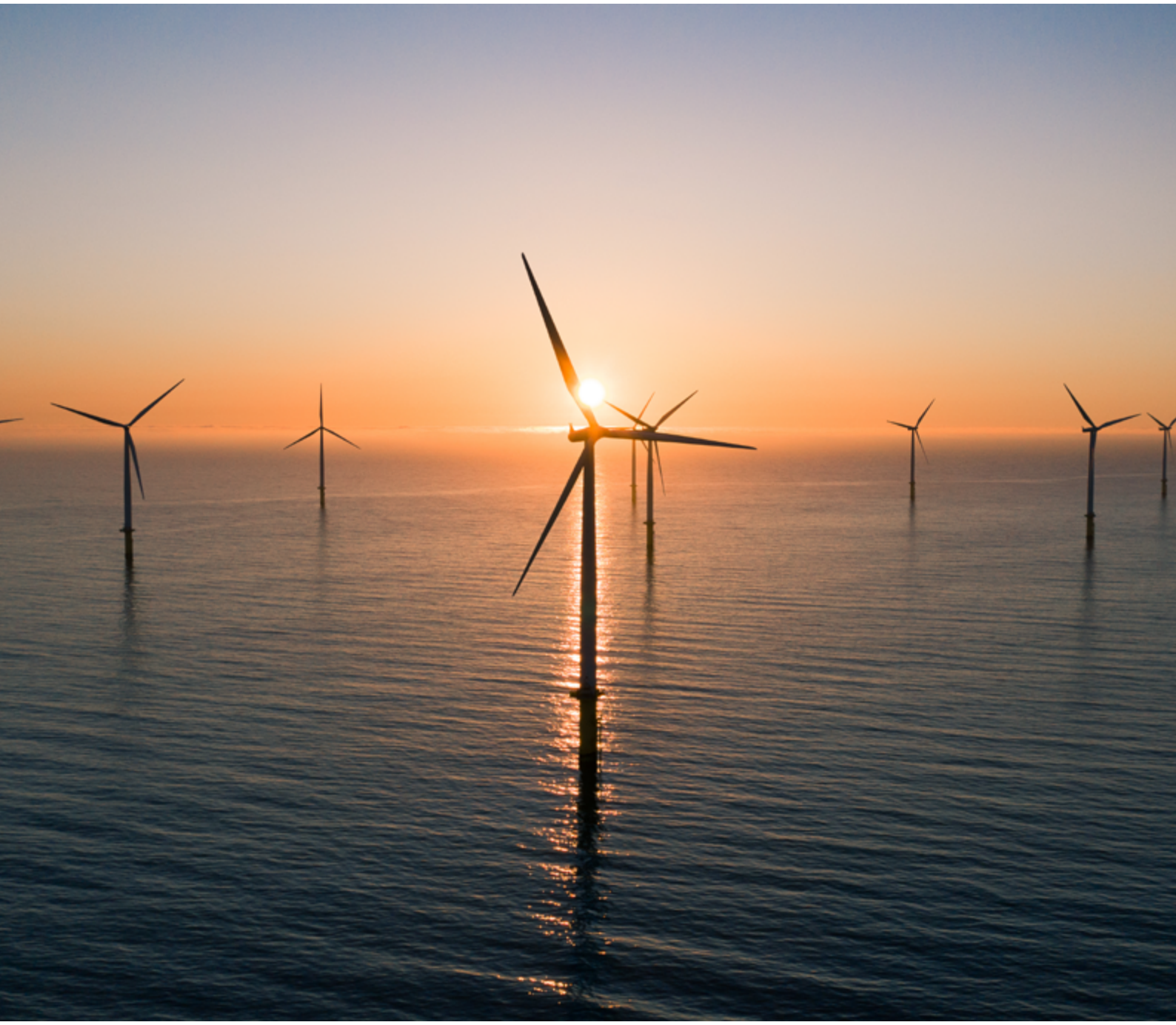
Review of electricity market design in Great Britain

SUMMARY REPORT



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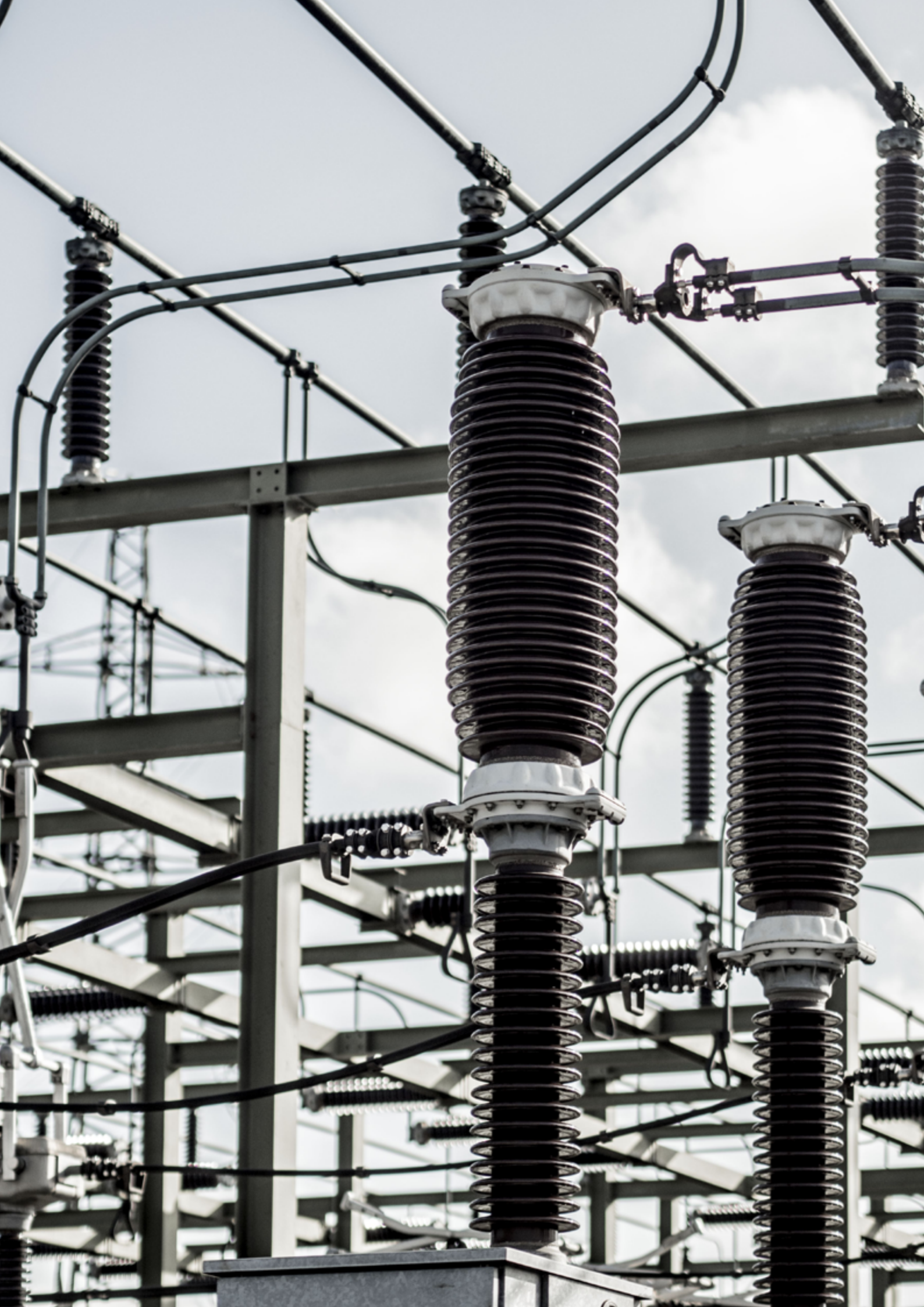

