THE ASSOCIATION FOR RENEWABLE ENERGY & CLEAN TECHNOLOGY

Review of Electricity Market Arrangements (REMA)

REA REMA Report

Enabling a secure, flexible and decarbonised electricity market fit for the future

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REA POWER & FLEXIBILITY

Executive Summary

The UK Government has been conducting an in-depth review of electricity market arrangements (REMA) since the summer of 2022. This report sets out an industry approach to REMA, proposing the next steps required to build a wholesale energy market aligned to the UK's net zero targets and energy security ambitions. The report highlights the need to build a market that facilitates and rewards the energy transition which is already underway. This means enabling the deployment of more renewables across the country while combining with innovative energy storage and demand-side response technologies. Doing so requires a market that successfully balances variable low carbon supply and demand, while rewarding flexibility services and firm supply contracts. This report calls for these attributes to be appropriately incentivised and rewarded within the new wholesale market design.

In delivering this market, the report calls for the adoption of an evolutionary approach by building on existing market arrangements, particularly the Contracts for Difference (CfD) and Capacity Market mechanisms. This differs from some of the other approaches currently being considered, such as a split market or green power pool. The industry remains concerned by the damage to developer and investor confidence that these more revolutionary approaches could cause. They risk creating unnecessary market complexity as well as delays to the energy transition as time is taken to implement and regulate new arrangements. This report makes recommendations for how the CfD and Capacity Market could be evolved to realise the overall ambitions of the REMA process.

Putting REMA in the context of the energy crisis

REMA was launched several months into the current energy crisis. Having had many years of low gas prices, the international market changed dramatically in response to several factors. This included gas supply shortages driven by Russia's invasion of Ukraine and significant levels of demand coming back online as global economies restarted after the pandemic. Unprecedented rises in consumer and business energy bills followed. At the same time, the crisis also revealed the UK's exposure to international fossil energy markets, which threaten our energy security and abilities to decarbonise.

The crisis has raised important questions about whether it is still sensible to set the wholesale electricity clearing price based on the last generator to turn on to meet demand, known as the marginal cost. This means that volatile international gas markets are setting the price for electricity generation, even when a growing proportion is coming from cheaper domestic renewable energy sources. As such, REMA asks how else the energy market might be structured to both reduce prices and deliver more domestic low-carbon energy sources for a more secure, affordable, and decarbonised energy system.

The need for evolution over revolution to maintain investor confidence and deliver a wholesale market fit for a decarbonised electricity system.

Since the launch of REMA, the Government has also instigated several immediate, and short-term, energy market interventions to lower the cost of energy bills. This has included the Energy Bills Support Scheme, in conjunction with a new Energy Profits Levy and Electricity Generator Levy, targeting cited excess profits. While the long-term impacts of these measures are yet to be seen, they have helped mitigate some (but certainly not all) of the more immediate energy cost concerns. As a result, REMA provides an opportunity to think more strategically about what wholesale market design can do in the medium and longer term to deliver a low-cost, low carbon and secure electricity system.

The past year has also shown that REMA cannot be done in isolation. The UK's energy transition has been ongoing for more than two decades, with numerous existing renewable energy assets and future pipelines relying on existing market and policy arrangements. These investments are vital for the energy transition, and the UK cannot afford to halt or lose them during the introduction of new market structures. This is particularly crucial to achieving the government's goal of a net-zero electricity system by 2035. As such, new market arrangements must be implemented in a way that speeds up, rather than hinders ongoing decarbonisation of the electricity system.

At the same time, international competition for clean energy investment has also intensified. America's Inflation Reduction Act and European Green Deal, mean that investors are being attracted to other markets. The UK has yet to fully respond to these support packages. However, the REMA process has also raised questions for investors and developers as to what the future UK market arrangements will look like. The REMA process, by its nature, has already caused uncertainty. The results of REMA must therefore be transparent, and the implementation of its final decisions be done in a gradual predictable fashion. Rather than creating new and untested structures, it is more effective to evolve existing mechanisms like the Contracts for Difference (CfD) and Capacity Market, which developers and financiers are already accustomed to.

At the same time, international competition for clean energy investment has also intensified. America's Inflation Reduction Act and European Green Deal, mean that investors are being attracted to other markets. The UK has yet to fully respond to these support packages. However, the REMA process has also raised questions for investors and developers as to what the future UK market arrangements will look like. The REMA process, by its nature, has already caused uncertainty. The results of REMA must therefore be transparent, and the implementation of its final decisions be done in a gradual predictable fashion. Rather than creating new and untested structures, it is more effective to evolve existing mechanisms like the Contracts for Difference (CfD) and Capacity Market, which developers and financiers are already accustomed to.

Ensuring that the Wholesale Market Supports a Low Carbon Energy System

This report highlights four key characteristics that REMA should be looking to promote in the future design of a wholesale market, consistent with high levels of renewable energy generation:

Flexibility: The wholesale market must be able to appropriately reward flexibility at all time scales, from milliseconds to decades. This is critical to managing a grid system with high deployment of Variable Renewable Energy (VRE). The market will also need to ensure flexibility is provided through true low carbon storage or generation technologies, as well as reward demand side response. We believe that reliance on unabated gas generation may foreclose low carbon flexibility, and risk failure against the 2035 carbon target for electricity.

Rewarding Firmness: To enable flexibility, we also argue that contract firmness should be rewarded when associated with low-carbon assets. Such contracts reward projects for being able to guarantee a specified quantity of electricity or energy supply at a fixed price for a defined period. We believe non-firm contracts will continue to be an important element in the market, but those who can provide firmness should also be able to gain additional premiums for being able to fulfil such contracts.

Transparent Signals: This report emphasises the importance of transparent signals for generators, developers, and financiers to understand revenue generation opportunities. Clear and transparent signals are necessary to minimise shortages and avoid stranding assets. REMA must develop efficient market signals to do this.

While geographically granular signals through locational marginal pricing are recognized as a potential solution here, the report suggests that implementing such a system today would introduce complexity and require a significant amount of time for developers to get used to it. Therefore, to ensure transparency and avoid an investment hiatus, the report suggests that locational pricing is not suitable for delivery at this time.

Harmonisation of energy markets: Efficiencies in energy market design will also be achieved by realising harmonisation across the five key markets of the wholesale market, CfD, capacity market and reserve and balancing. Ensuring that there is consistency in how low carbon generation and flexibility services are treated should be a key objective of REMA.

Key Options for evolving the Contracts for Difference and Capacity Market Mechanisms

This report explores the below options for how the CfD and Capacity Market could be evolved as part of the REMA process to deliver a future wholesale market.

- Reward firmness within the CfD contracts – this can be done as an additional non-price factor premium within the contract. This in turn will also help support flexibility and incentivise co-location with energy storage.
- Explore evolving the Market Reference Price by gradual extension of the price horizon out to 72 hours, to help firm up and encourage flexibility in the CfD.
- Incentivise the delivery of accurate long-term and granular forecasts for generation and demand. National Grid ESO will then be able to use this information to deliver clearer market signals.
- Develop a Green Premium, and wider Non-Price Factors, in the CfD which reward externalities of generation beyond just low carbon power production. This could include services such as the capture of greenhouse gasses or benefits provided in terms of supply chain investment, jobs, and skills.
- Enable CfD projects to also bid into, and benefit from, the capacity market to encourage flexibility.
- Have frequent CfD and Capacity market auctions, with a clear timetable for allocation rounds with a three-year rolling horizon and stipulated budgets.
- Consider how varying contract lengths could be provided in CfD contracts, including considering a descending clock auction mechanism.
- Develop a mechanism for using the CfD to extend the life of assets coming to the end of existing contracting arrangements, termed a 'repowering CfD'.

Government must also urgently address physical market barriers beyond market design

It must also be recognised that while changes to the wholesale market are necessary, it is not currently the largest barrier to the deployment of low-carbon generation or storage assets. The delivery of net zero requires physical market barriers to be addressed as a priority. This encompasses grid capacity constraints, causing significant delays sometimes in advance of ten years to be able to connect new projects. Additionally, there is a pressing need to expedite the planning system to ensure swift approval of new projects. While these issues are out of scope of REMA, failure to address them will undermine changes to the wholesale market. Policy development to resolve these urgent problems must run in parallel to REMA.

Above all, REMA must provide a coherent market design and implementation plan

Finally, we emphasise the fundamental importance of quickly having a target market design for REMA, which considers the whole energy market, accompanied by a definitive and sensible timetable for implementation. All the above proposals must be considered as a whole before being instigated. A clear plan of action is needed to remove uncertainty about the future structure of UK energy markets. Above all else, the industry desires understandable market arrangements against which they can design bankable projects to be able to get on and deliver the energy transition.

Introduction and framing of REMA

Overview of REMA

The changes in the electricity market in Great Britain have broadly been timely over a century in which the overall energy paradigm was slow moving. They have been in keeping with the development of consumption and of use of resources, and the prevailing political economy. Key events in the last century were in 1926 (the national grid), 1947 (nationalisation), 1990 (privatisation), 1998 (residential retail liberalisation), 2000 (separation of supply from distribution and formation of the Supplier Hub), 2001 (NETA New Electricity Trading Arrangements), 2005 (Scotland joining the BETTA British Electricity Transmission and Trading Arrangements), 2013 (EMR Electricity Market Reform). Development in metering arrangements, that we can place broadly under the umbrella of Reviews of Metering Arrangements, have been more incremental over the period, and remain important. The next major change is due, and REMA addresses all key areas of change.

EMR was responsive to the Climate Change Act 2008, mandating an 80% reduction of targeted greenhouse gas emissions by 2050, relative to 1990. EMR achieved its aim, bringing on bulk volume of (variable) renewable energy (VRE), especially in the form of offshore wind, adding to the pan European success of bringing solar PhotoVoltaic at volume into the global electricity complex (albeit not without its challenges). EMR had three main design compromises, made for speedy implementation in the knowledge that these could be addressed later. These were; i) lack of firmness in the CfD so that they are "spill" contracts, and ii) lack of strike price in the Capacity Mechanism, iii) separation of CfD and CapMech from each other and from the wholesale market.

The success of EMR has brought on the challenges that were broadly expected at the time. The principal challenge is the accommodation of the increase of role of Variable Renewable Energy and reduction in flexible thermal power generation, together with the anticipation of increased electrification of heat and transport.

Since EMR, the global ambition to climate change mitigation ambition has increased. The 2019 Net Zero target legislation was followed by a worldwide acceleration of regions, companies, and countries towards greenhouse gas reduction targets. All but four countries (Iran, Iraq, Libya, and Yemen) have ratified the "COP21" 2016 Paris Agreement. COP26 in Glasgow and COP27 in Egypt took this forward. The key date of 2050, the ultimate target of net zero, and associated policies are gradually solidifying internationally.

The Climate Change Committee Sixth Carbon Budget lays out the requirements of the electricity sector to become net zero by 2035. The National Grid ESO Future Energy Scenarios, the BEIS MacKay My2050 calculator and the emergent Distribution Future Energy Scenarios lay out ranges of possibilities. There is now a broad understanding of the sensitivity to assumptions in factors such as nuclear, carbon capture (use and) storage, international interconnection, and hydrogen. The range of outcomes for domestic heating remains very wide. Somewhat troubling are recent developments in favour of unabated fossil gas fired generation in 2035. This has the effect of foreclosing zero carbon solutions now, and thereby threatens the achievement of a net zero carbon electricity complex in 2035.

The overall challenge for REMA therefore begins with maintaining resolve for the trajectory to a zero carbon electricity complex by 2035. The three key design issues are; i) flexibility and firmness and ii) effective signalling to market actors through the medium of market prices, iii) harmonisation of the various markets. Together with stability of policy and market design, and maintained resolve to achieve a net zero electricity complex, this creates investability. In terms of the components of REMA, the key elements are CfD, CapMech and wholesale market transactability. Supporting these are reserve markets, continuation of the Renewable Electricity Guarantee of Origin as the source identity for load drawn from the grid, developments in metering arrangements, and manageable locational signals. To put these together requires breadth of vision, timeliness, coordination of multiple issues, prioritisation and a pragmatic view of implementation. We agree broadly with the direction of travel that DESNZ has laid out and in this report, we focus on the areas that we feel most qualified to address – namely the necessary development of Contract for Difference, increasing the maturity of the wholesale market and reserve markets, and the harmonisation of CfD and the Capacity Mechanism with the wholesale market.

REMA can be regarded as part of the government smart system and flexibility plan (SSFP). This focuses on four areas: i) consumer flexibility, ii) storage and interconnection, iii) market reform (wholesale, CfD, CapMech and implicitly reserve), iv) digitalisation. Elements of the SSFP of particular importance to REMA are; i) smart meters, ii) consumer access to technology, iii) product standards, iv) market-wide half hourly settlement, v) data and digitalisation, vi) buildings (fabric and technology readiness), vii) electric vehicles, viii) low carbon heating, ix) local energy solutions, ix) energy infrastructure, x) co-location, xi) harmonisation with interconnected countries, xii) integrated platform for balancing services and new suite of frequency and reserve services, xiii) ongoing harmonisation of Distribution System Operator contracts, xiv) development of the "P2" planning standard, xv) code governance, xvi) development of ancillary services markets. REMA seems to be well aligned to the SSFP and so REMA and SSFP mutually support each other.

The issues that REMA is trying to address

The electricity market is a critical enabler to the net zero transition, and REMA is just in time. However, this time we have less time. The developments of market arrangements need to be greater in the next ten years than the last hundred. Whilst respecting, and indeed requiring, a just transition, we can express the need of REMA as one thing – accommodating the replacement of dispatchable fossil generation by (largely variable) renewable generation. As cheap flexibility disappears from the system, and variability and inflexibility arrive into the system, the flexibility gap must be filled. Managing the flexibility gap by vast investment in networks and generation that have low utilisation is not affordable and probably cannot fill the gap anyway.

Due to the inherent variability of renewable resources, we can express the principal requirement of REMA in a single word – flexibility. We explain in this document how firmness options need to be developed to enable least cost flexibility. Net Zero 2050 cannot be achieved affordably without a radical change in flexibility, and definitively can be achieved with flexibility. With the resolution of flexibility, REMA can achieve the critical by-product of investability. These two together enable the most important thing of all – a Just Transition.

The need for flexibility to accommodate Variable Renewable Energy (VRE)

A stylised viewpoint is shown below. A key part of this is the need for new technology to run as close to baseload as possible for commercial and technical reasons. This applies for example to combined cycle gas turbine with carbon capture and storage, efficient hydrogen production, or hydrogen steelmaking. This greatly increases the variability of net power arriving into the consumer complex.

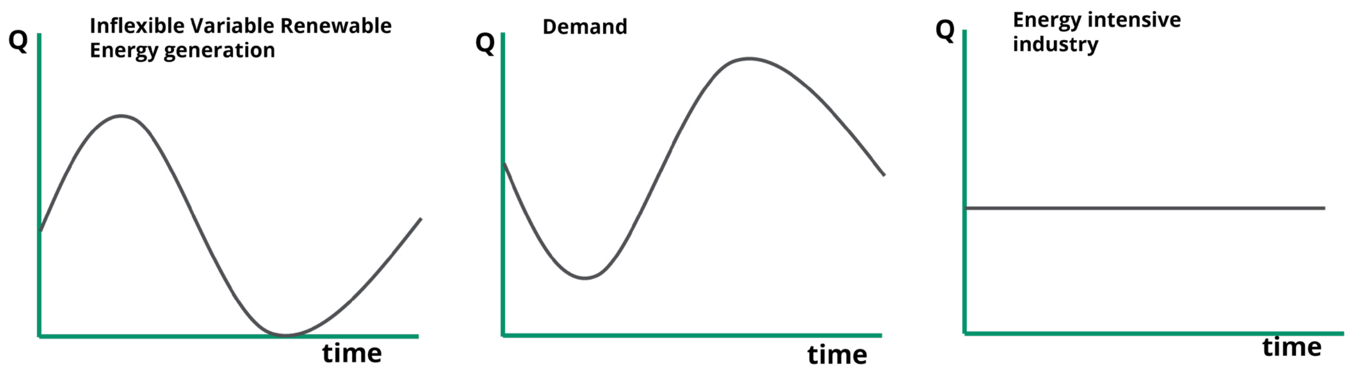


Figure 1: Stylised view of Variable Renewable Electricity, non-industry demand, and energy intensive industry demand.

We can see below that without flexibility we get curtailment of residential and industry demand and curtailed VRE generation when it has no host load.

