Department for
Energy Security
& Net Zero

Review of Electricity Market Arrangements

Summary of responses to consultation

Any enquiries regarding this publication should be sent to us at: REMA@beis.gov.uk

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Executive summary

The review of electricity market arrangements ("REMA") consultation opened on 18 July 2022 and closed on 10 October 2022. REMA encompasses all electricity-related (non-retail) markets, and all technologies are within scope to the extent that they currently do, or potentially could, participate in these electricity markets.

Government consulted on a range of issues and options related to electricity market reform across a number of market dimensions, including wholesale markets (chapter five), mass low carbon power (chapter six), flexibility (chapter seven), capacity adequacy (chapter eight), and system operability (chapter nine), as well as on several programme design and cross-cutting issues (chapters one to four).

The consultation received 225 responses from a range of electricity market participants and wider stakeholders. A significant number of responses were received from generators and developers, but representative bodies, energy infrastructure, academia, suppliers and private individuals were also well-represented.

Chapters one to four of the consultation covered our vision for market arrangements, the case for change, our approach to the Review and our assessment of cross-cutting issues. The majority of respondents agreed with the vision and objectives for electricity market arrangements we set out in the consultation, as well as the challenges we identified and our assessment that current market arrangements are not fit for purpose. Respondents also broadly agreed with the proposed options assessment criteria, though many recommended that we consider amending "least cost" to "best value". The majority of respondents also agreed with our organisation of options, though responses to our assessment of cross-cutting questions and trade-offs were more mixed, with some highlighting the need to better consider consumer impacts.

Chapter five considered options for delivering net zero wholesale market arrangements**.** The majority of respondents agreed that all credible options were being considered. Views on specific options were mixed; most respondents agreed with continuing to consider incremental reforms to wholesale market arrangements but were divided on the more transformative options under consideration.

Chapter six considered options for delivering mass low carbon power. Some respondents commented on the success of the Contracts for Difference (CfD) scheme, though some expressed that its current design could have limitations. Others noted the potential risk of an investment hiatus if there were too radical a change to the current arrangements. Overall, the majority of respondents expressed a preference to retain all centralised options where Government determines how much capacity is bought under long-term contracts; respondents did not support decentralised options (namely a supplier obligation) to the same extent due to greater perceived risk leading to increased capital costs.

Chapter seven considered options for delivering flexibility. The majority of respondents agreed that all credible options were considered and agreed that stronger operational signals were necessary to better incentivise flexibility. Responses on specific options were mixed: there was reasonable support for introducing a revenue cap and floor and strong support for reforming the Capacity Market in some form, but a majority of respondents were against introducing a supplier obligation for flexibility as set out in the consultation.

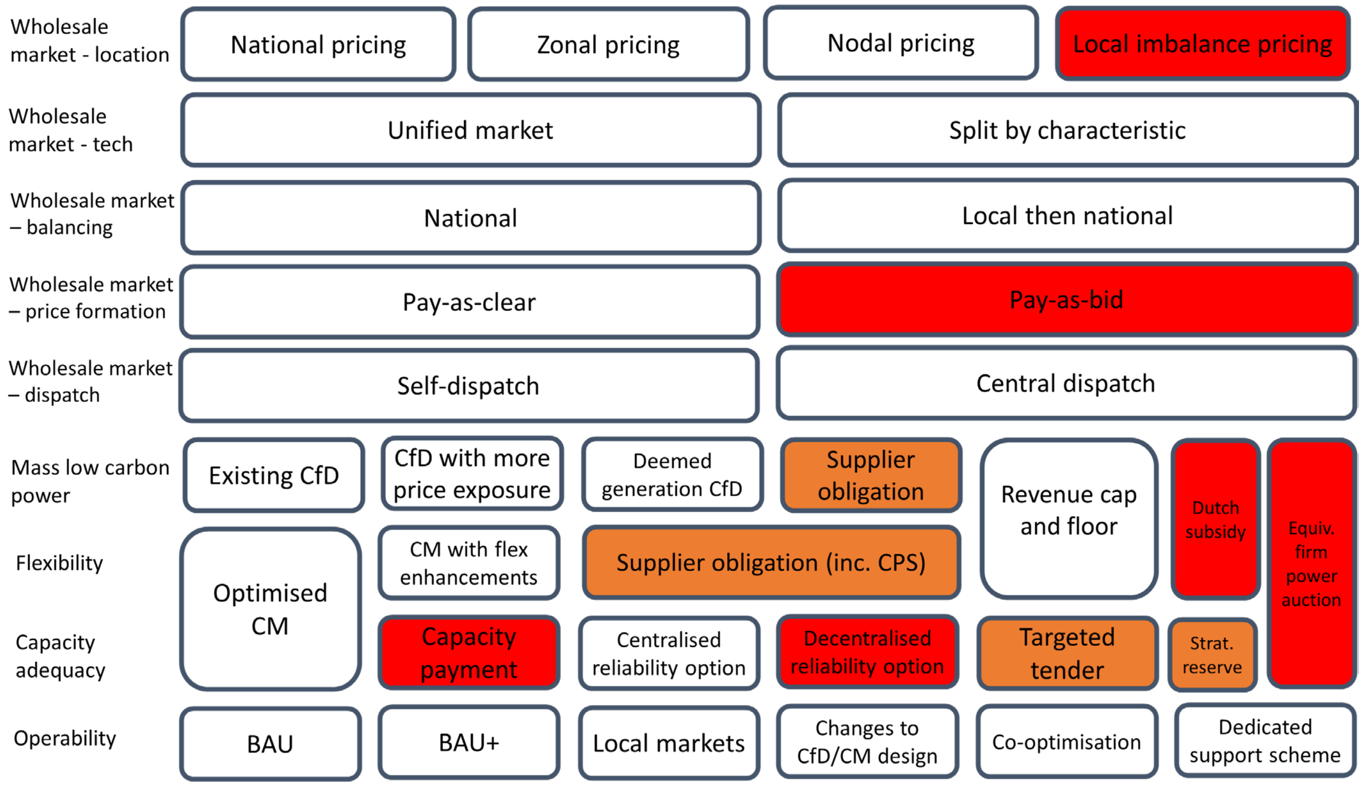
Chapter eight considered options for delivering capacity adequacy. Most respondents agreed that all credible options for reform were being considered, and the vast majority supported reforms to the Capacity Market (CM) to better align it with our decarbonisation objectives. Respondents agreed with the government's position not to pursue two options which appeared not to offer advantages over current arrangements (decentralised reliability options, capacity payments) but saw merit in continuing to consider a strategic reserve and centralised reliability options, reforms to the CM and exploring the potential merits of a targeted tender alongside a primary capacity mechanism.

Chapter nine considered options for delivering operability. The majority of respondents agreed that all credible options were considered and felt that continuing with the status quo was not a viable option. There was substantial support for enhancing existing policies and for improving the level of coordination between the Electricity System Operator (ESO) and distribution network operators (DNOs). Respondents also saw merit in amending the CfD to incentivise ancillary services though were more mixed on modifying the CM and on introducing co-optimisation within wholesale markets.

Chapter ten considered options covering multiple market elements**.** Respondents broadly agreed that we should not continue to consider a payment on carbon avoided for mass low carbon power; views were more mixed on such a payment for flexibility, though few respondents identified additional advantages. The majority of respondents did not support continuing to consider an Equivalent Firm Power auction.

Based on the feedback received, we have decided not to take a number of options forward into the next round of assessment, or to discount them as standalone options. We see this as an important step in the process to provide clarity for investors. These are summarised in Figure 1 (below, highlighted in red), and we set out our rationale in further detail in each option's respective chapter. Options highlighted in orange have been discounted as standalone mechanisms but are being considered in conjunction with other reforms.

Figure 1: A map of the options space highlighting options discounted based on consultation feedback.



Respondents frequently highlighted the need for the Review to better consider the potential impacts on consumers of any new market arrangements. Whilst we have not included consumer impacts as an explicit criterion at this stage, we recognise the importance of considering such impacts and have instigated an "end-user forum" to ensure they are sufficiently reflected in the Review going forwards. Respondents also frequently noted the need to take a proportionate approach. We recognise that some of the options under consideration would involve a fundamental redesign of current arrangements and in some cases are untested. The next phase of assessment will continue to consider the feasibility of these options alongside their potential benefits. Government decisions will be driven by whole system considerations which account for the needs of all energy market participants, with a high weighting for future considerations. We will continue to actively engage across the breadth of stakeholders to better understand the proposals for more transformative changes that disrupt the existing system but offer significant potential future benefits.

The government is publishing this summary of responses to update stakeholders on the key feedback received. It is our intention to publish a second consultation in 2023, and we will take decisions on shorter-term reforms more quickly where it is viable to do so. Government will continue to engage with stakeholders throughout this period and will set out more detailed engagement plans in due course.

Context

In April 2022, the British Energy Security Strategy announced the government's intention to undertake a comprehensive Review of Electricity Market Arrangements (REMA) in Great Britain. On 18 July 2022, the government subsequently published a consultation[1] which set out the case for change and the potential options for reform under consideration. The consultation closed on 10 October 2022; this document provides a summary of the responses received.

The consultation set out our assessment of current electricity market arrangements, our case for change, and an initial assessment of the options for reform under consideration. Crucially, whilst current market arrangements have successfully delivered the first phase of power sector decarbonisation, the government believes that they will need to change in order to deliver on our decarbonisation ambitions whilst ensuring affordability and security of supply for consumers. The Review therefore provides an opportunity to look again at our market arrangements, and to ensure that they can deliver on these objectives.

Overview of consultation proposals

The consultation posed 74 questions, which sought views on a wide range of options for electricity market reform across several key market dimensions, including:

- **Wholesale markets** – options included splitting the wholesale market, locational wholesale pricing, introducing local markets, pay-as-bid pricing and incremental reforms to current arrangements
- **Mass low carbon power** – options included changes to the Contracts for Difference (CfD) scheme, introducing a supplier obligation, and introducing a revenue cap and floor
- **Flexibility** – options included introducing a supplier obligation such as the Clean Peak Standard, a revenue cap and floor, and optimising the CM for flexible assets
- **Capacity adequacy** – options included optimising the CM, centralised and decentralised reliability options, introducing a strategic reserve, capacity payments, and a targeted tender / targeted capacity payment approach
- **System operability** – options included continuing with the status quo, enhancing existing policies, co-optimisation, and optimising the CfD and/or CM schemes for ancillary services provision
- **Options spanning multiple market elements** – including a payment on carbon avoided (the "Dutch Subsidy" scheme) and an Equivalent Firm Power Auction.

[1] https://www.gov.uk/government/consultations/review-of-electricity-market-arrangements

The consultation also invited views on:

- Our proposed **vision and objectives** for future electricity market arrangements,
- Our assessment of challenges in the electricity system (our "**case for change**"),
- Our proposed **approach to options assessment and developing packages of reform**, and
- A range of **cross-cutting issues**, including the trade-offs inherent in electricity market reform, the most effective way of delivering locational signals, and the role of electricity markets in incentivising demand reduction

This summary of responses outlines the feedback received and sets out the government's initial policy response.

Engagement with the consultation proposals

To support stakeholders' understanding of the consultation proposals, and to gather initial feedback, DESNZ officials hosted an online consultation launch alongside five online webinars ("chapter seminars"). These chapter seminars were attended by between one to two hundred stakeholders and covered issues and options discussed in chapters five to nine of the consultation.

DESNZ officials also hosted two in-person "REMA conferences" on 12 and 13 September 2022, attended by approximately ninety stakeholders in total. Attendees included a range of electricity market participants and wider stakeholders. Discussions covered the case for change and short- and long-term challenges for our electricity market arrangements, how packages of reform might be formed, and attendees' relative preferences for different hypothetical packages.

Responses to the consultation

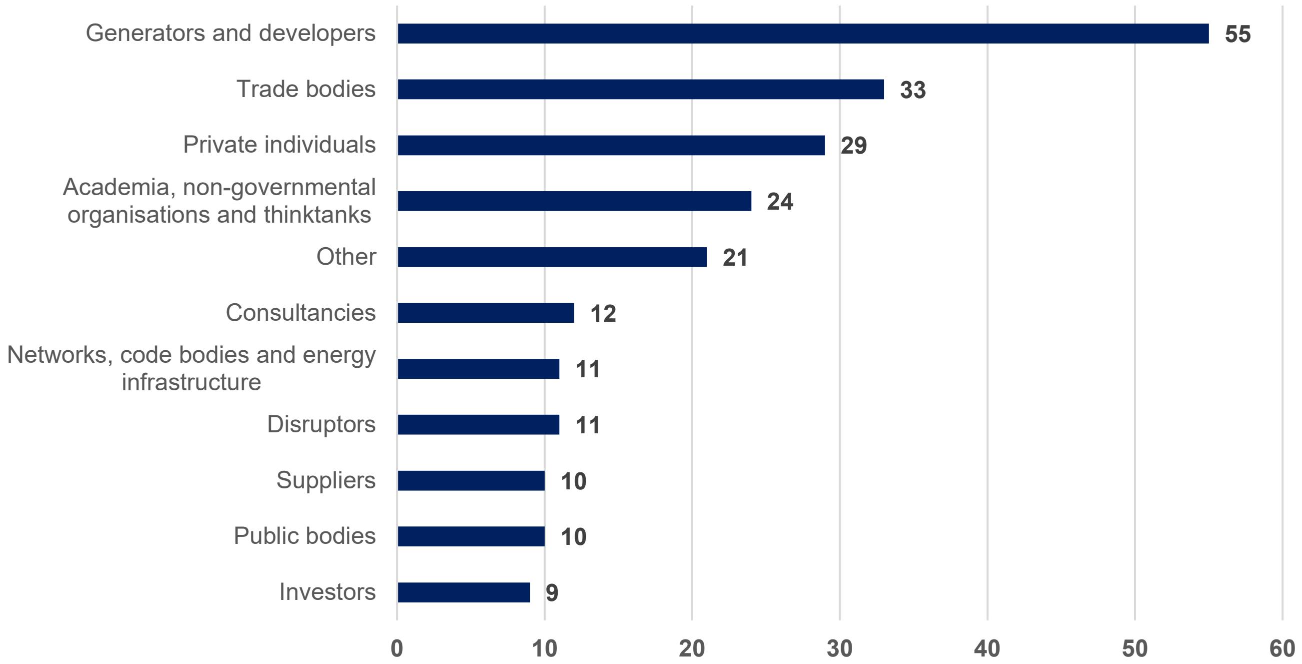
The consultation was published online and ran from 18 July to 10 October 2022. The consultation received 225 responses in total; these responses were submitted through an online portal (Citizen Space – 65 responses), by email (159 responses) or by post (1 response). We received three responses after the deadline. Figure 2 provides a breakdown of respondents by type[2]. The government is grateful to each and every respondent to the consultation for taking the time to submit their views.

Consultation responses were read and analysed by officials using a qualitative coding approach. Qualitative coding is a structured process for identifying and synthesising key

[2] "Disruptors" included respondents providing innovative system services or technologies; "other" includes respondents that did not fall into any of the other ten categories. Many respondents fell into multiple categories; we have classified these respondents according to their main business activity.

themes, or “codes”, within a set of oral or written data (in this case the consultation responses). Responses were initially analysed against twenty-five pre-identified high-level codes to ensure consistency: these high-level codes were then expanded on and added to in a second round of analysis to better reflect the feedback received. Our analytical approach is set out in more detail in the Annex.