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KEY MESSAGES

1. While there is a case for change, existing arrangements have had significant success in delivering decarbonisation, whereas radical change is likely to deter the necessary investment for the complete decarbonisation of the electricity sector by 2035
2. Wholesale power market reform is not enough on its own; action is also needed in network investment, planning policy, retail markets, and in related areas such as CCUS and hydrogen infrastructure
3. The scale and pace of the investment required to deliver rapid decarbonisation requires a centralised approach to capacity planning and procurement
4. Spot markets with central dispatch are limited in their treatment of flexibility and decentralised resources, whereas decentralised models are limited by their treatment of location and the degree of coordination
5. Locational energy prices improve incentives on market actors for efficient dispatch, but place new risks on investors and participants, increasing the cost of capital
6. Long-term support contracts for renewables will remain necessary to achieve rapid power sector decarbonisation, but need to incorporate improved incentives for efficient operational decisions
7. Capacity markets must adapt to procure low carbon resources while delivering the flexibility needed to manage variations in renewable production
8. Decentralised resources at low voltage levels could become hugely important in system planning, operation and risk management; and must be properly accommodated in all market timeframes
9. In the long-term, a world of state-backed long-term contracts is unlikely to be a desirable final position, and a pathway will be needed to encourage forward contracting, retail innovation and market-led investment
10. While AFRY will undertake further analysis, on an initial evaluation of a range of potential market designs, evolutionary rather than revolutionary solutions appear more credible in delivering a decarbonised GB power sector by 2035

INTRODUCTION

AFRY initiated a multi-party process in Spring 2022 to consider options for GB market reform. This was inspired by the National Grid ESO's net zero reform programme, and the REMA process which has since been launched by BEIS.

AFRY works globally on market design and provides commercial analysis, strategic and operational advice for private investors and operators. We have experience with a wide range of centralised and decentralised markets, which has given us a deep insight into the merits of alternative designs.

We have conducted many similar multi-party exercises looking at future market evolution. Our intention in each case was to reach conclusions which are valid from an economic perspective, not from particular interest groups. Although on this occasion the funding has been from private market participants, our members have a broad range of interests, we have involved independent stakeholders in the discussions and we believe that our findings are neutral towards industry and consumers' interests.

This report is the work of AFRY and presents our own views on the ways forward. We are grateful to the clients who have supported the work, both financially and through their active participation in the debate. We also extend thanks to observers from NGESO, Ofgem and BEIS who have – to varying degrees – joined actively in the discussions of the group. Despite these contributions, this report represents the independent opinion of AFRY, and the opinions may not be attributed to any of the parties who supported the process.

This report is the first in a two-phase project. The first phase has concluded with this report, which sets out alternative reform packages each with a qualitative evaluation. The forthcoming second phase will apply quantitative analysis to the alternative market models.

An immediate observation is that there are no functioning market models which effectively value both location and flexibility in the context of a renewables-dominated system, and no market design in existence is truly suitable for a decarbonised world. New thinking is required.

THE ROLE OF THE MARKET IS TO BRING TOGETHER SUPPLY AND DEMAND

The purpose of a market is to allow the effective co-ordination of supply and demand over both investment and operational timeframes. Although the power market design will not be the sole driver of investment decisions in adjacent sectors (e.g. CCUS, hydrogen networks), it must deliver appropriate incentives for effective siting and flexibility. Many of the new resources and electricity demands can be flexible if suitably designed, and a cost-effective energy transition can only be achieved if these resources are integrated into the electricity system.

Markets operate from several years ahead until close to real time. The sequence of forward markets allows buyers to manage energy procurement and sellers to plan maintenance, fuel procurement and operations. The forward markets are a vital part of the overall process of planning and risk management, and any future market arrangements must allow these processes to work effectively.

THERE ARE MANY POSSIBLE PATHS TO FULL DECARBONISATION, BUT EACH HAS COMMON ELEMENTS

The UK Government has committed to decarbonise the power sector by 2035 and to achieve a net zero economy by 2050.

It is important to define the world for which the market design is intended. We have chosen the 2025-2035 timeframe: a rapid transition to a fully decarbonised power system. Our working definition of a fully decarbonised power sector is based on achieving net zero emissions within the power sector itself i.e. negative emissions from biomass power generation with CCUS would be permitted, but the offsetting of emissions in other sectors through the purchase of emission credits would not be.