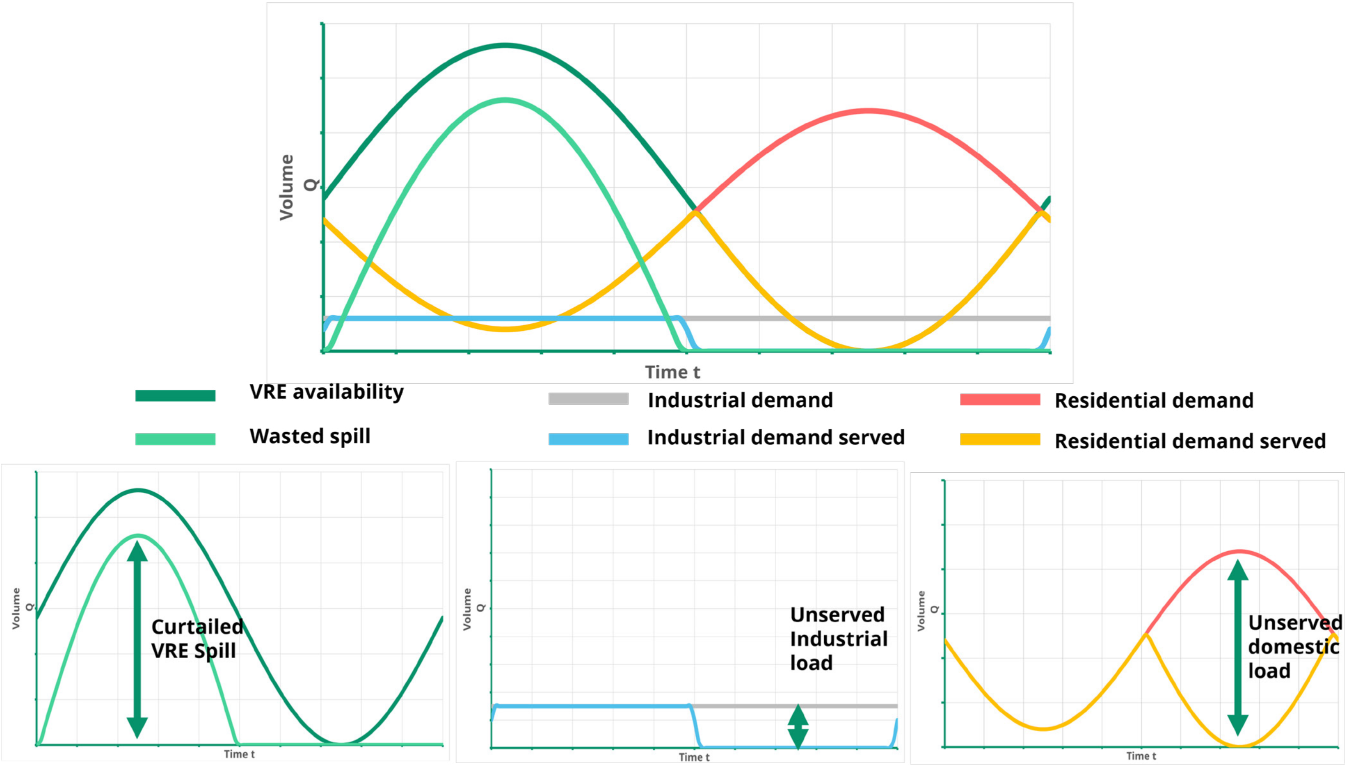


Figure 2: Results of the electricity complex with no flexibility

The answer of course is flexibility. The spill power can be absorbed by storage and inter-temporal demand side management, and released by storage and the same inter-temporal demand side management.

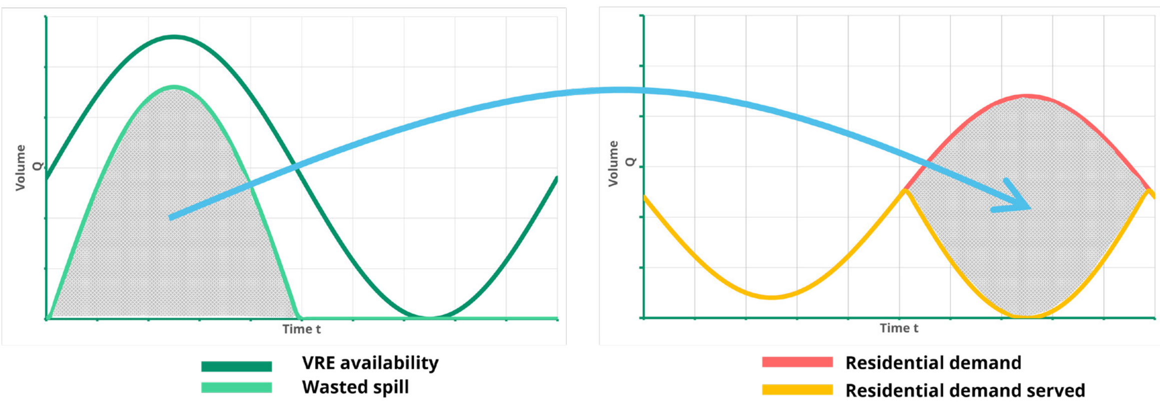


Figure 3: Using flexibility, including storage to use all the generation and avoid curtailment of load.

We can see in the figure below the urgency for flexibility solutions as VRE increases and flexible fossil fired generation decreases.

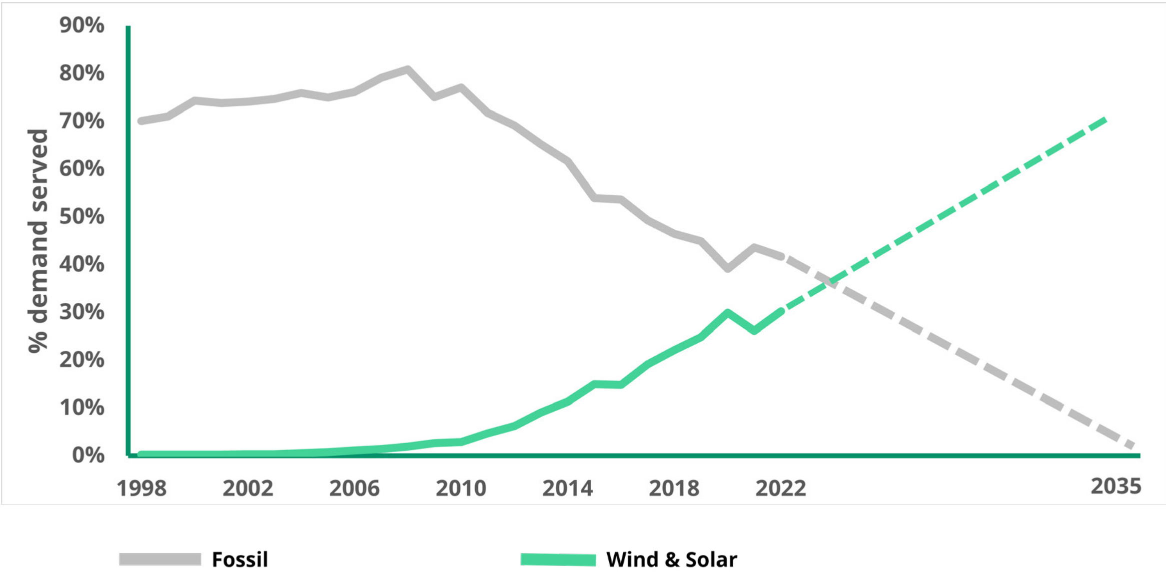


Figure 4: Pace of displacement of flexible fossil generation by VRE. Data source BEIS. 2022 is estimated. Projections to net zero in 2035 are added.

The need for flexibility is so high that it must be harnessed in all areas of generation, demand, and dedicated storage. As well as the total energy balance of production and consumption over the year, the flexibility volume must balance the variability. At this point we are heading towards substantial imbalance. This issue must now be addressed by REMA.

The key areas of development of rewarding flexibility (and charging for causing flexibility challenges) are:

i) Development of granular liquidity and transparency in Wholesale Markets

ii) Development of the Contract for Difference

iii) Development of the Capacity Mechanism

iv) Development of sub-markets integrated with the wholesale markets, such as reserve, balancing and ancillary services

v) Harmonisation of the five key markets

vi) Developments of the Supplier Hub that enable "behind the meter" participation in the wholesale markets (this falls largely outside REMA)

vii) Targeted government decisions on infrastructure and technology support (which complement REMA)

The harmonisation links of the five key markets are shown in Figure 5. The most pressing need is harmonisation of the CfD, and this therefore is given the greatest attention in this report. Focusing on the CfD also helpfully ensures future arrangements build on existing market mechanism that developers and investors already understand.

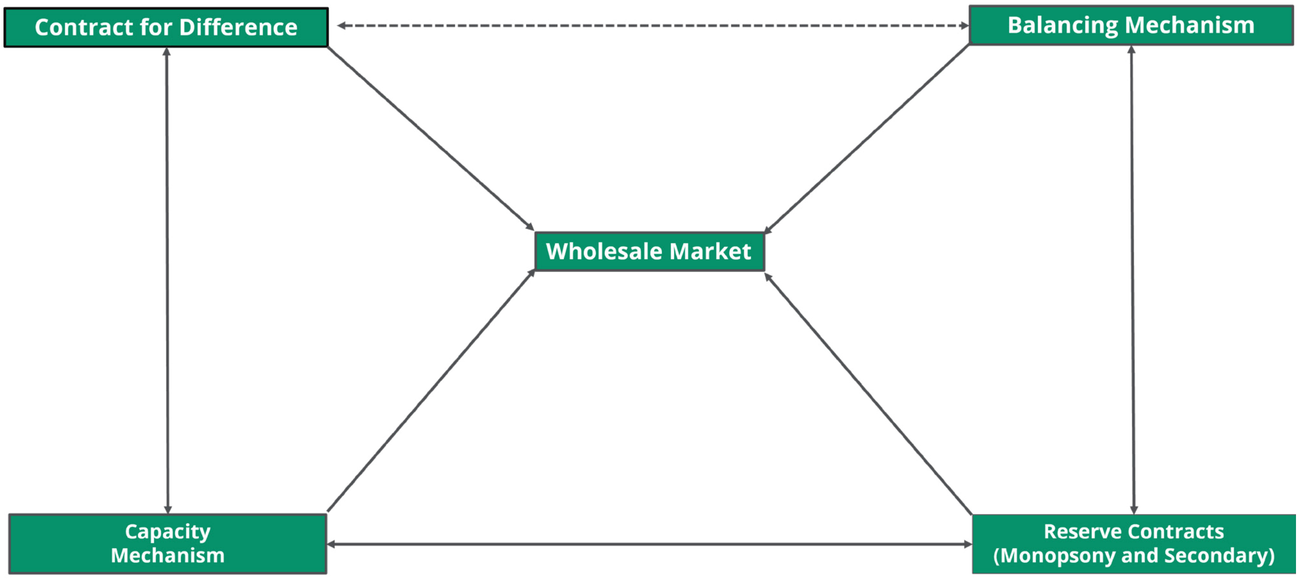


Figure 5: The links between the five markets

Not shown is how location management and the Balancing Services Use of System charges integrate into this. Note that linking between the CfD and the balancing mechanism is not ideal, since the market flexibility signal is provided too late. The link is not needed for firm CfD.

The structure of this report

Chapter 1 is about wholesale markets. We firstly address the paradigm change in electricity from flexible generation with variable inflexible demand, to variable inflexible generation with therefore the need for flexible demand. However, demand flexibility continues to fall short and we need to harness what flexibility we can in the generation and storage complex. This chapter addresses the design principles for the new paradigm.

Chapter 2 is about flexibility. We firstly explain how Variable Renewable Energy, the need to run industry technologies at high load factor, and variable inflexible demand, may cause extreme waste, very high cost, and unserved energy. We explain the flexibility requirements of the new complex in all time domains from 0.001 seconds to decade that can alleviate these problems. The flexibility challenge imposed by VRE can be addressed by the four markets of reserve, balancing, wholesale and Capacity Mechanism.

Chapter 3 is about the Contracts for Difference (CfD). We pay particular attention to addressing the growing problem of non-firmness, and how firmness options can minimise the flexibility requirement that Variable Renewable Energy which non-firm CfDs push into the system to manage.

Chapter 4 is about the Capacity Mechanism (CapMech). We pay particular attention to the integration between CapMech and the wholesale markets via the introduction of a strike price, and how some CapMech issues can be resolved by increasing the firmness of the contracts.

Chapter 5 is about investability. The key metric for investability is the cost of capital at which internationally mobile finance can be attracted. Cost of capital can be reduced by effective market and policy instruments. Cost of capital is reduced by investor confidence, which in turn requires actions beyond REMA, such as policy stability.

Chapter 6 covers some REMA options that should, in our view, now be rejected.

1 | Wholesale Market Design

The primary requirement of the wholesale market is the ability to transact the richest possible product array. The primary design requirement is route to market and enabling price discovery through signals and transactions.

The paradigm change from flexible "central station" thermal generation and variable inflexible demand

The central dispatch model developed gradually since the first occasions in which shared access to networks began in the 1890's. Wider pool models began in the 1920's and remain the basis of the standard models today, including in Great Britain.

The paradigm shift with the flexibilities and variations and inflexibilities swapping between generation and demand would be simple if the number and nature of the actors were the same. i.e., consumers were few and heterogenous, and they were accustomed to varying load by central dispatch.

The first change is in bringing the market to a consumer base numbered in tens of millions rather than tens or hundreds. This requires development of the Supplier Hub but is not the focus of this report.
The second change is in the nature of demand response. Demand response is predominantly inter-temporal shifting of demand, rather than reducing and increasing. In fact, the majority of demand response entails no change to end use (for example charging an electric vehicle at different times need not affect journeys) or limited change to end use (for example, doing laundry overnight incurs only a limited change in the crumpling of clothes).

Whilst we do believe that end use demand response will enable the paradigm change so that demand matches generation rather than vice versa, we recognise that that change will take a generation and that we need solutions for the interim. The immediate and enduring solution on the demand side is energy storage, so that the electricity import from the grid does not have to match instantaneously with the end use. The current thermal storage ability of UK building stock remains very poor but will (and must) improve. Energy storage could be a game changer in terms of inter-temporal shift. In electric vehicle charging in particular there is almost no round turn loss in terms of extra charge and discharge cycle. In the interim before this is a major effect in aggregate, then dedicated energy storage is essential, especially where the power electronics or other equipment can provide extra services. Market arrangements need to support this.

Design principles that need to be considered for wholesale market development.

Before considering the specifics of how wholesale markets should be developed, we set out some high-level design principles, that need to be considered:

Going beyond Carbon Pricing

If all markets work perfectly then an effective carbon price would be enough to decarbonise our power system and be applied at all levels, from prioritising renewable generation to rewarding low carbon ancillary services. No policy support, stimulation or intervention would be needed for low/zero carbon activity. However, in the presence of market imperfections it is generally agreed that, whilst this is a good starting point, it is not enough. The question in a market economy is how interventionalist this steering should be. The CfD is highly interventionist but has been highly effective. It is likely to remain effective, given the change from low to net zero carbon policy since the CfD was implemented.

Addressing the flexibility challenge

This is the most important challenge. Integration of solutions is needed for, wholesale markets, reserve and ancillary services, the capacity market and CfD and the route to market for "behind the meter" participation. Options for the first of these are described in this paper. Development of participation behind the consumer meter (grid edge and off grid edge) are very important but not the subject of this report.

Aligning wholesale market design with UK Carbon Budgets and increases in low carbon generation

To date, achieving the required levels of decarbonisation to align to UK carbon budgets has been realised through support mechanism and the UK carbon price (allowance and tax). The question arises whether additional market design support is now necessary. This could take several forms of intervention:

- Engaging low/zero carbon resources ahead of high carbon ones in the wholesale market.
- Rewarding flexibility on a cost reflective basis while also rewarding other attributes, such as CO2 savings or low carbon generation separately.
- Some form of bespoke technology discrimination may also need to be carefully considered, in order to pump prime technologies of strategic importance or provide services needed in a low carbon grid, such as inertia.

The above considerations will recognise the changing generation mix in the market. Today there is lots of thermal capacity and less VRE spill generation, so the thermal capacity is sufficient to accommodate the flex needed. With less fossil based thermal capacity and more VRE, the model becomes no longer adequate, and the above measures will need to be considered.

The need to maintain investment for existing and committed pipeline developments

Changes in the wholesale market will overlap with previous support mechanism and schemes, which form the basis of existing project pipelines and investments. With REMA considering both temporal and locational aspects of the wholesale market, current revenue streams - including those based on the current CfD model - are potentially undermined. Given that the great success the CfD has had reducing cost of capital (and therefore attracting capital) by reducing uncertainty, the reintroduction of uncertainty via the REMA process represents a major challenge. Previous transitions have generally been smoothed by instigating grandfathering arrangements, these will need to be carefully considered in the design of the wholesale market to keep existing project pipelines possible.

Greater certainty on policy decision and implementation timetables

Certainty of the timing of decisions is essential in the private sector, and in finance. Resources must be scheduled, the decision hierarchy process set to a strict timetable, and financing and refinancing timelines followed to preserve cashflow stability. For the REMA process this means having a set timetable for when decisions are made (and not reversed), gradually narrowing down options. Implementation of the subsequent energy policy must be transparent and then implemented in a sensible, but focused, timeline and include auctions for deployment that have a clear future rolling timetable that is stuck to. Finally, all policy decisions must also be clearly aligned to His Majesty's Treasury objectives and timetable and must not be later undone.

Manageable Transition Arrangements

Given the complexity of the energy markets transition arrangements will be needed for any future design. Any transitional arrangements will need to be subject to certain principle for example:

- They should not incur excessive or undue economic shocks to participants,
- Markets should function across the change without undue or excessive "basis" risk,
- The changes and the new arrangements must be understandable and manageable by participants without undue or excessive changes to systems and processes,
- They should be in keeping with long term energy policy and stable with respect to changes in parliamentary majority,
- there should be time for implementation,
- Distributional effects should be considered and, in many cases, addressed by protections, subsidies and cross- subsidies,
- Unforeseen consequences should be tracked and addressed.

Forward Market Liquidity and Accessibility

With the movement from few central actors to many decentral actors, it is essential that the market is accessible to small players. It is therefore important that the market segments (forward markets, reserve markets, etc.) are simple enough to act in.

However, typically, forward market liquidity and price discovery in electricity for any other product than baseload has generally been poor. The gas wholesale market is in general highly liquid and well functioning[1] and for about 20 years was the anchor point for the electricity market, providing liquidity. However, irrespective of events in the last two years in gas, the future power system will not be based on gas and therefore cannot rely on the gas price to form the power price. Electricity is a much more complex commodity and this is therefore a challenge. However, this is a challenge that must be faced, and can be achieved with market harmonisation. Accessibility is also important in its own right and increases liquidity. A key barrier to accessibility is credit. Another is navigating the plethora of rules that are necessary to protect market integrity. REMA can provide a supporting environment for this, for example in minimisation of basis risk.

The importance of price and volume signals

In a future decentralised energy system flexibility will be required on at least a half hourly basis. At the same time long term forecasts will be needed for long duration energy storage assets of many kinds. Therefore, technology and project development will need to be able estimate the likely intraday and seasonal structures in electricity, going far into the future.