Figure 2: Breakdown of consultation respondents by type



In summarising the responses received to each question, “the majority” indicates a view was held by more than 50% of respondents to that question, “most” or “many” indicates more than 70%, “some” between 30% and 70%, and “a few” less than 30% of respondents who expressed an opinion. This is consistent with the approach of other UK Government responses to consultations. When considering this summary of responses, please also note that:

- Due to the large volume of responses received, this summary does not seek to exhaustively capture all views expressed, but rather to summarise the prevalent themes and particularly notable points of feedback within responses
- Respondents used either an online response form, a downloaded response form, customised templates, or sent in their responses by letter
- Not all responses answered every question, or addressed specific questions, and the number of responses each question received varied significantly. We have noted the number of responses each question received in brackets; this number excludes those who stated they had no opinion or comment to give on the question.
- Where questions were multiple choice, we have provided a summary of this data at the beginning of each chapter. The survey data includes both tick-box answers and where we have made a qualitative assessment of the response’s sentiment - responses which

did not clearly express an answer were marked as “don’t know” for the purposes of triangulating results

- The government ran several stakeholder events during the consultation period to support respondents in developing their responses; views expressed solely during these events are not captured here

Next steps

The government is publishing this summary of responses to update respondents and other interested stakeholders on the key points of feedback it has received. It is our intention to publish a second consultation in 2023, and we will take decisions on shorter-term reforms more quickly where it is viable to do so. Government will continue to engage with stakeholders throughout this period and will set out more detailed engagement plans in due course.

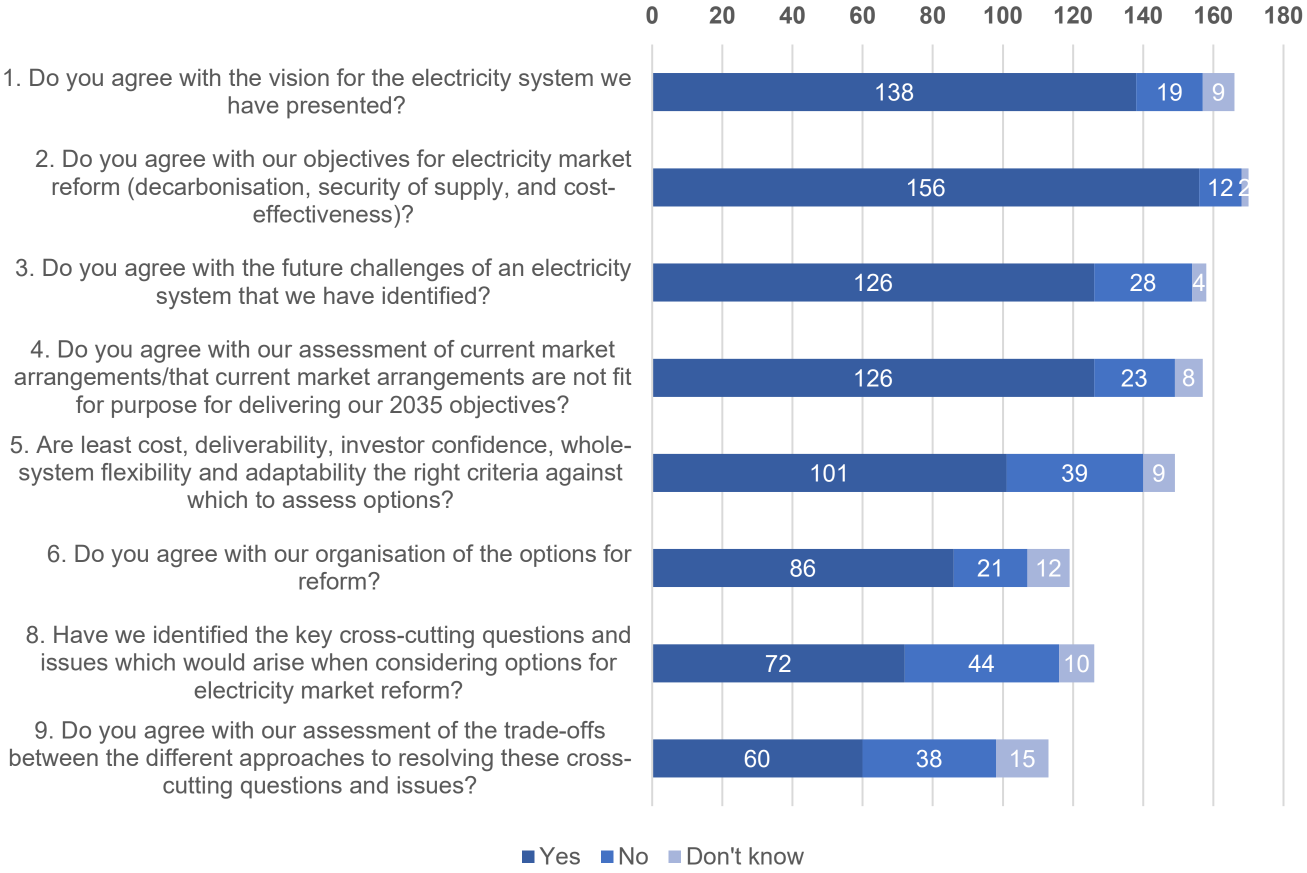
Programme design and cross-cutting issues

Chapters one to four: policy response
The government considers the vision, objectives and options criteria were appropriate to the needs of this consultation and is assessing whether any update is required ahead of the next phase of the Review. The government acknowledges the need to provide transparency and to maintain investor confidence, as well as the need to ensure cohesion with interdependent policy areas and issues.

This chapter summarises responses to Questions 1 to 9 of the consultation, which sought views on a range of programme design and cross-cutting issues. Figure 3 provides an overview of the survey responses received.

The majority of respondents agreed with the vision and objectives for electricity market arrangements we set out in the consultation, as well as the challenges we identified and our assessment that current market arrangements are not fit for purpose. Respondents also broadly agreed with the proposed options assessment criteria, though many recommended that we consider amending least cost to “best value” (or similar). The majority of respondents also agreed with our organisation of options, though responses to our assessment of cross-cutting questions and trade-offs were more mixed, with respondents highlighting the need to better consider consumer impacts.

Figure 3: A graph to show the number of respondents who agreed, disagreed and were unsure in response to Questions 1 to 6 and 8 to 9.



Vision and objectives

Questions 1 and 2 sought views on our vision for future electricity market arrangements, and the objectives we set out for electricity market reform.

Summary of responses

Question 1 (166 responses) sought views on our vision for the electricity system.

- Most responses (83%) agreed with the vision presented. There was consensus across these responses that current market arrangements would not deliver the change necessary to achieve decarbonisation by 2035, and that it was right to consider market design changes that could deliver decarbonisation, security of supply and value for money.
- Many respondents highlighted the importance of considering consumers in any reformed market arrangements, with a few noting the need to consider how to protect vulnerable consumers and incentivise demand reduction. Some respondents also noted the importance of avoiding an investment hiatus by providing a clear pathway to reform

and effectively managing any transition period.

Question 2 (170 responses) sought views on our proposed objectives for electricity market reform.

- Most respondents (92%) agreed that the objectives were appropriate as guiding principles based on the energy trilemma. Many respondents commented on the need to consider the relative priority of each objective.
- Most respondents agreed with the objective of decarbonisation and highlighted how the transition to low carbon generation could be a major driver of decarbonising the economy more widely. Some noted the importance of effective grid infrastructure in facilitating mass renewable deployment.
- Many respondents noted the importance of security of supply in the context of the Russian invasion of Ukraine and the role that decarbonisation could play in delivering this. Several respondents also highlighted the role of storage in ensuring resilience across all demand scenarios.
- Some respondents highlighted the need to better define the objective of ‘cost effectiveness’, in particular to ensure that it reflected best value for consumers.
- A few respondents identified possible additional objectives; these included reducing risk, deliverability, and consumer impacts.

Policy response

The government has taken into account the feedback received on our vision, objectives, case for change and approach to options assessment. The government is committed to a transparent development process providing a clear pathway to reform maintaining investor confidence and ensuring cohesion across interacting policy areas, including retail markets and consumer interests.

Following analysis of the consultation responses, the government considers that the vision and objectives were appropriate to the needs of this consultation and is assessing whether any update is required ahead of the next phase of the Review.

We note the range of feedback received and in particular those respondents that highlighted the need to better reflect the role of and impacts on consumers within any new market arrangements, and the need to take a whole-system approach. The next stage of the REMA option development process will focus on narrowing down a set of packages based on an assessment against objectives and criteria. Our next consultation will set out this process in more detail and ask for stakeholder feedback on our assessment.

The case for change

Questions 3 and 4 sought views on our assessment of current market arrangements and the challenges electricity market reform needs to overcome.

Summary of responses

Question 3 (158 responses) sought views on whether we identified the correct challenges for the electricity system.

- Most respondents (80%) agreed with the future challenges for the electricity system identified in the consultation.
- However, some respondents disputed the need for sharper locational signals and asserted that these would be unnecessary with sufficient network build.
- Some respondents noted a distinction between desirable and undesirable price volatility (with the former positively impacting short-term dispatch).
- Some respondents identified additional challenges; these included the impact on consumers and ensuring sufficient network investment and infrastructure.

Question 4 (157 responses) sought views on our assessment that current market arrangements are not fit for purpose and will not deliver a decarbonised power sector by 2035.

- Most respondents (80%) agreed with our assessment that current market arrangements are not fit for purpose.
- Most respondents who disagreed with this question agreed with our overall assessment but felt that our objectives could be met with incremental changes to existing market arrangements. For example, a few respondents noted that 'the solution should be proportionate to the problem' and felt that strong evidence would need to underpin any more transformative reforms.
- Some respondents also highlighted the challenge of maintaining investor confidence during any transitional period.

Policy response

Following analysis of the consultation responses, the government considers that the case for change is broadly supported, and that we have identified the key future market challenges. The government has considered stakeholder responses identifying additional challenges (outlined above) and, where appropriate, has incorporated these into our identification of current and future market issues. Government is assessing whether any formal update to capture this enhanced case for change is required ahead of the next phase of the Review. The government will continue to monitor the electricity system on an on-going basis and consider additional challenges if identified.

Approach to options assessment

Questions 5, 6 and 7 sought views on the design of the future electricity market and how to assess potential packages of reform.

Summary of responses

Question 5 (149 responses) sought views on our proposed options assessment criteria (least cost, deliverability, investor confidence, whole-system flexibility, and adaptability).

- The majority of respondents (68%) agreed with the proposed options assessment criteria.
- However, many respondents preferred 'best value' over 'least cost', on the basis that it better reflected considerations of overall system value, meeting Net Zero commitments and fairness across society. Some respondents also suggested that 'least cost' encourages short-term thinking and that 'value for money' would be more appropriate.
- Respondents also highlighted the significance of the investor confidence criterion, noting the risk of an investment hiatus driven by too radical change, a lack of clarity on timelines, insufficient network infrastructure and the need to manage a wide range of investors with different risk appetites. A few respondents stated that investment risks should be borne by those most able to manage them.

Question 6 (119 responses) sought views on our proposed organisation of the options for reform.

- Most respondents (72%) agreed with the schematic in the consultation[3] , and felt that it provided clarity and clearly identified where options were overlapping across multiple market dimensions.
- Those that disagreed with the schematic did so for a range of reasons, including that it was insufficiently holistic and assumed that market intervention was necessary.
- Some respondents highlighted the scale of change and associated complexity in reforming electricity markets. These respondents felt that a complex market design would add uncertainty and preferred minimum viable change as far as possible.

Question 7 (150 responses) sought views on what we should consider when constructing and assessing packages of options.

[3] See page 49 of the REMA consultation.

- Some respondents questioned the necessity of radical reform to current market arrangements, noting that sizeable transformations to the energy market would be time-consuming, cause disruption and could have unintended consequences, such as negative impacts on investor confidence and competition within markets.
- Some respondents drew attention to the increasingly diverse capacity mix, and in particular an increase in distributed generation. These respondents noted the need to drive competition and transparency (which could in turn drive down prices). As with responses to question six, complexity was noted as creating barriers to entry which could result in less competition and an investment hiatus.
- On package construction, respondents most commonly noted the need to consider compatibility between options, iterative and logical sequencing and technological readiness (for example, data and IT infrastructure).
- A few respondents expressed a desire for a narrower range of options to be considered. DESNZ has carefully considered the views expressed in responses to the consultation alongside its ongoing policy development and six options have consequently been discounted. Our rationale for discounting these options is provided under the corresponding questions.

Policy response

Following analysis of the consultation responses, the government considers that the assessment criteria were appropriate to the needs of this consultation and is assessing whether any update is required ahead of the next phase of the Review.

The government is considering how to use the criteria for option assessment, alongside identifying the market issues we see as most fundamentally needing to be resolved by market reform. Several suggestions were received from respondents for new assessment criteria, including fairness, security of supply, simplicity or avoiding complexity and likely effectiveness which focused on the extent to which options were workable and/or implementable in practice.

The government agrees with the importance of considering overall system value in the criteria and recognises that 'least cost' should not conflated with a short-term cost minimisation that is not suitable for an enduring 'whole systems' approach.

The government has considered concerns raised in responses to our questions on option assessment around scale of change and is committed to reducing complexity in energy markets. This will be taken into account when constructing packages, including more incremental reforms versus transformational ones.

Some stakeholders expressed a desire for the number of options under consideration to be significantly reduced. The government agrees that an important part of the REMA process is to iteratively reduce the number of options on the table, and has discounted six options which we do not reasonably believe could form part of final policy packages and identified a further three which we believe can only work in conjunction with other options. Stakeholder views were an important part of the assessment process of discounting these six options, and most respondents agreed with our assessment to discount them. It is important we ensure sufficient evidence prior to discounting more consequential options and therefore, the government believes that a partial narrowing of options at this stage is appropriate to allow more detailed investigation into the remaining options in the next phase of the programme. We will of course continue to engage with stakeholders and seek stakeholder views throughout the decision-making process.

Cross-cutting questions

Questions 8 and 9 sought views on the cross-cutting issues for electricity market reform and the trade-offs between approaches to resolve these.

Summary of responses

Question 8 (126 responses) sought views on whether we identified the key cross-cutting issues when considering options for electricity market reform.

- The majority of respondents (57%) agreed that we had identified the right cross-cutting issues.
- Some respondents raised other issues to consider, including network investment and access, the interactions between wholesale and retail electricity markets, and the role of central planning.
- A few respondents suggested there was insufficient consideration of the relationship between REMA and the ongoing retail market review. The role of consumers was also raised by several respondents, including the need to ensure consumer participation in future markets and provide accurate price signals, and the need to avoid consumers paying higher prices as a result of unintended consequences from market reform.

Question 9 (113 responses) sought views on whether we correctly assessed the trade-offs between different approaches to resolving cross-cutting issues.

- Responses were more mixed on this question. The majority of respondents (53%) agreed that we had correctly assessed the trade-offs; some had particular points of disagreement; others disagreed with a range of our assessments.
- Many responses considered: the role of marginal pricing; the role of the market; the extent of decentralisation; and the extent of competition.
- Respondents emphasised that marginal pricing is the basis for many commodity markets, and that it is important for incentivising efficient operation of assets.

Respondents also recognised the challenge of supporting investment in renewables on the basis of marginal pricing, given their high up-front costs and low operating costs.

- Respondents were mixed on the role of the market. Some respondents said that there should be a greater role for central planning in determining the capacity mix; others contended that the issues with our current market arrangements are due to mismatches between policies, rather than market failures.
- On decentralisation, some respondents said that decision-making should take place at a more local level, to take advantage of the greater visibility of assets and the granularity of information. Others claimed that there were relatively few relevant differences between local areas, and that the electricity system remains a primarily national system, which should be administered on a national level.
- On the extent of competition, most respondents agreed that effective competition between technologies is desirable where possible. Most respondents also agreed that there are limits to effective competition, particularly for nascent technologies.

Policy response

The government recognises that our future market arrangements need to play their part in the overall electricity system, and this means ensuring that they are designed coherently with retail markets and our plans for network investment. While network investment and retail markets are outside the formal scope of REMA, we work closely with relevant teams across DESNZ, HMG and Ofgem to ensure our respective approaches will work together to achieve our overall system objectives.

Our next steps will involve working closely with Ofgem on options to sharpen locational signals. This work will also consider the role of network charging under different options for reform and interactions with the planning and building out of the electricity network.

The next stage of our REMA process will also involve further mapping of key interdependencies between wholesale and retail reform and the establishment of a new forum that will seek the input from end users and consumer groups on overall electricity market reform.