There are widely diverging decarbonisation pathways, but each requires:

- accelerated investment in generation from zero carbon energy sources, particularly renewable energy sources (RES)
- deployment of technology and tools to support flexibility and system stability;
- substantial build of interconnection, transmission and distribution networks;
- electrification of heat, transport and industrial demand;
- deployment of new technologies, including CCUS and/or hydrogen infrastructure.

Common themes are: sharply increased demand at lower voltage levels, continued need for congestion management, and a growing reliance on variable RES generation which must be balanced by other flexible resources.

Today's electricity market and supporting contractual framework has been successful in delivering change, but the transformation to 2035 and beyond cannot credibly be delivered without some change to the existing arrangements.

THE EXISTING ARRANGEMENTS HAVE BEEN SUCCESSFUL IN DIRECTING INVESTMENT TOWARDS LOW CARBON PRODUCTION

We have already achieved major steps towards decarbonisation, with Great Britain power sector emissions falling by 68% between 2010 and 2020 , with support contracts in place for renewable and new nuclear generation, and fast-track 'connect and manage' arrangements to allow generation to connect quickly before grid reinforcements can be delivered. The CfD renewable support scheme and its predecessors have delivered 27GW of new low carbon capacity since 2014, compared to a current total UK installed capacity of around 75GW. The capacity market supports providers – including demand side providers – to meet system peak demand, and has delivered nearly 15GW of new capacity since its introduction in 2014 .

The regulatory regime enables innovation in system operation and network development, in particular allowing a substantial share of expected distribution network development cost to be offset through 'flexibility' instead of asset construction. Locationally-varying transmission network charges and losses give financial incentives for generators to connect closer to demand.

New interconnectors continue to be developed under the 'cap and floor' regulatory regime, with awards in principle having been made to 9 interconnector projects with a total capacity of 10.9GW since the first award in 2014. NGESO is developing new system services, offering long term contracts to enable investment. The regulatory framework has enabled offshore HVDC transmission to be developed, including point-to-point connections and alternatives to land-based transmission projects.

With the combination of support contracts for RES, new nuclear and the centralised capacity mechanism, today's power market has veered towards a centrally planned system for the quantity of new capacity, but arguably without the benefit of co-ordination that central planning implies.

THE EXISTING ARRANGEMENTS FACE MATERIAL CHALLENGES IN THE CONTEXT OF CONTINUING DECARBONISATION

In operational timeframes, the system of 'self-dispatch' and residual balancing is under strain: NGESO is re-dispatching a growing share of the market, with high system and constraint costs which are ultimately passed to customers. An increasing share of renewable output is being curtailed, and it seems unlikely that grid build will catch up with renewable deployment in the coming decade or more. Interconnector flows can exacerbate transmission constraints, with potential for significant swings close to real time.

Output-based support contracts fail to incentivise efficient dispatch, and legacy RES contracts can result in negative pricing in the spot or balancing markets, distorting market pricing for all resources.

Looking forward, there are fears that excess renewable output might drive energy prices to (or below) zero for extended periods – if generation deployment continues to run ahead of storage, new demand and network development. This could destroy value for existing RES generation, but also the prospects for storage and other providers of flexible capacity.

Recently, there are serious political concerns about the continued dependence on carbon and gas prices, as fossil fuels provide a diminishing share of total generation, which have led to the concept of marginal cost pricing – the foundation of all markets – being described as 'ludicrous' by the then Prime Minister.

There are several specific issues with the existing arrangements which revised arrangements should attempt to address:

i.) **Decentralised spot market arrangements deal reasonably well with flexibility but the scale of re-dispatch hampers efficiency**

Today's spot energy markets allow flexible resources to trade effectively, but opportunities to hedge forward are limited for all types of resource. Within-day optimisation of assets is handled by market operators against continuously-updated market prices, but efficiency is hampered by the scale of re-dispatch close to real time. Re-dispatch cannot properly optimise across longer time periods (e.g. unit commitment times for larger units or the overall pattern of battery charging/discharging across the day).

ii.) **Dispatch efficiency is limited by grid congestion**

A major cause of re-dispatch, congestion costs and wind curtailment in today's market is the extent of transmission congestion within today's GB-wide price zone. To a significant degree, this has resulted from the policy of 'connect-and-manage' and the rapid deployment of wind offshore and in Scotland, and the inability of transmission capacity build to keep pace. The combination of output-based renewable support payments and firm access rights further exacerbates congestion.

GB's market design does place commercial incentives on generators and consumers, in the form of locationally-varying network charges and also transmission loss factors. Despite these factors, it has been attractive for a variety of reasons to continue building wind in congested areas, and congestion is expected to worsen in the coming years before transmission build can catch up.

iii.) **Ancillary services are growing in importance and will be key to achieving efficient dispatch**

The delivery of ancillary services is a further cause of re-dispatch and is expected to grow significantly in cost in coming years. New services have been defined by NGESO, with longer term contracts which have supported both new investment and 'revenue stacking' (enabling resources to earn from a range of energy, capacity and balancing services). As ancillary services grow in importance, the system will need better within-day dispatch co-ordination between energy delivery and the provision of system services.

iv.) Renewable support does not incentivise efficient dispatch or pricing

The form of renewable support changed radically with the introduction of the CfD FiT in 2014. Most RES generation under contract faces trading incentives which would drive spot prices negative, and to deliver energy even when it is excess to requirements (and when the provision of system services might be more valuable). The effect has been that – within the contract period – supported generation is protected from 'cannibalisation' i.e. zero prices even at times of excess renewable generation.

