- Rationale behind why 5-minute settlement is assumed in the nodal baseline package, when it is such a large reform and is applicable to all wholesale market pricing options
- Why nodal pricing is only considered alongside centralised dispatch
- Could be helpful if there was a way of showing dependencies and uncertainty of different options within packages, and whether this could be made clearer in the scoring

On next steps for implementation of packages, attendees raised:

- Important to evaluate the implementation risk around the different packages and what this means for the 2035 decarbonisation target
- Would be useful to have a graphic that shows in each package when the transition from self-dispatch to centralised dispatch occurs
- Whether the assessed benefits of locational marginal pricing (LMP) is contingent on being able to implement quickly; need to consider once investment picture has improved how this impacts the case for LMP – could the benefit case be weaker in the late 2020s?

On other potential next steps, attendees raised:

- Given this is strictly a qualitative assessment, and therefore subject to bias, whether there will be any further analysis to quantify the study including an impact assessment of locational marginal pricing on generation investments and investor confidence
- Weighting of packages, and whether we will move away from weighting all packages equally to certain criteria having greater weighting

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Questions were also raised regarding the NZMR programme that ESO have answered in Appendix 1. Finally, any questions in relation to the new options being considered have been answered by Baringa in Appendix 2.

Breakout Sessions

ESO and Baringa coordinated breakout sessions at the workshops, and ESO have themed notes taken from the breakout rooms below. These points may have represented the views of a particular stakeholder and are not necessarily widely represented. For this reason, ESO and Baringa will be reviewing this feedback further and if appropriate using it to inform their respective conclusions. The points here have been listed for transparency of discussions in breakout sessions.

Breakout: National packages

For the national baseline package, stakeholders suggested that:

- Several questions were raised around evolved contracts for difference (CfD), these have been summarised below:
    - What are you trying to fix with evolved CfDs?
    - How would those evolved CfDs work in practice?
    - Who would run that evolved CfD process?
    - What risks would evolved CfDs present to generators and investors?
    - What impact might evolved CfDs have on investment appetite?
    - Whether we should have more ambitious CfDs in the baseline (e.g. deemed)?
- Co-optimisation, and why it was not included in the baseline package, was raised, with a stakeholder raising that it should be part of all packages

For the national build package, stakeholders suggested that:

- Need to carefully consider how ‘soft’ or ‘hard’ to make the revenue cap and floor in the package to preserve market signals
- Centralised dispatch could range from an evolution of current situation to more dramatic change, need to carefully consider consequences of this
- Whether reliability options with strategic reserves could be included in this package
- Concerns raised over deliverability of centralised dispatch and 5-minute settlement period, with more work required to understand the impacts
- Need for greater detail around centralised dispatch and how it works/looks from a generator point of view

On implementation, stakeholders suggested that:

- Planning process needs to be considered in implementation timescales, as delays in planning process will complicate implementation. Would be helpful to see more on planning reform considerations

Other points stakeholders raised:

- Whether Transmission Network Use of System (TNUoS) charging reform can be a substitute for locational pricing (e.g. if locational pricing is rejected), and can deliver the changes needed at both investment and operational levels – good to see this being considered further but need to make clear on interaction with task force. Specifically, a stakeholder questioned whether it would be possible to signal demand to site near generation through TNUoS

- The case for grid buildout with reformed TNUoS compared to locational marginal pricing for reducing constraint costs
- Length of contracts needs to be carefully considered in all policy decisions

Breakout: Zonal packages

For the zonal baseline package, stakeholders suggested that:

- Should include all options for evolved CfDs in the baseline (including deemed), as minimal changes to CfD scheme could solve several issues
- Evolved Capacity Market (CM) is not enough for baseline, would be better to have an optimised CM that includes flexibility enhancements
- Why centralised dispatch is not in the baseline, given it has been suggested as a pre-requisite for a move away from national pricing

For the zonal build package, stakeholders suggested that:

- Need to clarify the case for centralised dispatch in zonal build

On implementation, stakeholders suggested that:

- Prefer evolutionary change to move to zonal (or nodal) pricing, and need to consider carefully timing of centralised dispatch implementation and whether this is required with zonal (especially given the costs and scale of change)
- Coordination with retail reform required with the introduction of zonal (and nodal) packages, and more detail on the capability of retail markets in zonal (or nodal) markets would be helpful
- How would rezoning capability be included if a zonal market was introduced, and how to protect the market from implications of re-zoning