Wholesale markets

Policy response: chapter 5

Taking into account the feedback received, the government has decided to retain all options proposed in the wholesale markets chapter for further consideration, with the exceptions of pay-as-bid pricing across the entire market and local imbalance pricing (see Questions 19 and 21 for further detail on our rationale).

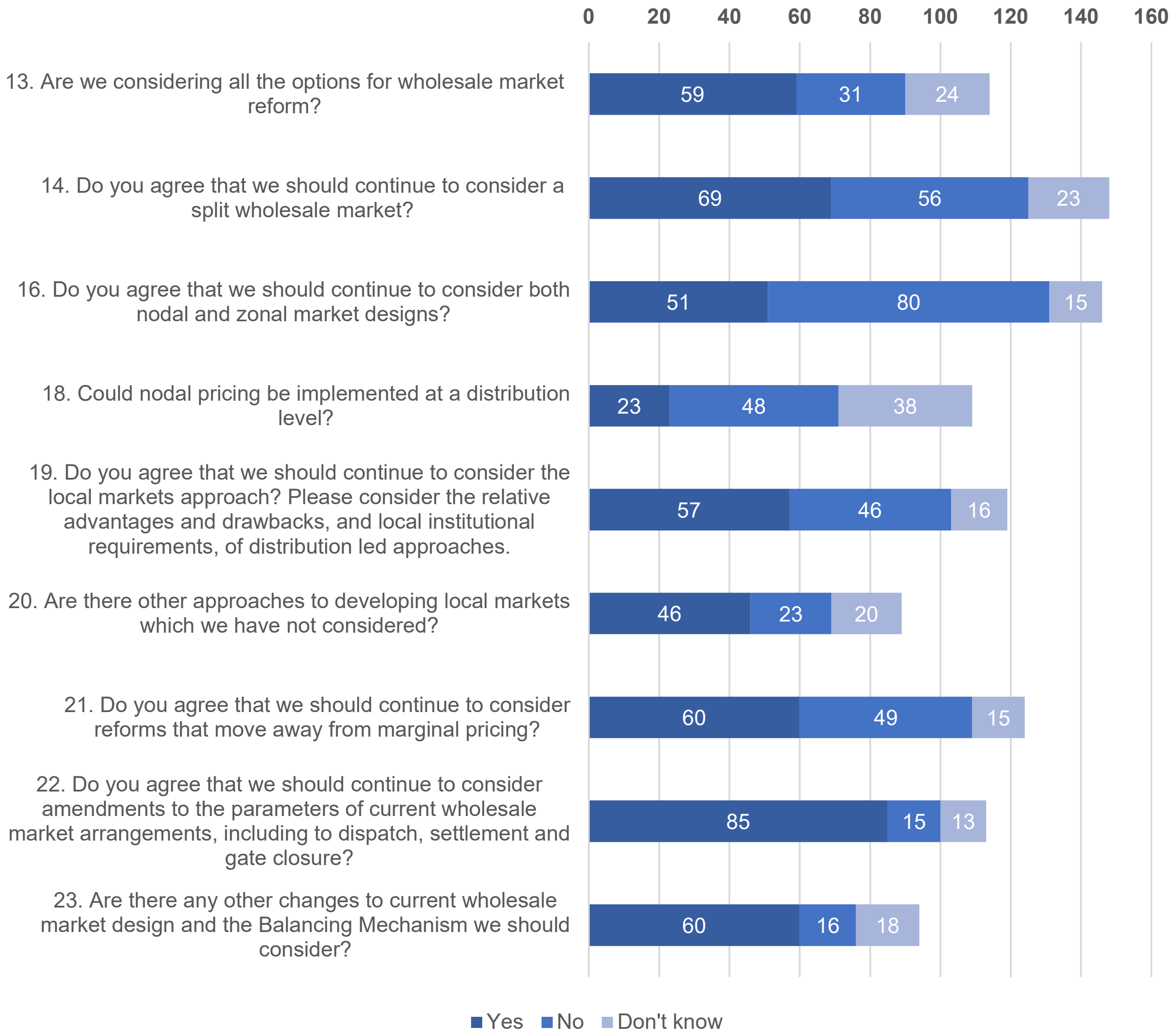
We note that the majority of respondents felt we were considering all credible options: we have reviewed the additional suggestions put forward and do not propose to include any of these within our assessment process at this time.

We recognise that whilst respondents strongly supported continuing to consider incremental changes to wholesale market arrangements, opinions were divided on more transformative changes. On split markets and a green power pool, we see merit in continuing to consider these options to understand how they might be applied in practice, though we recognise that the CfD scheme or additional support for the Power Purchase Agreement (PPA) market could be viable alternatives. On zonal and nodal pricing, responses were mixed: some respondents disagreed with continuing to consider both options whilst others preferred to retain zonal pricing only. Many respondents also noted alternative options for sending locational signals. We believe there is merit in continuing to consider both zonal and nodal pricing as means of providing sharper locational signals within market arrangements alongside less transformative options (e.g. minor reform to network charging arrangements) whilst further evidence is gathered on their potential costs and benefits. Lastly, on local markets, we note the alternative approaches suggested and will continue to develop our understanding of these options and how they might be applied to the GB market.

This chapter summarises responses to Questions 10 to 11 and 13 to 23 of the consultation, which considered a range of issues and options for reform related to wholesale market design. Figure 3 provides an overview of the survey responses received.

The majority of respondents agreed that all credible options were being considered. Views on specific options were mixed; most respondents agreed with continuing to consider incremental reforms to wholesale market arrangements but were divided on the more transformative options under consideration.

Figure 4: A graph to show the number of respondents who agreed, disagreed and were unsure in response to Questions 13 to 14, 16, and 18 to 23.



Options under consideration

Summary of responses

Question 13 (114 responses) sought views on whether we have considered all the credible options for reform in the wholesale market chapter.

- The majority of respondents (52%) agreed that we had considered all of the credible options for reform. Some felt that we were considering too broad a range of options and that some were not credible.

- Some respondents also felt that there was a need to define the future role of the wholesale market more explicitly, and to consider how the options within the wholesale market chapter might interact with others in the consultation.
- Of those who disagreed, a few respondents noted the single buyer model (wherein generation assets are provided with a capacity and energy payment and a central entity is responsible both for dispatch and for ensuring least cost delivery of the system).
- Other suggestions included a CM for inter-seasonal zero carbon firm capacity, introducing tolling agreements, and providing bilateral contracts.

Splitting the wholesale market

Summary of responses

Questions 14 (148 responses) and **15** (100 responses) sought views on the option to split the wholesale market – either by creating “on-demand” and “as-available” markets, or by implementing a green power pool.

- Respondents were divided on whether we should continue to consider a split market option (47% agreed, 38% disagreed, and 16% didn’t know).
- Some respondents felt that a split market option might better pass on both the lower long-term costs but also the risks of higher variability of renewables to consumers directly, and further decouple wholesale electricity prices from international gas prices.
- Respondents who argued against further consideration of split markets drew particular attention to the market disruption it could create. These respondents contended that the limited evidence base, and continued uncertainty about the detail of how the schemes would work, could undermine investor confidence. They noted that any successful design would need to ensure efficient market operation (including dispatch and balancing), liquidity, and investor certainty, as well as clarity on market participation and impact on consumers. With these points in mind, respondents noted effective design of a split market option requires considerable thought and collaboration with industry to design, assess, and provide a clear route for delivery – this was echoed by respondents who supported continuing to consider the option.
- Many respondents noted that the existing market arrangements already achieve a level of market-splitting, e.g. through operation of CfDs and access to PPAs, and that these arrangements could either be retained or expanded/extended to include a wider range of renewable generators.
- In response to question 15, which sought views on how a split market might be designed in practice, most respondents reiterated concerns and challenges with split market options.

Locational signals

Questions 10, 11, 16, 17 and 18 sought views on the option to introduce sharper locational signals into the wholesale market.

Summary of responses

Question 10 (128 responses) sought views on the most effective way of delivering locational signals to drive efficient investment and dispatch decisions of generators, demand users, and storage.

- Many respondents proposed alternatives to sending locational signals through the wholesale price, including combining locational Balancing Services Use of System (BSUoS) charges with changes to the CfD, or sending such signals through renewables support schemes, capacity adequacy mechanisms, creation of constraint markets or network access. Most notably, some respondents referenced reformed Transmission Network Use of System (TNUoS) charges as the best way to send sharper locational signals, noting Ofgem's ongoing work in this space and stating that changes to TNUoS and other charges should be considered first before making radical changes to the market via the introduction of locational pricing. However, a few respondents did not believe that reformed TNUoS charges were able to provide an efficient locational signal. Some respondents highlighted the importance of accelerating the build-out of transmission infrastructure and a few said that this would limit the benefits of introducing locational signals into electricity markets.
- Some respondents voiced concerns that the introduction of locational signals in the wholesale market would present a risk to investment in renewables going forward. Other respondents emphasised that both new and existing generation and demand are limited in their ability to respond to locational signals. Locational signals therefore do not and would not significantly impact investor decisions for these market participants; or that to do so, such signals must not be volatile, short-term, or unpredictable.
- A few respondents argued that whilst locational wholesale pricing provided efficient operational signals, it was not necessarily helpful for investment signals, due to the fact that nodal prices represent current rather than future constraints on the system.
- A few respondents stated that locational signals for investment may be better set through central planning for networks and/or generation than a market mechanism. A few respondents also noted that locational signals should not be considered a priority given the urgency of required changes in other areas, e.g., flexibility or decoupling gas and electricity prices; or that they should only be considered once it has been established that alternatives such as investment in more grid infrastructure do not provide better value for money. Respondents also highlighted the need to ensure continued deployment of renewables and felt that sharper locational signals could jeopardise this.

Question 11 (113 responses) asked how responsive market participants would be to sharper locational signals.

- Respondents stating that participants would be unresponsive to sharper locational signals for investment primarily cited the importance of alternative factors in the siting decision and questioned how receptive participants would be to such signals. Alternative factors cited by respondents as more impactful in determining where to locate included availability of required infrastructure, land suitability and planning. The challenge of obtaining a grid connection and planning restrictions were heavily cited.
- Of those respondents who believed that market participants would respond to sharper locational signals, responses commonly flagged that this responsiveness would vary by technology type with flexibility assets commonly cited as potentially being more responsive. Those respondents who believed that market participants would respond to the sharper locational signal also commonly cited the potential operational benefits that could be derived.
- Many respondents stressed that for participants to respond to such signals, they need to be investable, including the need for them to be transparent, predictable, non-volatile, and to consider the impacts on the whole system.

Question 16 (146 responses) asked whether we should continue to consider both nodal and zonal market designs.

- The majority of respondents (55%) thought that we should not consider both nodal and zonal market designs: of these, some respondents rejected both options whereas some argued we should discount nodal pricing but continue to consider zonal pricing. Respondents against both options felt that they would undermine investor confidence, risking an investment hiatus in renewables and potentially hindering the energy transition due to an increase in the cost of capital and revenue uncertainty, outweighing any potential benefits. Some felt that an investor hiatus would be more likely under nodal pricing, and that locational signals should be provided only to those able to respond to them.
- Respondents who favoured continuing to consider both options (35%) still agreed that there were challenges that needed to be considered. The key arguments cited for retaining these options included potential significant benefits to end-consumers due to greater operational efficiency and reduced system costs; incentivising the deployment of renewables and flexibility where they are needed; and encouraging energy-intensive industrial demand to locate closest to renewable generation. A few respondents also mentioned the potential for nodal and zonal pricing to reduce the complexity of system operation.
- On nodal pricing specifically, a few respondents argued that it most accurately reflects the full marginal cost of meeting demand at a certain time and location and would increase transparency (e.g., in relation to transmission losses). However, of those

respondents who voiced concerns about nodal pricing, some noted that implementing nodal pricing would be complex, computationally demanding, and likely to cause significant disruption in the market. Reduced liquidity in a nodal market was also mentioned as a concern by a few respondents, as was a potential shift of risks to generators. A few respondents also felt that nodal pricing would not provide an accurate investment signal given the potential price volatility at individual nodes, and that this volatility and unpredictability could negatively impact investor decisions. Finally, a few respondents argued that transitioning from zonal to nodal pricing rather than implementing nodal pricing immediately could resolve some of the challenges posed by nodal pricing.

- On zonal pricing, a few respondents noted that it could provide some of the benefits of nodal pricing with less complexity, including avoiding the need for central dispatch, and the fact that zonal pricing well-precedented (as it is already in place in continental Europe).

- Some respondents identified alternatives to nodal and zonal market designs to manage constraints which they viewed as easier to implement and less disruptive, such as reforming TNUoS charges, speeding up the development and expansion of the transmission network, or adding locational signals to the CfD scheme. Some respondents highlighted the limited ability of more locationally granular price signals to affect siting decisions of generation and demand given the influence of resource availability, planning rules, administrative hurdles, and access to the grid.

- Some respondents also argued that the benefits to consumers of introducing nodal or zonal pricing were not clear, particularly if the demand side wasn't exposed to locational prices. Respondents also argued the complexity of implementation and transition was too high and that locational pricing could cause delays to network infrastructure build out. A few respondents called for more targeted price signals for those most able to respond to them instead of a market-wide approach.

Question 17 (92 responses) sought views on how the challenges and design issues with nodal and zonal market designs we identified in the consultation might be overcome.

- Many respondents agreed with the challenges identified in the consultation and some felt that they were impossible to overcome. These respondents favoured retaining national pricing within the wholesale market. Respondents also noted the need for increased investment in transmission infrastructure regardless of the nature and extent of locational signals within the market.

- Some respondents noted in particular the potential for increases to the cost of capital and the scale of digitalisation necessary if nodal pricing were implemented, as well as the limited ability for some technologies to respond to sharper locational signals for investment in practice.

- On managing risk, respondents noted the introduction of financial transmission rights within a nodal or zonal market design might help (though a number highlighted outstanding design uncertainties in implementing these in the GB market).
- A few respondents noted that locational prices could be introduced solely on the supply-side to mitigate against any adverse consumer impacts (including potentially higher prices for some), though others felt that dampening these signals could remove some of the potential benefits.
- Other suggestions included using market surveillance measures to mitigate against gaming, grandfathering to protect existing generation assets and committed investments against additional risk and providing a clear and transparent roadmap for assessment and implementation.

Question 18 (109 responses) sought views on whether nodal pricing could be implemented at a distribution level.

- Respondents who felt that nodal pricing could not be implemented at a distribution level (44%) noted that it would have the same drawbacks as nodal pricing at the transmission level, i.e. it would be complex to implement due to a very high number of nodes; increase the regulatory burden; and exacerbate risks around costs, a potential investment hiatus, liquidity and complexity of dispatch. A number of respondents (35%) were unsure whether it would be feasible.
- Respondents also raised concerns about the impacts on flexibility, in particular stating that the inability to aggregate demand side response (DSR) or flexible resources across a portfolio under nodal pricing (both at transmission and distribution level) would hinder their development.
- A few respondents noted that in theory, implementing nodal pricing at distribution level could be feasible but wouldn't be desirable in practice for the reasons set out above.
- A few respondents felt that it was possible for nodal pricing to be introduced at distribution level and that DESNZ should explore this option further.

Local markets

Summary of responses

Questions 19 (119 responses) and **20** (89 responses) sought views on the option to adopt a local markets approach.

- Respondents were split on this option. Some respondents (39%) disagreed with continuing to consider the local markets approach due to the additional system complexity it would introduce and limited evidence and real-world examples to suggest that the option would be cost-effective. Respondents highlighted the potential to exacerbate existing liquidity issues.

- On the other hand, some respondents (44%) agreed with continuing to consider the approach citing its support in accelerating the deployment of distributed flexibility deployment and the building of a least cost and resilient system. Some respondents also commented on the role of Distribution System Operators (DSOs) and the need for improved co-ordination between distribution and transmission beyond changes already in the pipeline to ensure market challenges are effectively addressed; respondents felt that this improved co-ordination would be necessary in order to adopt a local markets approach.
- In terms of alternative approaches to developing local markets, some respondents flagged various trials and innovation projects which could function under existing market arrangements.