More recently, the contracts have offered less protection against zero prices, but the incentive to produce excess energy remains.

v.) The Capacity Market rewards peak capacity, although system needs to enhance reliability while decarbonising are becoming more complex

The Capacity Market is designed to reward 'peak capacity'. The future concern for security of supply is moving towards more complex needs which arise from variations in renewable production as well as peak demand, such as ramping capacity, or long duration storage to meet demand on the expected 'four cold days with low wind'. It provides no hedge to consumers for peak power prices. Fossil fuelled capacity is still able to obtain long term contracts, which we consider to be inconsistent with power sector decarbonisation by 2035. Looking forward, there is a potential risk of uncoordinated closure of unabated gas plant.

vi.) Increasing need for local flexibility markets

Under all decarbonisation pathways, we expect that flexible resources will increasingly be small scale, owned by customers and connected to the distribution networks. Congestion management at distribution level will become normal, and any use of flexibility at transmission level will need to be co-ordinated with the needs of the users themselves and the DSOs. As we electrify new – potentially flexible – forms of demand, the incentives and operational protocols must be in place to ensure that opportunities to provide flexibility from the demand side are not lost. This must also be integrated with the operation of the retail market, so that any dampening of risk towards consumers does not lessen incentives to offer much-needed flexibility.

WE BELIEVE THAT MARKET-LED INVESTMENT ALONE CANNOT DELIVER THE PACE OF INVESTMENT REQUIRED TO DELIVER A FULLY DECARBONISED POWER SECTOR BY 2035

Increasing power demand from electrification of heat and transport, combined with the need to replace existing unabated generation capacity, results in a requirement for unprecedented rates of investment in new low carbon generation over the next 13 years. BEIS foresees up to 300GW of installed capacity by 2035, and over 10GW of new capacity build every year, against a historical average of 5-6GW per year. The total public and private investment in the power sector required by 2035 is estimated at £280 to £400 billion .

Forward markets – which have tended to be for baseload blocks – have become illiquid as markets must adapt to variable RES production patterns.

Renewable PPAs directly with end customers have emerged but are not expected to deliver the volume of generation capacity required.

We share BEIS' view that reliance on decentralised procurement of capacity will not deliver the rate of investment needed for the decarbonisation of the power system by 2035. Market based approaches may become more credible with time.

IN SUMMARY, DECARBONISATION CHALLENGES THE POWER SYSTEM IN TERMS OF LOCATION, FLEXIBILITY AND COMMERCIAL DISRUPTION

The decarbonisation of the power system brings challenges relating to location, flexibility and stability, and commercial disruption, as described in Exhibit 1 below.

Location	Flexibility and stability	Commercial and investment
— Location of new generation is different from existing generation, necessitating grid build and congestion management — Growing demand and generation at lowest voltage levels implies huge need for distribution network investment and congestion management — Curtailment of renewable generation due to grid constraints — Increasing costs and the technical challenges of system balancing and constraint management — Interconnector flows exacerbate transmission constraints	— Transition from traditional to new providers of flexibility and stability at transmission and increasingly at distribution level — Ad hoc or missing signals to invest in new capability for stability and flexibility (especially for long duration storage and flexible demand) — Accommodating new technologies, new buyers and new market products for flexibility — Facilitating revenue stacking for flexibility providers, while enabling new investment	— Stranded assets, 'missing money' and devaluation of existing unabated generation as subsidised generation supplants existing high carbon technology — Increased price volatility and volume risk arising from renewables, limiting the effectiveness of forward trading using existing products — Revenue cannibalisation by RES, with exposure to sustained periods with zero or negative prices — Continued exposure to marginal electricity prices set by gas and carbon prices, although gas plays a diminishing role — Ongoing regulatory risk to market arrangements

Exhibit 1 – Challenges associated with the transition to a decarbonised electricity system

WE HAVE APPLIED A STRUCTURED PROCESS TO DESIGN AND APPRAISE STRAWMEN FOR REVISED MARKET ARRANGEMENTS WHICH ADDRESS THE MATERIAL CHALLENGES FACED BY THE EXISTING ARRANGEMENTS

Our starting assumptions for the market design are that decarbonisation of the power sector will be achieved by 2035, and that security of supply must be maintained.

We have developed four strawmen for revised market arrangements by following a process which combines top-down and bottom-up analysis.

For the top-down exercise, we considered the overall allocation of roles between centralised actors (government, regulators, network owners and system operators) and decentralised market actors (investors and operators in production and consumption assets). The strawmen models contain alternative allocations of roles at different times.

Each strawman option is created from component 'building blocks'. For the bottom-up exercise, we have subdivided the overall market design into a set of building blocks which broadly match the elements of the REMA process, as follows:

- wholesale energy and flexibility markets
- locational signals
- system services
- renewable support
- capacity remuneration
- local flexibility markets (in less detail)

For each of these building blocks, we have created a set of alternative options, which were then evaluated individually against summary objectives (investment decisions are effective, operational decisions are efficient, and the appropriate allocation of risk, cost and reward).

The options for each of the building blocks were then placed into the strawman models in ways which match the overall philosophy of each model. This process is somewhat subjective and there is space later for re-evaluation of which detailed option fits within the preferred model(s).

THE CHOICES ON BUILDING BLOCK OPTIONS ARE INTENDED TO ADDRESS THE MATERIAL CHALLENGES TO THE CURRENT MARKET ARRANGEMENTS

i.) Decentralised spot market arrangements deal reasonably well with flexibility but the scale of re-dispatch hampers efficiency

We have created ideas for market models which seek to enhance the quality of decentralised decision making in the spot markets, reducing the need for re-dispatch. Other models employ central dispatch as proposed by NGESO.

Although centralised market models appear superficially attractive in dealing with network congestion, they have flaws in other areas including dealing with flexibility. Centralised spot markets have one or at most two market timeframes, and intraday adjustments are typically made ad hoc under TSO instruction. Arrangements to deal with and provide commercial value for 'flexibility' in energy operation (aside from ancillary services) is, we believe, a clear weakness of centralised designs which has not been resolved in any operational market.

ii.) Dispatch efficiency is limited by grid congestion

We have designed market models which alleviate congestion in different ways: some with the existing GB-wide zone (introducing concepts of non-firm access for some generators), others using price zones and another using nodal pricing as outlined by NGESO.

Locational markets, in which the transmission network is represented in the spot market algorithm, deliver prices which vary dynamically by location. Any market design using price zones will still have congestion within the price areas, and there may be future pressure to re-define zonal boundaries.

iii.) Ancillary services are growing in importance and will be key to achieving efficient dispatch

We sketch ideas which could enable the TSO to procure its ancillary services in day ahead and within-day timeframes, enhancing the quality of decentralised dispatch by market actors. We also consider a centralised option in which ancillary services are co-optimised with the energy market.