Other points stakeholders raised:

- Interconnector distortions are not being resolved by either the baseline or the build packages, as their inflexibility has significant consequences for how the market behaves
- Need to consider zonal capacity market
- It would be helpful to have more detail on what the FTR/PTR market would look like, and there are a lot of careful design choices required here (and which assets would be exposed)
- Greater detail needed on the forward market and whether this would still be national, or reflective of the pricing mechanism
- Greater detail also required on design of evolved CfD and whether this would still have a national reference price or would include a locational element
- More information required on access right implications in zonal markets (in both self and central dispatch scenarios)

Breakout: Nodal packages

For the nodal baseline package, stakeholders suggested that:

- As the current markets need to change, why bother with baseline – perhaps should focus on build packages only. Need to move on from British Electricity Trading and Transmission Arrangements – nodal pricing will lead to more system accurate pricing that will result in lower prices
- Would be useful to clarify exactly what is meant by evolved CfD in this package

For the nodal build package, stakeholders suggested that:

- Need to consider the push back from wind generators and on demand argument, from US experience. On demand, need to carefully consider how much residential demand is exposed to nodal pricing, as this could limit the benefit case to locational marginal pricing
- Greater clarity needed on how the revenue cap-and-floor model would work for the carbon option, but agree that cap-and-floor would help maintain operational incentive to respond to prices and protect the consumer

On implementation, stakeholders suggested that:

- It may be possible to implement nodal build via policy in theory, but need to consider the additional challenges that will arise from implementation in practice
- Need to consider use of grandfathering to ensure that offshore wind remains financially viable in Scotland (high wind capacity and low demand), and that there is a lot of uncertainty in industry as to how the nodal market paired with grandfathering would work
- Worth slow walking investors through implementation, will need a clear roadmap/pathway with timescales for nodal delivery and regular assessments. Especially need to consider how small investors and developers will navigate complex change

Other points stakeholders raised:

- Baseline should consider more than the 'here and now', and should include market design options already in motion
- Be clear on how flexible assets will be supported in nodal packages (whether this is through the CM or other options)
- Impact assessment of moving to shorter settlement period (e.g. 5-minutes) has been proven to be inefficient twice in GB. Would nodal baseline/build still be possible if we do not move to 5-minute settlement period?
- Moving to 5-minute settlement period and changing over-the-counter (OTC) market from physical to financial would require large reforms
- Interest in virtual trading and how this would work
- Need to be careful with assumptions around use of grandfathering in our packages, given it is ultimately a BEIS decision
- Whether nodal pricing will impact the spatial distribution of wind farms in conservation areas

Feedback Form

The key themes stakeholders raised in the feedback form include:

- Need for greater rationale behind the scoring, so it can be challenged/confirmed in more detail
- The potential benefits from moving to locational marginal pricing should not be overlooked, and ESO is providing a lot of value in this debate
- CfD 2-way auction is a good idea and creates a platform to bring supply and demand together, but need to consider how residential consumers fit into this
- Would be useful to explain the next steps and how this work fits into the REMA process
- On logistics of the sessions:
    - Time available for the breakout session [note- we changed the agenda between external workshop 1 and workshop 2 to help with this] and having more structure in the breakouts
    - Difficult to give informed comment/feedback given the amount of technical information covered in the session through the workshop itself, despite being informative
    - Several upvoted questions were left unanswered [note- please see summary of key points from Q&A above, and any ESO specific questions in Appendix 1]
- Whether ESO could be misaligned with views of industry on the correct priorities, and that the options are heavily skewed towards major reform, rather than smaller changes to the status quo that give confidence for market to keep investing towards net zero

Next Steps

Following these workshops, Baringa has been adjusting their independent assessment based on feedback and are completing their final assessment of the six market design packages. ESO will be responding to and using Baringa's assessment, along with the feedback set out in this document, to inform our own NZMR assessment that will be published in 2023.

In parallel, we will continue to support BEIS in their package design and evaluation process. We also look forward to seeing the results from Ofgem's technical study on locational energy pricing and the implications, especially given that several stakeholders raised the need for quantitative assessment on multiple occasions across the workshops.

In the meantime, to keep up to date with the latest on our NZMR programme, you can subscribe to our mailing list. If you have any questions at all, please email box.Market.Strategy@nationalgrideso.com.