The key here will be to use more bottom-up information on the expected half-hourly profile of generation, storage and demand, with a 20-year horizon and to give greater weight to price responsive inter-temporal shifts in demand and in round turn storage. For the system operator to be able to collect this information there must be clear incentive for all participants to produce forecasts that are accurate and which update.

This will need to be reconciled to the top-down modelling of the National Grid ESO Future Energy Scenarios and the sixth carbon budget. Hard as this is, bottom up – top down reconciliation is an established practice.

[1] This was confirmed by the Competition and Markets Authority Energy Market Investigation 2014-16

2 | Flexibility

Flexibility is the central challenge of the market arrangements. Cost reflective arrangements in all time domains from millisecond to decade need to work together.

The importance of flexibility

We showed in figure 3 the concept of flexibility effectively moving electricity generation from one time into another time when it is needed. This was of course highly simplified. Some complications are; i) over and above the economic cycle, electricity has three main periodic cycles (day/week/season), ii) electricity generation and demand have substantial variations, relative to the periodic cycles, in all timeframes from 0.001 seconds to decade, iii) it is extremely difficult to assess ex ante the approximate size of these variations, iv) demand response and storage create serial correlation between sequential delivery periods, v) correlations between all factors are highly complex, non linear, uncertain, and very difficult to model, vi) the de facto UK standard for Expected Energy Unserved in transmission is extremely low, at around 0.00006%. Modelling at this level of confidence is extremely difficult.

One solution is to have vast round-turn storage charged up and on standby, and vast transmission and distribution lines to convey it. This is so inefficient as to be manifestly unaffordable. What we must do is first to form our best understanding of the most likely halfhourly demand and halfhourly production over a ten year period. This creates a volume signal, and because it has long notice, then it engages the cheapest resource. For example, the diurnal cycle of PhotoVoltaic power might be matched best by thermal demand side management, or dynamic Electric Vehicle charging, or dedicated diurnal round turn storage, or something else. The cheapest method is discovered using the medium of price. We now have at least a volume forecast, and ideally some contractual support to address the diurnal cycle. The more that is contracted, the less variability we have to contend with.

At the highest level, we can regard the solution as several fold:

i) Reduce the amount of variation driven into the system unless it is generation that is positively correlated to demand or negatively correlated to other generation

ii) Increase flexibility in all parts of the system

iii) Encourage installed volume of renewable electricity that has inherent storage (e.g., water systems and thermal systems)

iv) Harness energy storage and otherwise round-turn storage in all timeframes from 0.001 seconds upwards

v) Encourage demand side management, including solutions that go beyond using intertemporal shift of import with no change to service (e.g., temperature discretion within the comfort range, electric vehicle journey discretion)

vi) Interconnection with countries with low or ideally negative correlation for net demand, whilst ensuring that zero carbon Guarantees of Origin (CO) arrive with power import that is designated to be zero carbon (note that import without GO is at the residual mix, which may be lignite, as distinct to the grid average mix)

vii) Greatly enhance the Electricity System Operator aggregate volume forecast and signalling, and therefore the forecasts that the ESO receives

REMA has a bearing on all of these.

Firmness and flexibility

Firm commodity contracts can be described as "weight-rate-date". i.e., for electricity the weight is the MWh delivered over a halfhour, the rate is price in £/MWh and the date is the date and the halfhour. If the contract is firm, then it is either fulfilled or cashed out by a transaction with equal and opposite weight and date. If party A sells a contract to party B then, provided it is firm, then B can sell to C. Counterparty exposures are financial rather than physical. If the contract is not firm, then A can fail to deliver and nothing else happens. So, B cannot sell to C without taking on the non-delivery risk of A. This causes market failure.

A key feature of markets is that they are well placed to contend with risk but not well placed to contend with uncertainty, especially when accompanied by asymmetrical information and distorted incentives. Put simply, markets work with firm contracts, and non-firm contracts require non-market solutions that lose the efficiency benefits of markets. NETA was a significant development in developing forward contracts that were notionally physical (i.e., they become Physical Notifications) and notionally firm (failure to deliver or demand at the Physical Notification is cashed out at the imbalance price). This made the transaction in which party A sold (notionally physical) electricity to party B completely firm. Therefore, B had a tradeable contract. Failure of A to deliver power does not directly affect the flow of energy to B.

A seller of a firm contract that cannot deliver must make good the contract by procuring from another market actor the volume at the date and time. It is this procurement of replacement volume that requires flexibility in the universe of market actors. The key here is that the flexibility is timely. The maximum notice is given to the market for the flexible actions.

With non-firm contracts we do not have this certainty. We do not know until almost real time what the seller will deliver and, therefore, flexibility is engaged in the market with very little notice. This is highly inefficient and the cost to maintain high flexibility in very short timeframes is a deadweight cost that flows to consumers.

Therefore, firmness is intimately wrapped up with flexibility. Firmness is the norm in markets and enables efficient operation. Conversely, non-firm contracts are highly inefficient and should be firmed up as much as possible.

What is required to develop a flexibility market within REMA?

The key things are; i) cost reflectivity (including the costs of variability imposed on the system), ii) an integrated family of flexibility instruments, harmonised such that the same thing has the same value at the join between instruments and timeframes. The different time domains are described below.

One thing that cannot be covered in a short report is how to contend with revenue stacking. In revenue stacking, a flexible resource such as a battery can gain several revenues by acting simultaneously in several markets. For example, wholesale, capacity mechanism, frequency response and balancing. Revenue stacking is essential to attract the investment in flexibility across multiple domains, but has the complication of double committing the same volume. The solution to this is firmness plus an array of other things such as secondary market and deficiency mechanism. A simple example of good harmonisation is frequency response by a battery with a committed wholesale trade. The engagement of frequency response causes imbalance and the imbalance is cashed out in the balancing mechanism, thereby resolving the double commitment.

Different approaches for different time domains of flexibility

The thermal system inherently had high flexibility in all time domains. For example, in sub cycle time domain there was mechanical inertia. Over minutes there was steam pressure. Over a day, plant has cycled since the 1880's with short term fuel storage. Across seasons and years fuel was stocked post extraction and pre extraction (left in the ground with flexible production rate of indigenous stocks). The renewable system has none of these things but has different flexibilities that include power electronics, more round turn storage and demand side management. The market paradigm to harness these is very different indeed and furthermore instead of relying on a hundred years of experience, we are uncertain what can be achieved by "tech" (e.g. synthetic inertia and "grid forming" stabilisation of alternating current in the grid), by "society" (e.g. time shifting end use, embracing automation, elasticity of end use), "free" (such as inertia on the demand side, inertia in the wind) as well as what new pressures new equipment "behind the meter" (e.g. more and more inverters) may place on the system, and what climate change itself might do the variable renewable energy inflow.

We need therefore to look at each time domain and consider where we will get the flex for it and integrate them appropriately.

Subcycle – ~0.001 to ~0.02 seconds – Grid forming is not rewarded and resonance/instability not charged for. Whilst the grid code will deal with the technicalities, the commercial arrangements need to be integrated with ancillary services, and reserve markets in particular.

Frequency/inertia domain – ~0.02 to ~ 10 seconds – The solutions for this will be largely technical (e.g., synchronised system clocks), but as with all energy balancing, the commercial arrangements must integrate with the adjacent markets (subcycle, frequency response, imbalance)

Reserve family – ~10 seconds to ~ 30 minutes – This is an area that will need careful attention, for example if time of use tariffs drive coordinated demand changes on the hour. Voluntary 5 minute balancing is one way to integrate these with the market.

Balancing – [5]-30 minutes - The introduction of the balancing mechanism (BM) in NETA in 2001 was the significant development from the 1990 Pool. It created contract firmness. It brought in the cultural change of a market that encouraged demand side participation. The BM could come into its own with consumer side participation. The BM, and its modification process, work well and aligns naturally with REMA. BM changes, REMA changes, and changes to the Supplier Hub need to continue to be well coordinated.

Intraday – ~ 2 hours – This is a vital period as, with winter heating demand in particular being peaky, enables the system to ride through the highest demand periods. Whilst heating flexibility and efficiency remain uncertain but under-achieving, and Electric Vehicle responsiveness not being certainly universal, dedicated round turn storage may play a major role in flattening the peak with a diurnal cycle of charging before and after the peak and discharging in the peak. The Capacity Mechanism in its current form without strike price does defend the system from very infrequent peaks but does little for cyclic peaks. The wholesale market always faces the prospect of ad hoc caps, which has the effect of deterring capacity. System management such as voltage control has uncertain effects, as consumer devices are changing and the risk of voltage collapse changes with it. Hence, we must rely on matching supply and demand rather than system operator action.

Interday – This is a key feature for sustained low sun low wind (termed a dunkelflaute) and low wind cold anticyclone. Diurnal cycling of short term dedicated storage to ride through daily peaks may be compromised due to the inability to charge at low prices. Demand side flexibility is essential. This goes beyond storage flexibility in heating, but can be harnessed by Electric Vehicle charging flexibility. Longer term dedicated storage comes into its own here but is likely not to have the energy or the capacity to "keep the lights on" and hence structural pre-planned demand response such as turn-down of energy intensive industry and civic response to heating are needed. Industry turn-down and civic response are not covered in this report but both are very important to maintain the current extremely high grid reliability, without paying for expensive assets that are used for less than, say, 3 hours per year or even less or never. Because these high impact events have low probability, it is not economically feasible to maintain very large capacity and very large stored energy. In a dunkelflaute situation we may rely less on import and indeed contracted imports may be at risk. There are power generation solutions to maintaining sufficient energy flow to charge up storage of all forms in the off peak, including bioenergy with carbon capture and storage (BECCS), nuclear and other low carbon solutions, running at enough volume to offset the CCGT CO2 output. Hydrogen storage is one solution, especially if hydrogen is used to heat homes, but at this point this is highly uncertain. Finally, there are interconnector import solutions that are not exposed to Northern European dunkelflaute. Sustained low generation is a key scenario for REMA and there is a clear solution to maximise the harnessing of all flexibilities across the system. This is the halfhourly wholesale price vector to 72 hours ahead. This is a vital REMA delivery and can be achieved by developing the other four markets (CfD, CapMech, balancing, reserve) and harmonising them.

Seasonal – The seasonality of demand has always been the great challenge for electrification. The "silver bullet" remains radical improvement in the building stock, which both decreases the winter volume and flattens the peak. Hydrogen heating with hydrogen storage is actually better than the natural gas system due to electrical production rate discretion and large storage potential but this solution is highly uncertain. Renewable import (with Guarantees of Origin) from other countries which have net demand negatively correlated with Great Britain is also possible, and REMA does depend on this policy decision. At this point, REMA cannot take comfort from the prospective presence of interconnector wires, other than a degree of net demand diversification. Running BECCS will also be essential. Reservoir hydro volume and volume potential in Great Britain is necessary but limited. Other kinds of dedicated storage are appearing. Should cheap seasonal storage appear, then the REMA design need pay less attention to managing the high peaks. Overall, the seasonal challenge falls largely beyond the scope of REMA, but REMA can help, for example by the CfD profiling developments described and by enabling the formation of granular prices at least one year out.

One to five years – The principal challenge for assets that can deliver power to cover "1 in n" year net demand crises is reward. If they are "energy only" with no capacity payment, then the risk of private sector assets facing ad hoc offer caps is simply too high. This is where the capacity mechanism comes into its own, even in the current situation with no strike price and limited firmness. However, the range of physical options is limited; i) unabated gas generation with stored fossil methane requires idle infrastructure and a recognition of potential violation of net zero pledges, ii) hydro water stored for these would become less flexible for shorter periods, iii) interconnection is not suitable for 1-in-n years due to the high non linear correlations of net demand across Europe, iv) BECCS fuel cannot be stored in enough volume and the capacity is too low, v) large storage of hydrogen for hydrogen heating relies on hydrogen heating. Apart from resolving the UK building stock and behaviours regarding thermal waste, then there is no single solution here, so we need to harness as much as we can get from each type.

This adds considerable complexity to REMA. We can express the design principles as; i) as firmness as possible, ii) best possible forecasts, iii) international import/export agreements that are commercially as watertight as possible (and if so, then import/export can be factored into REMA), iv) formation of long term prices and capacity (i.e., option) prices.

Five+ years – Planning scenarios for this is very important. The government has to take national infrastructure and international agreement decisions. The key effect on REMA is the boundary of the state. Broadly speaking, the Great Britain position is to decide broadly what needs building and contract with the private sector for delivery (not build). The REMA question is the migration of the contract with the state into the market. For example, nuclear power has a state determined CfD but is integrated with the wholesale market by virtue of its fairly constant load profile. In some countries, "strategic reserve" is government owned and only interacts with the market under highly specified conditions. Whilst this is formally inefficient, this mechanism does prevent foreclosure of private sector assets. The main REMA question is not how Great Britain will manage strategic reserve for 1-in-n events, but what is the likely generation mix, network infrastructure, and demand and demand response profile that REMA should optimise to. Hence the great importance of the NG ESO Future Energy Scenarios and the Climate Change Committee carbon budgets.

3 | Evolution of the Contract for Difference

The Contract for Difference can continue its success by evolving with particular attention to a menu of firmness and flexibility options. The key development is to address the key challenge of more Variable Renewable Energy, electrification of heat and transport, and less thermal fossil generation.

In chapter 6, we examine the difficulties with the green power pool, split market and decoupling the marginal price of gas in the wholesale market. As a result, and as already discussed, we recommend that REMA focuses on the continued evolution of the existing market arrangement. In particular, below, we suggest ways that the CfD could be developed in future allocation rounds in order to deliver not only low carbon generation, but a structure that rewards contract firmness and flexibility.

Firmness

The connection between firmness and flexibility was described above. Non-firmness is now the greatest challenge that faces REMA overall and CfD in particular. In the absence of change, CfD generation would impose a very high need for flexibility into the market, with neither physical capability at scale or market or policy instrument to deliver it. This is exacerbated by the lack of deficiency notice in the CfD contracts. Indeed, there are perverse incentives, for example the owner of a variable and a flexible resource is incentivised to cause variability with CfD generation and be rewarded for resolving it with the four other available instruments of Capacity Mechanism, reserve, balancing and wholesale trading.

A key feature of the CfD is that it is a non-firm contract. This was initially a beneficial feature because it moved Variable Renewable Energy inflow and (short term) technical risk from project to consumers (via the state) and, when combined with the fixed price, enabled the low cost of capital that stimulated project development of Variable Renewable Electricity in large scale.

However, it has always been recognised that firmness in CfD will need to develop as the VRE volume increases and the thermal generation volume decreases.

Providing the option for firm CfD has the most significant benefit. There are several other design developments that could increase the level of firmness at the margin. Since firmness is so important in engaging flexibility, and we have an impending variability/flexibility imbalance, some of these are summarised below.

Choice of firmness

Converting the whole CfD to Equivalent Firm Power (EFP) has been considered in REMA and rejected. We are not proposing re-opening decisions made but we note that there remains a substantial mismatch between variability and flexibility. This can be addressed in two ways; i) voluntary firmness and ii) modifications that increase the value of firmness and have the effect of firming up. One key objection was lack of design for EFP. The main design solutions for optional firmness are explained in this chapter. For example, approaches to non-delivery, green premium and auction format.

As was shown in the Bank of England auctions[2] with two forms of collateral, it is possible to conduct the auction with projects making bids for both firm and non-firm, contingent on only one acceptance. The firm auction price gives the best indication of true value. We may expect the value differential between firm and non-firm to increase over time. Smooth transition can be achieved by slowing the rate of change of price differential. This can be done via simultaneous ascending and descending clock auctions and adjusting the acceptance vector such that in the first years, only a small amount of firm CfD is required to clear, and in the later years, a greater amount is required.

[2] See Klemperer 2018 and works by Elizabeth Baldwin. Auctions with much more complex bids can be handled with modern techniques. See Budish et al 2023

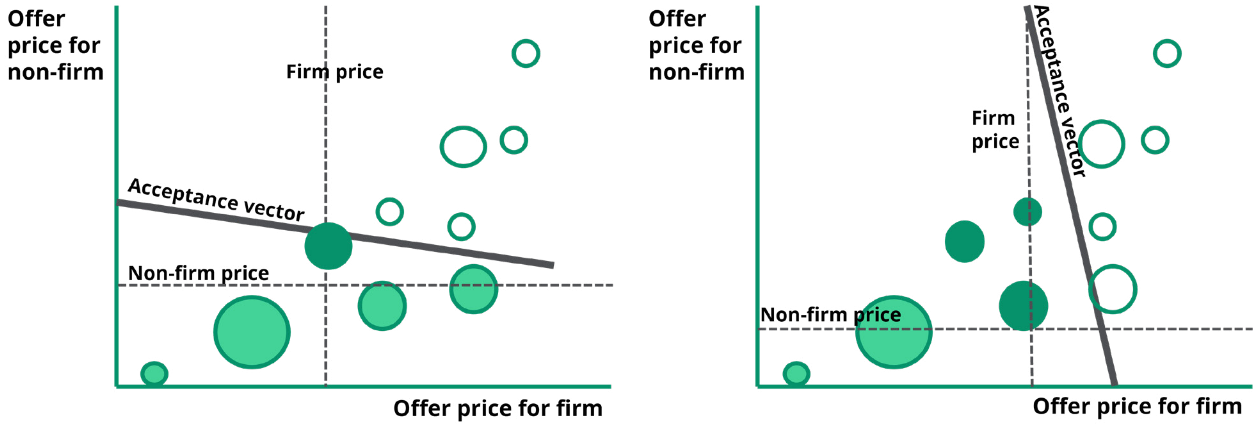


Figure 6: Schematic for CfD auction if all units may offer a firm and a non-firm price . Left: Limited orientation to firmness. Right: Stronger orientation to firmness. Solid fill means firm acceptance. Light shaded fill is non-firm acceptance

The firm power is then identical to a standard forward contract, other than green premium, which is discussed below.