Policy response

Taking into account the feedback received, the government has decided not to take forward local imbalance pricing as an option into the next phase of assessment on the basis that it does not meet the criteria of least cost and investor confidence.

Stakeholders did not substantially engage with this option. Where local imbalance pricing was referenced directly by respondents, concerns were raised around the practical implementation challenges and the option's untested nature as well as the predictability of the charge, and therefore, the invest-ability of the signal.

Other options that could send locational price signals will still be considered moving forward.

Alternatives to marginal pricing

Summary of responses

Question 21 (124 responses) sought views on alternatives to marginal pricing.

- Respondents were divided on continuing to consider pay-as-bid across the entire market and recommended discounting this option (48% agreed, 40% disagreed, and 12% didn't know).
- Respondents that supported the consideration of pay-as-bid as a move away from marginal pricing cited that this option could lead to lower consumer prices.
- However, some respondents mentioned the risk of tactical bidding under pay-as-bid pricing to determine dispatch, where generators are likely to bid at the price of the expected marginal plant, preventing a reduction in consumer prices unless caps on bids

are introduced. Furthermore, imperfect information on the likely marginal plant could then lead to distortions in merit order, leading to a more costly system.

- Some respondents therefore concluded that this option would need to be introduced alongside caps on bids in order to reduce wholesale electricity prices. A number of concerns were raised on the potential introduction of a pay-as-bid system with caps on bids:
    - Lower incentives for investment and decarbonisation: Capping the bids of cheaper technologies via fixed administered prices would lower the expected revenues of low-cost generation – lowering incentives for investment. A substantial decrease in investment could mean slower decarbonisation of the power sector.
    - Inefficient price setting: some argued that it would be challenging to set administrative technology-specific price caps at a level which allow efficient recovery of capital expenditure costs, potentially having implications for security of supply. Some respondents questioned the ability of a central body to deliver an efficient outcome by predetermining a price, compared to established markets with multiple buyers and sellers.
    - Scale of the change: Some respondents mentioned that this option would represent a fundamental change to the wholesale market, leading to a complex system that could be challenging to administer, requiring heavy regulation and likely a central dispatch function. These inefficiencies and cost of administration could mean there would not be a significant reduction in consumer prices.
    - Operational signals for flex: Administratively set price caps would dampen operational signals for flexible technologies and could lead to inefficient dispatch decisions because assets would no longer be rewarded at the marginal cost of the system (e.g., no incentive to dispatch at peak, rather than overnight).
- Some respondents mentioned alternative approaches to decoupling gas and electricity prices, such as CfDs and splitting the wholesale market. Some argued that an expanded CfD scheme would be a less disruptive and less costly way to allow consumers to benefit from increased low-cost generation.

Policy response

Taking into account the feedback received, the Government has decided not to take forward pay-as-bid pricing as an option into the next phase of assessment on the basis that it does not meet the criteria of least cost and investor confidence. Other options for decoupling gas and electricity prices for some generators will still be considered, such as a green power pool and moving more generation on to CfDs.

Amendments to current market arrangements

Summary of responses

Questions 22 (113 responses) and **23** (94 responses) sought views on amendments to the parameters of current wholesale market arrangements, including to dispatch, settlement and gate closure.

- Most respondents (75%) agreed that we should continue to consider incremental reforms to wholesale market arrangements, with some feeling it could be preferable to more drastic changes. However, some respondents felt that moving from self-dispatch to central dispatch would be a significant change and should not be viewed as an evolution of the status quo. Some respondents were also sceptical of the case for such a change, on the grounds that it could diminish efficiency and cost-effectiveness. They argued that asset owners and operators would have a better understanding of their plants capabilities than the system operator. Other respondents pointed to central dispatch as an important enabler for other options under consideration in the consultation.
- Most respondents were in favour of continuing to explore shorter settlement periods, for example because they could allow for better adjustment to changing weather conditions and a more granular matching of supply and demand. Some respondents felt this could better incentivise flexibility and improve operational efficiency.
- Most respondents were also in favour of continuing to explore reducing the gate closure interval, for example because it could enable generators to make final positions more accurate, potentially reducing the need for redispatch. However, a few respondents noted this would leave the System Operator with less time for final balancing actions.
- Most respondents were in favour of continuing to explore making changes to the Balancing Mechanism. There were a range of views on specific changes, with the most common requests being to improve transparency and to open up the Balancing Mechanism to more participants, including smaller generators and flexibility providers. Alignment of flexibility markets and long-term contracts for flexibility services were suggested.

Mass low carbon power and demand reduction

Policy response: chapter six

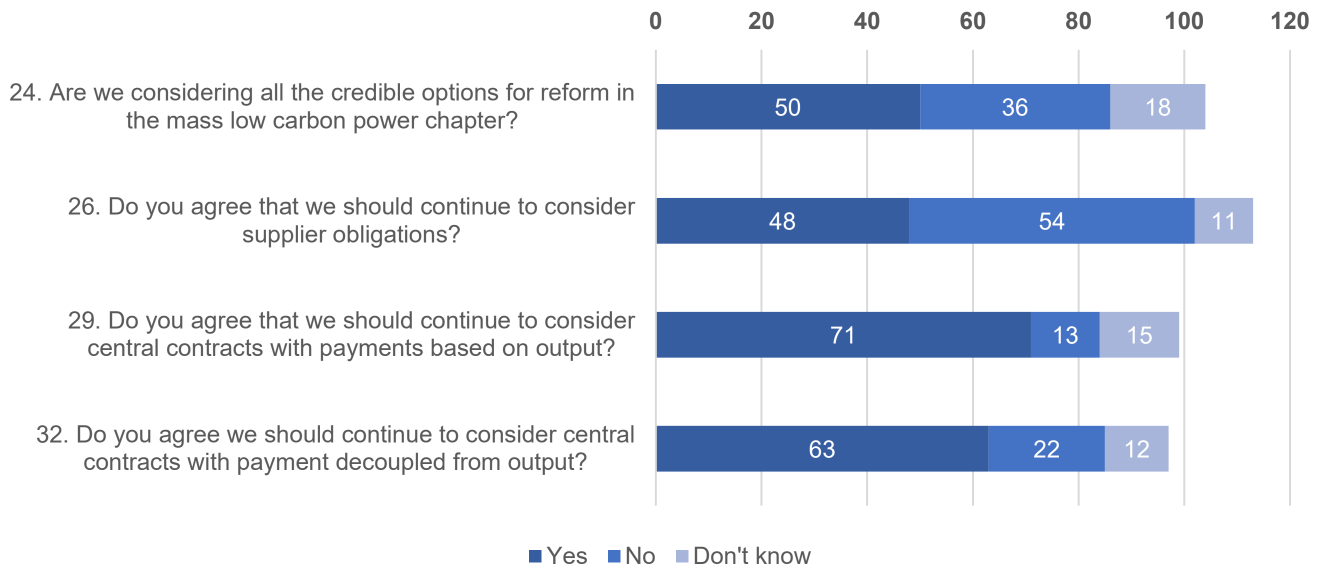
We will continue to consider all options under both central contracts with payments based on output and central contracts with payment decoupled from output. We will not be considering a supplier obligation as the main mechanism for driving mass investment in low carbon technologies in the short-term for the reasons given under Question 26.

We have reviewed the additional options put forward. Whilst we do not propose to include any of these in our formal options assessment process at this time, we note the range of suggestions made on facilitating the growth of the PPA market, which we will consider as part of ongoing policy development.

This chapter summarises responses to questions 12 and 24 to 34 of the consultation, which covered the main approaches under consideration to address the challenges our current arrangements pose as we look to accelerate the pace and breadth of investment in low carbon generation. The consultation sought views on our general approach to these challenges as well as opinions and evidence on each option being explored.

Some respondents commented on the success of the CfD scheme, though some felt that its current design could have limitations. Others noted the potential risk of an investment hiatus if there were too radical a change to the current arrangements. Overall, the majority of respondents expressed a preference to retain all centralised options where Government determines how much capacity is bought under long-term contracts; respondents did not support decentralised options (namely a supplier obligation) to the same extent due to a perceived increase in risk and consequently increased capital costs. A few respondents also highlighted the potential role of PPAs in driving mass low carbon generation investment.

Figure 5: A graph to show the number of respondents who agreed, disagreed and were unsure in response to Questions 24, 26, 29 and 32.



Options under consideration

Summary of responses

Question 24 (104 responses) asked whether we have considered all credible options for reform in mass low carbon power sector.

- Some respondents (48%) agreed that we are considering all credible options; others (35%) disagreed, and some presented further options for CfD reform, such as extending contract lengths, auction process reform, and allowing existing generators to bid for a CfD. Some respondents also highlighted the need to focus on incentivising flexibility.
- Some respondents indicated that a CfD-style mechanism is not appropriate for all forms of low carbon generation. Some respondents also felt that there were no incentives for CfD-supported generators to be flexible and any additional incentives elsewhere could cause double subsidy.
- A few respondents mentioned the importance of PPA agreements, and the possibility that they could be a credible alternative to a CfD. They encouraged the widespread increase of PPAs, highlighting significant potential for growth and suggesting that government considers how best to support this growth. For example, a few said that government could standardise PPA agreements, help pool supply and demand, and underwrite agreements to reduce counterparty risk. A few respondents also highlighted that the need to ensure CfDs don't crowd out PPA growth.

Policy response

We have reviewed all additional suggestions, and note in particular the feedback on the potential of the PPA market. We are considering whether Government could stimulate the PPA market, and what form this stimulation could take.

Demand reduction

Summary of responses

Question 12 (125 responses) sought views on the role of electricity demand reduction (through deployment of electrical energy efficiency measures) in electricity markets.

- Respondents most commonly noted the need to strengthen incentives for demand reduction, although there were mixed views on how this might be achieved in practice. Other common themes included: the benefits demand reduction brings in reducing system costs and investment; demand reduction benefits being undervalued currently in the market and a lack of clear signals; the role of demand reduction in supporting delivery of net zero; and barriers to the deployment of demand reduction measures such as lack of information for consumers, lack of skills and a poorly developed supply chain, up-front capital costs, and uncertainty around return on investment.
- Of those that expressed a view on which specific options should be considered, respondents preferred bespoke mechanisms, with a few responses citing the pay-for-performance mechanisms in Texas, California, and Portugal as potential design options.
- Of responses that favoured continuing to use existing non-market policies, the most common theme was the added complexity any new market interventions could bring to the market. Across all four options, respondents noted that a market intervention alone will not be sufficient to deliver demand reduction due to non-market barriers.

Valuing small-scale distributed renewables

Summary of responses

Question 25 (87 responses) sought views on how electricity markets could better value the low carbon and wider system benefits of small-scale distributed renewables.

- A range of topics were covered in responses, including some direct policy suggestions as well as wider feedback on the role of small-scale distributed assets.
- A few respondents challenged the premise of the question, arguing either that there is a lack of evidence that small scale distributed renewables are undervalued, or explicitly claiming that they are overvalued. However, other respondents were more positive about the potential to enhance valuation of the benefits of these assets.

- Several respondents highlighted what they viewed as limitations with the current Smart Export Guarantee (SEG), noting that there is no legislative floor on per kWh payments, and available tariffs often do not provide strong financial incentives for technologies like rooftop photovoltaic. Responses suggested that further market intervention in the form of a floor price would distort and provide inefficiencies to the wider market.
- Several respondents noted a need for improved visibility of small-scale assets, and the importance of effective co-ordination between the ESO and DNOs. This was often in the context of advocacy of local market solutions. A few referenced interactions between small scale renewable generation and flexibility assets. A few respondents also highlighted the role of Power Purchase Agreements (PPAs) in helping to support some forms of distributed renewables on a commercial basis. A few specifically advocated allowing small scale (<5MW) generation to participate in the CfD scheme.
- A few responses also noted the role aggregators can play in realising value and providing a route to market for small scale assets. One respondent noted there can be significant administrative burdens associated with aggregators pre-registering to provide system services, and another highlighted the particular role of DNOs in facilitating aggregation.

Supplier obligation for mass low carbon power

Questions 26, 27 and 28 sought views on the possibility of introducing a ‘supplier obligation’, requiring suppliers to contract a certain amount of low carbon power.

Summary of responses

Question 26 (113 responses) asked whether DESNZ should continue to consider a supplier obligation to drive low carbon power investment.

- Some respondents (48%) disagreed with continuing to consider a supplier obligation. Of these, some said obligating suppliers to contract with low carbon assets would increase capital costs given the current state of the supplier landscape and consequently hamper the rollout of low carbon generation. A few respondents said that a supplier obligation might not lead to system-optimal asset deployment and that suppliers might focus resources on a few technologies. A few respondents also felt that it could disadvantage smaller suppliers.
- Of those who agreed (42%), a few said that a supplier obligation could help drive innovative supplier business models, improved operational signals and new technologies. Similarly, a few respondents said this option would drive greater investment in renewables by incentivising innovation and by relying on market signals over Government procurement.

- Of those who neither agreed nor disagreed (10%), a few mentioned the need to wait for the outcome of the *Future of the energy retail market: call for evidence*[4] before giving a view. Respondents to questions 27 and 28 also highlighted this point.

Policy response

Considering both the feedback received and interdependencies with other ongoing market reviews, we will not be pursuing this option as the main mechanism for driving low carbon investment in the short-term. We will, however, continue to consider the role of suppliers – and whether it is necessary to place duties and requirements upon them – in support of the delivery of other REMA options.

Questions 27 (79 responses) and **28** (68 responses) sought views on how the supplier landscape would need to change to make any supplier obligation successful and how any financing and delivery risks could be overcome.

- Some responses thought that the supplier landscape would need to change for a supplier obligation model to support REMA objectives. A few respondents reflected views in earlier questions that a supplier obligation is not an effective tool to drive low carbon investment. As with those respondents who disagreed with question 26, a few also pointed to the risk of a supplier obligation favouring larger, incumbent suppliers.
- A few respondents to question 27 suggested potential solutions, including more stringent definitions of green tariffs and more transparent, consistent standards across the supplier market. All respondents felt the supplier landscape would need to change for a supplier obligation to work.
- Respondents also highlighted challenges to implementing a supplier obligation, including poor creditworthiness of some suppliers and the need for the supplier landscape to be on a firmer footing, with ‘well-capitalised’ suppliers. Having a government-backed counterparty, such as the Low Carbon Contracts Company, or the government acting to underwrite the supplier contracts were the most common solutions proposed to address these challenges.

Central contracts with payments based on output

Questions 29 to 31 consulted on using central contracts based on output as the primary mechanism for deploying mass low carbon power.

[4] https://www.gov.uk/government/consultations/future-of-the-energy-retail-market-call-for-evidence

Summary of responses

Question 29 (99 responses) sought views on whether we should continue to consider central contracts based on output. The two options considered here were minor reforms to the existing CfD and a CfD with more price exposure.

- Most respondents (72%) agreed that we should continue to pursue both options. A few respondents disagreed, with some of the view that solely incentivising output was not appropriate.
- Many respondents noted the success of the existing CfD scheme and some felt that modifications were unnecessary. Others felt that adaptations could be required, particularly given the other potential whole-system changes being considered under REMA. A few respondents noted that they would prefer an evolutionary rather than revolutionary approach to reforming the current mechanism.
- A few respondents felt more analysis was needed on the opportunities and costs that a CfD with more price exposure could present. Of the respondents that commented on the specific design choices set out for this option, the majority preferred a strike price range approach, but in general views were mixed. A few respondents also made design recommendations related to the CfD scheme more generally, such as shortening or lengthening new CfD contract lengths, increasing the frequency of auctions, and including locational signals.

Question 30 (66 responses) sought to understand if the benefits of increased market exposure for central contracts based on output would outweigh potential increased financing costs.