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Appendix 1 – ESO answers to Slido questions by theme

1. ESO role

1.1. What is the actual purpose of Phase 4? REMA deadline has passed so is this to lobby decision makers further with no consultation available?

ESO's Net Zero Market Reform (NZMR) programme was established to holistically examine the changes to current GB electricity market design that would be required to achieve net zero. The purpose of the fourth phase of the NZMR programme is to develop holistic market design and policy packages that combine investment and operational elements to effectively deliver the Review of Electricity Market Arrangement (REMA) objectives.

Whilst the initial REMA consultation indeed closed in October 2022, we will continue to support BEIS in their package design and evaluation process. We will also engage with REMA in any future workshops and consultations, where we will continue to share our views on the future of market reform informed by phase 4 of our NZMR programme.

1.2. National Grid Company's views on LMP vary with ESO advocating LMP whereas NGET doesn't. Who is right?

In April 2019, National Grid Electricity System Operator (ESO) became a legally separate business within National Grid PLC, and in April 2022, BEIS/Ofgem agreed to set up a new independent FSO (by, or in, 2024) meaning ESO will be made fully independent from National Grid PLC. As a trusted and expert body at the centre of the electricity system, ESO's views are independent, such as to the views of National Grid PLC. Ultimately any decision on whether to move to Locational Marginal Pricing will be made by BEIS; ESO looks forward to working with BEIS, Ofgem and the wider industry to help design and deliver market reform.

1.3. Is it right that National Grid who get measured on balancing cost, get to push for a reform that moves balancing costs from them to the customer?

Balancing costs are already borne by the consumer via Balancing Services Use of System (BSUoS) charges, and indeed by April they will be 100% recovered from consumers. BSUoS price signals do not accurately reflect system state and consumers do not have opportunity to respond and reduce these balancing costs. ESO takes the view that risk should sit with those best placed to manage it. Locational marginal pricing would shift some congestion risk from consumers to producers and shift balancing value from the Balancing Mechanism into wholesale energy prices, providing greater opportunity for consumers to respond to the price signals through either economic demand response to wholesale energy prices or through direct participation in the centrally dispatched energy market, thereby reducing the total costs borne by consumers.

1.4. If we go to locational balancing, what's the point of NG ESO? Why not just let the DSOs balance?

We recognise the growing importance of distribution-level organisations in managing electricity networks given the increasingly decentralised and locational characteristics of our energy system. We believe that the ESO (and the Future System Operator), Distribution System Operators (DSOs) and other local institutions such as local authorities must work in tandem, each playing to their respective strengths. Further clarity is required on the activities undertaken by each of these institutions, and how they must evolve to ensure delivery of net zero.

We recognise that DSOs will have greater visibility of flows on their network compared to the ESO, and in certain cases may be best placed to procure a service to manage local operability challenges e.g. managing distribution network thermal constraints. DSO operation of local system products is distinct from energy balancing. Our 2022 Future Energy Scenarios (FES) suggest that between 70 and 73 % of energy generation will come from the transmission system in 2030. We therefore do not believe at this stage there is evidence to support the idea that regional energy balancing would be efficient. Further, certain system services are better coordinated at the national level: for example, it is neither possible nor efficient to procure frequency response regionally in a fully connected system, since the service is instantaneously provided across the whole network. Whilst the DSOs will have greater visibility of their own networks, the ESO has visibility across the whole network, rather than individual grid supply point groups, and therefore has a unique role in optimising the GB network fully.

2. Case for change

2.1. Much of this is about reducing constraint costs. What empirical evidence has been gathered that the current level of constraints is indeed inefficient?

Please see page 11 of our Phase 3 report for empirical evidence from the Network Options Assessment (NOA) 6, highlighting key evidence on current and future levels of constraint costs. Evidence 1b shows that transmission congestion costs will rise sharply in the first half of this decade and could reach an annual cost of £2.3bn per year by 2026. Page 25 of our Phase 3 report also shows how new constraints are projected to evolve over the next ten years across different regions.

2.2. Can you give an example of how the current market results in inefficient dispatch (other than interconnectors which don't participate after gate closure)?

Please see the introduction of our Phase 3 report (pages 9-11) on how the current market results in inefficient dispatch.

2.3. Why constantly focus on storage as being only about balancing, when many can deliver concurrently: stability, operability, ancillary, restoration etc. services?