We note that some of the new system services are locational in nature, and that delivery of conventional reserve products may be hampered by transmission congestion.

No centralised market design today (to our knowledge) deals with locational system services, or with the new suite of products that NGESO is procuring (e.g. short circuit levels or inertia). Without dealing with these requirements, any centralised market system would still require re-dispatch to deal with ancillary service provision.

iv.) Renewable support does not incentivise efficient dispatch or pricing

We have been attracted to models for RES support which break the simple link between output and financial support. The 'deemed generation CfD' model has the effect that supported generation receives a top-up payment based on the market price which is independent of production, creating incentives for more efficient operational decisions that respond to price signals.

Longer term, renewable generators out of contract are exposed to zero or negative prices to the extent that RES deployment continues to outpace network build, storage and the development of new types of electricity demand. We have considered one model which extends RES support indefinitely, via 'evergreen' deemed generation CfDs. By 'evergreen' CfD, we mean a RES support arrangement based on CfDs, in which a new fixed price would be agreed at the end of an initial long-term contract period, and at further intervals thereafter on a rollover basis (akin to a split markets model).

The form of RES support may also influence the location of the plants, either by changing access arrangements and/or (in locational energy market designs) by choosing to link the reference price to a local or a national price.

v.) The Capacity Market rewards peak capacity, although system needs to enhance reliability while decarbonising are becoming more complex

We have explored alternative options for capacity remuneration which allow segmentation for different types of flexibility. In some of the models, the form of capacity contract becomes a 'reliability option' which acts as a hedge against extreme market prices.

vi.) Increasing need for local flexibility markets

We are moving to a world in which distributed energy resources form a larger share of the overall set of flexible assets. Distribution network congestion management will become more commonplace, and DSOs must move to active management of their networks, while maintaining close co-operation with TSOs and market actors.

Any local flexibility market design will require deep TSO–DSO interaction in order to balance in the shared interest of the two grid levels.

The issue of local flexibility markets has been examined in less detail than the other topics. We have considered models which enable peer-to-peer trading and also a world in which the DSOs take a more central role in system operation.

OUR 'STRAWMAN' MODELS EMBED DIFFERENT CORE PHILOSOPHIES

We have developed four strawmen for revised market arrangements: National Step, Evergreen Evolution, Zonal Leap and Central Revolution. These reflect different core philosophies, as summarised in Exhibit 2.

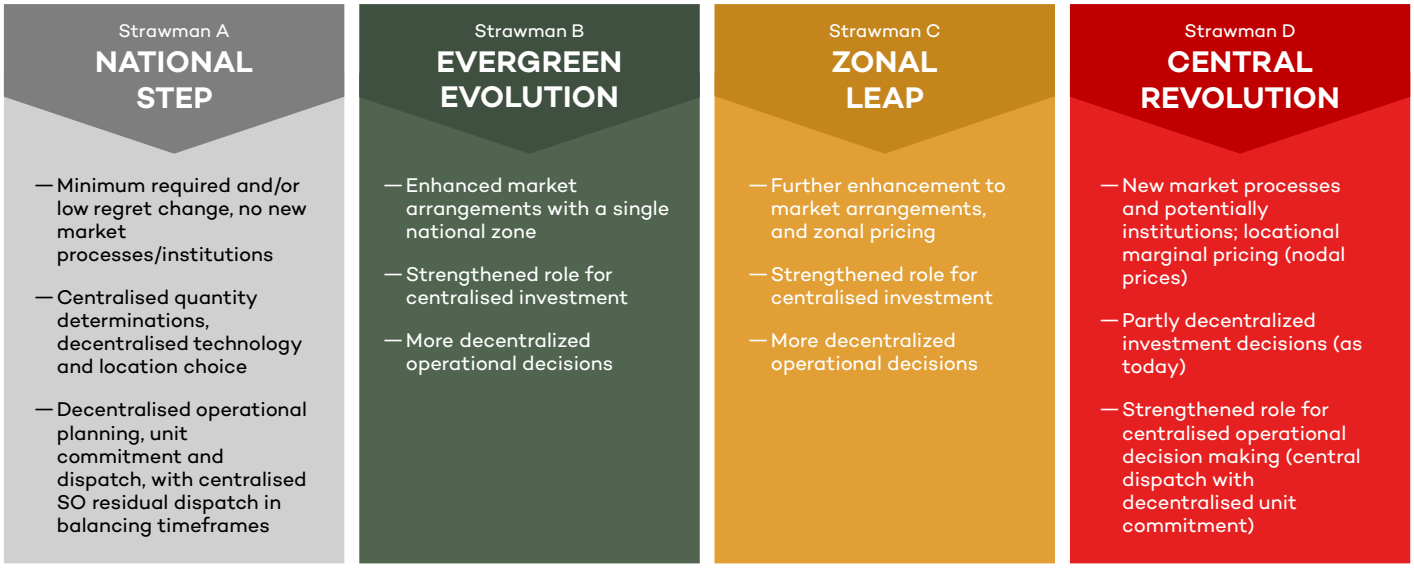

Exhibit 2 – Summary of strawmen philosophies

The strawmen are each built-up from choices on each of the market design building blocks, as follows:

1. **National Step** contains the following incremental improvements to the current arrangements:
   - information sharing between ESO and market participants on dispatch expectations and system requirements to support more effective within-day optimisation over extended periods (e.g. unit commitment, profile of battery charge and discharge)
   - deemed generation CfDs
   - enhanced Capacity Market derating factors to incentivise flexible capacity
2. **Evergreen Evolution** remains based on national pricing, and has the following additional features:
   - significant improvements to wholesale market/system services, including: additional option and ramping ancillary service contracts within spot energy trading timeframes, leading to shorter settlement periods; and co-ordinated procurement of ancillary services in spot market time frames
   - evergreen (rollover) deemed generation CfDs for renewable support, with revised constraint payments (i.e. no payments for being constrained off)
   - a segmented Capacity Market with multiple capacity segments (i.e. additional technology-specific capacity procurement targets, for example for different types of flexible capacity)
3. **Zonal Leap** has the following distinguishing features:
   - a zonal energy market (for both generation and demand)
   - as for the Evergreen Evolution: additional option and ramping contracts within spot energy trading timeframes, leading to shorter settlement periods, but additionally in the Zonal Leap, also shorter gate closure (which may be difficult to achieve with a national price zone); and co-ordinated procurement of ancillary services in spot market time frames
   - revised transmission access arrangements, with non-firm access for a period of time for new connections
   - deemed generation CfDs to provide investment certainty while improving operational efficiency
   - differentiated reliability options for firm capacity, varying by strike price and degree of flexibility
4. **Central Revolution** includes the most radical set of changes, comprising:
   - real time centralised dispatch with co-optimisation of ancillary services, and decentralised unit commitment
   - locational marginal pricing (for both generation and demand), which gives firm access to the local node, not the wider system
   - access to other nodes is determined by purchase of Financial Transmission Rights (FTRs), while some grandfathered rights would be granted for a transitional period
   - deemed generation CfDs to provide investment certainty while improving operational efficiency
   - standard reliability options for firm capacity

All the strawmen have the following common features:

— phasing out of long-term contracts for unabated thermal capacity under capacity remuneration arrangements
— as a transitional measure, options for the extension of existing renewable support contracts in the form of voluntary CfDs

All the strawmen could also be consistent with strategic reserve to mitigate uncontrolled CCGT exit.

WE HAVE MADE A QUALITATIVE ASSESSMENT OF THE STRAWMEN DESIGNS AGAINST AGREED OBJECTIVES

We have chosen a minimalist set of objectives, assuming that security of supply and decarbonisation will be met through some form of central procurement. Our chosen objectives are defined in Exhibit 3.

Investment decisions are effective	Investment decisions result in sufficient infrastructure of the right type and in the right location to maximise cost-effectiveness, given the need the achieve a net zero power sector by 2035 and maintain security of supply
Operational decisions are efficient	Operational decisions result in total system cost-effectiveness, given the system that has been built (and subject to achieving a net zero power sector by 2035 and maintaining security of supply)
Appropriate allocation of cost, risk and reward	Charges and payments are allocated appropriately with respect to fairness, cost reflectivity and the delivery of useful incentives. Risks are borne by those best able to manage them.
Deliverability of the transition	The transition to the new arrangements can be delivered quickly and with manageable levels of risk to enable a net zero power sector by 2035.
Enduring robustness	The new arrangements are robust on an enduring basis (e.g. do not have weaknesses with respect to: freedom of choice; regulatory risk; transparency; liquidity; high barriers to entry; and/or high transaction costs, etc.)

Exhibit 3 – Objectives of the strawmen designs

These objectives are subjective, but this provides a simple framework for evaluation of alternative design options.

We have evaluated the end-to-end 'strawman' models, using a Harvey Balls approach, and a summary of the results is shown in Exhibit 4.

	BAU baseline	NATIONAL STEP	EVERGREEN EVOLUTION	ZONAL LEAP	CENTRAL REVOLUTION
Investment decisions are effective					
Operational decisions are efficient					
Appropriate allocation of cost, risk & reward					
Deliverability of the transition	N/A				
Enduring robustness					

Exhibit 4 – Summary of the strawmen qualitative assessments

The four strawmen reflect differing levels of change from the business as usual (BAU) baseline, with National Step representing least change, and Evergreen Evolution, Zonal Leap and Central Revolution representing increasingly radical levels of change. The degree of change involved is primarily driven by the extent of locational pricing and centralisation introduced in the spot energy and flexibility markets. We also consider different degrees of central determination of investment choice.

Our qualitative assessment in the context of achieving a decarbonised power sector by 2035 indicates a number of high-level conclusions.

Effective investment decisions can be incentivised through enhanced support arrangements, but increasing costs of capital offset improved locational signals

- in National Step, the improved incentivisation of low carbon flexible capacity through an improved capacity market derating factor methodology and the use of deemed generation CfDs improves investment decision effectiveness compared to business as usual. Deemed generation CfDs give some additional revenue certainty to renewable generation as a protection against extended periods of zero prices, reducing costs of capital
- in Evergreen Evolution, the evergreen deemed generation CfD further increases RES investor confidence while also improving operational efficiency, and the segmented Capacity Market enables targeted procurement for various types of low carbon flexibility, resulting in further strengthening of signals for effective investment
- with the inclusion of zonal pricing, the Zonal Leap strawman captures improved investment effectiveness from locational signals which reflect expected congestion, but has significant risks of reduced effectiveness from increased costs of capital due to increased price volatility and the threat of rezoning
- in Central Revolution, locationally efficient investment decisions are fully enabled in theory; in practice, nodal price volatility makes long-run constraint costs difficult to estimate, and FTRs generally only provide hedges to price volatility a few years ahead, with likely consequent increases in costs of capital

All strawmen show an improvement in the efficiency of operational decisions

- as a minimum, in National Step, improved information sharing on intraday expectations combined with the improved operational incentives for RES via deemed generation CfDs should reduce the size and cost of the ESO re-dispatch problem
- operational efficiency in Evergreen Evolution is further enhanced by the further improvements to spot energy markets and co-ordination with system services
- the further addition of zonal pricing in Zonal Leap adds further operational efficiency based on locational price signals
- relative to Zonal Leap and National Step, the operational efficiency for Central Revolution falls back – the use of highly efficient locational signals and excellent real-time co-ordination with systems services is offset by the difficulty of managing inter-temporal constraints (e.g. on battery charge states) and the limited scope for co-ordination of diverse decentralised assets, which are growing in importance

Locational granularity of spot markets has a significant influence on appropriate allocation of cost, revenue and risk