Since the contract is identical to a standard forward contract for "grey" power, then the difference between the CfD strike and the prevailing forward price can be termed the "green premium". Note that the CfD generator still generates Renewable Electricity Guarantees of Origin that it can sell. The purchase of REGO's by consumers (via suppliers) are voluntary and should therefore not be regarded as a levy or part of the green premium.

A complication is that, unlike fossil generation, there is a natural periodicity of generation that needs to be contended with. This is discussed below in volume profile.

Deemed Generation Volumes

The CfD has options for deeming reliability or Variable Renewable Energy inflow. For example, a generator could provide firm reliability but still avoid the inflow risk by deeming the inflow. For more innovative technologies, both could be deemed, thereby making the deeming closer to a Regulatory Asset Base contract, rather than CfD. Deeming the inflow then creates the direct requirement for the system operator to take and use the best forecast.

Dynamic derating of capacity

Derating is a standard technique used in capacity mechanisms where the expected capacity of a power plant is adjusted based on its historic availability. It can be adjusted periodically or during the contractual delivery period.

In CfD as it stands, plant is incentivised to contract for the maximum CfD capacity that it can be awarded. If a plant contracts for its entire life in one CfD then the only way to derate dynamically is to derate the next year according to the availability in the prior year. Any generation above the derated capacity would be merchant power with no green premium. The dynamic derating can be adjusted to incentivise the plant to submit a capacity that equals the expectation of generation, and this can be time profiled.

Market Reference Price Mechanism

The Market Reference Price (MRP) is always the best reflection of the "grey" (i.e., with no allocation of source) wholesale price at the time of setting. Note that by 2035, the average carbon footprint of power delivered over each measurement year must be zero. We believe consideration should be given to the development of the granularity and transactability of the MRP at longer horizons. There are two key benefits. The first is that gradual extension of the MRP horizon has the effect of firming up the non-firm CfD and increasing its value. The second is that more granularity and a longer horizon has the effect of creating a market signal in a longer horizon which gives the market time to respond. This enables wide participation in flexibility, including storage, power generation, and consumers (mainly in thermal storage and flexible charging of electric vehicles). This reduces the increasing reliance on monopsony reserve contracts which contract short term (and therefore expensive) flexibility and pay for expensive standby flexibility that is unused. The harnessing of timely flexibility increases the value of Variable Renewable Energy and reduces electricity bills to consumers.

The normal actions taken by generators are; i) sell to LCCC at the CfD strike (the auction), ii) buy from LCCC at the MRP (closing out the auction CfD), iii) sell to market at the MRP (in order to deliver physical power), iv) re-hedge according to expectation or otherwise cashout imbalance. Trades (iii) and (iv) require granular liquid wholesale markets.

Assuming no re-hedge and imbalance, then the net trade is (i) sell at CfD strike. Note that trades (ii) and (iii) reinforce liquidity. Transparent granular MRP enables granular wholesale trading, and granular wholesale trading enables transparent granular MRP. If the plant completely fails before the MRP is set, then trades (i) and (ii) disappear and there are no trades (iii) and (iv). If the plant partially fails before the MRP, then trades (i) and (ii) and (iii) are at the delivered volume and there is no trade (iv). The net is the sale at CfD strike of delivered volume.

If the plant fails after the MRP is set and the expected volume sold at the MRP, the trades (i) and (ii) are at the delivered volume, (iii) is at the expected volume, and (iv) is at the difference between expected and delivered volume. If the market price has risen since the MRP then there is a cashout cost and if it has fallen there is a cashout benefit.

A key timeframe for flexibility harnessing is 72 hours. This captures the bulk of domestic flexibility in terms of import from the grid, in particular for heating and electric vehicle charging. In order to harness this flexibility, it is important for the wholesale market to be deep and liquid at halfhourly resolution to this horizon. Then consumer equipment can be programmed to optimise import from the grid according to user parameters such as energy use within the 72 hour period, charging status at the horizon, and reward related discretion on end use (temperature in the comfort range above the health threshold, duration of temperature, number of rooms heated, travel etc.).

Increasing the MRP horizon for non-firm CfD does not incur significant investor costs for VRE. It does however add management costs for managing changing forecast and harnessing what flexibility there may be. Therefore, pushing the MRP horizon to 72 hours in one go is too much transition at a time. The MRP can gradually be extended in each auction. Note that this increases the value of the VRE and this should be recognised in the CfD budget.

For flexible VRE with firm CfD contracts, the longer horizon and higher granularity of the MRP is of benefit. This is because a firm forward trade becomes a live option. The plant can continually rehedge to its benefit, and the benefit of the market, as market prices change. The practice of “gamma” trading of “real options” is well established in commodities and hence readily implementable.
For both CfD contract types we can see that granular transaction volumes in the market to the MRP horizon increase. There is a virtuous circle. More transactions create transparency and liquidity, which encourage more transactions.

Aligning CfD settlement Periods to half hourly settlement

Full alignment of the MRP to the wholesale market is strongly desirable as this enables harmonisation. Furthermore, halfhourly granularity is better attuned to the precise time of the two hour winter peak that is addressed in the Capacity Mechanism.

Metering interval apportionment

Level apportionment (assuming flat generation between reads) is a form of non-firmness since there is disincentive to increase meter temporal resolution. Incentive can be aligned by profiled apportionment. This has the effect of incentivising firmness. The method is almost the same as in Supplier Volume Allocation on profile, and deemed within halfhour profile that enables voluntary five minute settlement.

Volume profiling

As a non-firm contract, the CfD has no volume profile. This denies the market a volume signal to respond to. For example, the absence of solar power on a winter evening is something that the system operator forecasts in the short term, but there is no long term signal for anyone else unless the system operator conveys it. A firm CfD ideally needs a full volume profile, but it can otherwise manage a baseload CfD by trading in the wholesale market to adjust the profile.

Volume profile can be built into non-firm CfD. There is benefit then for both generator and system to profile the CfD. For example, a 20MW solar generator might contract 20MW in the day and 0MW in the night. As things stand, there is limited incentive to contract below capacity. To a degree, this can be managed by profiled de-rating. For example, PV without battery backup would be derated to 0% capacity on winter nights. An alternative is a long horizon Market Reference Price. The generator trades to match its physical output.

Balancing adjustment to strike price

This feature essentially adds firmness, since the Balancing Services Use of System charges are correlated with the ratio of VRE to thermal power. There is a case, for firm CfD offers, for removing BSUoS charges.

Deficiency

In general, there is no explicit penalty for non delivery, and there is always the incentive to deliver, since the strike price is secured whether the market price is lower or higher than the strike, as long as a sale can be made at the Market Reference Price. There are several situations in which actually a plant owner is incentivised to declare an available plant unavailable. Non delivery is currently only encompassed within the non-delivery disincentive regime.

Introduction of a deficiency mechanism can limit the risk of a firm CfD by limiting its worst case to the deficiency charge instead of the market price. This is a form of partial firmness. The deficiency change increases with shortening horizon. This creates the incentive for timely declaration and hence market signal to address the shortfall.

Deficiency can introduce partial firmness to a non-firm CfD.

Secondary Market

One form of VRE trading firm CfD in the secondary market with another VRE would need to claim and surrender their respective green premiums. However, the CfD is not technology neutral and therefore making a direct secondary market fungible is a challenge. However, with the concept of green premium it is possible simply to use the wholesale market as a secondary market. Making up firm CfD shortfall by purchasing "grey" power in the wholesale market would be accompanied by surrender of the green premium. We will see below that it is also ideal for the generator to be able to claim green premium for delivery beyond the firm CfD volume, possibly with some conditions or attenuation.

Incentivising forecast

We have noted the strong benefits of firm CfDs with price and volume profiles. This provides clear signals to the market of the times when the system is expected to be long or short.

The forecast is very important for all forms of CfD generation.

Noting the high importance of getting long and short term price and volume signals to the market, for example the value of long term inter-seasonal or decadal capacity, or in providing notice to consumers (via suppliers) to time-shift demand such as electric vehicle charging, needs notice.

Accurate forecasts of generation and demand (and possibly storage), at halfhourly granularity going out to about 20 years, is therefore very important. Currently there is very little incentive to convey an accurate generation forecast. The Grid Code requirement for Power Available forecast can be developed further. The firmer the CfD (and the more effective the capacity mechanism and the more deep and liquid the forward market), the greater the potential to make use of accurate forecast and the greater incentive on the generator to produce one.

In the extreme, the forecast incentive actually converts a non-firm contract to a firm contract. However, this would be a clumsy way to achieve this.

One "softer" way to incentivise forecast is to have some form of information imbalance mechanism for Power Available forecast. Information imbalance charges are normally set to zero but can be increased gradually, if necessary, with the revenue socialised back to other units producing more accurate forecasts.

An intermediate way is to use dynamic derating. This naturally incentivises forecast and has the benefit of the forecast being periodic (diurnal/seasonal).

The green premium

As presented by government in 2022, the principal benefit of CfD is reduction of exposure for producers and consumers to long term volatility of electricity prices. Nevertheless, a support cost is recognised; "CfDs incentivise investment in renewable energy by providing developers of projects with high upfront costs and long lifetimes with direct protection from volatile wholesale prices, and they protect consumers from paying increased support costs when electricity prices are high" (emphasis added). For non-nuclear, we can express the support as green premium.

Explaining the green premium

This is not a standard term and is used for explanation in this paper. The green premium is simply the difference between the CfD price and the prevailing wholesale price on a like for like basis. The wholesale price is for firm power. The green premium is implicitly a key metric for the Control for Low Carbon Levies[3]. If the wholesale price does not reflect the sectoral cap (zero in 2035), then its reference price must be uplifted by the cost of carbon removal.

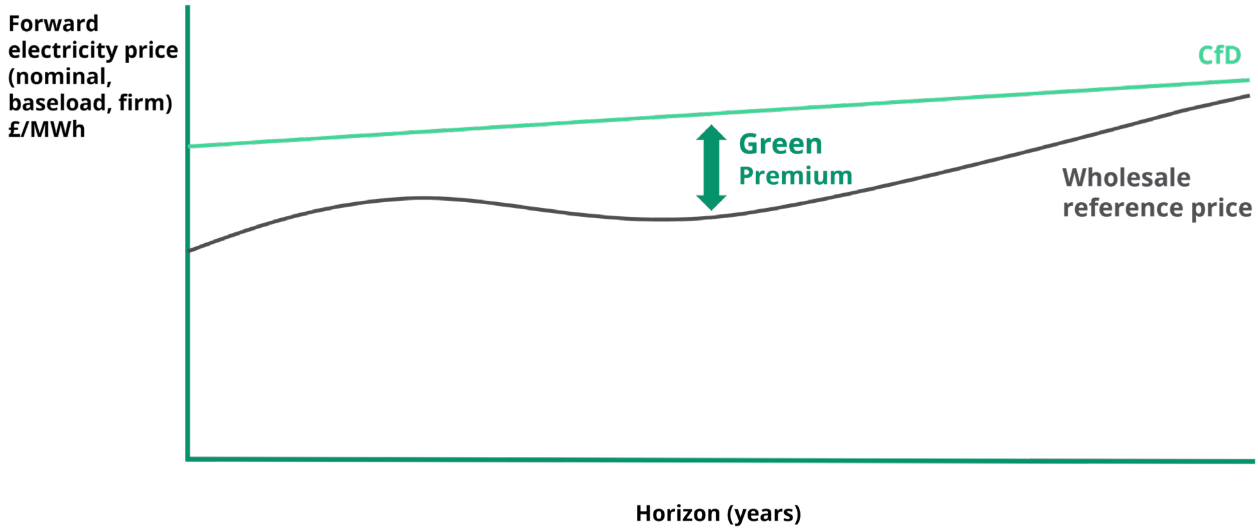


Figure 7: Green premium

Historically the long-term baseload price has been set by the new entry of baseload generation, i.e., Combined Cycle Gas Turbines (CCGT). The price was formed from four main elements: i) international gas price at the National Balancing Point, ii) emission cost (allowance plus tax), iii) amortised capital cost plus fixed operational costs, iv) marginal operating cost.

We had a clear reference price against which to evaluate subsidies for other generation types. If other generators have cited carbon benefits, then the comparator is the CCGT price minus the sum of carbon taxes and allowances.

We now have the challenge of establishing the key reference price which is annual baseload. Ideally, we have a carbon neutral reference price.

One possible candidate is nuclear. However, there are many nuclear specific elements, and nuclear entry is "lumpy" rather than continuous and hence in practice the levelised cost of nuclear power does not give us a useful reference price.

Historically, the forward grey wholesale annual baseload price has been determined by new entry combined cycle gas turbines. A carbon neutral price can be formed since CCGT would need to buy allowances and pay carbon tax. However, buying out of allowances leads us to carbon intensity in power generation, which is not consistent with the power sector carbon targets for 2035 and beyond.

Whilst we do not believe that carbon emission is acceptable, and further we believe that facilitating carbon emission forecloses zero carbon solutions, we recognise the apparent position of accepting some carbon emitting power generation, that therefore must be balanced by carbon negative generation.

A compromise carbon neutral reference price can be formed from the virtual combination of gas and biofuel into CCGT with Carbon Capture and Storage (CCS). The costs of CCGT, whether running at baseload or at peaks, are very well established because these form the basis of Cost Of New Entry (CONE) calculations used in capacity mechanisms in many countries. Since the capital and operational costs of CCGT are well known from CONE calculations, and the forward price of gas is reasonably well known, then it remains to estimate the capital, operational, and efficiency costs of CCS at the requisite capture level (which is ideally 95% but otherwise is realistically 90%).

Rather than the metaphorical CCGTCCS buying carbon allowances in the market (thereby violating the carbon target), we can consider that it buys from biofuel CCGTs with CCS (i.e., CCGT BECCS with negative carbon footprint). If we can estimate the biofuel cost, we now have a virtual generator with zero carbon footprint and known baseload volume and costs.

[3] For amounts not already committed. See House of Commons Library 2017

So, we have a carbon neutral reference price.

Note that we do not require actual build of CCGT to do this, since CONE is well established for CCGT, and CCS capture rates, efficiency cost, capital costs are reasonably well known and the net revenue or disposal for the CO2 is a relatively small part of the total cost.

Even before we consider CfD Non-price Factors, the Green Premium includes multiple benefits such as security of supply in relation to international factors, social cohesion, the positive externality of UK leadership in Net Zero ambitions.

Using the green premium in the auction

It is possible to enhance the harmonisation of approaches to generation technologies by having green premium as a "basis" in the auction. For example, suppose that technology A has not just absence of negative externality in the form of carbon, but a positive externality. An example externality would be methane removal from landfill gas generation. Putting aside the complications of the Global Warming Potential of methane, and using the current IPCC 100 year ratio, then the plant should clearly be awarded the net carbon equivalent benefit of methane removal.

Then A could receive a green premium uplift of £X/MWh over and above the auction price. In fact, the two (carbon and other) elements of total green premium paid is a very good candidate for consideration of the CfD budget. Methods for how this may work within the auction where recently consulted on by DES NZ in relation to Non-Price Factors and we are supportive of seeing these options explore further.

Green premium after the auction

As discussed in this paper, if firmness is added to the CfD, then a solution is needed for green premium. For example, green premium could be added to merchant revenue from CfD plant, and green premium could be paid back for generation undelivered.

The simplest solution is for green premium for each delivery year of each CfD to remain constant after the auction. Whilst it is economically efficient to change it, this would add uncertainty at auction time and hence increase cost of capital.

Green premium for non CfD plant

It is logical to award the same green premium to all generation of the same type, regardless of contract. For example, it should ideally be the same for renewable plant that is better suited to the capacity mechanism, or plant that sells a corporate PPA instead of a CfD contract. This can all be managed via the CfD. We show below the example of how this can be done with corporate PPAs.

Green premium and Non Price Factors

The green premium mechanism is highly amenable for other factors. Provided that it can be associated with either energy or capacity then it can accommodate almost any factor. For example, supply chain, jobs, habitat. In energy market terms these are all bases. The basis for each element can be either fixed or variable. For example, a habitat basis, normalised per MWh, and at anticipated load factor, could be fixed at £5/MWh. The project then gets the auction price plus £5/MWh. As things stand, the receipt is dependent on generation. Since there is a separate CfD consultation, this is considered only briefly here, and we introduce the main delivery effects.

Non-price factors (NPFs) essentially divide into those for which the NPF benefit relies on generation and those for which it does not.

If a project delivers habitat, then the habitat might be independent of output and therefore paid on deemed generation at a fixed monthly rate. If a project enables supply chain, then this may be driven by capacity (e.g., number of turbines times size of turbine) and hence is driven by capacity but not energy. Hence any deficiency payment would not be dependent on energy inflow but could be dependent on technical failure.

Now consider a NPF that relies on generation for benefit. Suppose that there is an externality benefit that is not explicitly rewarded. A direct example would be avoided methane emissions from landfill gas generation. For this example, we can simply apply an uplift to the strike price that is equal to the carbon price (e.g., the UK ETS price) times the agreed Global Warming Potential multiplier for methane. There is no change to the auction. The uplift can be set up front or on a dynamic basis as the UK ETS price and the agreed GWP multiplier for methane change. For firm and non-firm CfD, the green premium can be paid on generation.

Additionality is clearly a question for Non Price Factors. i.e., did paying the green premium make something happen that would not have happened. However, this is not a REMA question. REMA can simply consider that the green premium paid is at the right level.

The CfD NPF consultation will address this.

CfD budget

Consumers effectively buy power from CfD generators at the CfD strike prices. Where the CfD strike is above the prevailing "grey" forward market at auction time, this is regarded as a subsidy paid by people as consumers to people as citizens who benefit from climate change mitigation. This subsidy is subject to the levy control.