- There were mixed views from stakeholders in response to this question. Respondents most commonly cited the need for a stronger evidence base given generators' potentially limited ability to change their behaviour (and consequently limited potential benefits).
- The most common benefits cited were that increased market exposure could increase dispatch decision efficiency, reducing the risk of oversupply and making generators more responsive to market signals. Respondents also indicated that price exposure could incentivise co-location with storage, allowing generators to benefit as they could target dispatch at high price periods.
- A few respondents felt that non-dispatchable, weather-dependent assets are limited in their ability to react to price signals, and that increased price exposure could increase risk and consequently cost of capital.
- A few respondents also noted that the CfD has already started to evolve to deliver increased market exposure to generators, such as the Negative Price Hour Rule introduced in Allocation Round 4 (AR4). One respondent noted that CfD clearing prices were at record lows in AR4, and felt that this showed investors and developers'

willingness to commit to longer-term contracts at low prices despite greater market exposure.

- A few respondents provided further design considerations (set out in Question 29).
- A few respondents highlighted that more mature technologies could be better placed to take on the additional risk, and that dispatchable assets such as hydrogen or biomass could benefit more relative to other technologies as their behaviour is more positively influenced by market signals.

Question 31 (46 responses) sought evidence on the relative balance between capital cost and likely balancing costs under different scenarios and support mechanisms.

- Many respondents stated that they did not have any evidence to provide or noted that the relative balance would depend on many factors.
- A few respondents did point to relevant research papers. Most notably, the 2021 UKERC Working Paper "*Risk and Investment in Zero-Carbon Electricity Markets"* which was highlighted by three respondents. Two of these noted that the paper gives a helpful quantitative assessment of the potential cost of capital impacts under different scenarios and support mechanisms but does not address the trade-off of possible cost of capital increases against potentially reduced balancing costs. Two respondents also made note of the 2018 Arup Study *"Cost of Capital Benefits of Revenue Stabilisation via a Contract for Difference".*

Central contracts with payment decoupled from output

Questions 32, 33 and 34 asked respondents to consider the potential for a central contract for new low carbon generation with support levels not dependent on actual output.

Summary of responses

Question 32 (97 responses) asked whether stakeholders agreed that DESNZ should continue to consider financial support mechanisms not linked to low carbon generator output.

- The majority of respondents (65%) agreed that we should continue to consider these mechanisms. These respondents felt that they could provide optimal generation signals, encourage provision of ancillary services, and reduce the impact of price cannibalisation due to incentives to reduce correlation with other variable renewable generation.
- Of those that disagreed, some felt that contracts based on output would be more cost-effective, and that contracts decoupled from output would be too complex or too different to current arrangements.
- There were no common views between those who neither agreed nor disagreed with this question.

Questions 33 (71 responses) and **34** (85 responses) asked for design recommendations on the 'deemed CfD' and 'revenue cap and floor' options.

- Of those who gave design recommendations on the revenue cap and floor, some respondents suggested this option would need to have a 'soft cap', where revenue exceeding the cap wouldn't be fully surrendered. For example, revenue could be shared between the generator and consumer. This was the most frequently suggested design recommendation. Other recommendations for this option included: considering how closely it could mirror the revenue support mechanism for interconnectors; having a cap that flexes with the wholesale price; not including revenue earned outside the wholesale market in the calculation to incentivise operation in other markets; technology-specific approaches; and revenue floors set by auction.
- A few of those who gave design recommendations on deemed generation CfDs suggested ways of most accurately predicting generation, including using satellite weather data and historic or comparable local generation data from sites of similar size and orientation. A few respondents suggested using an independent body to provide these calculations, or to set a £/MWh limit to try to avoid or limit gaming impacts. Lastly, a few also mentioned the importance of generators being topped up even when providing ancillary services, suggesting that Elexon might be able to provide data to differentiate between non-generation and system service provision.

Flexibility

Policy response

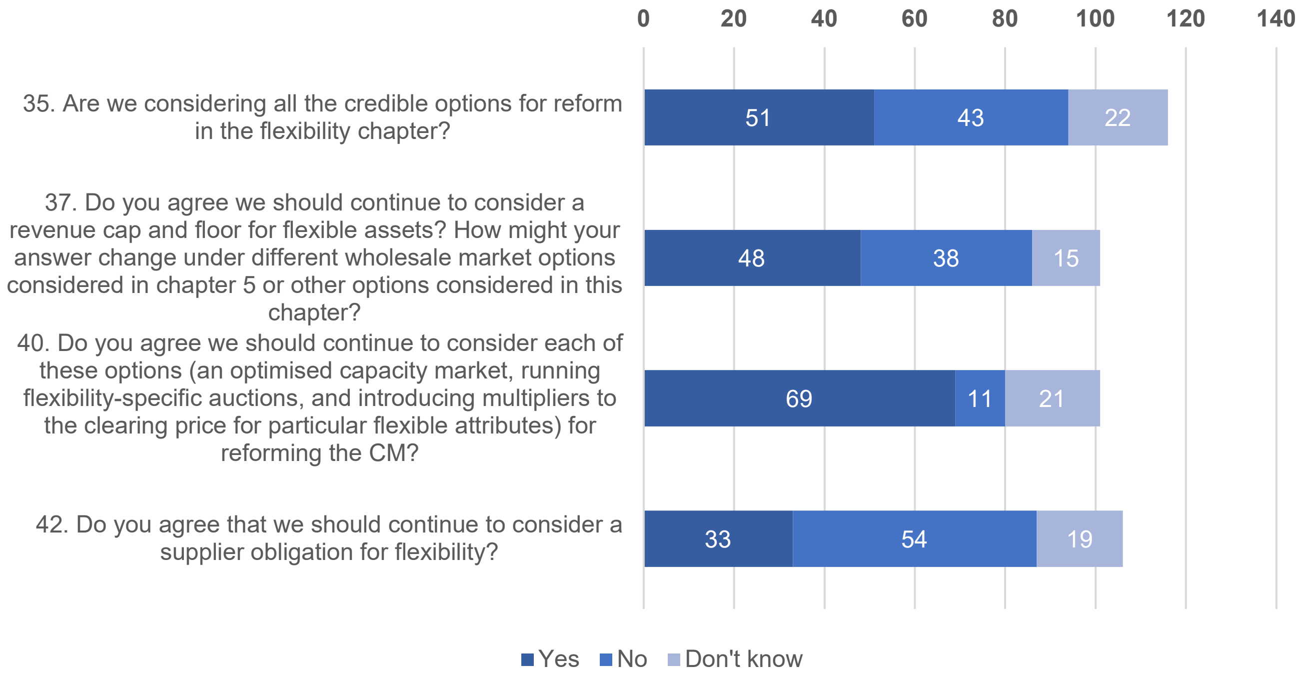
Taking into account the feedback received, there was sufficient support from respondents for government to continue developing and assessing proposals for reforming the CM and introducing a cap and floor mechanism for flexibility. We have considered both the feedback received and interdependencies with other ongoing market reviews and we will not pursue a supplier obligation for flexibility as the main mechanism for flexibility in the short-term. We will, however, continue to explore the role of suppliers in bringing the demand side flexibility- and whether it is necessary to place duties and requirements upon them- in support of the delivery of other REMA options.

We have also considered the new options put forward and do not propose to include any of these within our formal options assessment process at this time.

This chapter summarises responses to Questions 35 to 44 of the consultation, which considered a range of issues and options related to incentivising flexibility within electricity market arrangements.

Some respondents agreed that all credible options were considered and agreed that stronger operational signals were necessary to better incentivise flexibility. Responses on specific options were mixed: there was reasonable support for introducing a revenue cap and floor and strong support for reforming the CM in some form, respondents were generally against introducing a supplier obligation for flexibility although suppliers crucial role in bringing forward demand side flexibility was noted, which we will continue to explore.

Figure 6: A graph to show the number of respondents who agreed, disagreed and were unsure in response to 35, 37, 40 and 42.



Approach to flexibility

Questions 35 and 36 sought views on our approach to flexibility.

Summary of responses

Question 35 (116 responses) sought views on whether we are considering all credible options for reform in the flexibility chapter.

- Some respondents (44%) agreed that Government is considering all credible options for reform.
- Many respondents suggested that alongside the options set out in the flexibility chapter, Government should ensure that the wholesale market better values flexibility. Some respondents noted that reforms to the Balancing Mechanism are essential for unlocking flexibility and made several suggestions about how best to approach this, for example enabling ESO to take balancing decisions outside of the gate closure period, or disaggregating balancing mechanism actions into individual system requirements such as inertia.
- Many respondents also suggested that Government refine its definition of flexibility to facilitate a more in-depth analysis of the options being considered. These respondents highlighted the range and diverse nature of flexible assets, and that appropriate market arrangements may therefore differ across technologies.

- Respondents that disagreed (37%) suggested that Government prioritise putting in place the right market arrangements for storage technologies, with a notable focus on the need for long-term contracts – such as a cap and floor mechanism - to de-risk investment in long duration storage.
- Some respondents suggested that Government should consider facilitating the ability of demand side flexibility to access power markets, such as a temporary support subsidy for demand side flexibility in capacity and balancing markets.
- Some respondents suggested that wider reforms beyond the electricity market were essential to unlocking flexibility, such as the need for continued network upgrades, dealing with delayed grid connections, and upgrading ESO's digital systems.

Question 36 (89 responses) sought views on whether stronger operational signals would be enough to bring forward low carbon flexibility or whether additional support might be needed to de-risk investment to meet our 2035 commitment.

- Most respondents agreed that operational signals were important for unlocking flexibility, with varying views about how these could be delivered and the extent to which they would provide adequate investment signals in their own right.
- Many respondents suggested that the duration of flexibility or level of technology maturity, given these tend to have higher upfront costs should be considered when assessing assets' need for investment support. A few respondents suggested that electricity system need for different types of flexibility should shape the development of support mechanisms.
- Some respondents agreed that stronger operational signals should be sufficient to act as investment signals for short duration assets, including battery storage and demand side response. Many of these respondents noted that a range of incremental reforms to markets would be needed to achieve stronger operational signals, however. Examples included shortening gate closure and settlement periods, changes to the balancing mechanism to increase dispatch of smaller assets and reviewing the network charging regime.
- A few respondents felt that despite receiving stronger operational signals, the upfront costs associated with enabling domestic consumers to provide flexibility to the system could be a barrier requiring additional support. Some suggestions for addressing this barrier included green loans or new business models such as 'energy-as-a-service'.
- Many respondents agreed with the position set out in the consultation - namely that whilst operational signals are essential, some technologies need additional support where there are high capital costs, long construction times or technology immaturity. In addition, the tight timelines for power sector decarbonisation were identified as driving the need for additional support, in particular for long duration storage, although hydrogen and carbon capture, usage and storage (CCUS) were also referenced frequently.

Revenue (cap and) floor for flexibility

Questions 37 to 39 consulted on the possibility of introducing a revenue (cap and) floor for flexible assets and the possible design for such a mechanism.

Summary of responses

Question 37 (101 responses) sought views on whether we should continue to consider a revenue cap and floor for flexible assets and whether this differed under different wholesale market options or other options considered in the flexibility chapter.

- Some respondents (48%) agreed that government should continue to consider a revenue cap and floor for flexibility. Those who agreed suggested that the mechanism could be effective in deploying flexible assets through de-risking investment, particularly for those assets with high capital costs.
- The majority of respondents highlighted the suitability of a revenue cap and floor mechanism in de-risking investment in long duration storage, and the need for government to bring forward such a mechanism at pace.
- Respondents who disagreed (38%) suggested that a revenue cap and floor could distort other parts of the market by improving the investment case for high-capex flexibility ahead of other assets such as demand side response and batteries. Some respondents also felt that there would be a high administrative cost of implementing the regime.

Question 38 (61 responses) sought views on how a revenue cap and floor could be designed to ensure value for money, such as ensuring assets are incentivised to operate flexibly and remain available if they meet their cap.

- Respondents offered a range of design recommendations. Some suggested that the revenue cap and floor should be implemented in the same way as the existing interconnector regime, because this is well understood and trusted by developers and investors and strikes a good balance between providing necessary de-risking signals whilst minimising potential costs to consumers.
- A few respondents however thought that this approach could become bureaucratic if open to a large number of low carbon assets, which could consequently make setting the level of the cap and floor difficult.
- A few respondents gave suggestions on how the floor should be set to encourage participation. Some suggested that in order to receive government support, providers should meet a minimum level of performance. Others suggested that the floor should be based on the volume or size of the project, and that location should be taken into consideration.
- A few respondents said the level of the floor should be equivalent to the minimum return necessary to secure debt-based investment at a relatively low cost of capital. Some

respondents suggested a ‘soft cap’ could be a good way of ensuring value for money, whilst still incentivising technologies to provide system services once the cap is reached.

Question 39 (64 responses) sought views on whether a revenue cap and floor could be designed to ensure effective competition between flexible technologies including small scale assets.

- Many respondents disagreed that a revenue cap and floor could be designed to ensure competition between flexible technologies.
- Some respondents suggested that providers of small scale or short duration flexibility may struggle to engage with an allocation process that requires significant pre-qualification expenditure to be able to participate.
- A few respondents suggested that battery storage is already well-established and support for this technology through a revenue cap and floor is therefore unnecessary.

Options for reforming the Capacity Market for flexibility

Questions 40 and 41 sought views on reforming the CM to better incentivise flexibility. Questions 46 and 47 sought further views on the CM and proposals for reform; responses to these questions can be found on page 48.

Summary of responses

Question 40 (101 responses) sought views on whether we should continue to consider the following options for reforming the CM: 1) an optimised CM, 2) flexibility-specific auctions and 3) introducing multipliers to the clearing price. **Question 41** (66 responses) sought views on which flexibility characteristics should be valued in a reformed CM.

- The majority of respondents (68%) agreed that the CM should be reformed to some extent, and that there would be limited benefit in discounting any of the proposals at this stage. Most respondents also agreed that reforms to enable greater levels of low carbon flexible assets to access CM agreements are necessary to ensure a sufficient suite of technologies are available to meet future system needs.
- Some respondents felt that the proposals set out under an Optimised CM (differentiating technologies by carbon intensity, either by introducing a low carbon split auction or multiple clearing prices) would sufficiently incentivise a range of flexible assets. These respondents suggested that short-term markets and ancillary services were best positioned to appropriately reward certain flexible characteristics closer to real-time system needs and expressed concerns over long-term agreements locking-in characteristics that become misaligned to evolving system needs.

- Several respondents suggested that adjusting the parameters of the CM to primarily bring forward investment in low carbon flexibility could result in suboptimal results and ineffective market distortions.
- On the other hand, many respondents suggested that specific flexibility-enhancing reforms to the CM, either through flexibility auctions or applying multipliers to the clearing price, would be needed to guarantee the right types and required volumes of low carbon flexible assets are built at the pace and scale required for decarbonisation. These respondents expressed concerns over the ability of day-ahead and intra-day ancillary service markets to provide a sustained investment signal for flexible assets. Respondents also pointed out that the missing money problem in the wholesale market might hinder the scale of deployment needed for low carbon flexible assets.
- Respondents that disagreed (11%) were not in favour of adding additional layers of complexity to the CM. Some preferred reforms to the existing mechanism, such as automating pre-qualification, reforming secondary trading, and amending the derating methodology. Respondents that neither agreed nor disagreed (21%) stated that a deeper analysis of the alternative options would be required to make a judgment.
- Most respondents agreed with the characteristics of response time, duration, and location that were set out in the consultation. Several respondents noted the need to align a reformed CM with ancillary services.

Supplier obligation for flexibility

Questions 42 to 44 consulted on introducing an obligation on suppliers to procure flexibility, how the current supplier landscape might need to change, and the possible design of such an obligation.

Summary of responses

Question 42 (106 responses) sought views on whether we should continue to consider a supplier obligation for flexibility. **Question 43** (70 responses) sought views on whether suppliers should have a responsibility to bring forward flexibility in the long term and how the supplier landscape might need to change. **Question 44** (44 responses) sought views on how multipliers could be set to value the whole-system benefits of flexible technologies.