We agree that storage has an important role in providing various non-frequency ancillary services. Our vision for these services is set out in our Markets Roadmap.

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2.4. Given that by 2030 most of what is needed for net zero will either be done or a plan in place to get it done, why disrupt the market, increase the cost of capital, and potentially stop investment?

Given the growth in weather-dependent assets and increasing need for whole system optimisation to reduce costs, we believe a real time locational signal is necessary to ensure both efficient dispatch and investment. A hybrid market based on centralised/self-dispatch with nodal pricing 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.

We have not seen evidence that nodal pricing has had an adverse impact on investment in low carbon technologies in other countries and believe much depends on having robust investment and carbon policies in place. For this reason, we support continued use of CfDs in some form for mature technologies, as financing instruments for generators to hedge risk and as a means for government to secure targeted volumes of low carbon capacity. While it will take time to implement centralised dispatch and nodal pricing, we believe investors and developers will begin responding once the commitment to the change has been made, unlocking benefits ahead of implementation.

2.5. It will take longer than 2 years to make any of these change. So, isn't NG's 2025 target irrelevant?

ESO is on track to meet it's 2025 target of being able to operate a zero-carbon electricity system. By 2025, ESO will have transformed the operation of Great Britain's electricity system and put in place the innovative systems, products, and services to ensure that the system is capable of handling 100 % zero carbon resources when this occurs. These changes, however, are being made within the scope of the current legislative framework, whereas REMA's scope is broader, with the potential to change legislation in order to achieve this objective more cost effectively, and on an enduring basis for a fully decarbonised power system every hour of every day, every year.

2.6. Do you have realistic assumptions on demand side flexibility?

GB flexible capacity will need to dramatically increase and will likely comprise radically different sources in 2050 versus today. In FES 2022, for example, ESO set out that demand side flexibility could increase from around 6 GW today to potentially over 100 GW by 2050. Unlocking demand-side flexibility at scale requires creating the right enabling conditions, which includes full implementation of market-wide half hourly settlement, reforming market design so the true value of flexibility is revealed through markets signals, access for demand to electricity markets and stronger incentives for suppliers to work in consumers' best interests.

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3. REMA Policy focus

3.1. What is the reason driving extreme policy change? All 6 baseline and build are complicated. Simple tweak to current policy and more transmission is easier

The National Baseline scenario involves the least change.

The scope of market design and policy options being assessed are set out in BEIS' REMA consultation document, and we would recommend reading their consultation for why that list of market reform options are being considered. Working with Baringa, we have used the baseline and build approach to present a spectrum of policy packages, with baseline entailing minimal deviation from existing policies to address the case for change to some extent and build being a more cohesive set of policies to increase confidence in achieving the REMA objectives.

3.2. Where is the policy that is addressing the lack of physical capacity? Way too much effort seems to be on allocating capacity and not on building more.

We agree that investment in the electricity transmission network is fundamental to GB meeting net zero. ESO's Network Options Assessment (NOA) process already identifies the optimal network reinforcements, taking into account constraint costs projections. However, not all upgrades proposed by the TOs 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. Both more network build and market design reforms, which would ensure efficient siting of assets and efficient utilisation of built network are needed and it is not a case of one or the other.

3.3. How will the new models like elective CfD etc be looked at if they weren't part of REMA? REMA can only narrow down the options that were originally included.

Within each chapter of REMA there is the option to include any further credible options for reform and so options outside of the consultation are still within scope. It is also set out in the Mass Low Carbon Power section that all CfD options being considered are "subject to second order questions of auction design". For these reasons, we believe the Elective Participation CfD can still be looked at as part of REMA and we look forward to discussing this option further with BEIS.

4. ESO clarification questions

4.1. Do ESO believe it has detailed understanding of the wide range of assets on the system & the IT to make centralised dispatch work effectively?

As discussed in our Phase 3 report, ESO is often currently de facto central dispatcher, but lacks the appropriate tools such as complex bid formats and appropriate participation

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models that a formal central dispatcher would have. Our analysis of centralised dispatch mechanisms suggests system operators vary in how far they proscribe asset commitment decisions, for example in management of battery state of charge. We agree that any move to formalised centralised dispatch would require extensive engagement with market participants to ensure system operator models and systems could support efficient dispatch whilst retaining scope for innovation.