The question here, and under consultation, is what should happen to the budget if the CfD role is expanded to Non Price Factors. What happens to the budget and who should pay for it. This seems clear. If the CfD budget were exclusively about carbon, then the budget should be expanded commensurate with the increased reduction of carbon equivalent. As now, the cost should fall to billpayers not taxpayers. If the CfD is about other factors, such as jobs and supply chain and the UK economy overall, there is a case to charge taxpayers rather than billpayers. The administration of separating the two elements of Green Premium is straightforward.

Exploring the flexibility in renewable plant

Flexibility is apparently very low in most CfD plant. However, this is in the context in which there is no reward for flexibility. Over and above co-locating storage with Variable Renewable Energy, there are numerous flexibilities that can be harnessed. Many are similar to those in thermal plant, such as outage schedules, sizing the maximum MW output relative to the MWh stored, running plant in suboptimal but more flexible configuration, running in partly failed state, and accepting engineering damage or and/or failure risk in return for high reward. Developing the CfD structure would bring out these flexibilities.

With non firm CfD there is little incentive to explore these sensitivities since the strike price is the only price received. With firm CfD there is considerable incentive because the flexibility is merchant flexibility that can benefit from volatile wholesale prices.

There is one particular flexibility "behind the meter" at Variable Renewable Energy installations that benefits from the firm CfD option. This is co-location of storage. Currently an owner of VRE and storage in the same place is incentivised to have two connection points, since the variability is not penalised and the flexibility is rewarded. Using the same connection point reduces the CfD payment by an amount equal to the round turn storage loss. i.e., the storage has negative revenue. This is clearly inefficient, and this is resolved by rewarding firmness within the CfD

Auctions and contracts

Auction frequency

Less frequent auctions concentrate liquidity better and reduce the management overhead of participant and auctioneer. However, they produce more "lumpy" outcomes than frequent auctions and present less opportunities to refine volumes.

The optimum auction frequency is probably the frequency that bidders ask for. Biennial was too infrequent. The move to annual auctions has been a welcome and positive step. Given the volume of low carbon deployment required, REA members have also called for six-monthly auctions.

However, most important for industry is having a clear and specific timetable for auctions over the coming years. This requires having strict dates for, at least, the next three allocation rounds, with a rolling timetable and clearly assigned budgets. This provides confidence to the market and allows developers to properly plan and aim for specific auctions..

Contract lengths

Forward markets are effectively continuous auctions for the entire forward "vector" of prices as far forward as the market clears.
In the extreme, every delivery year trades every auction year. Note that this would probably be the same way that interest rates trade i.e., rather than each delivery year trading separately, the whole "strip" trades from one to two years, one to three years, one to four years etc. The individual year prices are implied from the strips but are not cleared directly in the auction.

If we have a 20 delivery year auction every year, then each delivery year trades 20 times. Although it is not visible, there is a fine structure to the implied 20 year forward price vector. This can be understood by considering seasonal commodities.

Each season trades at a different price. The whole year can be traded at a single price but even so, there is a seasonal price structure of the annual contract that is not evident because of borrowing and lending money within the contract. So, the CfD is already more complicated than is commonly described.

As with auction frequency, the optimum contractual structure is probably the one requested by participants.

Markets clear complex information by tâtonnement, i.e., iteration. It is, therefore, worth considering if this can be achieved via a change in auction format to an ascending or descending clock. So, in each round all actors can bid for any contract, for example year 1, year 7, years 1-20, years 3-5 etc. With a given volume vector objective, each year of the whole 20 year vector moves in each round of the clock. Each participant can change their bid in each round, and eventually the whole vector clears. This is shown below. Ignoring discounting for ease of explanation, a project clears if its average price for its bid period is no higher than the average auction clearing price for the same period. The clock vector for volume would ideally have a degree of tolerance for inter-year variations in contract volume.

The mechanism is standard in markets (best understood in interest rate markets) but requires concentration of liquidity.

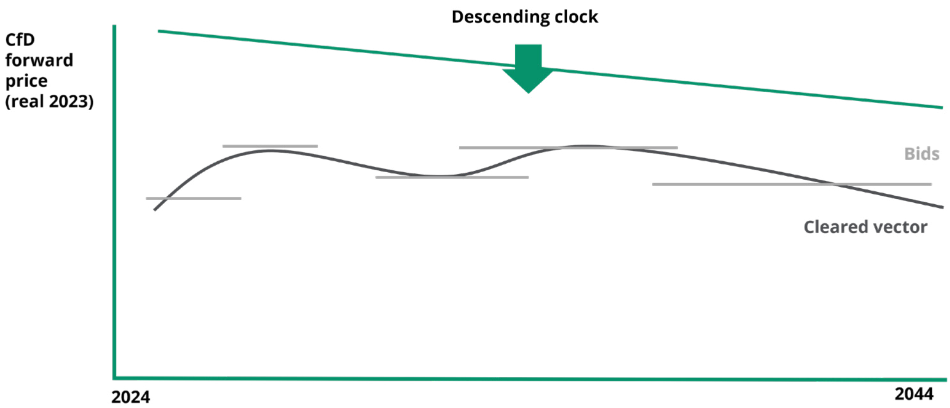


Figure 8: Descending clock CfD showing bids and final vector

The production of this CfD vector would enable a deficiency mechanism, continuously traded secondary market, and fungibility with the wholesale and PPA market.

This mechanism also allows for layering in more contract if and when project life extends, and for repowering plans.

We suggest it could be worth further modelling and exploration with industry as to the impact that introducing a descending clock auction mechanism could have to the CfD.

Technology dependent contract length

If a whole CfD price vector is cleared, then plants can choose their bid period. If this is not done and must remain in simple format with few parameters, then having different standard lengths for different technologies may be considered. Note, however, that this solution relies on the same techniques for evaluating the CfD price vector without the benefit of bid flexibility.

Option to extend CfD and repower sites contracted under the renewable obligation

With the development of CfD auctions, plants have the natural right to re-tender beyond the original period. In addition, we note a significant number of generation assets will start to come to the end of their existing contract arrangements under the renewable obligation from 2027 onwards, a 'repowering CfD' would enable such projects to continue generation. This was consulted on earlier in 2023 and we encourage further development of these proposals.

We also note that in development of Greenhouse Gas Removal business models government have also considered and accepted situations in which contract extension can be built into original contract arrangements, if certain criteria are met. Such arrangements should also be considered for the power CfD.

Part volume contracts

It is common in companies exposed to commodity prices to build up the long term hedge in layers. For example, if 10% of volume is hedged in 10 year strip each year, then all volume is hedged by the time it becomes physical. Both the Ofgem index for the retail price cap and standard energy supplier hedging follow this principle. This is the most efficient hedge for the individual companies and for society as a whole.

The extent to which VRE developers may wish to do this depends on their structure. Project financed entities have a clear focus on cost of capital and will generally wish to hedge to the end of the project financial plan. Utilities, and investors who use projects as a vehicle for positive exposure to green energy prices, may see this differently, and wish to layer. Hence (if the green premium is approximately zero) it may be best for them to sell only part of their volume into each CfD round. Non-firm CfD's are not particularly amenable to part volume sales because of the gradation of firmness. For a 100MW plant, the first 10MW is highly reliable and the last 10MW is highly unreliable.

For firm CfDs there then seems to be every reason to allow part volume. Where green premium is positive, this needs to be incorporated as described in this paper.

Eligibility rules (including non-project specific bids)

With the standard "real option" method, if there is a project that can turn on or off, or advance or delay, with a low cost of change, then it makes sense for both project and the state (on behalf of consumers) to engage in CfD prior to final decision. If the market rises, then the project is built. If the market falls, then the project can buy out in the deficiency mechanism (with price fallen to correspond to the wholesale change).

The same principle can be applied to a company with no project but the clear ability to develop one in time for the contract (for example a CfD with a start date ten years hence).

This may or may not be a good idea, largely dependent on management of credit risk for the deficiency payment and likely needs further modelling and industry consideration. However, the CfD structure can be developed to keep this option open. Note that non-physical actors already trade electricity right through to being cashed out in imbalance. Where there were defaults that incurred mutualisation to consumers and other actors, the problem encountered was not physical, but financial default.

Compatibility/fungibility with PPAs

PPAs can be firm and non-firm, just as we suggest that CfD's should be. PPA's can also be at fixed price, fixed with non-energy index such as inflation, or energy indexed (floating).

To compare like with like, consider fixed price firm contracts in either market. The key difference is now green premium. The generator gets it paid in the CfD but not the PPA. This is not efficient. One solution is to pay the green premium to both, i.e., regardless of CfD participation. Another solution is for the plant to contract a CfD and then sell a PPA at floating price. The consumer is now exposed to the wholesale market, but this is generally the best, as their natural profile is to buy in the wholesale liquid period out to about two years and not fix the price beyond that.

The consumer has now locked in the difficult bit, which is dedicated renewable generation, with the Renewable Electricity Guarantee of Origin, which does need a long term contract, and other attributes. The generator has claimed the green premium and locked in a hedge price.

Having voluntary CfD partial or full closeouts with episodic MRPs as far out as three years has the effect of releasing the hedge to the market and thereby enabling corporate hedging. Note that, just as in the short term, the presence of MRPs and of traded forward markets, reinforce each other in terms of liquidity and price discovery.

Auction format

There are two main considerations for the auction format.

The first is how to minimise gaming concerns when arriving at a single price. Absent gaming, auction theory tells us that all auctions achieve the same price, so the question is gaming. There seems no gaming reason to change the current format (sealed bid, pay as clear, "first" price at lowest cleared bid).

The second needs more consideration. This is when the auction has two (or possibly more) parameters. In this paper we introduced two key mechanisms; i) multi-product auction, explained as a two-product firm/non-firm auction and ii) descending and ascending clock repeat auction. The combination of these two provides enough auction flexibility for almost any policy decision and REMA structure.

Aggregation of bids

Co-located bids (mainly VRE+storage)

Under the current schemes (CfD and plants with connect and manage connection contracts) there is clear disincentive to co-locate round turn storage with VRE.

At the other extreme (firm CfD including the storage and uncompensated curtailment of export to grid) there is a clear incentive to co-locate even if this is inefficient in system terms.

The "right answer" depends on where the grid constraints are and the pattern of variability of VRE and demand in different places. Co-locating storage with VRE enables smaller connection capacity but at the same time constrains the storage from exporting. Having the storage far away may cause grid constraints at any point between VRE and demand and may increase average flow (and so losses and reactive power).

Whilst co-locating storage is not always the answer to VRE, it is sometimes the answer. Therefore, ideally the CfD (and CapMech) evolve to enable this, for example by rewarding firmness in the CfD. Network charging developments should be coordinated, for example shared connection and shallow entry.

Non co-located bids

For firm CfD there is clear commercial logic to the VRE in being able to submit a non co-located bid with storage. The question is whether this is efficient.

On first analysis, non co-located aggregate bids do not seem to be efficient. Consider the situation of a grid with infinite wirescape and copper plate and completely unconstrained in all respects. The VRE-storage complex is optimised by the company. However, there are market imperfections and hence the local optimum of the company does not conform to the global optimum of the system, which can generally be better managed if they bid in separately. Furthermore, the overhead of expensive analytic resource is increased.

On the other hand, if the flexibility and inflexibility markets are inefficient, for example flexibility under rewarded and imbalance charged punitively, then it is fair to plant to allow it to "self-balance" by a non co-located firm CfD bid.

We note also that firm CfD that uses the wholesale market to manage firmness inherently causes reveals (but probably does not cause) location differentials.

We have noted in this report that getting temporal and locational signals right at the same time is so difficult as to be insurmountable at this point, and that for the moment, temporal signals need to take priority.

Because non co-located aggregate bids add location complications, and the benefit of aggregating two bids at different locations is very limited, then we do not recommend widespread aggregation of non co-located bids, with the possible exception of widely disseminated small installations bidding in aggregate.

Virtual Power Plant bids (single and multiple connection points)

Noting that non co-located bids does not appear on first analysis to be optimal then it follows that Virtual Power Plants (which is almost always non co-located) also does not appear to be optimal.

Aggregated small scale plant needs a different solution for the aggregated dispatch. This can probably be achieved by firm CfD plus revenue stacked reserve contracts. Note that non-firm Feed in Tariff units are not ideally suited to flexibility provision as they are rewarded for flex whilst not paying for the flex requirement they cause.

Protection of existing contracts

A key advantage of CfD is surety of revenue. Before we consider constraint issues, the market can change its locational structure and the projects still be protected. This is done by a "basis swap" that simply swaps the new locational price for the old one.

How locational CfD would work with different locational models

It is possible to fully protect existing contracts. Financial Transmission Rights if there is Location Marginal Pricing, and their equivalents for other locational models, are one way to do this. At the same time, it may be beneficial to give the plant the option to adjust output according to volatile locational prices. This is not necessarily easy, as non-aligned incentives may arise.

Policy on locational differentials and socialisation (or not) of network costs

In Great Britain (and most countries) there is a strong culture of network cost socialisation. This is the case for connection, "shallow" costs (nearby reinforcement) "deep" costs (far away reinforcement), across regions and across time. This is not efficient. Great Britain goes some way towards cost reflectivity in transmission, and (apart from a single subsidy in the North of Scotland), there is no cross subsidy between distribution network areas.

There remain frequent calls for complete socialisation (sometimes called "pancaking" of "smearing") of consumer pass through of distribution costs across the whole of Great Britain. This can be achieved approximately be explicit regional cross subsidies after distribution has been charged for. However, it remains questionable whether the electricity sector isthe right place to cross subsidise regionally. Locational signals need to increase, but this is in the presence of a culture of socialisation, which therefore places a significant constraint on moving to cost reflectivity.

Different degrees of cost reflectivity or socialisation can be incorporated into wholesale prices, CapMech, CfD, reserve and other elements. This is done by "basis", so everyone gets the same before application of locational basis adjustment. The basis adjustment can vary (as in Locational Marginal Pricing) or be fixed (for example as conducted in locational capacity mechanisms).

Participation in ancillary, reserve, balancing, wholesale and capacity markets

Participation mechanisms even with non-firm CfD (as current)

Whilst in general, market products work best together when they are firm, ancillary and reserve markets are commonly designed to work on a partly firm basis. The non firmness can be accommodated in a number of ways such as derating and benign cashout. Consider the simple example of VRE with some storage resource providing reserve. It is well placed to provide upward reserve (more export or less import) if nearly full and downward reserve if nearly empty. It does not know ahead of time when it will be full and empty. The plant can sell both reserves and have a benign deficiency charge for non-delivery. For example, 110% of some agreed price for failed upward response and 90% for failed downward response.

Methods for collaring prices and revenues for CfD generators

There are two effects here.

The first effect is claims by the state that are not commensurate with the initial contract. These may be for example in relation to real or perceived windfall, burden sharing at times of high prices, emergencies, supply shortages and warfare. These fall outside REMA but it is worth noting that the CfD in particular is robust in this regard, due to the stability of revenue.

The second is investor exposure. Over-summarising greatly, there are two types of investor. The first is of bond type who simply wish to maximise their risk adjusted return. The second is strategic type who want positive exposure to renewable energy, including renewable energy prices. Typically, we would have both types simultaneously since the equity investors commonly lever their returns by gearing.

The situation can arise that the cost of capital is so high that in order to contract the required CfD volume then a very high green premium must be paid. There is an argument that this then leads to excess returns ("rent") on an expectation basis. There are multiple solutions to this, for example having a CfD length that ends when project payback has been achieved according to some metric. These are not discussed here, and what counts is the flexibility of the CfD instrument to attract the maximum amount of generation at the minimum cost.

The green premium makes this relatively straightforward. Since it is calculated using the actual or otherwise virtual forward price, then we have both elements. At auction time, the plant contracts the green premium and can choose whether or not to contract the forward price. In effect there is a Market Reference Price available at auction time, so the CfD is cashed out at the MRP at the time of the auction leaving it only with green premium. The forward price can be fixed for only part of the project duration whilst locking in the green premium for the whole duration. This greatly decreases the foreclosure of the corporate PPA market by the CfD.

Now with this price it is relatively straightforward to add sophistication to the CfD in the form of caps/ceilings, floors, and collars/corridors with caps and floors. Taking a simple example, a CfD at £60/MWh can be replaced by a CfD at floating price with a floor at £50/MWh and a cap at £70/MWh. Standard financial methods (flexicaps etc.) can be used to construct more sophisticated caps and floors, for example on annual average prices as distinct to halfhourly prices.

Bidding rules, REMIT and behaviour

Although the science of peak load pricing provides a clear rationale for offer uplift above variable cost in order to recoup fixed costs, any uplift above variable costs remains highly controversial, even amongst electricity economists. Furthermore, the definition of variable costs is controversial, with the most common definition being fuel costs plus variable operating costs.

It is common in electricity markets to apply rules on the variation of offer price over and above the variation in fuel costs or to prevent price elevation or technical plant restrictions that have price elevating effects. This can work in a thermal system with a complete spectrum of variable costs of generation plant. The inframarginal rent covers the fixed costs.

This method really falls apart if gaps appear in the variable cost continuum and there is a high percentage of plant with near zero variable costs. The market essentially splits into "regimes" and in the absence of engagement with flexibility of renewable generators, dedicated storage, and demand response, the price becomes highly unstable. The non-firm CfD exacerbates the problem and further exacerbates it by driving generation to the CfD as the only way to achieve a stable return. The market moves to a regime with zero price for much of the time. Other plants then have to rely on high prices in the non-zero time regime and must offer above, and potentially considerably above variable costs in order to cover fixed costs. The market becomes impossible to police, for example into deliberate imposition of grid constraint.

The main policing mechanism in Europe is now the Regulation on Wholesale Energy Market Integrity and Transparency (REMIT). The metaphor used by Ofgem chair Martin Cave is a useful one. How much one may charge for use of a boat in a desert town that has an exceptional flood depends on why the boat is there. If it was delivered to protect against such an event then the rent should be high. If it just happens to be there, then the rent should be low. So, a facility built to defend the grid against one in twenty year events, that receives no capacity payment, should receive a very high reward if called. However, behavioural regulations are intended to capture sporadic and generally large conduct episodes by individual companies. They are not designed for day to day market operations aimed at gaining sufficient inframarginal rent to cover annual fixed costs.