- The majority of respondents (51%) disagreed that Government should continue to consider a supplier obligation for flexibility. Some of these respondents felt that such an obligation would place an inappropriate level of risk on suppliers given concerns around their current stability. Respondents highlighted the importance of aligning the REMA programme with retail market reform; however, some did also note the importance of DSR within the electricity system and that suppliers could play a key role in enabling DSR through, for example, time of use tariffs.

- Some respondents (31%) agreed that we should continue to consider a supplier obligation for flexibility. These respondents suggested that an obligation could be particularly effective in providing strong operational and investment signals for demand side and small-scale flexibility, would enable competition across technologies, and improve liquidity in local flexibility markets. A few respondents suggested that if delivered correctly and alongside retail market and wholesale market reform, a supplier obligation could provide an opportunity for the flexibility aggregation market to develop.
- Many respondents felt that suppliers did not have the right level of visibility to be responsible for procuring flexibility and would therefore have to rely on centralised definitions of the capacity required. Some suggested that well-designed wholesale market and ancillary service arrangements should provide incentives for suppliers to develop products that encourage customers to provide demand side flexibility. Some respondents felt that the system operator was best placed to provide signals for flexibility.
- A few respondents were concerned by an approach designed to reduce emissions at peak times rather than incentivising shifting demand out of peak periods. Others suggested that a scheme like the clean peak standard could result in excessive investment in particular technologies and that it would be very difficult to predict peak periods. However, a couple of respondents suggested that the ESO and DNOs could be required to forecast peak periods, and that these forecasts could send a strong price signal to the market that could benefit distributed assets.

Capacity Adequacy

Policy response: chapter eight

Taking into account the responses received, the government has decided to retain the Optimised CM and Centralised Reliability Options and further investigate their benefits and risks. The government has also decided to retain Strategic Reserve and Targeted Tender/Payment as time-limited transitional and emergency measures only (not as primary mechanisms for capacity adequacy), and to carry out additional work to evaluate their potential benefits and risks in this capacity.

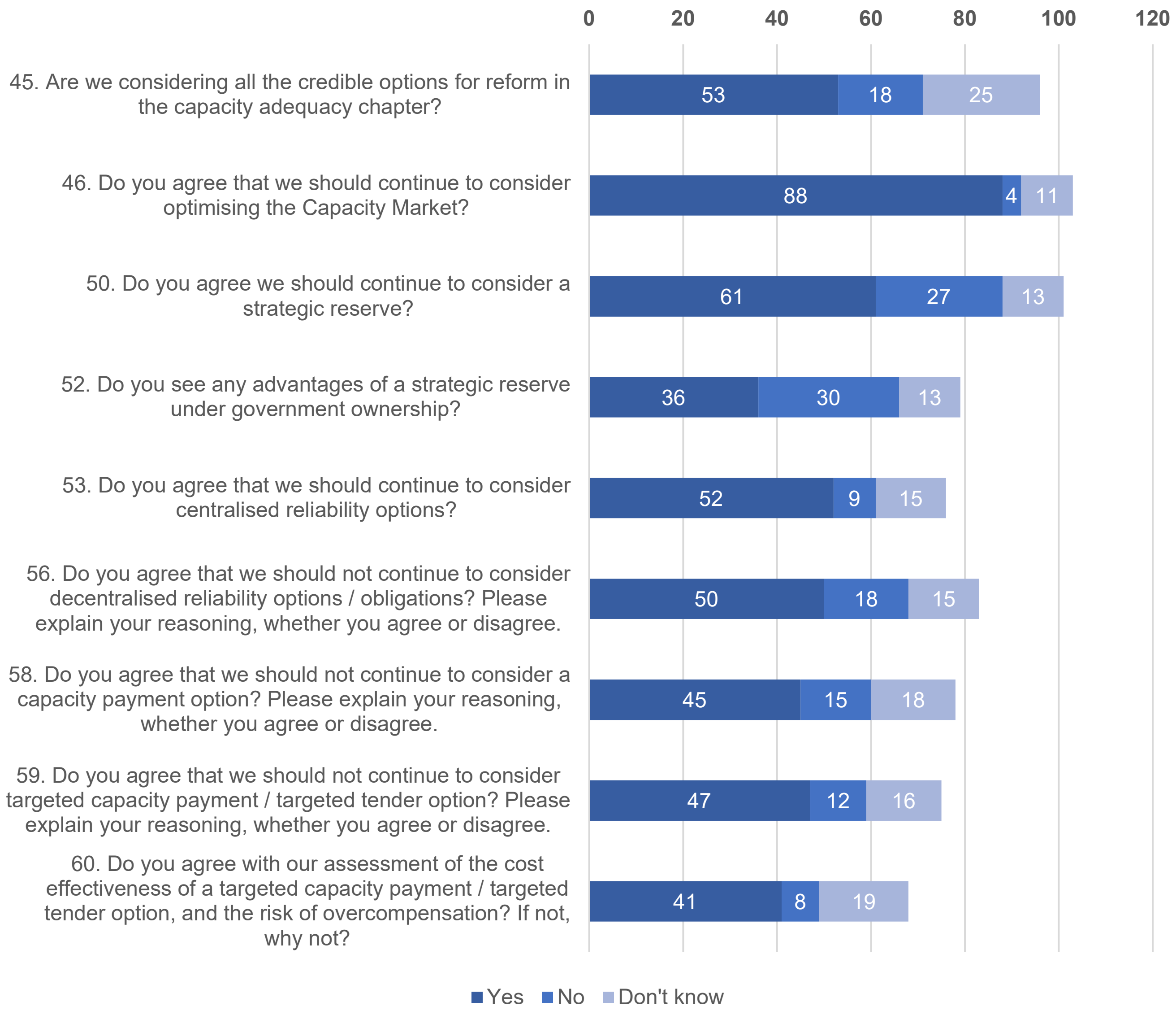
The government will not take forward Capacity Payments and Decentralised Reliability Options due to a lack of evidence to suggest that these would offer benefits relative to existing arrangements.

The government has reviewed the new options put forward and does not propose to include any of these within its formal options assessment process at this time. We note, however, the wide range of smaller design recommendations put forward by respondents and we will incorporate these into our assessment where it is appropriate to do so.

This chapter summarises Questions 45 to 60 of the consultation, which considered a range of issues and options related to ensuring capacity adequacy within electricity market arrangements.

The majority of respondents agreed that all credible options for reform were being considered, and the vast majority supported reforms to the CM to better align it with our decarbonisation objectives. Respondents agreed with the government's minded-to position on less preferred alternatives (decentralised reliability options, capacity payments and introducing targeted tenders) but saw merit in continuing to consider a strategic reserve and centralised reliability options alongside reforms to the CM.

Figure 7: A graph to show the number of respondents who agreed, disagreed and were unsure in response to Questions 45 to 46, 50, 52 to 53, 56 and 58 to 60.



Options under consideration

Summary of responses

Question 45 (96 responses) sought views on whether we are considering all credible options for reform in the capacity adequacy chapter.

- The majority of respondents (55%) agreed that we considered all credible options for reform. These respondents favoured prioritising optimising the CM and focusing on shorter-term reforms as flagged in the 2021 Call for Evidence.

- Of those who disagreed (19%), questions were raised about the purpose and role of the CM in a decarbonised power system, and suggestions included additional capacity mechanisms for consideration and implementing more than one capacity adequacy option.
- Other respondents suggested reforms should focus on the transition and exit of unabated gas, driving investment in grid infrastructure, and incentivising demand reduction and flexible technologies.

Optimising the Capacity Market

Questions 46 to 49 consulted on modifications to the existing Capacity Market mechanism and how it could best be aligned with the REMA objectives.

Summary of responses

Question 46 (103 responses) sought views on whether the government should continue to consider optimising the CM.

- Most respondents (85%) agreed that the Optimised CM reform option should be taken forward.
- Of those who provided further detail, many felt that an evolutionary approach would best support continued investor confidence, and that introducing changes to what is a well-established and well-understood mechanism would be less disruptive and simpler to implement and administer relative to introducing an alternative.
- Some respondents noted the need to review and clarify the purpose and objectives of the CM, flagging the risk of trying to address too many issues simultaneously.
- A few respondents had mixed views or disagreed with the proposal, most without providing a rationale.

Question 47 (69 responses) sought views on whether Separate Auctions, Multiple Clearing prices, or another unidentified route would best meet the REMA objectives.

- Responses to this question were mixed. Of those who answered the question, a few respondents suggested both multiple clearing prices and separate auctions could achieve similar results.
- A few respondents felt that it was too early to decide which design option would deliver better results and identified complexities and potential issues with both options. These respondents felt more developed policy proposals were necessary to express a preference.
- Those who expressed a preference were almost evenly split between multiple clearing prices and split auctions. Most respondents who preferred multiple clearing prices felt they would ensure sufficiently competitive tension and maintain simplicity in the auction

by retaining a single pot. The majority of these responses flagged the potential negative impact on competition and liquidity if the auction was split, the added complexity in setting parameters for different auctions and the danger of under or over-procurement, with cost implications.

- A few responses also acknowledged that the introduction of multiple clearing prices could result in price volatility.
- Respondents who supported the introduction of split auctions cited the potential benefit these could bring for flexible generation and wider system benefits, but also shared concerns about the potential risks, such as impact on auction liquidity and impact on cost

Question 48 (68 responses) sought views on whether the Capacity Market alone would be sufficient for ensuring capacity adequacy in the future, or whether additional measures could be needed.

- Responses were mixed; views were broadly evenly split between agreeing and disagreeing.
- Respondents highlighted the need to consider long duration storage and flagged the crucial role of flexible technologies in ensuring future security of supply.
- A few respondents highlighted the need to continuously improve the CM. Responses noted that the government may wish to consider the use of last-resort emergency measures for the transition to a decarbonised system, such as a strategic reserve.
- A few respondents agreed that the CM would sufficiently ensure future capacity adequacy provided that existing issues with the scheme are resolved (for example, avoiding locking in unabated gas under multi-year agreements, administrative complexities, and the eligibility of interconnectors).

Question 49 (63 responses) sought views on whether other major reforms were necessary to ensure the CM meets the REMA objectives.

- Responses focused on a wide range of recommendations, flagging the need to improve grid infrastructure investment in parallel with any changes, the changing nature of capacity adequacy and the role of peak demand, and the support needed for flexible technologies.
- A few respondents felt further reforms were unnecessary; others flagged the need to prioritise shorter-term reforms to the CM on areas such as secondary trading, the approach to calculating derating factors, interconnector eligibility, and reform to the penalties regime.

Strategic reserve

Questions 50 to 52 consulted on the option to introduce a strategic reserve, its compatibility with other capacity mechanisms, and the benefits and drawbacks of a government-owned reserve.

Summary of responses

Question 50 (101 responses) sought views on whether we should continue to consider a strategic reserve.

- Respondents were largely sceptical of a strategic reserve, but nonetheless a majority (60%) felt it should not be ruled out and could be useful alongside another mechanism if necessary for security of supply. These responses suggested a strategic reserve should only be used as a last resort in exceptional circumstances - as a time-limited transitional measure as fossil fuel generation facilities retire, or a backstop in case sufficient capacity cannot be procured in the main mechanism.
- Some respondents favoured a strategic reserve given current concerns about security of supply. Others noted that a strategic reserve could allow the rest of the market to operate ‘normally’, and that it could take high carbon plant out of the main capacity mechanism. Some felt it might be the most cost-efficient way to ensure adequate reserve capacity, especially for legacy fossil fuel plants. Respondents highlighted the need to fully understand the costs and benefits of a strategic reserve and its potential implications for different technologies.
- Some respondents were concerned by the potential for market distortion. Specific observations included the potential for adverse impacts on the CM clearing price and on wholesale market liquidity; some respondents recommended excluding strategic reserve participants from competitive markets and signalling a strategic reserve well in advance of the corresponding T-4 CM auction.
- Others flagged the potential for a strategic reserve to incentivise relatively unreliable high carbon plant to run longer than planned at high cost (and closing if not given a reserve contract), and/or questioned the extent to which a strategic reserve would be compatible with our decarbonisation objectives, depending on its design. Some felt that a strategic reserve could skew the technology mix toward supply-side technologies rather than demand-side technologies, based on international examples. Some respondents also cited cost-effectiveness concerns.

Question 51 (46 responses) sought views on options that would work best alongside a strategic reserve to meet flexibility and decarbonisation objectives.

- Only a very small number of these responses gave an opinion on which option would be most suitable alongside a strategic reserve.

- Of these, the majority preferred an optimised CM (e.g. enhanced for renewables and flex); some suggested Centralised Reliability Options or Decentralised Reliability Options. One respondent suggested it did not matter which other capacity renumeration mechanism was paired with a strategic reserve.

Question 52 (59 responses) sought views on whether there were any advantages of a strategic reserve under government ownership.

- Some respondents did not agree with a government-owned reserve, predominantly due to value-for-money concerns, though nearly half (46%) could see advantages.
- Some noted the importance of ensuring cost effectiveness of any ownership model, as well as avoiding market distortions. One respondent argued that public ownership of assets would be more secure and cost-effective than the private sector, if only used occasionally. Others considered that government ownership could be beneficial in cases where private interests were not aligned with wider system goals, and that it was therefore logical for government/the public to have ownership either for cost, commercial or security of supply reasons.

Policy response

Taking into account the responses received, the government has decided to retain the option of a strategic reserve as an emergency or transitional measure. A strategic reserve is not our preferred option - we only expect to progress the option if evidence suggests it is absolutely necessary. However, the government believes there could be merit in exploring how this mechanism could be used alongside others to help address specific security of supply/capacity needs in case we feel it would be needed in the future, or to enable the transition away from high carbon technologies on the pathway to full decarbonisation.

Centralised reliability options

Questions 53 to 55 consulted on Centralised Reliability Options (CROs) as an alternative to retaining the CM, and whether additional market interventions would be necessary if they were introduced.

Summary of responses

Question 53 (76 responses) sought views on whether the government should continue to consider Centralised Reliability Options.

- The majority of respondents (68%) agreed that we should continue to explore CROs, although a number noted it was not their preferred option. These respondents agreed with the arguments DESNZ set out in the consultation document; namely that the CRO could potentially provide a better incentive for generators to be available and could help create more price stability in times of stress events.

- Some of those who disagreed pointed out that CROs had been considered and discounted previously as part of the Electricity Market Reform programme, and others noted issues with international CRO models (for example, the assumption that assets with a capacity obligation will be dispatched when the strike price is exceeded, and the fact that a CRO model does not suit assets which need to sell in forwards markets). Some felt that CROs could deter investment and create barriers for smaller generators due to their additional complexity and risk. Respondents also felt that whilst CROs could offer benefits under existing market arrangements, they would not be suitable for a decarbonised power system.

Question 54 (53 responses) sought views on whether there were any advantages CROs could offer over the CM.

- The majority of advantages cited were those already set out by DESNZ as reasons for CROs being one of the preferred options; these included security of supply (through the more substantial penalty regime), reduced impacts on wholesale prices and cost-effectiveness.
- Other responses included stronger incentives for demand side response (DSR) and low carbon technologies (due to preserving sharper wholesale price signals), though some of these responses also suggested that changes to the CM could achieve the same results with less disruption.

Question 55 (46 responses) sought views on which other options or market interventions would be needed alongside centralised reliability options, if any.

- Some respondents suggested that another capacity adequacy measure, such as a strategic reserve, would be needed. Others suggested that local balancing would be required, as balancing at the local level would reduce the number of interventions required and decrease the likelihood of stress events. A few respondents felt that a CRO would need to be accompanied by a cap and floor for long-duration storage; others felt CROs could be modified such that additional interventions would be unnecessary.
- Although not the favoured option for most respondents, there was solid support for continuing to explore the potential of CROs to determine the extent to which the theoretical advantages they offer could be realised in practice in GB. While many pointed to the fact there have been issues with international examples, others suggested mechanisms that might resolve these challenges, which warrant further consideration.

Decentralised reliability options

Questions 56 and 57 consulted on the option to introduce decentralised reliability options (DROs), as well as the possibility of isolating specific design aspects and incorporating these within another option.

Summary of responses

Question 56 (83 responses) sought views on whether the government should discount DROs.