5. Baringa/ESO next steps

5.1.1. Will the front-runner options be tested to see whether they help or hinder achieving the 2035 and 2050 ambitions?

5.1.2. Will there be a quantitative assessment into the options? It is easier to qualitatively justify options and it feels like the work is trying to justify the minded position

5.1.3. It looks like all options score reasonably similarly in "total" - what are the next steps? (Consultation responses, Ofgem technical report etc)

ESO currently do not have plans with Baringa to carry out a quantitative assessment of the packages. Baringa will be publishing their final qualitative assessment in January 2023, which ESO will be responding to; this will include setting out ESO's next steps. Our own NZMR assessment, to be published mid-2023, will build on our previous work and take account of Baringa's assessment and other evidence from stakeholders.

In parallel, we will continue to support BEIS in their package design and evaluation process. We also look forward to seeing the results from Ofgem's technical study on locational energy pricing and the implications.

5.2. What is the most effective way for parties to comment in detail on the scoring and how will Baringa/ESO give feedback on commentary received on the assessment so far?

Following the workshop, a feedback form was emailed to stakeholders so they could provide detailed feedback on Baringa's assessment, including scoring. ESO has summarised this feedback, along with the views from stakeholders during the session, by theme in this document. Baringa has adjusted their independent assessment based on this feedback and will be publishing their final assessment in the New Year. Our own NZMR assessment, to be published mid-2023, will build on our previous work and take account of Baringa's assessment and other evidence from stakeholders. If you would like to provide any additional feedback or if you have any further questions, please email box.Market.Strategy@nationalgrideso.com.

5.3. Has ESO done an impact assessment of locational pricing on spatial planning, with consideration of the interaction with land and marine protected areas?

ESO has not completed such impact assessment. When proposals are further developed by Government, impact assessments are typically carried out.

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Appendix 2 – Baringa answers to questions on new market design options being considered

6.1. Does CRO/RRO have to be part of this regulatory framework or simply could become a product developed by the market now?

Although it's possible that the Centralised Reliability Option (CRO) could be developed by the market, this is deemed unlikely due to market failures, justifying the need for regulatory intervention. As with the Capacity Market (CM), however, the CRO reduces the incentive on the market to come up with an alternative solution.

Currently, suppliers have no incentive, or obligation, to secure the system in the medium term, or to ensure that supply can balance demand subject to network constraints. Suppliers have an incentive to procure power to meet customer demand within the timeframe of existing contracts, which are typically short term.

For the Reverse Reliability Option (RRO), contracts between generators and storage assets could be agreed granting the generator the option to sell power at an agreed price to a storage asset. However, market failures include the current absence of locational wholesale signals, the inability to hedge against the risk associated with uncertain future transmission investment and the shielding effect of CfDs that reduce incentives for generators to contract with storage providers.

6.2. Is the Reverse Reliability Option in effect an upwards demand/reduced generation flexibility service?

The RRO could have this effect by facilitating demand response. The holder of the RRO would have the option to sell power at a guaranteed floor price. The trigger for exercising this option would be wholesale prices falling below the floor price, indicating generation exceeds demand.

6.3. For the Elective Participation in CFD auction - in effect is the aggregator a Supplier? And is there anything preventing a supplier from doing this now?

Although further detail needs to be developed, the initial concept is that the aggregator would be a government backed authority. A supplier could participate though in this model as an intermediate aggregator, feeding in its demand and bid with other participants to the central aggregator. Suppliers can enter into Power Purchase Agreements (PPA) currently but cannot participate in CfD auctions.

6.4. Wouldn't weaker credit of I&C customers in elective participation not feed through to higher costs of capital for developers?

This could be the case but there are potential solutions subject to a decision on how CfD payments are to be insured or guaranteed by government e.g. a mutualisation fund or clearing service.

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6.5. How would elective participation account for the creditworthiness of the different I&C customers and associated impact on the price developers would accept?

As above this would need to managed subject to a decision on how CfD payments are to be insured or guaranteed by government.

6.6. 2-way CFD auction: how can gov't know how much to bid for when they don't foreknow which big users will be bidding for themselves, and for how much?

Government could ask for demand side participants to submit bids in advance and then factor this elective participation into their demand curves prior to running the auction. Transparency could be achieved through specification of auction parameters, and specifying format of acceptable bids for pre-qualified elective participants in advance of the auction.