For the market to bifurcate into two regimes of zero price and high price would be highly unsatisfactory and highly inefficient. The solution is to develop the wholesale market so that it has the depth, liquidity, granularity and transparency for participation across the whole price spectrum. The missing region in prices is almost entirely completed by storage, whether it be dedicated round turn, or intertemporal shift of heating and charging, achieved through time of use tariffs. The main storage engaged here is short term, and hence relies on a halfhourly forward price vector out to 72 hours.

Negative price rules

Applying a lower limit of Market Reference Price to zero is an understandable change. Note however that the forward wholesale baseload price incorporates negative prices. Therefore, the removal of negative prices in theory increases the wholesale reference price against which the green premium in the CfD is benchmarked.

Note that Location Marginal Pricing would introduce negative prices.

4 | Evolution of the Capacity Mechanism

The Capacity Mechanism could be developed on standard international lines towards the Reliability Option method with strike prices. CfD plants should be able to bid into the Capacity Market.

Capacity mechanisms remain controversial. Broadly speaking, at either end of the debate the "markets don't work" cohort of opinion is more supportive of centralised capacity mechanisms and the "markets work" cohort is more supportive of "energy only" markets. The European Commission remains broadly against capacity mechanisms, but the global trend of over 20 years has been to instigate them and then develop them to capture some of the advantages of energy only markets. Within the thermal paradigm, energy only and capacity markets can achieve similar outcomes. With increased proportions of Variable Renewable Energy, the division between capacity and energy markets becomes sharper. Energy only markets can develop the price signals necessary to stimulate storage and demand side management, but this comes with high price volatility, and social and political challenges. Capacity mechanisms can develop better to include storage and demand side participation, but this comes with fairly substantial market redesign needs. The starting point in Great Britain is that we have a capacity mechanism, which was installed as a result of the Electricity Market Reform, in large part as a complement to the CfD.

The CapMech in GB broadly corresponds to the thermal power system designs of around the year 2000. Hence there is now considerable global experience of developing them. Key developments are; i) introduction of strike prices, ii) improved allocation to demand, especially to peak demand, iii) demand side participation, iv) import and export across interconnectors, v) derating, deficiency and secondary markets, vi) locational factors, vii) credit arrangements, viii) treatment of round turn storage, ix) scarcity price uplifts.

In the purest sense, the CapMech in GB had a single purpose – a national planning tool to manage total generation capacity to contend with very infrequent very high net demand, without resorting to the energy only solution of relying on high prices to incentivise increase in flexible generation and decrease in flexible peak demand.

The security standard most relevant to consumers is the Expected Energy Unserved (EEU). In GB this runs at about 0.00006%. Other measures include Loss of Load Expectation (LOLE) in terms of hours per year in which some load is lost somewhere on the transmission system. In Europe a common LOLE standard is 3 hours per year (0.034% of the time) and in states in the USA it is commonly one event per 10 years (0.034% of the time if the event were 30 hours). 0.00006% EEU and 0.03% LOLE are equivalent if the percentage loss on outage is 0.2%. It is worth noting that in Great Britain, to the best of our knowledge, there have been no realised adequacy events (where there is less generation capacity and fuel than demand) for about 70 years[4]. In the old paradigm (fossil thermal generation and variable demand with limited electrification), the LOLE and EEU calculations could at least be attempted. In the new paradigm they are essentially impossible, especially at the 99.99994% confidence level. Even if the CapMech did initially serve as a measure of total capacity to contend with net demand peaks, it no longer does so because the theoretical demand peak with electrified heat and transport is becoming far higher, and renewable generation is likely to contribute capacity even in the times of highest net demand.

A key (and intentional) effect of the CapMech, relative to an energy only market, is to reduce the price excursions above variable costs (necessary to recover fixed costs) by rewarding generators with capacity premiums and charging consumers for them.

From the "markets work" viewpoint, the best thing is to phase out the capacity mechanism with the first stage being introduction of strike prices, and ultimately the strike/premium capacity contracts become strike/premium option contracts tradeable in the wholesale market. This enables wholesale price formation that is essential for flexibility response. The "markets don't work" viewpoint shares the same first stage because it places demand flexibility in particular on the same footing and is no longer foreclosed. Therefore, adding strike prices is a common path for both extremes of viewpoint.

[4] Key drivers at transmission level have been; i) industrial action, resulting in actual outages in 1973-4, ii) Getting to work (petrol/diesel shortage, weather, pandemic, etc.), with no outages, iii) major gas infrastructure failure, with no outages, iv) coal production (post war to early 1950's) with outages, v)

Firmness

CapMech contracts are more firm than CfD contracts but nevertheless not fully firm as non-delivery is not cashed out at prevailing market prices.

The firmness methods are essentially the same as CfD, for example dynamic de-rating, deficiency, profiling, secondary markets. A key difference is that there is no green premium in the CapMech. There is a strong case to allow eligible generation that is flexible and has high variable costs to participate in the CapMech instead of the CfD (or as well as if the CapMech has no strike) and receive the same green premium.

There is an international dimension that is particularly sharp in the CapMech. In reality we expect international repudiation of import/export contracts at times of crisis. This adds considerable uncertainty. CapMech can address this via a deficiency mechanism. So, if a country "recalls" committed export by banning it then it simply pays the normal deficiency charge. This has the effect of normalising the situation (since it is much harder to repudiate the deficiency financial contract than the physical export). Indeed, it is rational on both sides of the interconnector for deficiency to be exercised "ruthlessly", i.e. without recourse to emergency provisions. Deficiency declaration in turn creates the response signal in Great Britain since the deficiency volume is signalled to the market which then responds.

Strike prices and reliability options

Introduction of strike prices to capacity mechanisms is a fairly standard procedure and can be done incrementally.

Since this greatly improves the efficiency of the mechanism, the auction is more complex because as well as having two bid parameters, cost is optimised whilst achieving target volume. We rely on bidders altering their strike/premium ratios in each round. The auction method is summarised in the figure below. In the descending clock, the auction strike/premium line starts very high, so that all capacity is captured. The line is then progressively lowered in a manner that achieves optimum cost expectation as well as target volume. The expected movement of unit bids is shown schematically. All accepted bids end up on the line. Note that with the resultant strike/premium line can be inferred the expectation distribution of wholesale market prices.

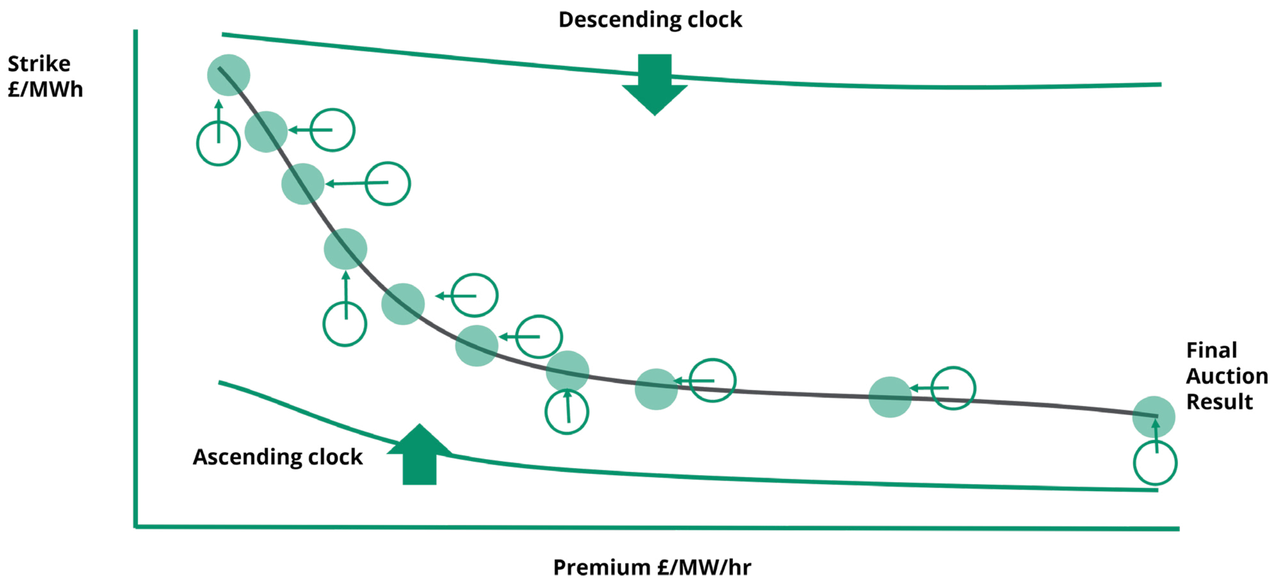


Figure 9: Descending clock "reliability option" capacity mechanism

It is actually beneficial to do the ascending and descending clocks in the same auction rounds. The descending clock reveals the entire universe of possibilities. The ascending clock gives an impression of what can be done at least cost and more compromise to service. The clock vectors converge in each round. Note that generators and other market actors commonly have a degree of discretion in their fixed/variable cost ratios and therefore their strike/premium ratios.

"type fault" for generation fleets, with no outages, vi) storms (some planned grid supply point disconnection 1987 to protect the system but no loss of continuity)

Variants of reliability options

There are numerous variants around a single theme of having a strike price. The below are indications of options available.

At one extreme, the strike price takes the form of a one-way CfD. This is actually the most efficient mechanism, with plant owners incentivised to set their strike at marginal costs, but relies on the Single Buyer mechanism. If the market price is above the strike, then the plant pays the capacity market operator the difference between strike and Market Reference Price. In the fullest extreme, this applies halfhourly for every halfhour in the year (a family of "caplets") or has a limit on the number of exercises (various forms of "flexicaps"). This can only work (and does work in other countries) if any forward volume sold by the plant has an embedded call option, so that the plant does not have to deliver twice (once for the CapMech and once for the forward contract). The capacitor market operator would normally return the call option value to the suppliers, so their long and short call positions match. The system in the island of Ireland is similar to this (with a single strike price).

A softer entry to this mechanism in Great Britain is to introduce gradually. So, at the beginning, all plant receiving CapMech premium may not sell their electricity at higher prices than the strike. The strike can then be lowered. It can then be graded so that plants receiving higher premium must offer at lower strikes. Whilst evasion is relatively easy, by selling flat rate contracts over longer periods, evasion is also fairly easy to detect and constrain.

In the ideal case, there is a full range of strike prices from zero to the Value of Lost Load. The effect of this is to reduce the price (and volume) instability of regime switching when there are gaps in market offer vectors.

If the reliability option framework is developed, then storage can be harnessed much more effectively because the path dependence of charging and discharging is more readily handled by using the disciplines of traded options.

Gas price indexation for reliability options

This is easiest to explain with reliability options in their more advanced form. Each plant receives a commitment fee premium and a call off strike if called. If the premium equals fixed costs and the strike equals variable costs then the plant is indifferent to prices and running. This is in effect a tolling option.

The issue with gas is that the consumer ideal for reliability options is for the strike to be fixed, whilst for the plant it is ideal for it to be indexed to the two volatile costs of gas prices and emission allowances.

If the strike is fixed, then the gas plant must manage its risk by hedging. The risk increases cost of capital and the risk management has a high cost overhead. If the strike is indexed then the gas price volatility is returned to the market to manage. If the market has flexibility (e.g., demand side and round turn storage) then this is the most efficient solution. If round turn storage is the only form of flexibility, then it is most efficient for this flexibility to be harnessed with a bespoke capacity mechanism, and this has the effect of reducing price volatility. However, if we have demand side management (as we require and expect), then use of the capacity mechanism instead of the wholesale price forecloses the market for demand side response. Since harnessing demand side management has been very elusive for at least 50 years, a hybrid solution is indicated for the interim. This would be i) indexing the reliability option strike for gas plant, ii) including round turn storage in the capacity mechanism.

This explanation was made for the most mature reliability option market, which does not yet exist anywhere. Simpler versions abound. For example, a single strike price for all plant. The same question still applies, i.e., whether to index the strike. The arguments are broadly the same as for the mature reliability option.

There is an argument, where the strike is indexed for the gas plant, for the market operator to conduct a "delta" gas hedge, the payoff which flows back to consumers via suppliers, in much the same way as the CfD fixed strike hedge flows to consumers. There are two advantages of this; i) the System Operator has the best view of the likelihood of the gas plants running (which is approximately the same as the delta) and ii) this action reduces electricity consumer exposure to gas prices. There are significant legal and vires challenges to the market operator doing this.

All in all, since abated gas fired generation is naturally inflexible for commercial and technical reasons, and we may not rely on unabated gas in sufficient volume to balance the nation, adding the system hedge management complications of hedging gas does not seem appropriate, and therefore the contracts should be fixed strike and not gas indexed. This is less efficient but reduces consumer exposure to gas prices.

Scarcity uplifts

With scarcity uplifts, an uplift is applied to a reference price when the market is within designated regimes of scarcity. Under the scarcity regime, generators get more (i.e., above the strike price or the market price) and this is paid by consumers. It is most efficient for the extra payment to be charged to consumers in the same period that it is paid, but it is possible (and would be considered normal) to smear the cost over a longer period.

Scarcity uplifts are common in capacity mechanisms. They are also common in pool type models (of which British Electricity Transmission and Trading Arrangements (BETTA) is one, due to the role of the balancing mechanism). In pure pool models this is straightforward and was done in England and Wales in the form of a capacity uplift to the system marginal price. It is more complex in BETTA but can nevertheless be achieved, for example by an uplift to the Balancing Services Use of System (BSUoS) charge.
Scarcity uplifts in part correct for deficiencies that capacity mechanisms have in replicating the signals that exist in "energy only" markets. In the extreme, the CapMech converges to the energy only market, which is more efficient (but more exposed to excess rent or expropriation from private sector and the state respectively). In the extreme, the scarcity uplift converges the CapMech to an energy only market on the generator side, and if applied cost reflectively to consumption, then also converges the CapMech to an energy only market on the consumer side, i.e., making a whole energy only market.

Scarcity uplifts therefore need careful consideration. In general, the question is what is the problem that the uplift is solving and is there a better solution?

Demand side participation

In the long term, demand side participation is not ideal in the CapMech. This is for two main reasons; i) unlike generators who sell fixed volume, consumers generally have a volume option in their supply contracts ("full requirements", minimum and maximum, "take or pay", "swing" etc.), so there is no clear reference point for the capacity contract, ii) direct consumer participation strains the Supplier Hub model. As things stand, demand side management gets paid up to three times (CapMech, reduced obligation on metered consumption, time of use tariff), albeit all three at attenuated rates since CapMech forecloses the energy only market. The arguments are similar for consumer reserve such as turn down rewards by National Grid. Participation in the energy only market via time of use tariffs is the most efficient. In turn this requires a transparent halfhourly price vector out to 72 hours so that optimal consumer equipment response can be automated.

CapMech cost flow through to consumers

Note that there is a range of choice for how price variation flow through to consumers. If the capacity premium is levied on total energy consumed, then the price variation is low (and demand side management is foreclosed). If the capacity premium levied to consumers is weighted to historically high price periods (winter, evening, weekday) then the price variation is higher (and time of use tariffs can stimulate periodicity in metered import). The price volatility may be lower due to more effective response to the peaks. Currently the capacity premium has a medium weighting to historically high price periods (November to February 4-7pm, working days, i.e. about 3% of the time) and is ultimately reconciled to actual consumption.

Participation of CfD plant in CapMech

Note that as the CapMech currently stands, it is not incompatible for CfD plant to sell also into the CapMech. There is no logical problem from double delivery. However, this is due to a shortcoming in the CapMech. If strike price is introduced to the CapMech, then a CfD generator may have a double delivery problem when prices are high, since the CapMech and the CfD will both effectively require the same power.

The optimal solution seems to be this:

i) Limited flexibility VRE plant sell firm CfD and nothing in the CapMech. Flexibility is then merchant in the "energy only" market. Ideally gaining extra green premium for merchant sales and surrendering green premium for shortfalls.

ii) Renewable plant that is flexible and has high variable costs, sell into the CapMech and not the CfD with the strike prices set at variable costs, and receive the green premium prevailing in the CfD, adjusted for the technology. An example might be biofuel with no CCS

iii) Renewable plant that is highly flexible with low variable costs, sell firm CfD with a price and volume profile, and re-trade actively. Ideally gaining extra green premium for merchant sales and surrendering green premium for shortfalls.

For a developed CapMech, whilst it is optimal to give the renewable plant the option to sell in either CfD or CapMech, and have a green premium mechanism in the CapMech, this is quite a lot of change for what may be a relatively small plant cohort. A very close second best is for the plant to sell a price and volume profiled firm CfD, with gain and surrender of green premium based on actual metered generation. This is an energy only, rather than a capacity solution, for this type of plant which does increase its cost of capital.

CapMech auctions

The CapMech already has a two round structure. There is a T-4 auction four years ahead and a T-1 auction for the same delivery period, one year ahead.

The system has worked well. Nevertheless, it has not been without challenge because the decisions are focussed on the one and four year horizons, which are not ideal for all actors. Demand response in particular has been a challenge (and indeed was the subject of legal challenge), since a four year horizon and a longer commitment period fall far beyond the standard tenor for supplier-consumer relationships. Whilst to some extent this can be dealt with via aggregators with longer term relationships with consumers, this still remains generally beyond the consumer decision horizon. At the same time, a one year horizon, to gain the CapMech contract and then mobilise the demand response is a challenging timeline.