- The majority (60%) of respondents agreed with the government's minded-to position that DROs should be discounted. These respondents largely reiterated the reasoning set out in the consultation; additional arguments included that it would hinder investment, discourage participation (especially of flexible assets) and that it would be administratively too complex. Some felt that security of supply should be a government responsibility and that suppliers would not want this burden.
- Those who disagreed (22%) felt that DROs had advantages due to the incentives for suppliers to procure locally that could facilitate innovation and flexibility. Others felt that suppliers and aggregators were much closer to the needs, preferences, and assets of consumers. Some suggested that a decentralised policy framework based on outcome-based policy mandates would be significantly more technology neutral compared to the current approaches under the CfD/CM.

Question 57 (45 responses) sought views on whether there were any benefits within DRO models that we could isolate and integrate into one of the preferred options.

- Most responses to this question focused on the benefits of a DRO model in general rather than drawing out elements that might be applied within a different model.
- One respondent suggested that any centralised option will struggle to deal with the massively increased number of electricity market participants they saw in the future.

Policy response

The majority of respondents agreed that we should not continue to consider this option, though some provided well-argued reasoning around the potential benefits, particularly innovation in low carbon and flexibility – especially in a system with many smaller and local generators.

However, there was no evidence put forward to invalidate the government's original rationale for not making DROs a preferred option due to the increased risks to security of supply; the strong weight of opinion among respondents was to discount the option due to its complexity, the scale of potential upheaval, and security of supply concerns.

Therefore, though the government recognises that this option does offer some beneficial design components, we have decided not to take DROs forward into the next stage of assessment at this time.

Capacity payment

Summary of responses

Question 58 (78 responses) sought views on whether the government should continue to consider a capacity payment option.

- The majority of respondents (58%) agreed with the Government's minded-to position to not pursue this option further and agreed with the concerns set out in the consultation. These included cost-effectiveness (e.g., from difficulties setting the appropriate price) and whether the option would sufficiently incentivise new build capacity. Many respondents flagged that the price variability would provide less revenue certainty and would harm investment. Some also highlighted the potential for insufficient competition.
- Those that disagreed felt that an availability style payment could be necessary for renewables and flexible generation when not running (similar to a deemed CfD), and that remuneration of capacity adequacy should be linked to real-time dynamic price signals. Other responses favoured the simplicity of capacity payments. Another response noted that a capacity payment could be helpful for renewable projects with high upfront CAPEX costs but low running costs, or to reward technologies meeting wider system needs.

Policy response

The government outlined concerns with introducing capacity payments in the consultation, including cost effectiveness and dangers of over-remuneration, which were shared by many respondents. There remain outstanding concerns whether the capacity payment would incentivise new investment. There was, in the main, a lack of support for the option and limited compelling evidence to continue considering it, as opposed to other options where design changes might be able to offer some of the same potential benefits such as improving availability and incentivising delivery. The government has therefore decided not to take this option forward into the next stage of assessment.

Targeted tender or targeted capacity payment

Questions 59 and 60 consulted on the option to use targeted tenders or targeted capacity payments to ensure capacity adequacy.

Summary of responses

Question 59 (59 responses) sought views on whether the government should continue to consider targeted tenders or targeted capacity payments.

- The majority of respondents (63%) agreed with the government's minded-to position not to consider this option further. These responses flagged the risk this mechanism could pose by not providing support for existing capacity, as well as the risk of relying on a central body to determine longer-term system needs. A few recognised that a targeted tender could be beneficial for addressing specific and/or emergency system needs.
- A small number of respondents (16%) disagreed and felt that ambitious decarbonisation targets required a diverse range of tools to respond. These respondents felt that the urgent need to decarbonise and maintain security of supply could not be left to the market alone to effectively address the complexities of procuring the optimal mix.

Question 60 (68 responses) sought views on the government's assessment of potential cost effectiveness and overcompensation risks associated with the introduction of targeted tender/payment.

- The majority of responses (60%) agreed with the government's assessment, with a few querying whether alternative mechanisms could ever completely minimise or resolve issues around cost effectiveness, potential overcompensation and liquidity risks.
- A few respondents disagreed, flagging that the overcompensation risk might be overstated, but did not provide further evidence to support this.

Policy response

There is a lack of evidence to suggest that introducing this mechanism would translate to more effectively addressing security of supply challenges or meeting decarbonisation targets than the existing arrangements. Taking into account the responses received, the government has decided not to consider targeted tender/payment as a stand-alone mechanism for future policy exploration.

However, the government believes there is merit in exploring how a version of this mechanism, or isolated beneficial design components, could help address specific and time-limited capacity or wider system needs. The government has therefore decided to retain targeted tender/payment as an emergency or transitional measure. The government intends to carry out additional work to determine the extent to which the theoretical advantages could be realised in practice, and how the risks could be minimised.

Operability

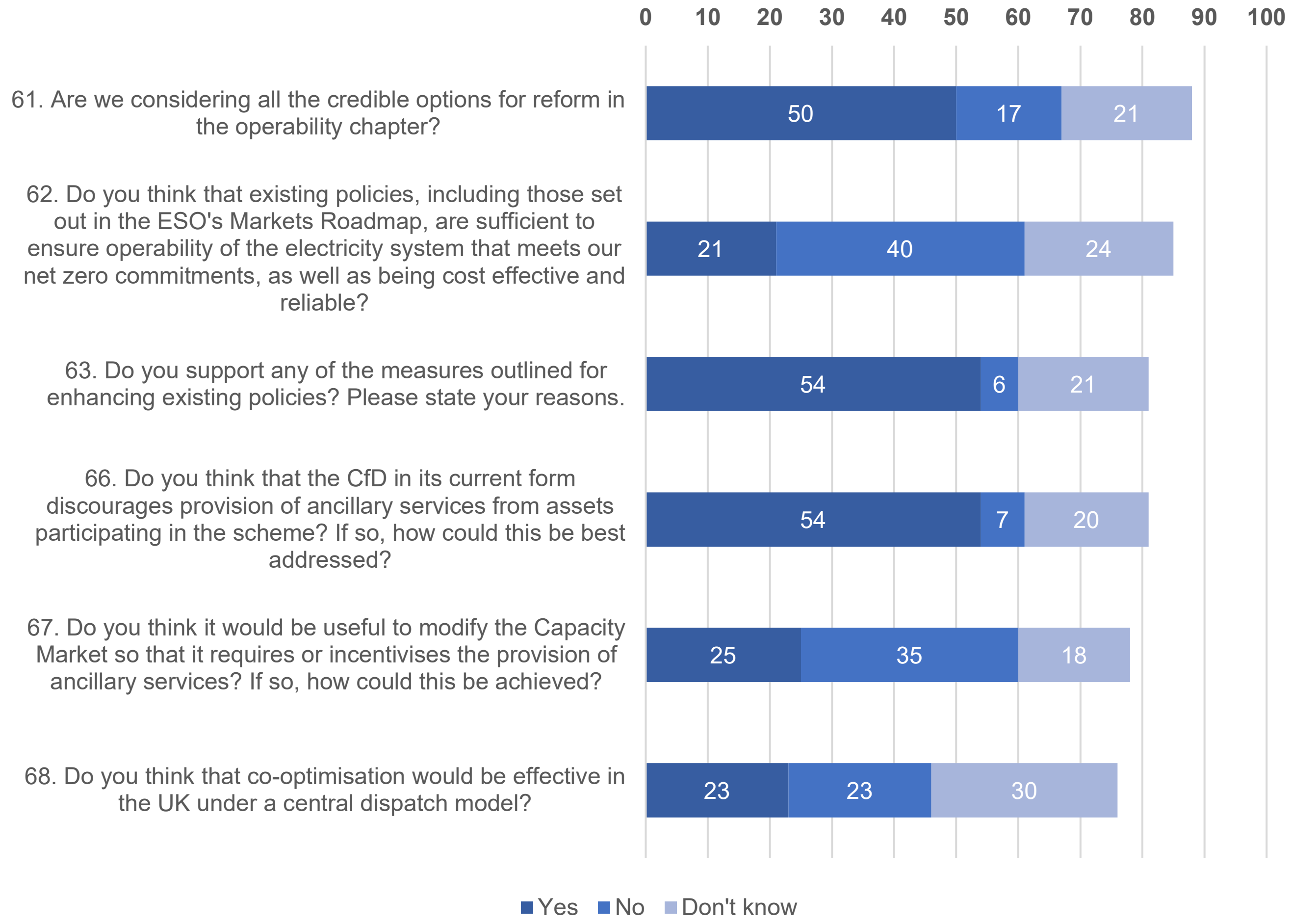
Policy response: chapter nine

Taking into account the feedback received, the government has decided to retain all options under consideration in the operability chapter. We have reviewed the additional options put forward and will consider them within our assessment where it is appropriate to do so, including the option to create a separate constraint management market.

This chapter summarises responses to Questions 61 to 68, which consulted on a wide range of options for ensuring operability of a low carbon electricity system; these included continuing with existing policies, incremental modifications to existing arrangements, developing local ancillary services markets, modifications to the CfD and/or CM, and co-optimisation with the wholesale market.

The majority of respondents agreed that all credible options were considered. A majority also felt that continuing with the status quo was not a viable option. There was substantial support for enhancing existing policies and for improving the level of coordination between ESO and DNOs. Respondents also saw merit in amending the CfD to incentivise ancillary services though were more mixed on modifying the CM and on introducing co-optimisation within wholesale markets.

Figure 8: A graph to show the number of respondents who agreed, disagreed and were unsure in response to Questions 61 to 63 and 66 to 68.



Options under consideration

Summary of responses

Question 61 (88 responses) sought views on whether the Government has considered all credible options for reform to operability.

- The majority of respondents (57%) agreed that the Government considered all credible options.
- A smaller, but still significant number, proposed additional areas for intervention. One of the most frequently raised was the need to address IT and digitalisation issues with ESO which are seen as threatening the ability of delivering the objectives that are set out in the consultation. A number of respondents called for more transparency by ESO in its decision making.

- Some asked for greater consideration of how demand-side response technologies, like those which could be fitted to consumer devices, could be brought into the system to provide operability services like frequency response and inertia.
- Several respondents called for consideration of markets for network congestion management, with one respondent commenting that a constraint management market could be implemented under current national pricing arrangements. These options would be additional to options that we are considering for wholesale market reform which could help reduced network congestion.

Continuing with existing policies

Summary of responses

Question 62 (85 responses) sought views on the extent that existing policies, including those set out in the ESO's Markets Roadmap, are sufficient to ensure operability of the electricity system that meets our net zero commitments, as well as being cost effective and reliable.

- Of those who expressed an opinion, some respondents (47%) did not believe that existing polices would be sufficient to meet the Government's objectives for operability. Concern was expressed by a number of respondents at the perceived lack of pace in progressing reform, including implementation.
- While some respondents welcomed initiatives such as the ESO's markets roadmap, the joint BEIS and Ofgem Smart Systems and Flexibility Plan as steps in the right direction, this was qualified by disappointment that they did not provide sufficient confidence that a reliable and low carbon system could be delivered in the required timescales.
- The point was made that full decarbonisation of the whole electricity system's operation is too great a challenge to be left to these and other current measures, with some expressing the view that the current approach is not attracting sufficient investment to replace fossil fuel-based operability resources. Inadequacy of current market signals for future investment in low carbon operability assets was cited as a factor in explaining why insufficient investment in low carbon operability was coming forward. It was pointed out that some operability services remain stubbornly dominated by thermal providers.
- Some respondents, however, were content that the current approach was working at least reasonably effectively and were wary of radical reform.

Enhanced existing policies

Summary of responses

Question 63 (81 responses) asked consultees if they supported any of the measures outlined for enhancing existing policies set out in the consultation.

- A large majority of respondents (67%) agreed: most supported at least one of the sub-options for enhanced existing policies. A significant minority supported all four, and very few respondents opposed all four sub-options.
- The sub-option of giving the ESO or Future System Operator the ability or an obligation to prioritise zero/low carbon procurement received the highest level of support with the support of a majority of respondents. Proponents argued that this would help accelerate the net zero transition, including by reducing deployment of high carbon supply and de-risking investment in innovative technologies by giving greater confidence that they are likely to attract a certain level of revenue. A few respondents commented that carbon pricing could be relied upon to decarbonise ancillary services.
- A significant proportion of respondents supported a requirement for the ESO to determine an optimal balance for procurement of ancillary services between long-term contracts and close to real time markets, with a few noting that this could attract a range of technologies which required more certainty for financing. A very small number of respondents opposed this sub-option.
- The sub-option of aligning the CM and CfD tenders with those for ancillary services received the support of a substantial proportion of respondents. Arguments in favour included that coordinating timings would make it easier for developers to align and stack revenue streams from the different markets. The point was also made that it would provide more revenue visibility to the providers to aid and inform their investment planning/decisions. A small number queried the practicality of the sub-option, pointing out that the CfD and CM operate on longer-term contracts for prospective assets (e.g. up to 15 years), whereas some Ancillary Services are increasingly procured over shorter timescales. It was also suggested that alignment could create a barrier to entry for smaller providers.
- The sub-option to introduce a matrix approach to ancillary service provision attracted the support of nearly half of respondents. It was argued that this would enable greater transparency in assessing the technical feasibility of providing multiple services and potential of revenue stacking. This could lead to lower bids and greater levels of participation. A small number of respondents opposed this sub-option. Concerns were raised on the complexity and lack of transparency that could result.

Developing local ancillary services markets

Questions 64 and 65 consulted on options and interventions that could facilitate the development of local ancillary services markets.

Summary of responses

Question 64 (71 responses) sought views on the extent that existing and planned coordination activity between ESOs and DNOs ensure optimal operability.

- A majority of respondents did not believe that existing and planned coordination activity between ESOs and DNOs will ensure optimal operability. Some of them expressed a lack of confidence in the capability of existing measures to promote the improved integration between the national and local networks that will be necessary for the transition to a low carbon system.
- Some referenced the lack of progress in coordinating system operability activity between the ESO and DNOs/DSOs through the Open Networks Project. The need to take prompt action to formalise DNO/DSO governance arrangements following Ofgem's review into the effectiveness of institutional and governance arrangements at a sub-national level, was raised by some respondents. The need to invest in digitalisation and improve exchange of data between DNOs and the ESO to support the operation of an increasingly complex system was singled out as a priority.
- Respondents drew attention to the need to improve the visibility of assets on all parts of the network so that system operators can make the best whole system decisions. It was pointed out that this is likely to become more challenging with the electrification of heat and transport at the local level and the aggregation of domestic assets. Evidence was provided, however, of progress in some areas, including the commissioning of a coordinated visibility and control system by a DNO.

Question 65 (69 responses) asked stakeholders to comment on the scope, if any, for distribution level institutions to play a greater role in maintaining operability and facilitating markets than what is already planned, and how could this be taken forward.

- A majority of respondents were of the view that there is scope for distribution level institutions to play a greater role in maintaining operability and facilitating markets than under current plans.
- A number of respondents mentioned the need for DNOs/DSOs to play a more active role in maintaining operability in areas like constraint management, voltage and stability. Some tempered their support for a greater role for DNOs/DSOs in operability, however, by drawing attention to the importance of the ESO retaining a central coordinating function.
- Several respondents highlighted the need for some ancillary services like frequency support and reserve to be managed at the national level. As mentioned in responses to question 64 on DSO-ESO coordination (above), lack of data transparency is seen as an obstacle to DNOs/DSOs and ESOs being able to address operability issues effectively at a local level.
- Several respondents pointed to the need for standardisation of DNO/DSO products to enable greater market participation. Standardisation was also mentioned as important for DSO rules and tendering arrangements to aid liquidity. The lack of expertise of DNOs to take on more responsibility was mentioned by some respondents.

Changes to CfD design to support low carbon ancillary services

Summary of responses

Question 66 (81 responses) sought views on whether the CfD in its current form discourages provision of ancillary services from assets participating in the scheme and - if so - how this could best be addressed.