- National Step and Evergreen Evolution achieve some improvement on the status quo: the policy/planning risks of over-planting renewable capacity relative to the development of networks, new demand and supporting infrastructure would not be faced by renewable capacity owners, and although in Evergreen Evolution the enduring nature of deemed generation CfDs would shift some additional lifetime costs onto consumers, costs of capital under the CfD arrangements would also be lower
- Zonal Leap and Central Revolution have significant issues with the appropriate allocation of risk, cost and reward, which are more severe in Central Revolution. Lower costs from congestion arising from poor locational efficiency would be passed to consumers; however while congestion risk is placed on market participants, it is not generally within their control, being heavily influenced by the timeliness of network reinforcement, the decisions of other market participants and ongoing regulatory risk relating to the level of locational granularity (e.g. re-zoning decisions)

As the scale of the change within the strawmen increases, the deliverability of the transition to 2035 progressively falls

- with more radical designs, the time required to design and implement new market systems and processes increases
- faced with uncertainty over the detail of the new arrangements, and their commercial effects, it is highly likely that investment will be deterred
- the relatively near-term target date of 2035, and the need to more than double current rates of investment, means that deliverability falls as the scale of change increases

Enduring robustness does not vary to a large extent across the strawmen

- all the strawmen reflect relatively high degrees of centralised contracting through the CfD and capacity remuneration schemes, which is undesirable on an enduring basis due to the suppression of more market based signals of value
- all the strawmen embed trade-offs, resulting in improvements in some areas but residual weaknesses in others, which may lead to a need for further market reform

Many of the detailed issues will require quantification, which will be conducted in the second stage of the project.

KEY MESSAGES

1. **While there is a case for change, existing arrangements have had significant success in delivering decarbonisation, whereas radical change is likely to deter the necessary investment for the complete decarbonisation of the electricity sector by 2035**

   The scale and pace of the investment required to deliver a decarbonised power sector by 2035 means that investor confidence needs to be enhanced. This becomes harder to achieve as the proposed changes to existing arrangements become more radical. Any significant change to market arrangements is likely to impact investor confidence in the short-term, given that new risks and opportunities will not become fully apparent until detailed design and implementation has taken place. Revised arrangements to 2035 should therefore aim to address the problems with the current arrangements to the extent necessary, but not more.

2. **Wholesale power market reform is not enough on its own; action is also needed in network investment, planning policy, retail markets, and in related areas such as CCUS and hydrogen infrastructure**

   Although of critical importance, revised wholesale power market arrangements are only one component of the overall effort required to deliver a decarbonised power sector by 2035, with the following out-of-market arrangements also critical for success:

   - investment in network capacity needs to keep pace with renewable and distributed generation appropriately
   - the planning system needs to enable generation capacity to be installed faster and in more diverse locations
   - the retail electricity market needs to better enable flexible demand-side response from consumers

   Furthermore, the electricity system must become better integrated with adjacent sectors with planning co-ordinated with network, CCUS and hydrogen infrastructure.

3. **The scale and pace of the investment required to deliver rapid decarbonisation requires a centralised approach to capacity planning and procurement**

   All credible decarbonisation visions require centralised long-term contracting for low carbon and flexible capacity, at least until 2035. In each of our strawman market designs we have therefore assumed centralised long-term contracts for new renewables and for the capacity needed to deliver reliability over the timeframe

to 2035. This echoes BEIS' thoughts in its REMA consultation paper, being minded to exclude decentralised capacity arrangements. We recognise there is already some corporate procurement of long-term contracts, but this is not considered a primary motivator for large scale investment over the period until 2035.

4. **Spot markets with central dispatch are limited in their treatment of flexibility and decentralised resources, whereas decentralised models are limited by their treatment of location and the degree of coordination**

   A necessary feature of any revised market arrangements will be improved operational efficiency within the wholesale energy and flexibility markets intraday, with a range of ambition and designs across our strawmen.

   There are trade-offs in operational efficiency in the choice between centralised and decentralised dispatch. Allowing opportunities to re-trade (potentially continuously) close to real time as information changes is an important feature of decentralised market design.

5. **Locational energy prices improve incentives on market actors for efficient dispatch, but place new risks on investors and participants, increasing the cost of capital**

   Locational energy markets aim to improve the locational efficiency of both investment and operational decisions, reducing the costs to consumers of locational inefficiencies. Locational value and risk are passed onto market participants, which would represent a major change to the investment cases for both new and potentially (retrospectively) for existing generation.

   Increased price uncertainty which is unlikely to be fully hedgeable over the financial lifetime of a new asset would increase costs of capital for new investments, while existing assets in constrained areas would potentially face endemic exposure to zero-priced periods. The risks to investor confidence, particularly for renewable investors, are serious given the need to improve investor confidence further to achieve the pace of investment required to 2035.

6. **Long-term support contracts for renewables will remain necessary to achieve rapid power sector decarbonisation, but need to incorporate improved incentives for efficient operational decisions**

   Renewable generators face exposure to price cannibalisation and zero pricing; conversely customers are facing marginal pricing set by gas and carbon although the share of these technologies is falling. Solutions to both these issues involve longer term fixed price contracts for renewables, with potentially an 'evergreen' option in which a new fixed price would be agreed at the end of the initial contract period (akin to a split markets model).

   Revised market arrangements should also provide increased incentives for renewable generators to make more efficient operational decisions from a system perspective, and deemed generation CfDs feature heavily in our strawmen as a key tool in enabling this.

7. **Capacity markets must adapt to procure low carbon resources while delivering the flexibility needed to manage variations in renewable production**

   Revised market arrangements should provide increased investment and operational signals for flexible capacity which is consistent with decarbonisation. The existing capacity market targets peak capacity which relates to variation in demand. Future reliability needs will arise from fluctuations in available renewable generation, and the nature of the capacity needs will change, for example to deal with ramping requirements or 'four cold days with no wind'.

   In our strawmen this changing flexibility need is met in different ways, through fine-tuning of the derating factors in the existing capacity market, a segmented capacity market with targeting of flexible capacity, or alternative designs of reliability options (in which the capacity contract takes the form of an option contract against a reference market price).

   Long term contracts should be limited to low carbon generation in order to avoid carbon lock-in. Capacity procurement must be consistent with the decarbonisation targets.

   Each of our models is consistent with an option of strategic reserve to mitigate the uncoordinated closure of existing thermal capacity generation (principally CCGTs).