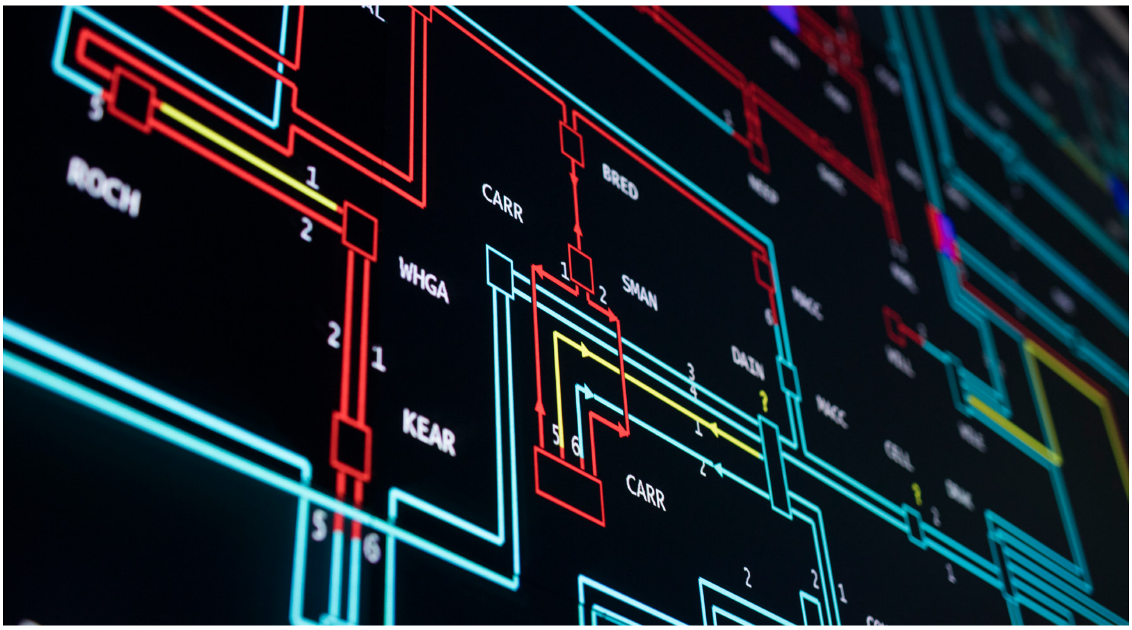
Hence, as with CfD, consideration of annual auctions with a wide choice of delivery window (e.g., five years delivery starting in two years time) seems to have merit.

Managing CapMech and CfD together

If plant is allowed to bid into CapMech and CfD then this raises the question of how the auction works. It is worth considering that the most efficient option may be to have them run together, with synchronised repeated "clock" rounds, so that plant can bid into either or both (subject to a single acceptance if CapMech has a strike price), and adjust the bid volumes and prices. Otherwise, the plant has to "leg" into the contracts one at a time, which entails high risk.

Whilst coordinated auction rounds are complex, they are not impossible. Multi-product auctions are developing in other markets, and computational techniques developing. Indeed, the tâtonnement in the auction concentrates the market liquidity that would otherwise be diluted by the tâtonnement in the market without the auction.

At this point in time, whilst it does make sense generally to align the timings of CfD and CapMech auctions, since few or no plant will consider the choice between the two instruments, then running the auctions together may be overly complex. The exception is if the CapMech does not change and the plant could (and should) be able to bid into both auctions with no risk of double committing the same volume.



5 | Creating an attractive market for investment and importance of addressing other more physical barriers to deployment

Maintaining and developing investability by reducing cost of capital is critical. The two key elements are minimisation of uncertainty, and manageable transition arrangements.

Why an attractive investment climate is needed

Prior to the current crisis, low risk investments such as pension funds had a very challenging environment, as long term government bond yields went negative even in nominal terms. The search for yield was in investments with inherent protections such as state backed contracts. UK networks could secure debt at very low rates and the UK CfD was a particularly attractive environment. The UK remains attractive in this area but the investment environment has changed and international competition for capital has now increased. Therefore, creating an environment with low cost of capital is vital in ensuring investment.

Maintaining investor confidence through a market transition

Key elements for investors are:

i) No retrospective changes, for example transition a new regime that impairs the business plan executed under the previous regime

ii) Reduction of uncertainty, especially in political decisions

iii) Ability to evaluate risk, for example the commercial impact of weather driven variation of output that is well understood

iv) Clear time windows for long term policy decisions

v) Clear time windows for short term operations (auction dates etc.)

vi) Minimal asymmetry (information, incentive, etc.)

Design principles to minimise cost of capital

The core principles for minimisation of cost of capital are:

i) Place risks where they can most effectively be mitigated

ii) Place risks where the cost of risk is lowest and diversification highest

iii) Reduce uncertainty (as distinct to risk)

iv) Minimise asymmetries (information, incentives, etc.)

Apart from political risk, we can express VRE project risk in the confluence of three risks; market (e.g., power prices), technical (e.g. grid capacity constraints, equipment failures and project over-runs) and environmental (variable renewable energy resource inflow). The confluence of these three differs significantly to that for thermal plant. For example, we expect high correlation between market and environmental risks, as high VRE inflow drives down market prices. Technical risk is largely subsumed in environmental risk as a second factor that causes output variation.

Figure 10 is intended to illustrate the tension between the first two core principles. At first sight this does seem to indicate three things; i) enable transfer of long term market risk, which in the absence of long term wholesale liquidity means continue with CfD, ii) move technical risk to the generating company, iii) environmental risk is more complex but is probably continue to place long term risk with state intermediated, whilst treating short term VRE inflow risk with technical risk and move it to the generator by making CfD contracts firm.

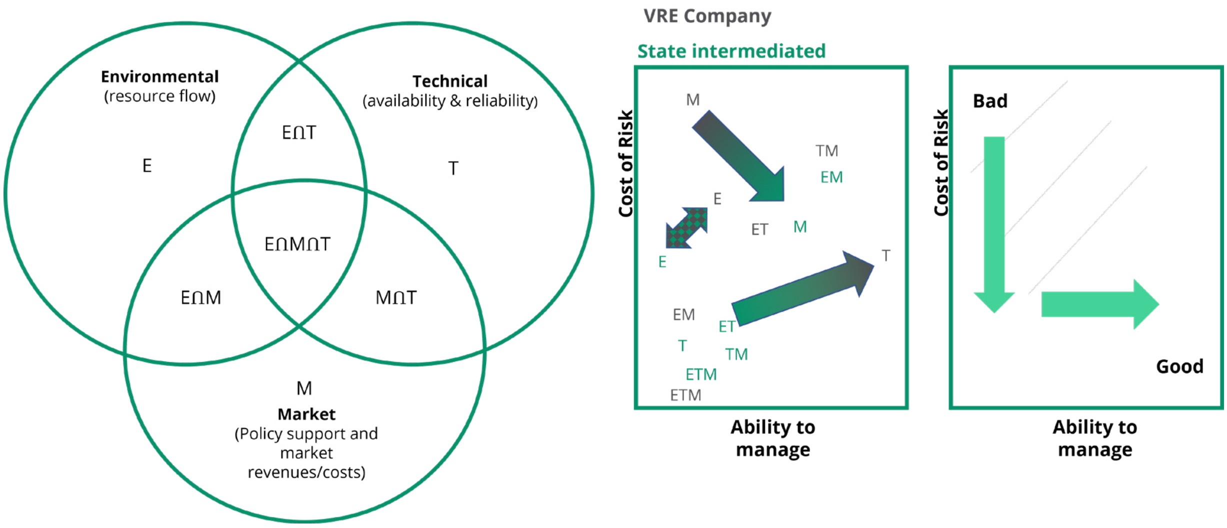


Figure 10: Representation of the three core risks and first indication of best placement

CfD up to now has attended well to the four principles above. In particular, market and environmental risk were transferred from generators to consumers via the state and the market. However, as the percentage of VRE rises and the percentage of capacity that is thermal falls, the tension between the first two principles increases. The ability of the thermal system to mitigate risk is falling and the cost of risk of consumers and the state rises as the prospects of dunkelflaute have greater impact. These have the effect of depressing the CfD price, thereby risking return on capital below the hurdle rate.

The answer is to maintain the return on capital whilst placing more risk with the project. This can be done by rewarding both firmness and flexibility in the CfD.

Other changes that complement REMA

The Smart Systems and Flexibility Plan addresses much of the support environment that complements REMA for a zero carbon electricity system.

Further changes are required that fall outside the SSFP. Perhaps the biggest three are; i) targeting support to vulnerable consumers, ii) resolving the visual amenity objections of energy infrastructure[5], iii) macroeconomic decisions on borrowing and infrastructure spend.

Network capacity

The global community of electricity participants has wrestled with the challenge of network planning and charging for 130 years and is far from solving it. The changed paradigm that switches variability and flexibility between generation and demand adds further complications.

REMA can neither solve the network capacity puzzle nor perfectly respond to network capacity decisions. Indeed, the puzzle goes far beyond tech, since society has the option massively to reduce network build and reinforcement need, by energy management.

[5] See The Economist. 5th April 2023

REMA can neither solve the network capacity puzzle nor perfectly respond to network capacity decisions. Indeed, the puzzle goes far beyond tech, since society has the option massively to reduce network build and reinforcement need, by energy management.

All we can really do is consider some principles and consider how these may indicate REMA orientations:

i) The physical network must correspond to at least one carbon compliant (i.e., CCC 6th carbon budget) scenario

ii) REMA must be robust with respect to the actual physical scenario changing from what had been considered most likely. i.e., the "cost of being wrong" must not be high. The CapMech already has a mechanism for optimising capacity from the perspective of "least worst" according to scenario outcome

iii) If the physical network is not adequate for a carbon compliant scenario, then an energy policy decision must be made, and then reflected in REMA

iv) Notwithstanding the caution in this paper on radical changes in locational pricing in REMA, locational signals are essential at all scales from residential to international, and in addition these signals need to have temporal elements (i.e., space-time pricing)

v) The norm of 0.00006% Expected Energy Unserved in transmission needs serious consideration. This in turn leads to consideration of rationing solutions (voltage reduction, device related cessation, industry turn down agreements) instead of Grid Supply Point disconnection. This in turn leads to design considerations in reserve, ancillary services, grid and disconnection codes, product standards, live smart meter data access and use, connection, and use of system charging, CapMech and CfD developments, 72 hour ahead wholesale markets and price caps.

vi) Specific weather scenarios (e.g., dunkelflaute, anticyclone, multi-year hydro drought) need scenario modelling to consider how REMA is resilient to them

vii) REMA design should consider (as did the DECC energy pathways) a handful of uncertainties in major assumptions and how resilient it is to these. Examples are CCS/CCUS, interconnector import (of zero carbon electricity with Guarantees of Origin), installed capacity of large fission nuclear, pipes for molecules and space heating by hydrogen

Planning and consent

Consent is a very great challenge faced by the electricity sector, and probably the greatest challenge overall. Examples are visual amenity of networks and renewable generators, smart meters, data sharing for social purposes, thermal standards for premises, time of use tariffs.

The transmission Future Energy Scenarios and the Distribution Future Energy Scenarios contain assumptions both on what may be consented (e.g., overhead lines) and which will not receive consent (e.g. data sharing, cost reflective tariffs for energy and use of system).

Much network reinforcement could be avoided if there were more flex in the system and hence build-or-flex is a frequent question. Broadly speaking, such are the challenges in consent to consume differently, the general assumption is "build". To build needs consent.

Consent is always part of a project plan and consent for visible infrastructure has commonly taken years in both transmission and generation. Now there is no time for long consent processes, as we aim to achieve a net zero power system by 2035. Furthermore, long consent has a very high impact on the cost of capital, and competition for capital is now fierce.

Over and above consenting, the challenge in coordinating transmission and generation build, when generation build is based on auctions rather than central planning, is a longstanding one. There has been no easy answer and there will not be one. Nevertheless, on a project by project basis, the planning and consent issue needs solving. The solution is too large and complex to fall within REMA, but it must be recognised in REMA, and in addition, REMA may be affected by it. For example, it may be best for overall national planning, for the cost of market access for a project to be mainly in connection, or use of system, or in locational pricing.

6 | Things that we believe should now be rejected

Below we highlight why we believe other, more revolutionary, options currently being considered within the REMA workstream are unlikely to work and could lead to delays in delivery of the energy transition.

Rejected options - Green Power Pool

There seems then to be no case for a Green Power Pool. A green paddling pool for smaller renewable schemes that spill power may have merit, and may also support community energy projects, but there is no reason to integrate this vertically with a consumer cohort.

In a Green Power Pool (GPP) scenario, a System Operator (SO) would run a renewable power pool alongside the existing market. There are various options such as; i) retain the CfD and give generators the choice, ii) retain the CfD but make generators eligible for only one mechanism, iii) structural options for the GPP, such as firm CfD, non-firm CfD, capacity contract or Regulatory Asset Base contract, iv) merge with the wholesale market in the balancing mechanism or maintain a separation on the consumption side as well as the generation side. Under the main proposal, the proposed Green Power Pool has a consuming cohort that is variable and inflexible and a producing cohort that "spills" power to this.

We believe it has several issues that would make it difficult to implement:

i) It increases reliance on marginal pricing (the second tier of the two tier price) and yet has a limited marginal price signal unless it connects with the main market and is therefore not separate

ii) There is no "private good" benefit of Renewable Electricity Guarantees of Origin, beyond a virtual signal that is in this case unjustified. The allocation of REGOs with no additionality on the part of the receiving cohort does not match the power generation. Inflexible peaky demand requires flexible peaky generation that has high carbon intensity.

iii) The eligible community in the protected segment of consumers is broadly drawn (e.g., vulnerable industries, companies who have bought REGO's), and even if the cohort could be agreed, actually separating it, sorting out distributional anomalies and managing transition between eligible and ineligible would likely prove insurmountable, especially given the current poor status of consumer targeting and the existing patchwork of industry protections

iv) The Green Power Pool and the eligible cohort with no flexibility incentive, collectively (and inefficiently) externalises a large flexibility challenge to the rest of the market

v) The system is complex and has a challenging transition

Given the above we do not think a full-scale green power pool to be appropriate or would deliver the overall objectives of REMA. However, we believe it could still be worth considering a smaller green power pool, dubbed a 'green paddling pool', to operate alongside a reformed Contracts for Difference (which is explored elsewhere in the report). This could provide a route to market for sub 5MW generation projects, which are currently not supported by the CfD, allowing for an easy and more price reflective contracting route for suppliers. We note that this may also prove beneficial for community-based projects.

However, as described, this would need to be considered alongside wider REMA reforms that could better address flexibility and low carbon generation objectives.

Rejected options - Split Market

The markets should be harmonised and not split

This report advocates harmonisation, especially across the five key markets. Splitting is the opposite of harmonisation and should only be done where there are compelling reasons.

In the presence of infinite capacity in the wires, it is perfectly possible to split the market in two. For example, a Green Power Pool serving a specific consumer cohort. In practice, as described above there is a significant imbalance between variability and flexibility and the solution is highly inefficient even with an infinite wirescape.

With wires properly sized, then the split market adds artificial constraints, which thereby incurs unnecessary reinforcement costs, unnecessary flexibility costs and/or load curtailment.

Rejected options – Decoupling power and gas

The solutions to exposure of marginal gas prices are to reduce physical and contractual exposure to physical gas at the margin, not in changing gas or electricity market arrangements.

International gas has rightly received a lot of attention. Growing demand, especially in Asia, has driven up wholesale prices, sustained Russian export revenues and caused exceptionally high consumer gas bills. The European demand trend[6] has shown that sustained effort is needed to deliver significant reduction both to deliver energy security and a decarbonised energy system.

However, the debate on decoupling power prices from gas prices, despite its prominence in REMA, does not acknowledge that the market merely exposes structural issues rather than causing them. The longstanding dependence on gas, including Russian gas, has been a subject of debate for the last 20 years, with the European Commission making continuous efforts to reduce it.

The UK was in aggregate inadequately hedged in gas, and the reduction of gas demand in response to price was limited, and arguably seriously inadequate[7]. This meant that in order to consume gas for domestic heating, we had to go to the international market to buy gas at whatever the price was, i.e., the marginal price. Either that or reduce gas for heating.

The problems were, in approximate order of importance:

i) Inadequate ability to moderate gas demand, largely due to the poor thermal status of the UK building stock

ii) Inadequate aggregate supplier hedge (for example Bulb)

iii) Inadequate ability to shift the time of use of electricity demand (in part due to the longstanding regulatory suppression of price signals by cost socialisation)

iv) The government decision (which may have been right or wrong) not to invest in "just in case" access to gas, such as stored in caverns

v) The structure[8] of the Energy Price Guarantee, which depressed the marginal price of energy consumption, (relative to that of support by tariff tiers targeted to benefit low consumers, with bespoke support for specific consumer cohorts) thereby reducing consumer opportunity to make consumption decisions

vi) The structure of the Contract for Difference and the associated absence of signal for flexibility

vii) Inadequate developments in the Capacity Mechanism, leaving it short of flexibility signals

[6] 4.3% 2020 to 2021. Source Eurostat. 8% Q3 2021 to Q3 2022. Source European Commission. 17.7% reduction winter 2022/23 vs 5 year average (source Reuters)

[7] This is explained further in Harris 2021

[8] Discussed in a separate paper

High gas marginal prices exposed these problems and created the opportunity to alleviate them. They did not cause the affordability problem.

In the current "central station" thermal paradigm, gas fired generation backs up Variable Renewable Energy. Put simply, if we have not bought gas and then find that we need it, then we have either to pay the person who has it, at the price they are prepared to sell at, or go without it. A normative view on what a gas exporting country or international gas trader "should" charge for gas below what it can attain in the market is of little practical use. The market price is simply determined by what the sellers will offer at and what other buyers will pay.