- A large majority of respondents (67%) believed that the CfD in its current form discourages provision of ancillary services. Respondents noted that generators like windfarms, for example, would need to make uncompetitively high bids to provide ancillary services to offset the amount of lost revenue under their CfD. Moreover, it was also argued that the current structure of the CfD discourages providers from installing the relevant equipment to provide ancillary services. For example, the cost of installing grid-forming technology to deliver inertia and Short Circuit Level (Stability), would necessitate a higher CfD bid price which might not be cleared in the CfD auction. A number of suggestions for reform were presented including changes to the support mechanism, for example a move to deemed generation or revenue cap and floor. Alternatively renewable projects could receive additional payment or priority in the CfD auction where they have made plant capable of delivering low carbon ancillary services.
- Some respondents expressed concern that the current CfD does not provide adequate incentives for hybrid projects (for example offshore wind with long duration energy storage).
- A few respondents commented that it was important that provision of ancillary services should not be mandatory in CfDs as this could deter investors. It was also pointed out by one stakeholder that there are no contractual barriers within the CfD to the participation of CfD generators in balancing services and that a large proportion of CfD projects are active in the Balancing Market. A few pointed out that the increasing share of electricity from low marginal cost renewables, like wind, could mean that in the future ancillary services will be a more attractive source of revenue than the wholesale market, reducing the need for a modification in the CfD for the purpose of incentivising generators to supply ancillary service markets.

Changes to Capacity Market design to support low carbon ancillary services

Summary of responses

Question 67 (78 responses) asked consultees if it would be useful to modify the CM so that it requires or incentivises the provision of ancillary services and - if so - how this could be achieved.

- Respondents were fairly evenly divided on whether the CM should be amended to incentivise the provision of ancillary services. A number of respondents felt that the option was worth considering but a careful assessment would need to be undertaken due to the potential complexities involved and the risk of unintended consequences, such as distorting short-term markets.
- A number of suggestions were offered for the form that incentives could take, including multipliers to reward flexible assets for characteristics such as faster response times. It was also suggested that REMA should consider different auction parameters, including potentially different auction pots, minima and/or differential pricing based on attributes.
- Some of those who disagreed with the need for modification pointed out that most assets are already able to "stack" their ancillary services revenues in the CM.
- Some queried how regional/local operability requirements would be factored in the option. A few respondents suggested that changes could be made to add operability services such as voltage control, and these could be auctioned against locational or temporal criteria.
- A few respondents said that they would support the option as long as provision of ancillary services would not be a condition for entry to the CM.

Co-optimisation of ancillary services

Summary of responses

Question 68 (76 responses) sought views on whether co-optimisation would be effective in the UK under a central dispatch model.

- Responses were mixed on this question. Rejection of co-optimisation was largely on the grounds that it would be conditional on a move to central dispatch, which was seen as too radical and disruptive, risking unsettling the market and undermining investor confidence. A number of respondents commented that central dispatch and co-optimisation would be highly complex and impose a major IT burden. It was also pointed out that while co-optimisation may work for national services such as frequency response and reserve, it is far from clear whether it would be suitable for other area specific ancillary services like voltage, inertia and restoration. Some respondents made the point that co-optimisation could make it more difficult to build investment cases for flexible technologies which can currently be demonstrated through revenue stacking. It was also pointed out that self-dispatch allows for adjustments to be made under competitive pressure much closer to real-time, which is important for an energy system with a higher volume of renewables.
- Advocates of co-optimisation argued that the ESO would be in the best position to decide on the optimum future and operational requirements (locations, volume, and timing of flexibility resource needs) and that it would optimise the dispatch of resources while maintaining security of supply. One respondent suggested it would both increase

liquidity of frequency response and reserve markets and give the system operator access to a wider range of resources for energy and balancing needs in near real-time. Several respondents commented that while they disagreed with a move to central dispatch, if a decision was taken to implement it, there would be merit in applying co-optimisation.

Options across multiple market elements

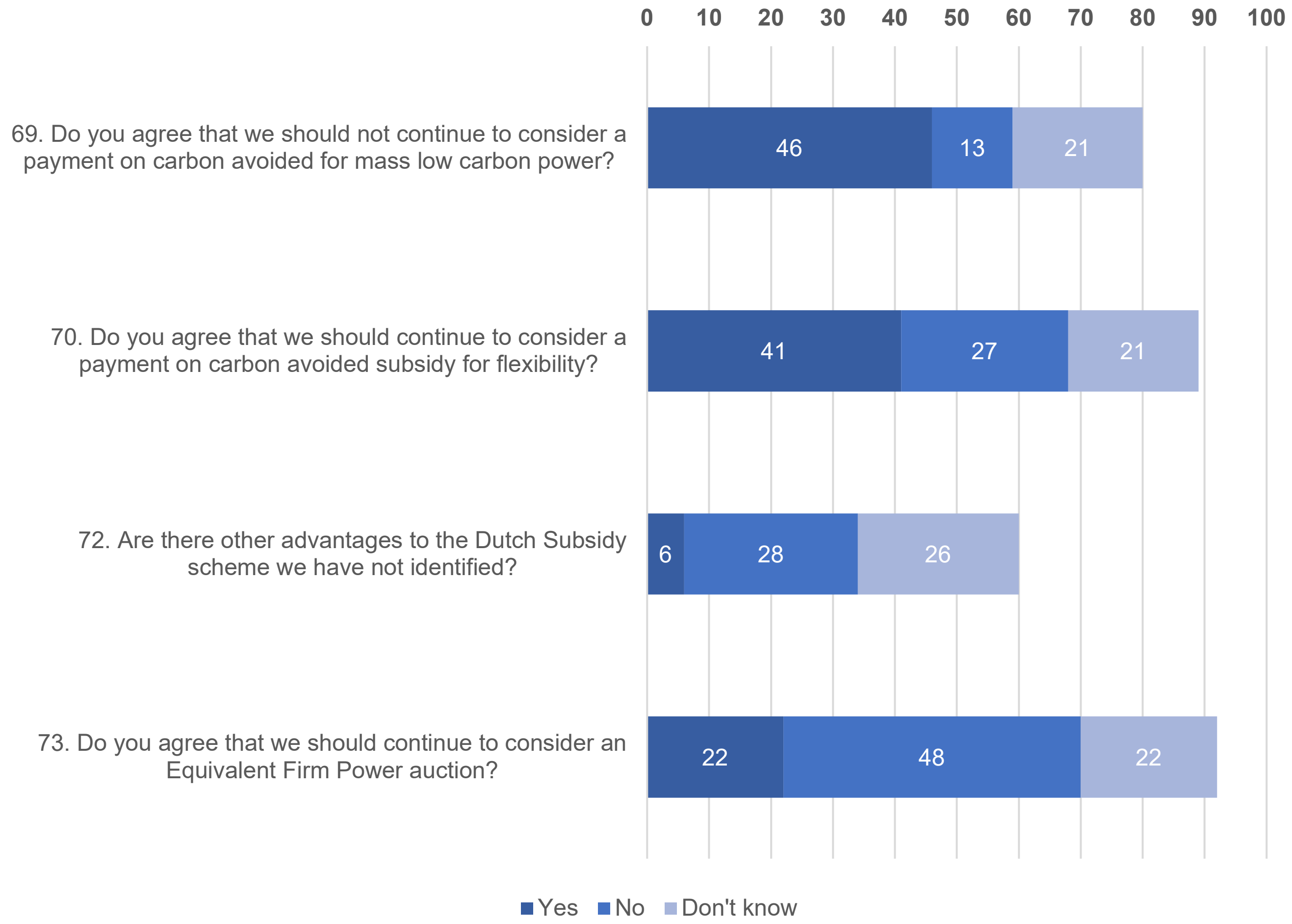
Policy response: chapter ten

The government has decided not to take forward the options considered in chapter ten (a payment on carbon avoided subsidy for either mass low carbon power or flexibility, or an equivalent firm power auction). Respondents were not generally in favour of these options and there were particular concerns about how mandating electricity system assets to individually deliver multiple objectives could undermine system wide efficiency and impact on the cost of capital, and greater uncertainty for investors risking disruptions to investment. Our rationale for discounting these options is set out further under Questions 69, 70 and 73. We are in agreement with the broad objectives of these cross-market proposals - to support the growth and efficient deployment of low carbon power while maintaining a secure system. These proposals also seek to maximise the role of the market and avoid the risks of multiple uncoordinated support schemes and increased complexity. The REMA programme will continue to examine other interventions which support these objectives and enable simplification over time. As part of the REMA programme, we are also considering the potential for convergence of scheme operation that in due course facilitates greater competition between technologies and secures the right balance between the role of markets and continued Government intervention where necessary.

This chapter summarises responses to Questions 69 to 74 of the consultation, which covered options spanning multiple market elements.

Respondents broadly agreed that we should not continue to consider a payment on carbon avoided for mass low carbon power; views were more mixed on such a payment for flexibility, though a few respondents identified additional advantages. Respondents did not support continuing to consider an Equivalent Firm Power auction.

Figure 9: A graph to show the number of respondents who agreed, disagreed and were unsure in response to Questions 69 to 70 and 72 to 73.



Payment on carbon avoided for mass low carbon power

Summary of responses

Question 69 (80 responses) asked whether we should continue to consider a cross-sector avoided-carbon subsidy for low carbon technologies.

- The majority of respondents (58%) agreed that we should not continue to consider this option. Respondents who agreed felt that it would be too complex, undermine investor confidence, disincentivise investment in flex assets and emerging technology, and that it would be better for a possibly revised form of existing carbon markets to help drive decarbonisation in this way.
- There were no common views among those disagreeing with this question.
- Of those who didn't explicitly agree or disagree, many highlighted significant challenges with this option or stated that other options were preferable. Challenges given across all

responses to this question included whether this option would do a better job of decarbonising different sectors than existing carbon markets, and the complexity of introducing and administering a 'Dutch Subsidy' scheme.

Policy response

Taking into account the feedback received that most respondents did not think we should progress this option, and due to its complexity and uncertain benefits, the government has decided not to take a payment on carbon avoided subsidy for mass low carbon power forward for further consideration.

Payment on carbon avoided for flexibility

Summary of responses

Question 70 (89 responses) sought views on whether we should continue to consider a payment on carbon avoided subsidy for flexibility. **Question 71** (52 responses) sought views on whether the Dutch Subsidy scheme could be amended to send appropriate signals to both renewables and supply and demand side flexible assets. **Question 72** (60 responses) sought views on whether there are other advantages to the Dutch Subsidy scheme that we have not identified.

- Some respondents (46%) agreed that we should continue to consider a payment on carbon avoided subsidy for flexibility. Those that agreed suggested that carbon avoided is a good common metric to help fund technology agnostic solutions and could enable low carbon flexible assets to reach price parity with high carbon alternatives. Most respondents that agreed, however, also suggested that more comprehensive carbon pricing could achieve the same outcomes and robust carbon pricing would be preferable to a payment on carbon avoided subsidy.
- Some respondents (30%) disagreed that we should continue to consider this option. These respondents had significant concerns about the unintended consequences that might occur as a result of this approach. Others agreed that a subsidy based on output is not suitable for flexible assets, and that it would be difficult to overcome this issue. A few respondents did not think a carbon avoided subsidy offered value for money for consumers.
- Many respondents to question 71 disagreed that the Dutch Subsidy scheme could be amended to send appropriate signals to both renewables and flexible assets. Respondents suggested that other mechanisms, such as a revenue cap and floor, could be better suited to incentivising deployment of these assets. Few respondents to question 72 (10%) suggested further advantages of the Dutch Subsidy scheme.

Policy response

Taking into account the responses received, the Government has decided to discount a payment on carbon avoided subsidy for flexibility from the REMA programme. Respondents highlighted significant concerns about the complexity of designing and delivering such a subsidy mechanism and provided insufficient evidence to support progressing with design of this option.

However, there are a number of helpful policy recommendations included in the responses to these questions that will be taken into consideration by the REMA programme – for example, the need to ensure that there is sufficient revenue support for deployment of low carbon flexible assets and a need for effective carbon pricing to improve the business case of low carbon flexibility, particularly for small scale flexible assets.

Equivalent firm power auction

Summary of responses

Questions 73 (92 responses) and **74** (51 responses) asked whether DESNZ should continue to consider an Equivalent Firm Power auction to drive mass low carbon power and how challenges to this option could be overcome.

- The majority of respondents (52%) disagreed that we should continue to consider an equivalent firm power auction. These respondents argued that making variable generators (particularly renewables) responsible for ensuring firm supply would not be ensuring that risks are borne by those best placed to manage them, potentially leading to a suboptimal capacity mix, with possible over-procurement of certain kinds of flexibility infrastructure and the penalisation of non-co-located storage. Some also pointed to the increased risk and uncertainty this option could create for these variable generators, leading to increased capital and financing costs.
- Those who agreed argued that this option could improve incentives for flexibility services, which would be necessary for firming up variable power. Other reasons given by those who advocated this option included that it was a technology-neutral approach for procuring new power, and that it would boost security of supply.
- Question 74 received few design recommendations. Of those who provided suggestions, a few said that adding factors such as response time and location into auction design would help overcome the challenges to this option. One respondent also suggested the auction parameters should be set by an independent expert organisation. A few respondents felt that it would be impossible to overcome the challenges.

Policy response

Taking into account the feedback received, the government has decided not to consider this option further at this point in time. A majority of respondents did not think we should progress this option. There was insufficient evidence that putting the responsibility for procuring flexibility on generators, which would likely mean decisions being taken at a project – rather than system – level, would lead to a low-cost capacity mix. Many respondents also expressed concern that this option would increase risks on renewable generators, leading to higher strike prices and overall system costs, without compensating benefits in terms of efficiency or security of supply. We also recognise the ideal is for government to maintain market neutrality and that administratively set parameters are open to influence and do not benefit from the same information discovery benefits more market-based reforms do - though this is likely an aspect of all government interventions, which we will seek to minimise over time and through our market design process.

Annex: Methods

This annex sets out our approach to analysing the consultation responses and its key limitations.

Qualitative analysis: free text responses

Analysis was based on a hybrid qualitative coding approach. Qualitative coding is a structured analytical process for identifying and synthesising key themes, or "codes", within a set of oral or written data (in this case the consultation responses). Officials used a qualitative analysis software package, NVivo, to support this coding process.

Officials developed a high-level coding framework with twenty-five high level codes prior to the consultation closing. These included "sentiment" codes (e.g. "positive", "negative", "neutral"), codes based on wider themes in the consultation (e.g. "extent of competition", "investor confidence"), and more specific codes (e.g. "role of PPAs", "operational signals for flexibility"). Officials subsequently applied these codes when considering responses to the consultation.

Once an initial analysis was completed, codes were refined and officials performed a second round of coding which included additional, more granular codes based on the feedback in responses (e.g. "financial transmission rights", "SEG reform"). These codes were then collectively uploaded into NVivo. One key output from the NVivo analysis was a set of tables that assessed the frequency of each code across each question, which facilitated identifying the key themes within responses.

Quantitative analysis: survey responses

Officials merged responses from CitizenSpace and those provided in responses submitted by email and letter to compile the survey data. The survey data therefore included both data where respondents had provided a clear tick-box answer and data based on a qualitative assessment of sentiment. Responses which did not express a clear opinion were marked as "don't know" for the purposes of compiling the data; those responses that had no opinion or comment to give were excluded from calculations and from the overall number of responses listed.

Key limitations

Whilst officials sought to conduct as systematic and robust an analysis as possible, there are several key limitations to note:

- There is inherently a degree of subjective judgement in using qualitative coding in practice – application of the coding framework may have differed slightly across the different officials reviewing responses

- The number of responses to each question, as well as the extent to which respondents elaborated on their answers, varied significantly across the consultation. Additionally, whilst we received 225 responses, these responses may not form a representative picture of those impacted by electricity market arrangements as a whole.
- Whilst every effort was made to provide an accurate qualitative assessment of responses in compiling the survey data, this again involved an element of subjective judgement.

This publication is available from: https://www.gov.uk/government/consultations/review-of-electricity-market-arrangements

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