8. **Decentralised resources at low voltage levels could become hugely important in system planning, operation and risk management; and must be properly accommodated in all market timeframes**

   We are moving to a world in which distributed energy resources form a larger share of the overall set of flexible assets. Distribution network congestion management will become more commonplace and DSOs must move to active management of their networks, while maintaining close co-operation with TSOs and

market actors. However, we do not see a strong case for a switch to a model in which system operation is led from distribution areas.

We note the long-term inconsistency of reconciling a centralised market model – whether centrally-directed investment or centralised market operation and dispatch – with innovative use of diversified distributed energy resources. The fabled 'smart energy system' will not be dominated by central planning, long term contracts or central dispatch.

9. **In the long-term, a world of state-backed long-term contracts is unlikely to be a desirable final position, and a pathway will be needed to encourage forward contracting, retail innovation and market-led investment**

   The more centralised approach to investment that may be necessary to achieve a fully decarbonised power sector by 2035 is likely to be sub-optimal in the longer term; the current review of market arrangements should not preclude a longer-term return to more market-based arrangements with less need for large-scale government intervention.

   Having market-based arrangements which include longer-term bilateral forward contracts brings a number of benefits:

   - forward contracting enables retail competition, allowing space for alternative strategies for hedging and risk management through trading and demand side flexibility
   - large corporate consumers may achieve their own decarbonisation commitments – potentially earlier than 2035 – through the purchase of long term renewable PPAs
   - liquid forward markets over different timeframes enable the sequence of maintenance, operational planning and risk management to work effectively
   - ultimately, we believe that market-led investment is likely to deliver more efficient outcomes including greater use of innovative solutions

10. **While AFRY will undertake further analysis, on an initial evaluation of a range of potential market designs, evolutionary rather than revolutionary solutions appear more credible in delivering a decarbonised GB power sector by 2035**

About AFRY Management Consulting

AFRY Management Consulting provides leading-edge consulting and advisory services covering the whole value chain in energy, forest and bio-based industries. Our energy practice is the leading provider of strategic, commercial, regulatory and policy advice to European energy markets. Our energy team of over 250 specialists offers unparalleled expertise in the rapidly changing energy markets across Europe, the Middle East, Asia, Africa and the Americas.

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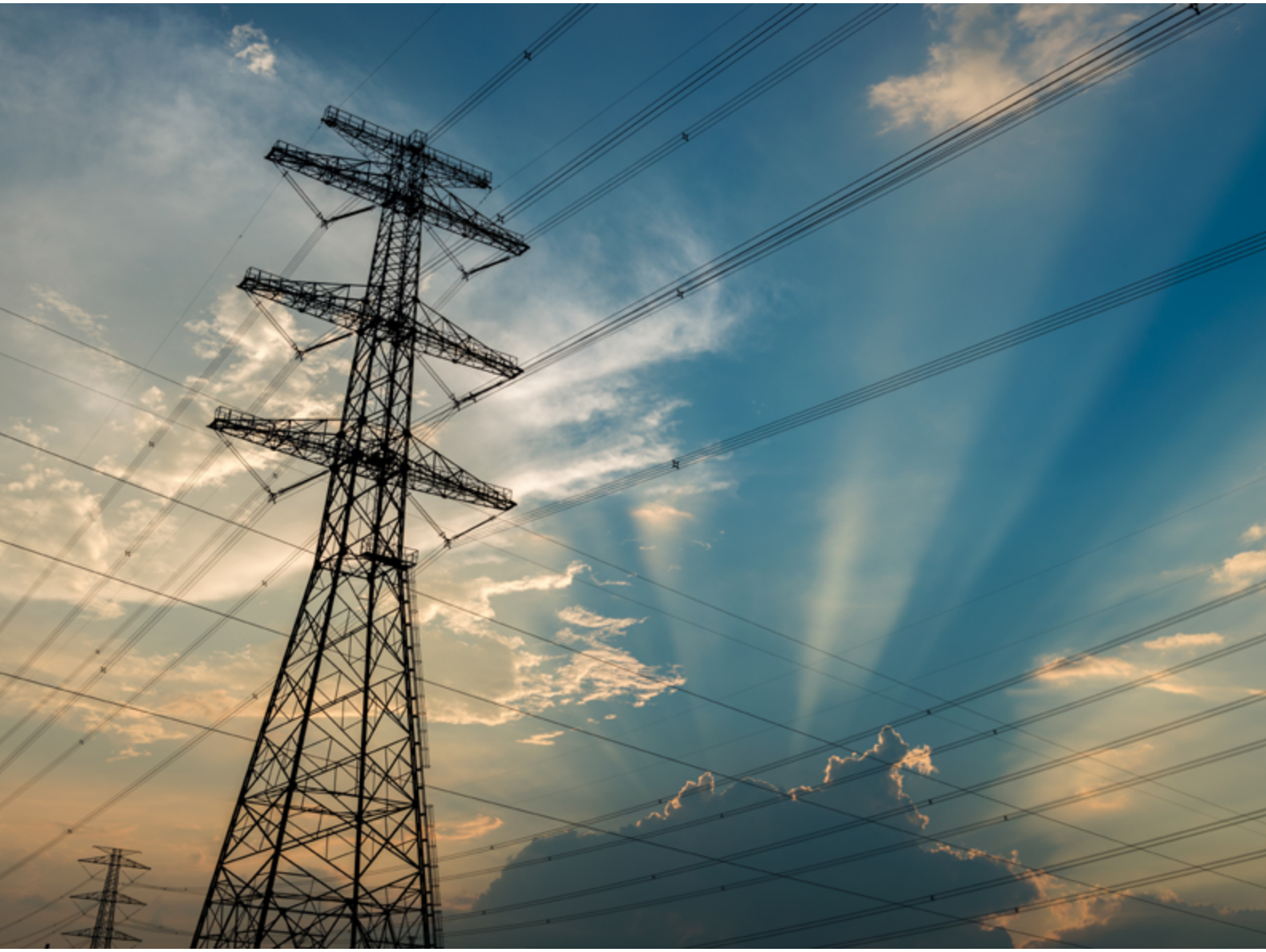

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