The answer, therefore, is to reduce exposure to physical gas. This will naturally reduce the exposure to gas prices. To achieve this, rather than trying to affect the marginal price, REMA should look to reforming existing market mechanism. In particular, this includes:

i) Reforming the CfD to enhance market signals. This would have the effect of reducing dependence on gas to balance the system. This reduces the consumer problem, albeit providing the VRE sector a challenge as well as opportunity.

ii) Good volume forecasts from the ESO would reduce exposure to short term gas prices by harnessing timely (and less expensive) flexibility responses with more notice.

iii) Reforming the capacity mechanism to the more modern "reliability option" form with strike prices could reduce price volatility and exposure to short term gas price fluctuations. This does not, however, necessarily reduce average prices, because the capacity cost causes an uplift to average price.

iv) Harnessing flexibility (principally storage and demand side management) is essential. If we do not then, as the amount of Variable Renewable Energy increases, and the amount of gas fired generation (MWh volume but not GW capacity if we need the backup) necessarily decreases, we must expect the power price exposure to gas fired generation to increase. This is because the fixed costs of the gas fired stations must be recovered over a smaller amount of running hours and a plant with low running hours or an unpredictable schedule must buy gas in the volatile near-term wholesale market.

Nevertheless, we do also recognise it is also helpful for REMA to address wider social issues of exposure to gas prices whilst we remain dependent on gas. Some actors, such as vulnerable consumers, were exposed to the marginal prices but had little ability to mitigate this exposure. The problem here was not a market problem. It was the very high inefficiency of subsidy targeting.

Rejected options – Moving away from marginal pricing

Marginal pricing is how markets work and is the mechanism by which they deliver the most efficient solutions. Marginal costing is also how administered systems work most efficiently.

Where a market price is very high or very low indicates either some degree of control by a market actor (or actors) or a physical imbalance in the system. The actions of market actors outside the legal jurisdiction of Great Britain are a reality to be contended with, as distinct to a normative issue to wish away. It is the market price signal that allows the escape from imbalance in the form of physical cessation. So, in the recent exacerbation of the gas crisis by the invasion of Ukraine, Great Britain had the choice to pay the international price or reduce gas consumption. The presence of the gas price in Great Britain, set at the margin, enabled the least cost reduction of gas demand. Market prices provide the ability to hedge, and if energy is not hedged then it is naturally subject to the vagaries of the market. Poor hedging strategies added to the energy crisis.

It is worth noting that consumers have the choice between benefitting from volatile marginal prices or being protected from them. We can see in Figure 11 how consumer response at the margin can respond to Variable Renewable Energy and form prices.

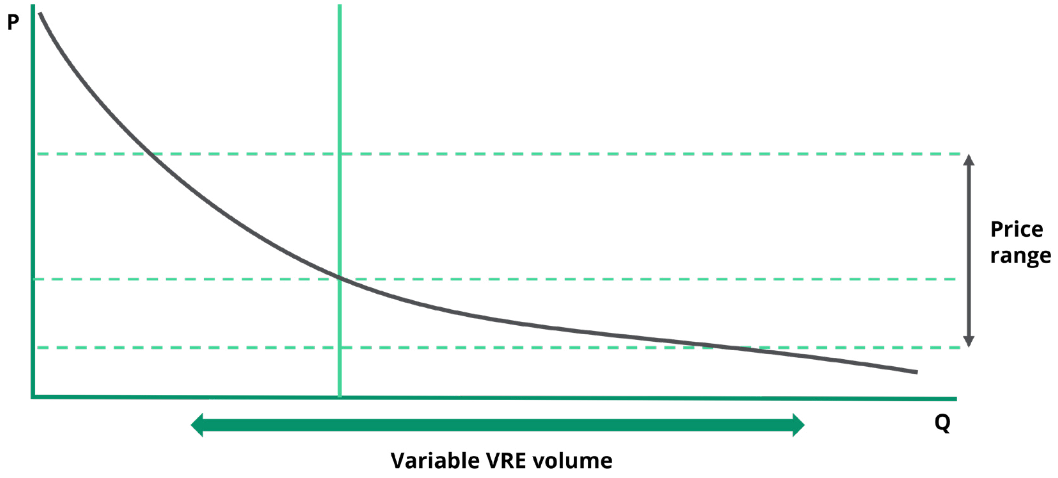


Figure 11: Price range for VRE and demand response

As the traditional thermal merit order "stack" thins in the middle region, and much renewable energy and high load factor generation such as nuclear is in the low variable cost region, we have a potential problem with price formation. Fortunately, with wholesale market maturity maintained, dedicated round-turn storage and flexible demand can enable price formation as well as reducing the incidence of very high and very low prices.

Rejected options - Location Marginal Pricing at this stage

Getting locational markets right is a very important but very difficult challenge. At this stage, a narrowing of options is needed. A "big bang" change to models based on thermal centrally dispatched nodal systems would not be proportionate or fit for the future.

Since markets work best at the margin, then considering (short run) marginal pricing in networks has clear merit. Furthermore, LMP provides a stronger signal for the location of production, demand, and network reinforcement than the other locational models.

However, in making significant changes to the locational regime, we face significant challenges:

i) Temporal variation in prices is the priority, and simultaneously to develop space and time both together is a formidable challenge with high implementation risk

ii) The change from the 1990 Pool to 2001 NETA was relatively slight in process but strong in culture. It took forward a system ready for consumer participation. Reverting to central dispatch would take us back to the 1990 model, itself based on a model that was broadly in place in the USA in 1927.

iii) Whilst Locational Marginal Pricing is tried and tested in transmission, it is in practice based on the central station thermal paradigm and might not work when storage and demand response are the new sources of flexibility, and Variable Renewable Energy generators

iv) Locational models across country borders must be compatible. Where the degree of interconnection is high, it is much harder to implement a nodal model in one country that is compatible with zonal models prevailing in the region. The international coupling methods developing in Europe are based on zonal models within each country

v) There are many solutions for locational pricing in transmission. Different models are inherently more or less suitable in different countries, according to prevailing locational model, natural resources, nature of demand, and political and social model. Unilateral change of locational model in one country changes the interconnector price differential (or inherent price differential in the interconnector fixed cost recovery regime)

vi) Marginal models such as Locational Marginal Pricing are economically efficient in the short term and provide very good signals. However, even when transmission reinforcement needs can be associated with particular locations of production and demand, the inherent "public goods" nature of networks means that when a constraint between generator A and demand B is resolved by transmission reinforcement, the cost of the line A-B is socialised, and the A-B nodal price differential disappears.

vii) Constraints are in practice not limited to thermal constraints on individual lines. Other factors such as redundancy, fault currents, locational reserve, and reactive power also have constraint effects. Line flow can to some extent be directed by transmission system operators. Processing run times for calculating flow in large systems is long. Although computational power increases all the time, linear programme algorithms have developed considerably, and much experience has been gained on trial solutions that shorten the run time, the new systems are so very different to the central station thermal ones that we cannot be confident that we will get rapid stable algorithm solutions that arrive at the global rather than local optimum

viii) Constraints in distribution systems are increasingly important. Developments in transmission location models should not impede developments in distribution location models

ix) With Location Marginal Pricing, nodal pricing can be in the reverse direction to power flow, so power can flow from high to low price nodes. This is caused by central dispatch but is against the general principle of markets, would cause market actors to adjust their bids and offers away from marginal costs and creates some problems with negative congestion rent

x) With Location Marginal Pricing, nodes can have negative prices, so demand has negative cost. Whilst this is a real short term economic efficiency effect, it is not ideal to stimulate wasteful demand

xi) It is very difficult (and probably impossible) to trace "green electrons" associated with Renewable Electricity Guarantees of Origin, when redispatch is conducted to alleviate line constraints

xii) For the linear programme to take into account all system requirements (inertia, redundancy, reactive power flow, fault currents, etc. etc.) is fiendishly complicated. It can be done but in order to keep computer run times low does require considerable expertise in trial solutions, sensitivities, most biting constraints, etc. The black box system then arrives at a set of prices that is entirely opaque and which is not technology neutral

xiii) Whilst it is efficient, locational pricing always butts up against the arguments for fairness and "postcode lottery" of the essential good for electricity. The arguments for locational pricing are easier to explain for use of system differentials, than LMP which is a black box with difficult concepts

xiv) Managing liquidity is a challenge, as liquidity is not concentrated into a single price but multiple prices

xv) Managing market power is a challenge, particularly when a market actor at one location can cause constraint that provides it with a gain at another location

We do believe that locational pricing needs to be continued to be considered, with a general movement to being more locational.

The three main instruments are shown below.

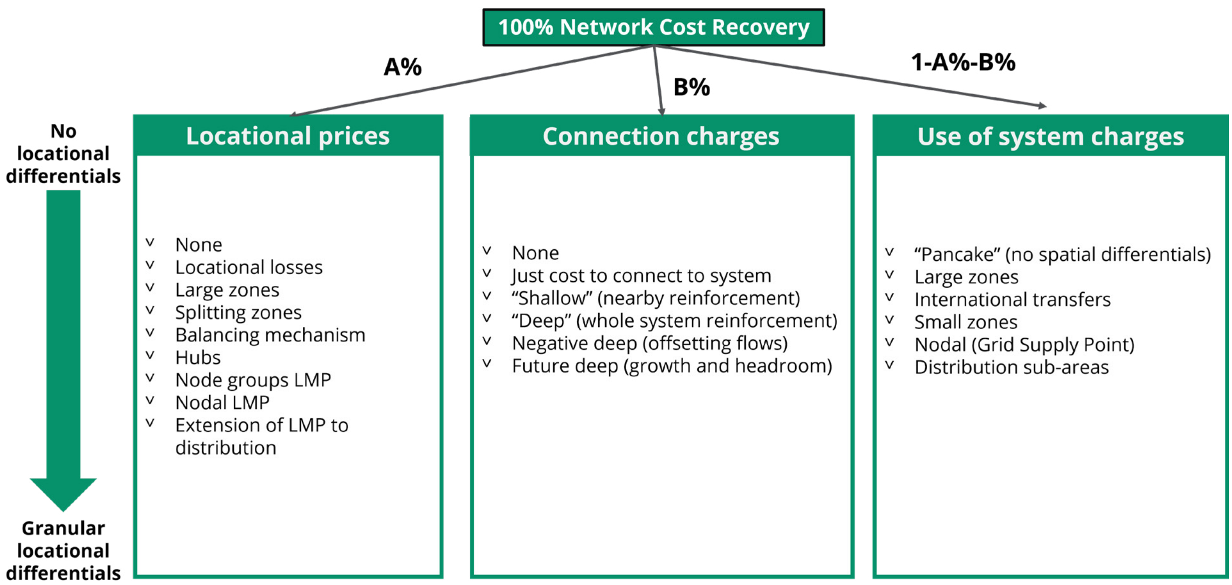


Figure 12: The three methods of covering the costs of the physical grid

Appendices

Appendix 1 - Glossary

ACER – Agency for the Cooperation of Energy Regulators

Apportionment – The application of linear or non linear volume profile between two points in time

Baseload – Running all day every day

Basis – The differential of a commodity to the main traded product. So if the price at the notional market hub is C and the price at a particular location is B, the C-B is the basis.

Bases – The plural of basis

BAU – Business As Usual

Behind the meter – On the consumer side of the meter at the connection point to the grid. The term can also apply to generators

BETTA – British Electricity Transmission and Trading Arrangements, in which Scotland harmonised with NETA

Call option – The right, but not the responsibility, to buy a fixed volume of commodity at a fixed price and (for "European" options) on a fixed date

CapMech, CM – Capacity Mechanism

CCC – Climate Change Committee

CCGT – Combined cycle gas turbine

CCS/CCUS – Carbon Capture and Storage. The U stands for "use" of the CO2

CERT – Carbon Emissions Reduction Target 2008-2012 – A supplier obligation that was effectively the requirement to deliver a certain amount of insulation in each compliance period

CESP – Community Energy Savings Plan – Community Energy Savings Programme 2009-12. Similar to CERT and included some generators

CfD – Contract for Difference

Clean dark spread – The price of electricity minus the cost of coal and emissions allowance at prevailing prices and benchmark efficiency

Clean spark spread – The price of electricity minus the cost of gas and emissions allowance at prevailing prices and benchmark efficiency for Combined Cycle Gas Turbine

CMA – Competition and Markets Authority

Collar – A maximum and minimum range for a price or a revenue

Congestion rent – Where the prices differ in two locations, the differential goes to the system operator

Connect and Manage – A connection scheme in which plant gets a constraint payment if curtailed due to transmission constraint

Control for Low Carbon Levies – Measures and controls the cost of low carbon support. Replaced the Levy Control Framework.

Comfort factors – Uncertainty margins used mainly in engineering

COP – UNFCC Annual Conference of Parties

Corridor – A maximum and minimum range for a price or a revenue

CPI – Consumer Price index

cPPA – Corporate PPA

Dark electricity – Electricity with embedded carbon

Deadweight – Unlike win-lose, deadweight costs have no winners

Deemed contracts – A contract with part or all part of explicit agreement. In generation, the volume is deemed rather than measured

Degression – Reduction of feed in tariff rates over time

Dunkelflaute – Dark and low wind, hence low Variable Renewable Energy inflow

ECO – Energy Companies Obligation schemes – 2013 onwards. Essentially followed CERT

EEU – Expected Energy Unserved – the estimated loss of GWh lost in a year from transmission failure divided by total GWh served in transmission in that year.

EMI – CMA Energy Market Investigation 2014-16

EMR – Electricity Market Reform 2013

Energy only – Energy only markets have no capacity mechanisms. They rely on the price signal to engage flexible response

EPEX – European Power Exchange

ESO – Electricity System Operator

EV – Electric Vehicle

FACTS – Flexibility AC Transmission System methods and technology

FES – Future Energy Scenarios, produce by NG ESO

FiT – Feed In Tariff

Flexicap – A series of call options (caplets) in which the total number of allowed exercises is less than the number of caplets

Flowgate – Wheeling that is nominally along a specific transmission path

Foreclosure – Favouring of one contractual type over another, thereby forcing exit or no-entry of the second type

FSO – Future System Operator

Gearing – Borrowing money with bonds

GHG – Greenhouse gases

Grandfathering – The protection of existing terms for existing installations/actors, whilst scheme rules change

Green electrons – A metaphor for tracing green electricity from generation to demand

Grey electricity – Electricity with no source attribution

Grid edge – The service points of the distribution system and "behind the meter" at which some responsive electrical activities happen

Grid forming – Power electronics that support the grid electricity in terms of voltage, reactive power and more complex factors

Grid parity – Generation able to compete without subsidy (note that carbon allowances and taxes are not regarded as subsidies to non emitters)

GW, GWh – Gigawatts, Gigawatt hours. Giga=billion. 1GW for 1h equals 1GWh

Guarantee of Origin – as REGO but including foreign generation and non renewable (e.g. nuclear)

HP – Heat Pump

ICE – Intercontinental Exchange

Inertia – For mechanical power this is inertia of spinning mass. Power electronics can create virtual inertia, generally backed up by batteries

Inframarginal rent – The difference between the variable cost and the clearing price

IPCC – Intergovernmental Panel on Climate Change

Latency – The delay between real time and the receipt of information or response to signal

LCCC – The Low Carbon Contracts Company – Government owned company that transacts the CfD

LEBA – London Energy Brokers Association

Levelised costs – Total cost divided by total delivered volume, usually calculated on an annualised basis

LNG – Liquefied Natural Gas

LOLE – Loss of Load Expectation – In most common use this is the minutes per year at which some demand is curtailed because the transmission grid cannot provide the power, divided by 365*24*60

MAR – Market Abuse Regulation

Merchant – Operating in the wholesale market, outside of support mechanisms

MW, MWh – Megawatts, Megawatt hours. Mega=million. 1MW for 1h equals 1MWh

N2Ex – Day ahead auction prices in the UK conducted by the Nordpool exchange

NETA – New Electricity Trading Arrangements in England and Wales 2001

Net Demand – Usually demand minus Variable Renewable Electricity including on consumer site

NG ESO – National Grid ESO

NPF – Non Price Factor uplift to the CfD, currently under consultation

NZ – Net Zero – GHG emissions matched by GHG sequestration

Off grid edge – Participating in electricity but not currently connected. For example, electric vehicles

P2 Planning standard – The standards for reliability in distribution systems

Pool – Central dispatch of power stations based on a merit order of variable costs

PPA – Power Purchase Agreement – Long term supply contracts

Private good – A good that benefits only the purchaser

Public good – A good that benefits many or all people, not just the purchaser

Put option – As per call option but the right to sell rather than buy

PV – PhotoVoltaic

RAB – Regulatory Asset Base – Underpins a regulatory revenue control in which volume risk is taken by consumers

Real prices – Inflation adjusted. So, if something costs £100 today, inflation is 6% and the price next year is £110, the real price has risen by ~4% in money of 2023

REGO – Renewable Electricity Guarantee of Origin – "produced" by generators and can be sold separately to the power. Regarded across Europe as the single source of truth in terms of accounting for the total amount of renewable electricity supplied. REGOs are matched to supply contracts by matching REGO volume to supplied volume

REMIT – Regulation on Wholesale Energy Market Integrity and Transparency

Revenue stacking – More than one revenue stream

RO – Renewables Obligation

SCADA – Supervisory control and data acquisition - control system with sensors and actuators

Scopes 1, 2, 3 – Scope 1 is direct greenhouse emissions, scope 2 is mainly carbon embedded in electricity, scope 3 is other things such as embedded in materials. Governed by WRI GHG protocol

Spill – Power generation export to grid that is affected only by energy inflow to the generator

Stochastic – Random variation in a manner that can be characterised

Supplier Hub – The current market arrangement in which the consumer relationship is only with the supplier, apart from connections and grid outages

Synchronous – Thermal plant rotates at the grid frequency (or an integer fraction of it). This rotation is in step with the voltage and current at the grid

Tâtonnement – Repeated auction, gradually converging on a solution

Tenor – The time difference between the date of observation or contract agreement, and the delivery date

UNFCC – United Nations Framework on Climate Change

Vector – In this context it is an array of variables, such as a series of prices or volumes

VRE – Variable Renewable Energy, Variable Renewable Electricity

Walkaway – When a project is abandoned on financial grounds

Wheeling – A term used to denote the agreement to transport electricity from one place to another, generally in different grid control area

WRI – World Resources Institute

Appendices

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